

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY



October 14, 2022

DOE/NETL - 2023/4320

Disclaimer

This project was funded by the United States Department of Energy, National Energy Technology Laboratory, in part, through a site support contract. Neither the United States Government nor any agency thereof, nor any of their employees, nor the support contractor, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

All images in this report were created by NETL, unless otherwise noted.

Tommy Schmitt²: Methodology, Software, Formal Analysis, Writing – Original Draft, Writing – Review & Editing; **Sarah Leptinsky²**: Methodology, Software, Formal Analysis, Writing – Original Draft, Writing – Review & Editing; **Marc Turner²**: Software Validation, Writing – Review & Editing, Supervision; **Alexander Zoelle³**: Software Validation, Supervision; **Charles W. White²**: Software Validation, Writing – Review & Editing; **Sydney Hughes²**: Software Validation, Writing – Review & Editing; **Sally Homsy²**: Software Validation, Writing – Review & Editing; **Mark Woods²**: Writing – Review & Editing, Supervision; **Hannah Hoffman²**: Writing – Review & Editing; **Travis Shultz¹**: Conceptualization, Writing – Review & Editing; **Robert James^{1*}**: Writing – Review & Editing

¹National Energy Technology Laboratory (NETL)

²NETL support contractor

³Former NETL support contractor

*Corresponding contact: Robert.James@netl.doe.gov, 304.285.4309

Suggested Citation:

T. Schmitt, S. Leptinsky, M. Turner, A. Zoelle, M. Woods, T. Shultz, and R. James “Fossil Energy Baseline Revision 4a,” National Energy Technology Laboratory, Pittsburgh, October 14, 2022.

This page intentionally blank

TABLE OF CONTENTS

List of Exhibits	vii
Acronyms and Abbreviations	xviii
Executive Summary	1
Results Analysis.....	6
Sensitivities.....	20
Special Considerations on Reported Costs.....	23
CO ₂ Capture Rates Above 95 Percent	24
1 Introduction.....	28
1.1 CO ₂ Capture Rates Above 95 Percent.....	29
1.2 Generating Unit Configurations	30
2 General Evaluation Basis.....	33
2.1 Site Characteristics	33
2.2 Coal Characteristics.....	36
2.3 Natural Gas Characteristics.....	37
2.4 Environmental Targets.....	38
2.4.1 Air Emissions Targets.....	38
2.4.2 Water Emissions Targets.....	40
2.4.3 Study Cases.....	42
2.4.4 Carbon Dioxide	46
2.5 Capacity Factor	46
2.5.1 Capacity Factor Assumptions	46
2.5.2 Existing Plant Data	47
2.5.3 Capacity Factor for Coal Units without Carbon Capture.....	48
2.5.4 Capacity Factor for IGCC Plants	50
2.5.5 Capacity Factor for NGCC Plants.....	50
2.5.6 Capacity Factor for Plants with Carbon Capture	50
2.5.7 Perspective	50
2.6 Raw Water Withdrawal and Consumption	51
2.7 Cost Estimating Methodology	52
2.7.1 Capital Costs.....	54
2.7.2 Operation and Maintenance Costs	58
2.7.3 CO ₂ Transport and Storage	60
2.7.4 LCOE and Cost of CO ₂ Captured/Avoided.....	61
3 Integrated Gasification Combined Cycle Plants	63
3.1 IGCC Common Process Areas	63
3.1.1 Coal Receiving and Storage	64
3.1.2 Air Separation Unit Selection	64
3.1.3 Water Gas Shift Reactors	67
3.1.4 Mercury Removal	68
3.1.5 AGR Process Selection	70
3.1.6 CO ₂ Compression and Drying System.....	74

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

3.1.7	Sulfur Recovery/Tail Gas Cleanup Process Selection	76
3.1.8	Slag Handling.....	78
3.1.9	Power Island.....	79
3.1.10	Steam Generation Island	82
3.1.11	Accessory Electric Plant	86
3.1.12	Process Water Systems	86
3.1.13	Waste Treatment/Miscellaneous Systems.....	102
3.1.14	Instrumentation and Control	102
3.1.15	Performance Summary Metrics	103
3.2	Shell Global Solutions IGCC Cases.....	104
3.2.1	Gasifier Background.....	105
3.2.2	Key System Assumptions	106
3.2.3	Sparing Philosophy	107
3.2.4	Case B1A – Shell IGCC Power Plant Without CO ₂ Capture Process Description	108
3.2.5	Case B1A – Performance Results.....	117
3.2.6	Case B1A – Major Equipment List	129
3.2.7	Case B1A – Cost Estimating	134
3.2.8	Case B1B – Shell IGCC Power Plant with CO ₂ Capture Process Description 141	
3.2.9	Case B1B – Performance Results	149
3.2.10	Case B1B – Major Equipment List.....	161
3.2.11	Case B1B – Cost Estimating.....	166
3.3	CB&I E-Gas™ IGCC Cases	173
3.3.1	Gasifier Background.....	173
3.3.2	Key System Assumptions	174
3.3.3	Sparing Philosophy	175
3.3.4	Case B4A – E-Gas™ IGCC Power Plant Without CO ₂ Capture Process Description	176
3.3.5	Case B4A – Performance Results.....	185
3.3.6	Case B4A – Major Equipment List	197
3.3.7	Case B4A – Cost Estimating	202
3.3.8	Case B4B – E-Gas™ IGCC Power Plant with CO ₂ Capture Process Description	209
3.3.9	Case B4B – Performance Results	216
3.3.10	Case B4B – Major Equipment List.....	227
3.3.11	Case B4B – Cost Estimating.....	233
3.4	General Electric Power IGCC Cases	240
3.4.1	Gasifier Background.....	241
3.4.2	Key System Assumptions	242
3.4.3	Sparing Philosophy	243
3.4.4	Case B5A – GEP Radiant IGCC Without CO ₂ Capture Process Description 243	
3.4.5	Case B5A – Performance Results.....	252
3.4.6	Case B5A – Major Equipment List	263

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

3.4.7	Case B5A – Cost Estimating	268
3.4.8	Case B5B – GEP Radiant IGCC with CO ₂ Capture Process Description ...	275
3.4.9	Case B5B – Performance Results	282
3.4.10	Case B5B – Major Equipment List.....	293
3.4.11	Case B5B – Cost Estimating.....	298
3.4.12	Case B5B-Q – GEP Quench IGCC with CO ₂ Capture Process Description 305	
3.4.13	Case B5B-Q – Performance Results	311
3.4.14	Case B5B-Q – Major Equipment List	323
3.4.15	Case B5B-Q – Cost Estimating	328
3.5	IGCC Case Summary	335
4	Pulverized Coal Rankine Cycle Plants	347
4.1	PC Common Process Areas.....	348
4.1.1	Coal, Activated Carbon, and Sorbent Receiving and Storage.....	348
4.1.2	Steam Generator and Ancillaries.....	349
4.1.3	NO _x Control System.....	353
4.1.4	Activated Carbon Injection.....	354
4.1.5	Particulate Control	355
4.1.6	Mercury Removal	355
4.1.7	Flue Gas Desulfurization	363
4.1.8	Carbon Dioxide Recovery Facility.....	370
4.1.9	CO ₂ Compression and Drying System.....	373
4.1.10	Process Water Systems	375
4.1.11	Ash Handling System	377
4.1.12	Power Generation	378
4.1.13	Balance of Plant	379
4.1.14	Performance Summary Metrics	380
4.2	Subcritical PC Cases.....	382
4.2.1	Key System Assumptions	382
4.2.2	Sparing Philosophy	384
4.2.3	Case B11A – SubC PC without CO ₂ Capture Process Description	385
4.2.4	Case B11A – Performance Results.....	389
4.2.5	Case B11A – Major Equipment List	397
4.2.6	Case B11A – Cost Estimating	402
4.2.7	Case B11B.90 – SubC PC with 90 Percent CO ₂ Capture Process Description 409	
4.2.8	Case B11B.90 – Performance Results	414
4.2.9	Case B11B.90 – Major Equipment List.....	421
4.2.10	Case B11B.90 – Cost Estimating.....	427
4.2.11	Case B11B.95 – SubC PC with 95 Percent CO ₂ Capture Process Description 434	
4.2.12	Case B11B.95 – Performance Results	439
4.2.13	Case B11B.95 – Major Equipment List.....	447
4.2.14	Case B11B.95 – Cost Estimating.....	453
4.3	Supercritical PC Cases	460

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

4.3.1	Key System Assumptions	460
4.3.2	Sparing Philosophy	462
4.3.3	Case B12A – SC PC without CO ₂ Capture Process Description.....	462
4.3.4	Case B12A – Performance Results.....	466
4.3.5	Case B12A – Major Equipment List	473
4.3.6	Case B12A – Cost Estimating	478
4.3.7	Case B12B.90 – SC PC with 90 Percent CO ₂ Capture Process Description 484	
4.3.8	Case B12B.90 – Performance Results	489
4.3.9	Case B12B.90 – Major Equipment List	497
4.3.10	Case B12B.90 – Cost Estimating	503
4.3.11	Case B12B.95 – SC PC with 95 Percent CO ₂ Capture Process Description 510	
4.3.12	Case B12B.95 – Performance Results	515
4.3.13	Case B12B.95 – Major Equipment List	523
4.3.14	Case B12B.95 – Cost Estimating	529
4.4	PC Case Summary	536
5	Natural Gas Combined Cycle Plants.....	549
5.1	NGCC Process Areas	549
5.1.1	Natural Gas Supply System	549
5.1.2	Combustion Turbine	550
5.1.3	Heat Recovery Steam Generator	552
5.1.4	NO _x Control System.....	553
5.1.5	Carbon Dioxide Recovery Facility.....	553
5.1.6	Steam Turbine	555
5.1.7	Water and Steam Systems	555
5.1.8	Accessory Electric Plant	557
5.1.9	Waste Treatment/Miscellaneous Systems.....	557
5.1.10	Instrumentation and Control	558
5.1.11	Performance Summary Metrics	558
5.2	F-Frame NGCC Cases	559
5.2.1	Key System Assumptions	559
5.2.2	Sparing Philosophy	561
5.2.3	Case B31A – NGCC without CO ₂ Capture Process Description.....	561
5.2.4	Case B31A – Performance Results.....	564
5.2.5	Case B31A – Major Equipment List	571
5.2.6	Case B31A – Cost Estimating	574
5.2.7	Case B31B.90 – NGCC with 90 Percent CO ₂ Capture Process Description 580	
5.2.8	Case B31B.90 – Performance Results	583
5.2.9	Case B31B.90 – Major Equipment List.....	589
5.2.10	Case B31B.90 – Cost Estimating	592
5.2.11	Case B31B.95 – NGCC with 95 Percent CO ₂ Capture Process Description 598	
5.2.12	Case B31B.95 – Performance Results	602

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

5.2.13	Case B31B.95 – Major Equipment List	609
5.2.14	Case B31B.95 – Cost Estimating	612
5.3	H-Frame NGCC Cases	618
5.3.1	Key System Assumptions	618
5.3.2	Sparing Philosophy	620
5.3.3	Case B32A – NGCC without CO ₂ Capture Process Description	620
5.3.4	Case B32A – Performance Results.....	623
5.3.5	Case B32A – Major Equipment List	631
5.3.6	Case B32A – Cost Estimating	634
5.3.7	Case B32B.90 – NGCC with 90 Percent CO ₂ Capture Process Description 640	
5.3.8	Case B32B.90 – Performance Results	643
5.3.9	Case B32B.90 – Major Equipment List	649
5.3.10	Case B32B.90 – Cost Estimating	652
5.3.11	Case B32B.95 – NGCC with 95 Percent CO ₂ Capture Process Description 658	
5.3.12	Case B32B.95 – Performance Results	662
5.3.13	Case B32B.95 – Major Equipment List	669
5.3.14	Case B32B.95 – Cost Estimating	672
5.4	NGCC Case Summary	678
6	Results Analysis	689
6.1	Performance Results	689
6.1.1	Energy Efficiency	693
6.1.2	Environmental Emissions	700
6.1.3	Water Use	700
6.2	Cost Results	702
6.2.1	TOC and TASC	705
6.2.2	LCOE	709
6.2.3	CO ₂ Emission Price Impact	711
6.2.4	CO ₂ Sales Price Impact	712
6.3	Sensitivities	714
7	Revision Control	725
8	References	734
	Appendix A: PC with 99 percent CO ₂ Capture	744
A.1	Case B11B.99 – SubC PC with 99 Percent CO ₂ Capture Process Description	744
A.1.1	Case B11B.99 – Performance Results	749
A.1.2	Case B11B.99 – Major Equipment List	757
A.1.3	Case B11B.99 – Cost Estimating	763
A.2	Case B12B.99 – SC PC with 99 Percent CO ₂ Capture Process Description	770
A.2.1	Case B12B.99 – Performance Results	775
A.2.2	Case B12B.99 – Major Equipment List	783
A.2.3	Case B12B.99 – Cost Estimating	789
	Appendix B – NGCC with 97 percent CO ₂ Capture	796
B.1	Case B31B.97 – NGCC with 97 Percent CO ₂ Capture Process Description	796

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

B.1.1	Case B31B.97 – Performance Results	799
B.1.2	Case B31B.97 – Major Equipment List	805
B.1.3	Case B31B.97 – Cost Estimating	808
B.2	Case B32B.97 – NGCC with 97 Percent CO ₂ Capture Process Description	814
B.2.1	Case B32B.97 – Performance Results	817
B.2.2	Case B32B.97 – Major Equipment List	823
B.2.3	Case B32B.97 – Cost Estimating	826
Appendix C – Summary of Capture Rates Above 95 percent		833

LIST OF EXHIBITS

Exhibit ES-1. Case configuration summary.....	2
Exhibit ES-2. Performance summary and environmental profile for IGCC cases	7
Exhibit ES-3. Performance summary and environmental profile for PC cases	8
Exhibit ES-4. Performance summary and environmental profile for NGCC cases	9
Exhibit ES-5. Net plant efficiency (HHV basis)	10
Exhibit ES-6. Cost summary for all IGCC cases	14
Exhibit ES-7. Cost summary for all PC cases.....	15
Exhibit ES-8. Cost summary for all NGCC cases	16
Exhibit ES-9. LCOE by cost component.....	17
Exhibit ES-10. LCOE sensitivity to natural gas costs.....	21
Exhibit ES-11. LCOE sensitivity to coal costs	21
Exhibit ES-12. Lowest cost technology options at various natural gas and CO ₂ sales prices for NGCC and PC.....	22
Exhibit ES-13. Capital cost uncertainty ranges	23
Exhibit ES-14. Performance summary and environmental profile for PC and NGCC cases with CO ₂ capture rates greater than 95 percent	26
Exhibit ES-15. Cost summary for PC and NGCC cases with CO ₂ capture rates greater than 95 percent	27
Exhibit 1-1. Case descriptions.....	32
Exhibit 2-1. Site characteristics	33
Exhibit 2-2. Site ambient conditions.....	34
Exhibit 2-3. Design makeup water quality.....	35
Exhibit 2-4. Design coal	36
Exhibit 2-5. Probability distribution of mercury concentration in the Illinois No. 6 coal	37
Exhibit 2-6. Natural gas composition.....	38
Exhibit 2-7. MATS and NSPS emission limits for SO ₂ , NO _x , PM, Hg, and HCl.....	39
Exhibit 2-8. New source treated FGD wastewater discharge limits [27]	41
Exhibit 2-9. New source treated gasification wastewater discharge limits [27]	41
Exhibit 2-10. Environmental targets for IGCC cases [23] [24] [25]	42
Exhibit 2-11. Water discharge targets for IGCC cases [27]	43
Exhibit 2-12. Environmental targets for PC cases [23] [24] [25]	44
Exhibit 2-13. Water discharge targets for PC cases [27]	44
Exhibit 2-14. Environmental targets for NGCC cases [23] [24] [25]	45
Exhibit 2-15. Coal unit equivalent availability factor.....	48
Exhibit 2-16. Number of coal units reporting in the 2011 and 2016 data	48
Exhibit 2-17. Coal unit availability factor.....	49
Exhibit 2-18. Reported high capacity factor coal units	49
Exhibit 2-19. Capital cost uncertainty ranges.....	53
Exhibit 2-20. Capital cost levels and their elements.....	55
Exhibit 2-21. CO ₂ transport and storage costs	60
Exhibit 3-1. Typical ASU process schematic	66
Exhibit 3-2. Flow diagram for a conventional single-stage AGR unit.....	71
Exhibit 3-3. Flow diagram for a conventional two-stage AGR unit.....	72
Exhibit 3-4. CO ₂ compressor interstage pressures	74
Exhibit 3-5. IGCC CO ₂ compressor enthalpy versus pressure operating profile	75

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-6. Typical three-stage Claus sulfur plant	77
Exhibit 3-7. State-of-the-art 2008 F-class combustion turbine performance characteristics using natural gas [70]	79
Exhibit 3-8. Typical fuel specification for state-of-the-art 2008 F-class machines	81
Exhibit 3-9. IGCC steam conditions	83
Exhibit 3-10. Example diagram of an ejector type venturi scrubber	87
Exhibit 3-11. Simplified syngas scrubber block flow diagram	88
Exhibit 3-12. Simplified low temperature heat recovery system	89
Exhibit 3-13. Typical operating parameters for sour water strippers	90
Exhibit 3-14. Simplified sour water stripper diagram	91
Exhibit 3-15. Example diagram of a spray tower absorption column	93
Exhibit 3-16. Example diagram of a process water drum	94
Exhibit 3-17. Gasification wastewater quality	95
Exhibit 3-18. Simplified diagram of vacuum flash system	97
Exhibit 3-19. Example diagram of a brine concentrator	99
Exhibit 3-20. Example diagram of a forced-circulation, steam-driven crystallizer	100
Exhibit 3-21. Shell IGCC plant study configuration matrix	106
Exhibit 3-22. Balance of plant assumptions	107
Exhibit 3-23. Case B1A block flow diagram, Shell IGCC without CO ₂ capture	109
Exhibit 3-24. Case B1A stream table, Shell IGCC without capture	110
Exhibit 3-25. Case B1A plant performance summary	118
Exhibit 3-26. Case B1A plant power summary	119
Exhibit 3-27. Case B1A air emissions	120
Exhibit 3-28. Case B1A carbon balance	121
Exhibit 3-29. Case B1A sulfur balance	121
Exhibit 3-30. Case B1A water balance	122
Exhibit 3-31. Case B1A overall energy balance (0°C [32°F] reference)	123
Exhibit 3-32. Case B1A coal gasification and ASU energy and mass balance	125
Exhibit 3-33. Case B1A syngas cleanup energy and mass balance	126
Exhibit 3-34. Case B1A combined cycle power generation energy and mass balance	127
Exhibit 3-35. Case B1A total plant cost details	135
Exhibit 3-36. Case B1A owner's costs	139
Exhibit 3-37. Case B1A initial and annual operating and maintenance costs	140
Exhibit 3-38. Case B1A LCOE breakdown	141
Exhibit 3-39. Case B1B block flow diagram, Shell IGCC with CO ₂ capture	142
Exhibit 3-40. Case B1B stream table, Shell IGCC with capture	143
Exhibit 3-41. Case B1B plant performance summary	150
Exhibit 3-42. Case B1B plant power summary	151
Exhibit 3-43. Case B1B air emissions	152
Exhibit 3-44. Case B1B carbon balance	153
Exhibit 3-45. Case B1B sulfur balance	153
Exhibit 3-46. Case B1B water balance	154
Exhibit 3-47. Case B1B overall energy balance (0°C [32°F] reference)	154
Exhibit 3-48. Case B1B coal gasification and ASU energy and mass balance	157
Exhibit 3-49. Case B1B syngas cleanup energy and mass balance	158
Exhibit 3-50. Case B1B combined cycle power generation energy and mass balance	159
Exhibit 3-51. Case B1B total plant cost details	167

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-52. Case B1B owner's costs	171
Exhibit 3-53. Case B1B initial and annual operating and maintenance costs.....	172
Exhibit 3-54. Case B1B LCOE breakdown.....	173
Exhibit 3-55. E-Gas™ IGCC plant study configuration matrix	174
Exhibit 3-56. Case B4A block flow diagram, E-Gas™ IGCC without CO ₂ capture.....	178
Exhibit 3-57. Case B4A stream table, E-Gas™ IGCC without capture	179
Exhibit 3-58. Case B4A plant performance summary	186
Exhibit 3-59. Case B4A plant power summary	187
Exhibit 3-60. Case B4A air emissions.....	188
Exhibit 3-61. Case B4A carbon balance	189
Exhibit 3-62. Case B4A sulfur balance	189
Exhibit 3-63. Case B4A water balance	190
Exhibit 3-64. Case B4A overall energy balance (0°C [32°F] reference)	191
Exhibit 3-65. Case B4A coal gasification and ASU energy and mass balance	193
Exhibit 3-66. Case B4A syngas cleanup energy and mass balance	194
Exhibit 3-67. Case B4A combined cycle power generation energy and mass balance	195
Exhibit 3-68. Case B4A total plant cost details	203
Exhibit 3-69. Case B4A owner's costs	207
Exhibit 3-70. Case B4A initial and annual operating and maintenance costs	208
Exhibit 3-71. Case B4A LCOE breakdown	209
Exhibit 3-72. Case B4B block flow diagram, E-Gas™ IGCC with CO ₂ capture.....	210
Exhibit 3-73. Case B4B stream table, E-Gas™ IGCC with capture.....	211
Exhibit 3-74. Case B4B plant performance summary	217
Exhibit 3-75. Case B4B plant power summary.....	218
Exhibit 3-76. Case B4B air emissions	219
Exhibit 3-77. Case B4B carbon balance.....	220
Exhibit 3-78. Case B4B sulfur balance	221
Exhibit 3-79. Case B4B water balance	221
Exhibit 3-80. Case B4B overall energy balance (0°C [32°F] reference).....	222
Exhibit 3-81. Case B4B coal gasification and ASU energy and mass balance	223
Exhibit 3-82. Case B4B syngas cleanup energy and mass balance	224
Exhibit 3-83. Case B4B combined cycle power generation energy and mass balance	225
Exhibit 3-84. Case B4B total plant cost details.....	234
Exhibit 3-85. Case B4B owner's costs	238
Exhibit 3-86. Case B4B initial and annual operating and maintenance costs.....	239
Exhibit 3-87. Case B4B LCOE breakdown.....	240
Exhibit 3-88. GEP IGCC plant study configuration matrix	242
Exhibit 3-89. Case B5A block flow diagram, GEP IGCC without CO ₂ capture	245
Exhibit 3-90. Case B5A stream table, GEP IGCC without capture.....	246
Exhibit 3-91. Case B5A plant performance summary	253
Exhibit 3-92. Case B5A plant power summary	254
Exhibit 3-93. Case B5A air emissions.....	255
Exhibit 3-94. Case B5A carbon balance	256
Exhibit 3-95. Case B5A sulfur balance	256
Exhibit 3-96. Case B5A water balance	257
Exhibit 3-97. Case B5A overall energy balance (0°C [32°F] reference)	258
Exhibit 3-98. Case B5A coal gasification and ASU energy and mass balance	259

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-99. Case B5A syngas cleanup energy and mass balance	260
Exhibit 3-100. Case B5A combined cycle power generation energy and mass balance	261
Exhibit 3-101. Case B5A total plant cost details	269
Exhibit 3-102. Case B5A owner's costs	273
Exhibit 3-103. Case B5A initial and annual operating and maintenance costs	274
Exhibit 3-104. Case B5A LCOE breakdown	275
Exhibit 3-105. Case B5B block flow diagram, GEP IGCC with CO ₂ capture	276
Exhibit 3-106. Case B5B stream table, GEP IGCC with capture	277
Exhibit 3-107. Case B5B plant performance summary	282
Exhibit 3-108. Case B5B plant power summary	283
Exhibit 3-109. Case B5B air emissions	285
Exhibit 3-110. Case B5B carbon balance	286
Exhibit 3-111. Case B5B sulfur balance	286
Exhibit 3-112. Case B5B water balance	286
Exhibit 3-113. Case B5B overall energy balance (0°C [32°F] reference)	287
Exhibit 3-114. Case B5B coal gasification and ASU energy and mass balance	289
Exhibit 3-115. Case B5B syngas cleanup energy and mass balance	290
Exhibit 3-116. Case B5B combined cycle power generation energy and mass balance	291
Exhibit 3-117. Case B5B total plant cost details	299
Exhibit 3-118. Case B5B owner's costs	303
Exhibit 3-119. Case B5B initial and annual operating and maintenance costs	304
Exhibit 3-120. Case B5B LCOE breakdown	305
Exhibit 3-121. Case B5B-Q block flow diagram, GEP quench-only IGCC with CO ₂ capture	306
Exhibit 3-122. Case B5B-Q stream table, GEP quench-only IGCC with capture	307
Exhibit 3-123. Case B5B-Q plant performance summary	312
Exhibit 3-124. Case B5B-Q plant power summary	313
Exhibit 3-125. Case B5B-Q air emissions	314
Exhibit 3-126. Case B5B-Q carbon balance	315
Exhibit 3-127. Case B5B-Q sulfur balance	316
Exhibit 3-128. Case B5B-Q water balance	316
Exhibit 3-129. Case B5B-Q overall energy balance (0°C [32°F] reference)	317
Exhibit 3-130. Case B5B-Q coal gasification and ASU energy and mass balance	319
Exhibit 3-131. Case B5B-Q syngas cleanup energy and mass balance	320
Exhibit 3-132. Case B5B-Q combined cycle power generation energy and mass balance	321
Exhibit 3-133. Case B5B-Q total plant cost details	329
Exhibit 3-134. Case B5B-Q owner's costs	333
Exhibit 3-135. Case B5B-Q initial and annual operating and maintenance costs	334
Exhibit 3-136. Case B5B-Q LCOE breakdown	335
Exhibit 3-137. Estimated performance and cost results for all IGCC cases	336
Exhibit 3-138. Net plant efficiency (HHV basis) for all IGCC cases	339
Exhibit 3-139. Raw water withdrawal and consumption in IGCC cases	340
Exhibit 3-140. Plant capital cost for all IGCC cases	341
Exhibit 3-141. LCOE for all IGCC cases	343
Exhibit 3-142. Breakdown of Cost of CO ₂ Captured for IGCC cases	344

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-143. Breakdown of Cost of CO ₂ Avoided for IGCC cases	345
Exhibit 4-1. Effect of SO ₃ concentration on PAC injection rate.....	357
Exhibit 4-2. Pollutant removal efficiency versus hydrated lime injection rate.....	358
Exhibit 4-3. Typical DSI injection process flow diagram	359
Exhibit 4-4. Mercury removal versus PAC injection rate for Case B12A.....	361
Exhibit 4-5. Typical ACI injection process flow diagram	362
Exhibit 4-6. Typical disposal- and commercial-grade gypsum characteristics and limits	364
Exhibit 4-7. Wet flue gas desulfurization process flow diagram.....	365
Exhibit 4-8. Cross section of the wet FGD absorber tower.....	366
Exhibit 4-9. FGD process wastewater quality	369
Exhibit 4-10. CANSOLV CO ₂ capture process typical flow diagram for PC	371
Exhibit 4-11. CO ₂ compressor interstage pressures	373
Exhibit 4-12. PC CO ₂ compressor enthalpy versus pressure operating profile	374
Exhibit 4-13. Spray dryer block flow diagram	376
Exhibit 4-14. PC steam conditions.....	378
Exhibit 4-15. SubC PC plant study configuration matrix.....	382
Exhibit 4-16. Balance of plant assumptions.....	384
Exhibit 4-17. Case B11A block flow diagram, SubC unit without CO ₂ capture	386
Exhibit 4-18. Case B11A stream table, SubC unit without capture	387
Exhibit 4-19. Case B11A plant performance summary	389
Exhibit 4-20. Case B11A plant power summary	390
Exhibit 4-21. Case B11A air emissions.....	391
Exhibit 4-22. Case B11A carbon balance	392
Exhibit 4-23. Case B11A sulfur balance	392
Exhibit 4-24. Case B11A water balance	392
Exhibit 4-25. Case B11A energy and mass balance, SubC PC boiler without CO ₂ capture	395
Exhibit 4-26. Case B11A energy and mass balance, SubC steam cycle	396
Exhibit 4-27. Case B11A overall energy balance (0°C [32°F] reference)	397
Exhibit 4-28. Case B11A total plant cost details	403
Exhibit 4-29. Case B11A owner's costs	407
Exhibit 4-30. Case B11A initial and annual operating and maintenance costs	408
Exhibit 4-31. Case B11A LCOE breakdown	409
Exhibit 4-32. Case B11B.90 block flow diagram, SubC unit with CO ₂ capture.....	410
Exhibit 4-33. Case B11B.90 stream table, SubC unit with capture	411
Exhibit 4-34. Case B11B.90 plant performance summary	414
Exhibit 4-35. Case B11B.90 plant power summary.....	415
Exhibit 4-36. Case B11B.90 air emissions	416
Exhibit 4-37. Case B11B.90 carbon balance.....	417
Exhibit 4-38. Case B11B.90 sulfur balance	417
Exhibit 4-39. Case B11B.90 water balance	418
Exhibit 4-40. Case B11B.90 energy and mass balance, SubC PC boiler with CO ₂ capture	419
Exhibit 4-41. Case B11B.90 energy and mass balance, SubC steam cycle.....	420
Exhibit 4-42. Case B11B.90 overall energy balance (0°C [32°F] reference)	421
Exhibit 4-43. Case B11B.90 total plant cost details	428
Exhibit 4-44. Case B11B.90 owner's costs	432

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-45. Case B11B.90 initial and annual operating and maintenance costs	433
Exhibit 4-46. Case B11B.90 LCOE breakdown	434
Exhibit 4-47. Case B11B.95 block flow diagram, SubC unit with CO ₂ capture	435
Exhibit 4-48. Case B11B.95 stream table, SubC unit with capture	436
Exhibit 4-49. Case B11B.95 plant performance summary	439
Exhibit 4-50. Case B11B.95 plant power summary	440
Exhibit 4-51. Case B11B.95 air emissions	441
Exhibit 4-52. Case B11B.95 carbon balance	442
Exhibit 4-53. Case B11B.95 sulfur balance	442
Exhibit 4-54. Case B11B.95 water balance	443
Exhibit 4-55. Case B11B.95 energy and mass balance, SubC PC boiler with CO ₂ capture	445
Exhibit 4-56. Case B11B.95 energy and mass balance, SubC steam cycle	446
Exhibit 4-57. Case B11B.95 overall energy balance (0°C [32°F] reference)	447
Exhibit 4-58. Case B11B.95 total plant cost details	454
Exhibit 4-59. Case B11B.95 owner's costs	458
Exhibit 4-60. Case B11B.95 initial and annual operating and maintenance costs	459
Exhibit 4-61. Case B11B.95 LCOE breakdown	460
Exhibit 4-62. SC PC plant study configuration matrix	461
Exhibit 4-63. Case B12A block flow diagram, SC unit without CO ₂ capture	463
Exhibit 4-64. Case B12A stream table, SC unit without capture	464
Exhibit 4-65. Case B12A plant performance summary	466
Exhibit 4-66. Case B12A plant power summary	467
Exhibit 4-67. Case B12A air emissions	468
Exhibit 4-68. Case B12A carbon balance	469
Exhibit 4-69. Case B12A sulfur balance	469
Exhibit 4-70. Case B12A water balance	469
Exhibit 4-71. Case B12A energy and mass balance, SC PC boiler without CO ₂ capture	471
Exhibit 4-72. Case B12A energy and mass balance, SC steam cycle	472
Exhibit 4-73. Case B12A overall energy balance (0°C [32°F] reference)	473
Exhibit 4-74. Case B12A total plant cost details	479
Exhibit 4-75. Case B12A owner's costs	482
Exhibit 4-76. Case B12A initial and annual operating and maintenance costs	483
Exhibit 4-77. Case B12A LCOE breakdown	484
Exhibit 4-78. Case B12B.90 block flow diagram, SC unit with CO ₂ capture	485
Exhibit 4-79. Case B12B.90 stream table, SC unit with capture	486
Exhibit 4-80. Case B12B.90 plant performance summary	489
Exhibit 4-81. Case B12B.90 plant power summary	490
Exhibit 4-82. Case B12B.90 air emissions	491
Exhibit 4-83. Case B12B.90 carbon balance	492
Exhibit 4-84. Case B12B.90 sulfur balance	492
Exhibit 4-85. Case B12B.90 water balance	493
Exhibit 4-86. Case B12B.90 energy and mass balance, SC PC boiler with CO ₂ capture	495
Exhibit 4-87. Case B12B.90 energy and mass balance, SC steam cycle	496
Exhibit 4-88. Case B12B.90 overall energy balance (0°C [32°F] reference)	497
Exhibit 4-89. Case B12B.90 total plant cost details	504
Exhibit 4-90. Case B12B.90 owner's costs	508

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-91. Case B12B.90 initial and annual operating and maintenance costs	509
Exhibit 4-92. Case B12B.90 LCOE breakdown	510
Exhibit 4-93. Case B12B.95 block flow diagram, SC unit with CO ₂ capture	511
Exhibit 4-94. Case B12B.95 stream table, SC unit with capture	512
Exhibit 4-95. Case B12B.95 plant performance summary	515
Exhibit 4-96. Case B12B.95 plant power summary	516
Exhibit 4-97. Case B12B.95 air emissions	517
Exhibit 4-98. Case B12B.95 carbon balance	518
Exhibit 4-99. Case B12B.95 sulfur balance	518
Exhibit 4-100. Case B12B.95 water balance	519
Exhibit 4-101. Case B12B.95 energy and mass balance, SC PC boiler with CO ₂ capture	521
Exhibit 4-102. Case B12B.95 energy and mass balance, SC steam cycle	522
Exhibit 4-103. Case B12B.95 overall energy balance (0°C [32°F] reference)	523
Exhibit 4-104. Case B12B.95 total plant cost details	530
Exhibit 4-105. Case B12B.95 owner's costs	534
Exhibit 4-106. Case B12B.95 initial and annual operating and maintenance costs	535
Exhibit 4-107. Case B12B.95 LCOE breakdown	536
Exhibit 4-108. Estimated performance and cost results for PC cases	537
Exhibit 4-109. Raw water withdrawal and consumption in PC cases	540
Exhibit 4-110. Plant capital cost for PC cases	541
Exhibit 4-111. LCOE for PC cases	542
Exhibit 4-112. Sensitivity of LCOE to capacity factor for PC cases	544
Exhibit 4-113. Sensitivity of LCOE to coal price for PC cases	545
Exhibit 4-114. Breakdown of Cost of CO ₂ Captured in PC cases	546
Exhibit 4-115. Breakdown of Cost of CO ₂ Avoided in PC cases	546
Exhibit 5-1. Combustion turbine typical scope of supply	550
Exhibit 5-2. F- versus H-class combustion turbines	551
Exhibit 5-3. CANSOLV CO ₂ capture process typical flow diagram for NGCC	554
Exhibit 5-4. NGCC steam conditions	555
Exhibit 5-5. NGCC F-frame plant study configuration matrix	560
Exhibit 5-6. F-frame NGCC balance of plant assumptions	560
Exhibit 5-7. Case B31A block flow diagram, NGCC without CO ₂ capture	562
Exhibit 5-8. Case B31A stream table, NGCC without capture	563
Exhibit 5-9. Case B31A plant performance summary	564
Exhibit 5-10. Case B31A plant power summary	565
Exhibit 5-11. Case B31A air emissions	565
Exhibit 5-12. Case B31A carbon balance	566
Exhibit 5-13. Case B31A sulfur balance	566
Exhibit 5-14. Case B31A water balance	567
Exhibit 5-15. Case B31A energy and mass balance, NGCC without CO ₂ capture	569
Exhibit 5-16. Case B31A overall energy balance (0°C [32°F] reference)	571
Exhibit 5-17. Case B31A total plant cost details	575
Exhibit 5-18. Case B31A owner's costs	578
Exhibit 5-19. Case B31A initial and annual operating and maintenance costs	579
Exhibit 5-20. Case B31A LCOE breakdown	579
Exhibit 5-21. Case B31B.90 block flow diagram, NGCC with CO ₂ capture	580
Exhibit 5-22. Case B31B.90 stream table, NGCC with capture	581

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-23. Case B31B.90 plant performance summary	583
Exhibit 5-24. Case B31B.90 plant power summary	584
Exhibit 5-25. Case B31B.90 air emissions	584
Exhibit 5-26. Case B31B.90 carbon balance	585
Exhibit 5-27. Case B31B.90 sulfur balance	586
Exhibit 5-28. Case B31B.90 water balance	586
Exhibit 5-29. Case B31B.90 energy and mass balance, NGCC with CO ₂ capture	587
Exhibit 5-30. Case B31B.90 overall energy balance (0°C [32°F] reference)	589
Exhibit 5-31. Case B31B.90 total plant cost details	593
Exhibit 5-32. Case B31B.90 owner's costs	596
Exhibit 5-33. Case B31B.90 initial and annual operating and maintenance costs	597
Exhibit 5-34. Case B31B.90 LCOE breakdown	598
Exhibit 5-35. Case B31B.95 block flow diagram, NGCC with CO ₂ capture	599
Exhibit 5-36. Case B31B.95 stream table, NGCC with capture	600
Exhibit 5-37. Case B31B.95 plant performance summary	602
Exhibit 5-38. Case B31B.95 plant power summary	603
Exhibit 5-39. Case B31B.95 air emissions	603
Exhibit 5-40. Case B31B.95 carbon balance	604
Exhibit 5-41. Case B31B.95 sulfur balance	605
Exhibit 5-42. Case B31B.95 water balance	605
Exhibit 5-43. Case B31B.95 energy and mass balance, NGCC with CO ₂ capture	607
Exhibit 5-44. Case B31B.95 overall energy balance (0°C [32°F] reference)	609
Exhibit 5-45. Case B31B.95 total plant cost details	613
Exhibit 5-46. Case B31B.95 owner's costs	616
Exhibit 5-47. Case B31B.95 initial and annual operating and maintenance costs	617
Exhibit 5-48. Case B31B.95 LCOE breakdown	618
Exhibit 5-49. NGCC H-frame plant study configuration matrix	619
Exhibit 5-50. NGCC balance of plant assumptions	619
Exhibit 5-51. Case B32A block flow diagram, NGCC without CO ₂ capture	621
Exhibit 5-52. Case B32A stream table, NGCC without capture	622
Exhibit 5-53. Case B32A plant performance summary	623
Exhibit 5-54. Case B32A plant power summary	624
Exhibit 5-55. Case B32A air emissions	624
Exhibit 5-56. Case B32A carbon balance	625
Exhibit 5-57. Case B32A sulfur balance	626
Exhibit 5-58. Case B32A water balance	626
Exhibit 5-59. Case B32A energy and mass balance, NGCC without CO ₂ capture	629
Exhibit 5-60. Case B32A overall energy balance (0°C [32°F] reference)	631
Exhibit 5-61. Case B32A total plant cost details	635
Exhibit 5-62. Case B32A owner's costs	638
Exhibit 5-63. Case B32A initial and annual operating and maintenance costs	639
Exhibit 5-64. Case B32A LCOE breakdown	639
Exhibit 5-65. Case B32B.90 block flow diagram, NGCC with CO ₂ capture	640
Exhibit 5-66. Case B32B.90 stream table, NGCC with capture	641
Exhibit 5-67. Case B32B.90 plant performance summary	643
Exhibit 5-68. Case B32B.90 plant power summary	644
Exhibit 5-69. Case B32B.90 air emissions	644
Exhibit 5-70. Case B32B.90 carbon balance	645

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-71. Case B32B.90 sulfur balance	646
Exhibit 5-72. Case B32B.90 water balance	646
Exhibit 5-73. Case B32B.90 energy and mass balance, NGCC with CO ₂ capture.....	647
Exhibit 5-74. Case B32B.90 overall energy balance (0°C [32°F] reference)	649
Exhibit 5-75. Case B32B.90 total plant cost details	653
Exhibit 5-76. Case B32B.90 owner's costs	656
Exhibit 5-77. Case B32B.90 initial and annual operating and maintenance costs.....	657
Exhibit 5-78. Case B32B.90 LCOE breakdown.....	658
Exhibit 5-79. Case B32B.95 block flow diagram, NGCC with CO ₂ capture.....	659
Exhibit 5-80. Case B32B.95 stream table, NGCC with capture	660
Exhibit 5-81. Case B32B.95 plant performance summary	662
Exhibit 5-82. Case B32B.95 plant power summary.....	663
Exhibit 5-83. Case B32B.95 air emissions	663
Exhibit 5-84. Case B32B.95 carbon balance.....	664
Exhibit 5-85. Case B32B.95 sulfur balance.....	665
Exhibit 5-86. Case B32B.95 water balance	665
Exhibit 5-87. Case B32B.95 energy and mass balance, NGCC with CO ₂ capture.....	667
Exhibit 5-88. Case B32B.95 overall energy balance (0°C [32°F] reference)	669
Exhibit 5-89. Case B32B.95 total plant cost details	673
Exhibit 5-90. Case B32B.95 owner's costs	676
Exhibit 5-91. Case B32B.95 initial and annual operating and maintenance costs.....	677
Exhibit 5-92. Case B32B.95 LCOE breakdown.....	678
Exhibit 5-93. Estimated performance and cost results for NGCC cases.....	679
Exhibit 5-94. Raw water withdrawal and consumption in NGCC cases	682
Exhibit 5-95. Plant capital cost for NGCC cases	683
Exhibit 5-96. LCOE of NGCC cases.....	684
Exhibit 5-97. Sensitivity of LCOE to capacity factor in NGCC cases.....	685
Exhibit 5-98. Sensitivity of LCOE to fuel price in NGCC cases.....	686
Exhibit 5-99. Breakdown of Cost of CO ₂ Captured in NGCC cases	687
Exhibit 5-100. Breakdown of Cost of CO ₂ Avoided in NGCC cases	687
Exhibit 6-1. Performance summary and environmental profile for IGCC cases	690
Exhibit 6-2. Performance summary and environmental profile for PC cases.....	691
Exhibit 6-3. Performance summary and environmental profile for NGCC cases	692
Exhibit 6-4. Net plant efficiency (HHV basis)	694
Exhibit 6-5. GEP IGCC Sankey diagram with and without CO ₂ capture.....	695
Exhibit 6-6. SubC PC Sankey diagram with and without CO ₂ capture	696
Exhibit 6-7. SC PC Sankey diagram with and without CO ₂ capture.....	697
Exhibit 6-8. NGCC F-class Sankey diagram with and without CO ₂ capture	698
Exhibit 6-9. NGCC H-class Sankey diagram with and without CO ₂ capture	699
Exhibit 6-10. Raw water withdrawal and consumption	701
Exhibit 6-11. Cost summary for all IGCC cases	702
Exhibit 6-12. Cost summary for all PC cases.....	704
Exhibit 6-13. Cost summary for all NGCC cases	705
Exhibit 6-14. Plant capital costs.....	707
Exhibit 6-15. Plant capital costs PC and NGCC capture cases.....	708
Exhibit 6-16. LCOE by cost component.....	710
Exhibit 6-17. Impact of carbon emissions price on study technologies.....	711
Exhibit 6-18. Lowest cost power generation options comparing NGCC and PC	712

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-19. Impact of carbon sales price on study technologies	713
Exhibit 6-20. Lowest cost power generation options comparing NGCC and PC	714
Exhibit 6-21. LCOE sensitivity to natural gas costs.....	715
Exhibit 6-22. LCOE sensitivity to coal costs	716
Exhibit 6-23. LCOE sensitivity to capacity factor	717
Exhibit 6-24. LCOE sensitivity to debt-to-equity ratio	718
Exhibit 6-25. Cost of CO ₂ captured sensitivity to debt-to-equity ratio	718
Exhibit 6-26. Cost of CO ₂ avoided sensitivity to debt-to-equity ratio.....	719
Exhibit 6-27. LCOE sensitivity to effective tax rate	719
Exhibit 6-28. Cost of CO ₂ captured sensitivity to effective tax rate	720
Exhibit 6-29. Cost of CO ₂ avoided sensitivity to effective tax rate.....	720
Exhibit 6-30. LCOE sensitivity to interest rate on debt	721
Exhibit 6-31. Cost of CO ₂ capture sensitivity to interest rate on debt.....	722
Exhibit 6-32. Cost of CO ₂ avoided sensitivity to interest rate on debt	722
Exhibit 6-33. LCOE sensitivity to return on equity	723
Exhibit 6-34. Cost of CO ₂ capture sensitivity to return on equity	723
Exhibit 6-35. Cost of CO ₂ avoided sensitivity to return on equity	724
Exhibit 6-36. LCOE sensitivity to combined financial parameters	724
Exhibit 7-1. Record of revisions	725
Exhibit A-1. Case B11B.99 block flow diagram, SubC unit with CO ₂ capture	745
Exhibit A-2. Case B11B.99 stream table, SubC unit with capture.....	746
Exhibit A-3. Case B11B.99 plant performance summary	749
Exhibit A-4. Case B11B.99 plant power summary	750
Exhibit A-5. Case B11B.99 air emissions.....	751
Exhibit A-6. Case B11B.99 carbon balance	752
Exhibit A-7. Case B11B.99 sulfur balance	752
Exhibit A-8. Case B11B.99 water balance.....	753
Exhibit A-9. Case B11B.99 energy and mass balance, SubC PC boiler with CO ₂ capture	755
Exhibit A-10. Case B11B.99 energy and mass balance, SubC steam cycle	756
Exhibit A-11. Case B11B.99 overall energy balance (0°C [32°F] reference)	757
Exhibit A-12. Case B11B.99 total plant cost details	764
Exhibit A-13. Case B11B.99 owner's costs.....	768
Exhibit A-14. Case B11B.99 initial and annual operating and maintenance costs	769
Exhibit A-15. Case B11B.99 LCOE breakdown	770
Exhibit A-16. Case B12B.99 block flow diagram, SC unit with CO ₂ capture.....	771
Exhibit A-17. Case B12B.99 stream table, SC unit with capture	772
Exhibit A-18. Case B12B.99 plant performance summary	775
Exhibit A-19. Case B12B.99 plant power summary	776
Exhibit A-20. Case B12B.99 air emissions.....	777
Exhibit A-21. Case B12B.99 carbon balance	778
Exhibit A-22. Case B12B.99 sulfur balance	778
Exhibit A-23. Case B12B.99 water balance	779
Exhibit A-24. Case B12B.99 energy and mass balance, SC PC boiler with CO ₂ capture	781
Exhibit A-25. Case B12B.99 energy and mass balance, SC steam cycle.....	782
Exhibit A-26. Case B12B.99 overall energy balance (0°C [32°F] reference)	783
Exhibit A-27. Case B12B.99 total plant cost details	790
Exhibit A-28. Case B12B.99 owner's costs.....	793

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-29. Case B12B.99 initial and annual operating and maintenance costs	794
Exhibit A-30. Case B12B.99 LCOE breakdown	795
Exhibit B-1. Case B31B.97 block flow diagram, NGCC with CO ₂ capture	796
Exhibit B-2. Case B31B.97 stream table, NGCC with capture	797
Exhibit B-3. Case B31B.97 plant performance summary	799
Exhibit B-4. Case B31B.97 plant power summary.....	800
Exhibit B-5. Case B31B.97 air emissions	800
Exhibit B-6. Case B31B.97 carbon balance.....	801
Exhibit B-7. Case B31B.97 sulfur balance.....	802
Exhibit B-8. Case B31B.97 water balance	802
Exhibit B-9. Case B31B.97 energy and mass balance, NGCC with CO ₂ capture.....	803
Exhibit B-10. Case B31B.97 overall energy balance (0°C [32°F] reference)	805
Exhibit B-11. Case B31B.97 total plant cost details	809
Exhibit B-12. Case B31B.97 owner's costs	812
Exhibit B-13. Case B31B.97 initial and annual operating and maintenance costs.....	813
Exhibit B-14. Case B31B.97 LCOE breakdown.....	814
Exhibit B-15. Case B32B.97 block flow diagram, NGCC with CO ₂ capture.....	814
Exhibit B-16. Case B32B.97 stream table, NGCC with capture	815
Exhibit B-17. Case B32B.97 plant performance summary	817
Exhibit B-18. Case B32B.97 plant power summary.....	818
Exhibit B-19. Case B32B.97 air emissions	818
Exhibit B-20. Case B32B.97 carbon balance.....	819
Exhibit B-21. Case B32B.97 sulfur balance.....	820
Exhibit B-22. Case B32B.97 water balance	820
Exhibit B-23. Case B32B.97 energy and mass balance, NGCC with CO ₂ capture.....	821
Exhibit B-24. Case B32B.97 overall energy balance (0°C [32°F] reference)	823
Exhibit B-25. Case B32B.97 total plant cost details	827
Exhibit B-26. Case B32B.97 owner's costs	830
Exhibit B-27. Case B32B.97 initial and annual operating and maintenance costs.....	831
Exhibit B-28. Case B32B.97 LCOE breakdown.....	832
Exhibit C-1. Performance summary and environmental profile for PC and NGCC cases with CO ₂ capture rates greater than 95 percent	834
Exhibit C-2. Cost summary for PC and NGCC cases with CO ₂ capture rates greater than 95 percent	835

ACRONYMS AND ABBREVIATIONS

AACE	Association for the Advancement of Cost Engineering	CH ₄ S	Methanethiol
AC	Alternating current	Cl ⁻	Chloride ion
acfm	Actual cubic feet per minute	CL	Closed-loop
ACI	Activated carbon injection	cm	Centimeter
ADIP	Aqueous di-isopropanol	CO	Carbon monoxide
AF	Availability factor	CO ₂	Carbon dioxide
AGR	Acid gas removal	COE	Cost of electricity
ANSI	American National Standards Institute	COS	Carbonyl sulfide
Ar	Argon	CS	Carbon steel
Aspen	Aspen Plus®	CT	Combustion turbine
ASU	Air separation unit	CTG	Combustion turbine-generator
atm	Atmosphere (14.696 psi)	CWP	Circulating water pump
BACT	Best Available Control Technology	CWR	Cooling water return
BDL	Blowdown losses	CWS	Circulating water system
BEC	Bare erected cost	CWT	Cold water temperature
BEP	Breakeven emissions penalty	db, DB	Dry basis
BFD	Block flow diagram	DBQ	Dry Bottom Quench
BFW	Boiler feedwater	DC	Direct current
BOP	Balance of plant	DCS	Distributed control system
BSP	Breakeven sales price	DI	De-ionized
Btu	British thermal unit	DIPA	Diisopropanolamine
Btu/hr	British thermal units per hour	DLN	Dry low NO _x
Btu/kWh	British thermal units per kilowatt hour	DME	Di-methyl ether
Btu/lb	British thermal units per pound	DOE	Department of Energy
Btu/scf	British thermal units per standard cubic foot	DSC	Dry Syngas Cooler
CaCO ₃	Calcium carbonate	DSI	Dry sorbent injection
CaSO ₄	Calcium sulfate	E-Gas™	CB&I gasifier technology
CB&I	Chicago Bridge & Iron Company	EAF	Equivalent availability factor
CCS	Carbon capture and sequestration	EGU	Electric utility steam generating unit
CCS	Carbon capture and storage	ELG	Effluent Limitation Guidelines
CDR	Carbon dioxide recovery	EMF	Emission modification factors
CF	Capacity factor	Eng'g CM H.O.& Fee	Engineering, construction management, home office and fees
CFR	Code of Federal Regulations	EOR	Enhanced oil recovery
CGCU	Cold gas cleanup	EPA	Environmental Protection Agency
CGE	Cold gas efficiency	EPC	Engineering, procurement and construction
CH ₄	Methane	EPCC	Engineering, procurement and construction cost
		EPRI	Electric Power Research Institute

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

ESP	Electrostatic precipitator	ID	Induced draft
ESPA	Energy Sector Planning and Analysis	IGCC	Integrated gasification combined cycle
FD	Forced draft	IGV	Inlet guide vane
FE	Fossil Energy	in.	Inch
FEB	Fossil Energy Baseline	in. Hg	Inch mercury
FG	Flue gas	IOU	Investor-owned utility
FGD	Flue gas desulfurization	IP	Intermediate pressure
FRP	Fiberglass-reinforced plastic	IPM	Integrated Planning Model
FSQ	Full-slurry quench	IRROE	Internal rate of return on equity
ft	Foot, feet	ISO	International Organization for Standardization
ft ³	Cubic feet	kg/GJ	Kilograms per gigajoule
FW	Feedwater	kg/hr	Kilograms per hour
GADS	Generating Availability Data System	kg/s	Kilograms per second
gal	Gallon	kgmol	Kilogram mole
GDP	Gross domestic product	kgmol/hr	Kilogram moles per hour
GEP	General Electric Power	kJ	Kilojoule
GJ	Gigajoule	kJ/hr	Kilojoules per hour
GJ/hr	Gigajoules per hour	kJ/kg	Kilojoules per kilogram
gpd	Gallons per day	kJ/m ³	Kilojoules per cubic meter
gpm	Gallons per minute	kJ/Nm ³	Kilojoules per normal cubic meter
gr/100 scf	Grains per one hundred standard cubic feet	km	Kilometer
Gt	Gigatonne	KO	Knockout
h, hr	Hour	kV	Kilovolt
H ₂	Hydrogen	kW, kWe	Kilowatt electric
H ₂ O	Water	kWh	Kilowatt-hour
H ₂ S	Hydrogen sulfide	kWt	Kilowatt thermal
HCl	Hydrochloric acid	LAER	Lowest Achievable Emission Rate
HCO ₃	Bicarbonate	lb	Pound
HDPE	High density polyethylene	lb/gal	Pound per gallon
Hg	Mercury	lb/ft ²	Pounds per square foot
HHV	Higher heating value	lb/ft ³	Pounds per cubic foot
hp	Horsepower	lb/hr	Pounds per hour
HP	High pressure	lb/MMBtu	Pounds per million British thermal units
HRSG	Heat recovery steam generator	lb/MWh	Pounds per megawatt hour
HSS	Heat stable salt	lb/s	Pounds per second
HVAC	Heating, ventilating, and air conditioning	lb/TBtu	Pounds per trillion British thermal units
HWT	Hot water temperature	lbmol/hr	Pound moles per hour
HX	Heat exchanger	LCOE	Levelized cost of electricity
Hz	Hertz	LCV	Low calorific value
I&C	Instrumentation and control	LHV	Lower heating value
ICR	Information Collection Request		

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

LIW	Loss-in-weight	NETL	National Energy Technology Laboratory
LNB	Low NOx burner		
LP	Low pressure	NFPA	National Fire Protection Association
lpm	Liters per minute		
LTHR	Low temperature heat recovery	NG	Natural gas
		NGCC	Natural gas combined cycle
m	Meter	NH ₃	Ammonia
M	Thousand	NH ₄ Cl	Ammonium chloride
m/min	Meters per minute	Nm ³	Normal cubic meter
m ³ /min	Cubic meters per minute	Nm ³ /hr	Normal cubic meter per hour
MAC	Main air compressor	NOAK	N th -of-a-kind
MAF	Moisture and ash free	NOx	Oxides of nitrogen
MATS	Mercury and Air Toxics Standards	NSPS	New Source Performance Standards
MCR	Maximum continuous rate	NSR	New Source Review
MDEA	Methyldiethanolamine	NTU	Nephelometric turbidity unit
MEA	Monoethanolamine	O ₂	Oxygen
MESA	Mission Execution and Strategic Analysis	O&M	Operation and maintenance
		OEM	Original equipment manufacturers
mi	Mile	OFA	Overfire air
MJ/Nm ³	Megajoules per normal cubic meter	O-H, OH	Overhead
MJ/scm	Megajoule per standard cubic meter	OP/VWO	Over pressure/valve wide open
mm	Millimeter	PA	Primary air
MM	Million	PAC	Powdered activated carbon
MMacf	Million actual cubic feet	PC	Pulverized coal
MMBtu	Million British thermal units	p.f.	Power factor
MMBtu/hr	Million British thermal units per hour	ph	Phase
		pH	Power of hydrogen
MNQC	Multi Nozzle Quiet Combustor	PM	Particulate matter
mol%	Percent by mole	POTW	Publicly-owned treatment works
MPa	Megapascal		
MVA	Mega volt-amps	ppb	Parts per billion
MW	Megawatt	ppm	Parts per million
MWe	Megawatt electric	ppmv	Parts per million volume
MWh	Megawatt-hour	ppmvd	Parts per million volume, dry
N ₂	Nitrogen	ppmw	Parts per million weight
N/A	Not applicable	ppmwd	Parts per million weight, dry
NaCl	Sodium chloride	ppt	Parts per trillion
NaOH	Sodium hydroxide	PRB	Powder River Basin
NEMA	National Electrical Manufacturers Association	PSD	Prevention of Significant Deterioration
NERC	North American Electric Reliability Council	psi	Pounds per square inch
		psia	Pound per square inch absolute

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

psid	Pound per square inch differential	T&S	Transport and storage
psig	Pound per square inch gage	TASC	Total as-spent cost
QGESS	Quality Guidelines for Energy System Studies	TDS	Total dissolved solids
R&D	Research and development	TEG	Triethylene glycol
R+Q	Radiant plus quench	TEWAC	Totally Enclosed Water-to-Air Cooled
RD&D	Research, development, and demonstration	TG	Tail gas
RH	Reheater	TGTU	Tail gas treating unit
RO	Reverse osmosis	TOC	Total overnight cost
RR	Ramp rate	tonne	Metric ton (1,000 kg)
SC	Supercritical	TPC	Total plant cost
SC PC	Supercritical pulverized coal	tpd	Ton per day
SC&T	Shell Catalyst & Technologies	tph	Tons per hour
scfh	Standard cubic feet per hour	U.S.	United States
scfm	Standard cubic feet per minute	UCC	United Conveyor Corporation
Sch.	Schedule	USC	Ultra-supercritical
SCOT	Shell Claus Off-gas Treating	V	Volt
SCR	Selective catalytic reduction process or equipment	V-L	Vapor liquid portion of stream (excluding solids)
SDA	Spray dryer absorber	vol%	Percent by volume
SDE	Spray dryer evaporator	VT	Voltage transformers
SGC	Synthesis gas cooler	WGS	Water gas shift
Shell	Shell Global Solutions	wt%	Percent by weight
SNCR	Selective non-catalytic reduction	yr	Year
SNG	Synthetic natural gas	ZLD	Zero liquid discharge
SO ₂	Sulfur dioxide	\$/GJ	Dollars per gigajoule
SO ₃	Sulfur trioxide	\$/kW	Dollars per kilowatt
SRU	Sulfur recovery unit	\$/MMBtu	Dollars per million British thermal units
SS	Stainless steel	\$M	Millions of dollars
STG	Steam turbine generator	μS/cm	Micro Siemens per cm
SubC PC	Subcritical pulverized coal	°C	Degrees Celsius
SWS	Sour water stripper	°F	Degrees Fahrenheit
		5-10s	50-hour work week

This page intentionally blank

EXECUTIVE SUMMARY

This report presents an independent assessment of the cost and performance of select fossil energy power systems—integrated gasification combined cycle (IGCC), pulverized coal (PC), and natural gas combined cycle (NGCC) plants—using a systematic, transparent technical and economic approach. This is Volume 1 of a four-volume series that comprises the following reports:

- Volume 1: Bituminous Coal and Natural Gas to Electricity
- Volume 2: Coal to Synthetic Natural Gas and Ammonia (Various Coal Ranks)
- Volume 3: Low Rank Coal and Natural Gas to Electricity
- Volume 4: Bituminous Coal to Liquid Fuels

The cost and performance of fossil fuel-based generation technologies represented in this report (and the series at large) are important inputs to assessments and determinations of technology combinations to be utilized to meet the projected demands of future power markets. In addition to informing technology comparisons, the reference plant configurations found in this report provide perspective for regulators and policy makers. From a research and development perspective, this report is used to assess goals and metrics and to provide a consistent basis for comparing developing technologies.

Nineteen power plant configurations are analyzed in this report. A summary of the configurations is shown in Exhibit ES-1:

- Seven IGCC configurations—two Shell Global Solutions (Shell) gasifiers (with and without carbon dioxide [CO₂] capture), two Chicago Bridge and Iron (CB&I) E-Gas™ full-slurry quench (FSQ) gasifiers (with and without CO₂ capture), and three General Electric Power (GEP) gasifiers (one without [radiant] and two with [one radiant and one quench] CO₂ capture), all with two state-of-the-art 2008 F-Class combustion turbines
- Six PC power plant configurations—three subcritical (SubC) and three supercritical (SC) (with [one 90 percent and one 95 percent] and without CO₂ capture)
- Six NGCC power plant configurations—three state-of-the-art 2017 F-Class combustion turbines and three state-of-the-art 2017 H-Class combustion turbines (with [one 90 percent and one 95 percent] and without CO₂ capture)

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit ES-1. Case configuration summary

Case ^A	Plant Type	Steam Cycle, psig/°F/°F	Combustion Turbine	Gasifier/Boiler Technology	H ₂ S Separation	Sulfur Removal	PM Control	CO ₂ Separation	Capture Rate ^D	Process Water Treatment
B1A	IGCC	1800/1050/1050	2 x State-of-the-art 2008 F-Class ^B	Shell	Sulfinol-M	Claus Plant/Sulfur	Cyclone, candle filter, and water scrubber	N/A	N/A	Vacuum flash, brine concentrator, crystallizer
B1B		1800/1000/1000			Selexol			Selexol 2 nd stage	90%	
B4A		1800/1050/1050		CB&I E-Gas™	Refrigerated MDEA			N/A	N/A	
B4B		1800/1000/1000			Selexol			Selexol 2 nd stage	90%	
B5A		1800/1050/1050		GEP Radiant	Selexol		Quench, water scrubber, and AGR adsorber	N/A	N/A	
B5B		1800/1000/1000			Selexol			Selexol 2 nd stage	90%	
B5B-Q		1800/1000/1000		GEP Quench	Selexol			Selexol 2 nd stage	90%	
B11A	PC	2400/1050/1050	N/A	SubC PC	N/A	Wet FGD/ Gypsum	Baghouse	N/A	N/A	Spray dryer evaporator
B11B.90								CANSOLV	90%	
B11B.95				95%						
B12A		3500/1100/1100	SC PC ^C	N/A				N/A		
B12B.90				CANSOLV				90%		
B12B.95								95%		
B31A	NGCC	2378/1085/1084	2 x State-of-the-art 2017 F-Class	HRSG	N/A	N/A	N/A	N/A	N/A	N/A
B31B.90								CANSOLV	90%	
B31B.95									95%	
B32A		2668/1085/1044	2 x State-of-the-art 2017 H-Class					N/A	N/A	
B32B.90								CANSOLV	90%	
B32B.95									95%	

^AAll plants in this report are assumed to be located at a generic plant site in the midwestern United States

^BThe IGCC F-class combustion turbines represent the same technology considered in the previous version of this report. There have not been significant recent advances in high-H₂ syngas turbine technology; consequently, these turbines are still considered state-of-the-art.

^CWhile labeled as SC conditions, the SC steam cycle conditions utilized in this report are also generally representative of commercial plants characterized as ultra-supercritical (USC), particularly with respect to temperature (593°C [1,100°F]). Because efficiency is more sensitive to steam cycle temperature than pressure, the resulting performance is at or near that of top-performing commercially-available USC PC plants.

^DThe capture rate for IGCC cases is based on the total feedstock minus unburned carbon in slag. The capture rate for PC and NGCC cases is based on the total feedstock minus unburned carbon in ash (PC cases). The rate of CO₂ capture from the flue gas in the CANSOLV systems and from syngas in the Selexol systems varies. An explanation for the difference is provided in Section 2.4.4. All cases sequester the CO₂ offsite.

All plant configurations were evaluated based on installation at a greenfield site. Capacity factors (CFs) utilized were 80 percent for all IGCC configurations, and 85 percent for all PC and NGCC configurations. Availability is defined as the percent of time during a specific period that a generating unit is capable of producing electricity. This report assumes that each new plant would be dispatched any time it is available and would be capable of generating the nameplate capacity when online. Therefore, CF and availability are equal. The calculations assume that the CF and availability are constant over the life of the plant. These plants are considered to be built for a thirty-year life, are well-maintained plants with sufficient and adequate maintenance budgets, and are operated in a manner that supports the assumed CF. Achieving such CFs would require that these plants be near the top of the dispatch list. This report includes a sensitivity analysis on the impact of plant capacity factor on LCOE.

The combustion turbines (CTs) used in each of the IGCC and NGCC configurations are manufactured in discrete sizes, with each of the configurations assuming combustion turbine operation at its rated output. While the output of the combustion turbines is consistent between configurations within a technology type, the IGCC cases have net outputs ranging from 499 (Case B5B-Q) to 641 MW (Case B4A). The range in IGCC net output is caused by the significant auxiliary load imposed in the CO₂ capture cases—primarily due to CO₂ compression—and the need for steam for CO₂ capture and the water gas shift (WGS) reactions, which reduces steam turbine output. The output in NGCC cases varies from 640 MW (F-frame CT with 95 percent capture) to 992 MW (H-frame CT without capture). The nominal net plant output for all PC plants in this study is 650 MW, which remains consistent with Revision 4 of this report (Fossil Energy Baseline Revision 4 [FEBR4]).

Air pollution control devices for all technologies are designed to meet the limits of the February 2013 update to the New Source Performance Standards (NSPS) for sulfur dioxide (SO₂), nitrogen oxide (NO_x), and particulate matter (PM), and the March 2013 update to the Utility Mercury and Air Toxics Standards (MATS) for mercury (Hg) and hydrochloric acid (HCl). Liquid waste streams are regulated by the November 2015 update to the Effluent Limitation Guidelines (ELG), and all plants in the study are in compliance.

For the IGCC cases, hydrogen sulfide (H₂S) is separated with an acid gas removal (AGR) process and converted to elemental sulfur in a Claus plant with tail gas recycle to limit SO₂ stack emissions; carbonyl sulfide (COS) hydrolysis is employed in non-capture cases, but not in capture cases where WGS is used; NO_x formation is minimized with low NO_x burners (LNBs) and nitrogen (N₂) dilution, and where required, syngas humidification; the PM is controlled with some combination of a water quench, syngas scrubber, cyclone, and/or candle filter, depending on the gasifier technology; Hg is controlled with dual sulfur-impregnated carbon beds; the HCl is primarily removed in the syngas scrubber with the remainder removed with the low temperature heat recovery condensate. The HCl is removed from the syngas scrubber effluent with a brine concentrator and crystallizer.

For the PC cases, SO₂, NO_x, PM, Hg, and HCl are actively controlled with wet flue gas desulfurization (FGD), LNBs with overfire air (OFA) and selective catalytic reduction (SCR), a baghouse, dry sorbent injection (DSI) and activated carbon injection (ACI), and a spray dryer evaporator to treat FGD blowdown, respectively.

For NGCC cases, NO_x is controlled with LNBs and an SCR.

All power plant configurations with carbon capture are designed to achieve 90 percent or greater capture, resulting in atmospheric CO₂ emissions at levels far below the proposed Environmental Protection Agency (EPA) regulation.^a

This revision reflects varying degrees of updated technology vendor input. The majority of modeling inputs remained constant from FEBR4 except for those noted below. For IGCC plants, the performance was unchanged. However, the air separation unit (ASU) costs were updated to maintain greater consistency with Revision 3 of this report and other NETL reports. For PC and NGCC plants, the CO₂ capture system was updated to reflect a new 2021 vendor quote. The primary revision was the adjustment of the NGCC capture system to match more closely that of the PC system in terms of both solvent used and system layout. For both PC and NGCC, 95 percent capture cases were included. Aside from the capture system, new vendor quotes were not obtained for the balance of plant items. Rather, costs were scaled according to NETL's current Quality Guidelines for Energy System Studies (QGESS) methodology. Finally, H-frame NGCC cases were included utilizing data from a 2017 vendor quote. The final assessment of performance and cost was determined independently by NETL and is not endorsed by the individual vendors.

To ensure methodologically-sound, consistent, and transparent technology assessments and comparisons, NETL relies upon its QGESS reports, which provide guidance on topics ranging from recommended feedstock specifications and pricing, [1] [2] recommendations for performance modeling assumptions, [3] and guidance for cost estimation methodology. [4]

The methodology for developing the performance results presented in this report included performing steady-state simulations of the power plant configurations at the nameplate rating using the Aspen Plus® (Aspen) process modeling software. The major plant equipment performance and process limits were based on published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgment. [3] Mass and energy balance data from the Aspen models were used to size major pieces of equipment, which formed the basis for developing the cost estimates presented.

The capital and operating costs for the major equipment and plant sub-systems were estimated by Black & Veatch based on the simulation results using an in-house database, legacy plant estimates, and conceptual estimating models. The cost results were further calibrated using a combination of adjusted vendor-furnished data and scaled estimates from previous design/build projects. The cost results are reported in 2018 dollars.^b

^a EPA promulgated an NSPS on October 23, 2015, for emissions of CO₂ for new fossil fuel-fired electric utility generating units. [36] The limit set by the regulation was 1,000 lb-CO₂/MWh-gross for NGCC, and 1,400 lb-CO₂/MWh-gross for PC and IGCC plants. As of the publication of this report, the EPA has proposed changes that increase the CO₂ emissions limit for the PC and IGCC plants considered in this study to 1,900 lb-CO₂/MWh-gross. [137] [37] These changes do not impact the previously established emissions limit for NGCC plants.

^b The Chemical Engineering Plant Cost Index [49] indicates relatively high volatility for capital and labor costs, with the cost index rising by 30 percent between December 2018 and March 2022. As these fluctuations are not captured by the reported cost uncertainty, the reader should adjust the reported costs if required by the end use of the data.

The baseline fuel cost for this analysis is specified in the 2019 revision of the QGESS report on “Fuel Prices for Selected Feedstocks in National Energy Technology Laboratory [NETL] Studies.” [5] The levelized price for Illinois No. 6 coal delivered to the Midwest is \$2.11/GJ (\$2.23/MMBtu), on a higher heating value (HHV) basis and in 2018 United States (U.S.) dollars. The levelized price for natural gas delivered to the Midwest is \$4.19/GJ (\$4.42/MMBtu), on an HHV basis and in 2018 U.S. dollars.^c

The cost metric used in this report is the levelized cost of electricity (LCOE) reported in real 2018 dollars, which is the revenue that must be received by the generator per net MWh produced to meet the desired return on equity after meeting all debt and tax obligations and operating expenses. Detailed information pertaining to LCOE calculations is available in the 2019 revision of the QGESS report “Cost Estimation Methodology for NETL Assessment of Power Plant Performance.” [4] The cost of CO₂ transport and storage (T&S), on an equivalent dollar per MWh basis, is added to the LCOE and represents a 62 km (100 mile) CO₂ pipeline and storage in a deep saline formation in the Midwest.^d On a unit basis, the cost of CO₂ T&S applied is \$10 per tonne (\$9/ton) of CO₂.

The LCOE results shown for the cases considered in this study are not intended to reflect all the potential market pressures experienced by plants operating today, or the price consumers can expect to pay. Rather, the primary focus is on a sound, transparent, consistent methodology to develop those results, built with industry and vendor input, which ultimately leads to an independent benchmark for the cases considered. This outcome is of significant value to internal and external stakeholders.

Selection of new generation technologies will depend on many factors, including:

- Capital and operating costs
- Overall energy efficiency
- Operational flexibility (e.g., ramp rate, turndown, start-up time)
- Fuel prices
- Project financial requirements
- Availability, reliability, and environmental performance
- Current and potential regulations governing air, water, and solid waste discharges from fossil-fueled power plants
- Specific site and application constraints and requirements
- Market penetration of coal technologies that have matured and improved as a result of commercial-scale demonstrations

^c The Energy Information Administration [138] indicates relatively high volatility for natural gas, with the Henry hub spot price increasing to \$7.83/GJ (\$8.26/MMBtu) in May 2022. As these fluctuations are not captured by the reported cost uncertainty, the reader should adjust the reported costs if required by the end use of the data.

^d Estimated using the Office of Fossil Energy (FE)/NETL CO₂ Transport Cost Model and the FE/NETL CO₂ Saline Storage Cost Model. Additional detail on development of these costs is available in the 2019 revision of the QGESS report “Carbon Dioxide Transport and Storage Costs in NETL Studies.” [51]

While critical to the power generation market, operational flexibility is not explicitly considered in the cases in this report. NETL is producing a new volume for this report series examining flexible plant technologies, configurations, and operation. [6]

RESULTS ANALYSIS

The performance and environmental profile summary for IGCC cases is shown in Exhibit ES-2, for PC in Exhibit ES-3, and for NGCC in Exhibit ES-4. A graph of the net plant efficiency (HHV basis) is provided in Exhibit ES-5.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit ES-2. Performance summary and environmental profile for IGCC cases

Case Name (Legacy Naming Convention) ^A	IGCC						
	Shell		E-Gas™ FSQ		GEP R+Q		
	B1A (5)	B1B (6)	B4A (3)	B4B (4)	B5A (1)	B5B (2)	B5B-Q (2a)
Performance							
CO ₂ Capture Rate (%)	0	90	0	90	0	90	90
Capacity Factor (%)	80	80	80	80	80	80	80
Gross Power Output (MWe)	765	696	763	742	765	741	685
Auxiliary Power Requirement (MWe)	125	177	122	185	131	185	186
Net Power Output (MWe)	640	519	641	557	634	556	499
Coal Flow Rate (lb/hr)	435,418	467,308	456,327	482,173	464,732	482,580	482,918
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HHV Thermal Input (kWt)	1,488,680	1,597,710	1,560,166	1,648,535	1,588,902	1,649,926	1,651,082
Net Plant HHV Efficiency (%)	43.0	32.5	41.1	33.8	39.9	33.7	30.2
Net Plant HHV Heat Rate (Btu/kWh)	7,940	10,497	8,308	10,101	8,554	10,118	11,287
Raw Water Withdrawal (gpm/MWnet)	6.5	9.8	6.8	9.3	7.6	9.9	12.6
Process Water Discharge (gpm/MWnet)	1.4	2.1	1.5	2.0	1.6	2.0	2.4
Raw Water Consumption (gpm/MWnet)	5.0	7.7	5.3	7.4	5.9	7.9	10.2
CO ₂ Emissions (lb/MMBtu)	200	21	199	20	197	20	20
CO ₂ Emissions (lb/MWh-gross)	1,328	161	1,391	153	1,396	151	163
CO ₂ Emissions (lb/MWh-net)	1,588	215	1,657	204	1,685	201	224
SO ₂ Emissions (lb/MMBtu) ^B	0.020	0.000	0.028	0.000	0.002	0.000	0.000
SO ₂ Emissions (lb/MWh-gross)	0.130	0.000	0.192	0.000	0.015	0.000	0.000
NO _x Emissions (lb/MMBtu)	0.059	0.049	0.056	0.049	0.054	0.048	0.048
NO _x Emissions (lb/MWh-gross)	0.390	0.382	0.393	0.371	0.379	0.364	0.394
PM Emissions (lb/MMBtu)	0.007	0.007	0.007	0.007	0.007	0.007	0.007
PM Emissions (lb/MWh-gross)	0.047	0.056	0.050	0.054	0.050	0.054	0.058
Hg Emissions (lb/TBtu)	0.452	0.383	0.430	0.396	0.423	0.395	0.365
Hg Emissions (lb/MWh-gross) ^C	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06

^A Previous versions of this report used a different naming convention (this report re-combines cases from *Cost and Performance Baseline for Fossil Energy Plants, Volume 1a* [7] and *Volume 1b*. [8]) The old case numbers are provided here, paired with the new case numbers for reference

^B Trace amounts of sulfur emissions may exist in the flue gas stream to the stack in capture cases

^C The mercury capture units were designed to attain the emissions target of 3.00x10⁻⁶ lb/MWh-gross

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit ES-3. Performance summary and environmental profile for PC cases

Case Name (Legacy Naming Convention) ^A	PC					
	SubC PC			SC PC		
	B11A (9)	B11B.90 (10)	B11B.95	B12A (11)	B12B.90 (12)	B12B.95
Performance						
CO ₂ Capture Rate (%)	0	90	95	0	90	95
Capacity Factor (%)	85	85	85	85	85	85
Gross Power Output (MWe)	688	769	774	686	763	768
Auxiliary Power Requirement (MWe)	38	118	124	36	113	118
Net Power Output (MWe)	650	650	650	650	650	650
Coal Flow Rate (lb/hr)	493,115	630,940	640,819	473,055	600,801	609,741
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A
HHV Thermal Input (kWt)	1,685,945	2,157,162	2,190,938	1,617,359	2,054,118	2,084,684
Net Plant HHV Efficiency (%)	38.6	30.2	29.7	40.2	31.7	31.2
Net Plant HHV Heat Rate (Btu/kWh)	8,849	11,317	11,495	8,490	10,778	10,938
Raw Water Withdrawal (gpm/MWnet)	10.0	15.3	15.7	9.3	14.3	14.6
Process Water Discharge (gpm/MWnet)	2.1	3.9	4.0	1.9	3.7	3.8
Raw Water Consumption (gpm/MWnet)	8.0	11.4	11.7	7.4	10.6	10.9
CO ₂ Emissions (lb/MMBtu)	202	20	10	202	20	10
CO ₂ Emissions (lb/MWh-gross)	1,693	195	98	1,628	187	94
CO ₂ Emissions (lb/MWh-net)	1,790	230	117	1,718	219	111
SO ₂ Emissions (lb/MMBtu) ^B	0.081	0.000	0.000	0.081	0.000	0.000
SO ₂ Emissions (lb/MWh-gross)	0.675	0.000	0.000	0.649	0.000	0.000
NO _x Emissions (lb/MMBtu)	0.084	0.073	0.072	0.087	0.076	0.076
NO _x Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.700	0.700
PM Emissions (lb/MMBtu)	0.011	0.009	0.009	0.011	0.010	0.010
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.090	0.090
Hg Emissions (lb/TBtu)	0.359	0.313	0.311	0.373	0.326	0.324
Hg Emissions (lb/MWh-gross) ^C	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06

^A Previous versions of this report used a different naming convention (this report re-combines cases from *Cost and Performance Baseline for Fossil Energy Plants, Volume 1a* [7] and *Volume 1b*. [8]) The old case numbers are provided here, paired with the new case numbers for reference

^B Trace amounts of sulfur emissions may exist in the flue gas stream to the stack in capture cases

^C The mercury capture units were designed to attain the emissions target of 3.00x10⁻⁶ lb/MWh-gross

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

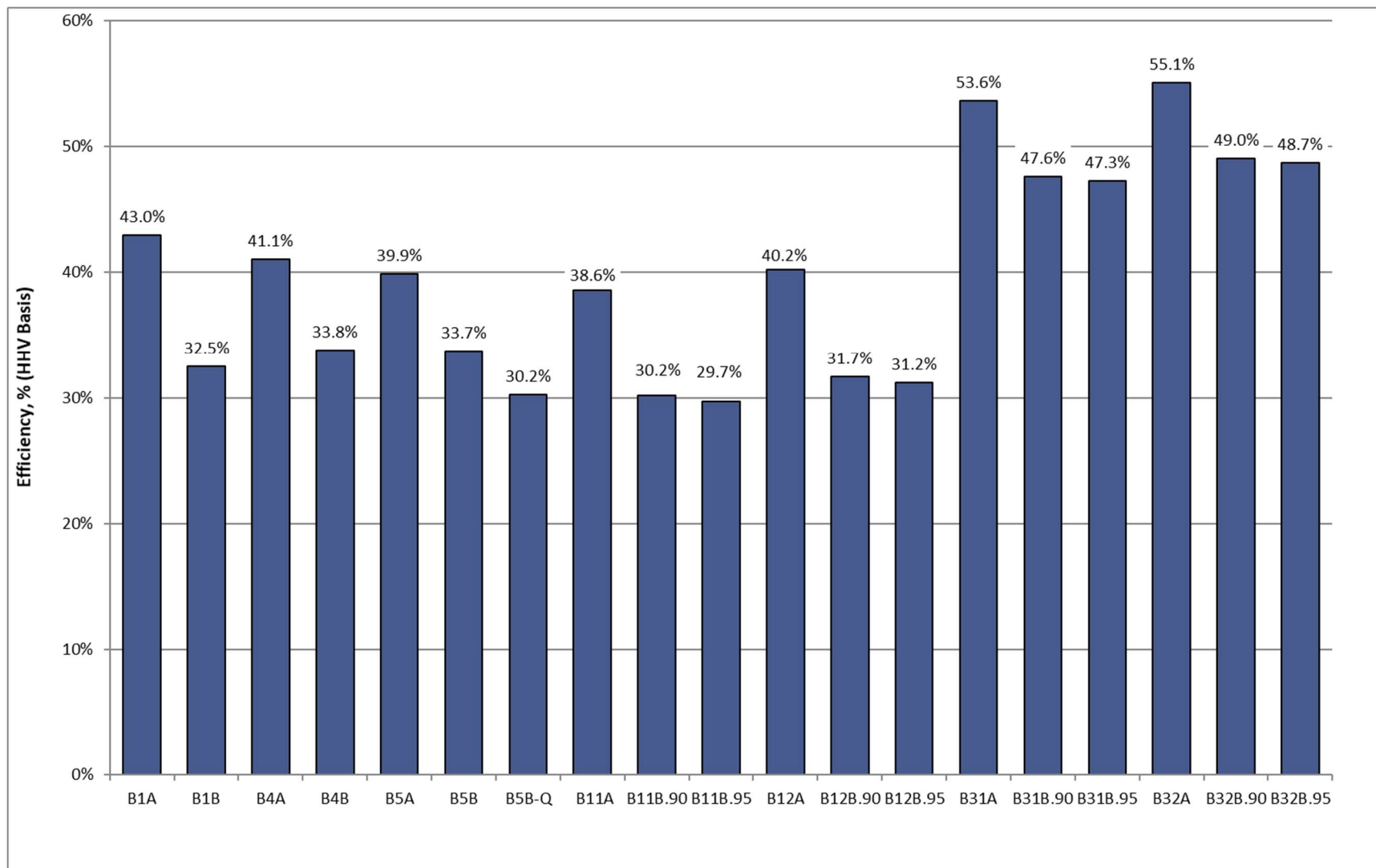
Exhibit ES-4. Performance summary and environmental profile for NGCC cases

Case Name (Legacy Naming Convention) ^A	NGCC					
	State-of-the-art 2017 F-Class			State-of-the-art 2017 H-class		
	B31A (13)	B31B.90 (14)	B31B.95	B32A	B32B.90	B32B.95
Performance						
CO ₂ Capture Rate (%)	0	90	95	0	90	95
Capacity Factor (%)	85	85	85	85	85	85
Gross Power Output (MWe)	740	692	690	1,009	945	942
Auxiliary Power Requirement (MWe)	14	47	49	17	62	65
Net Power Output (MWe)	727	645	640	992	883	877
Coal Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A
Natural Gas Flow Rate (lb/hr)	205,630	205,630	205,630	273,429	273,429	273,429
HHV Thermal Input (kWt)	1,354,905	1,354,905	1,354,905	1,801,631	1,801,631	1,801,631
Net Plant HHV Efficiency (%)	53.6	47.6	47.3	55.1	49.0	48.7
Net Plant HHV Heat Rate (Btu/kWh)	6,363	7,169	7,220	6,196	6,959	7,007
Raw Water Withdrawal (gpm/MWnet)	4.0	6.9	7.0	3.6	6.4	6.5
Process Water Discharge (gpm/MWnet)	0.9	2.3	2.4	0.8	2.2	2.2
Raw Water Consumption (gpm/MWnet)	3.1	4.6	4.7	2.8	4.2	4.3
CO ₂ Emissions (lb/MMBtu)	119	12	6	119	12	6
CO ₂ Emissions (lb/MWh-gross)	741	79	40	723	77	39
CO ₂ Emissions (lb/MWh-net)	755	85	43	735	83	42
SO ₂ Emissions (lb/MMBtu) ^B	0.001	0.000	0.000	0.001	0.000	0.000
SO ₂ Emissions (lb/MWh-gross)	0.006	0.000	0.000	0.006	0.000	0.000
NO _x Emissions (lb/MMBtu)	0.004	0.003	0.003	0.004	0.003	0.003
NO _x Emissions (lb/MWh-gross)	0.022	0.022	0.022	0.022	0.022	0.022
PM Emissions (lb/MMBtu)	0.002	0.000	0.000	0.002	0.000	0.000
PM Emissions (lb/MWh-gross)	0.012	0.000	0.000	0.011	0.000	0.000
Hg Emissions (lb/TBtu)	0.000	0.000	0.000	0.000	0.000	0.000
Hg Emissions (lb/MWh-gross)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

^A Previous versions of this report used a different naming convention (this report re-combines cases from *Cost and Performance Baseline for Fossil Energy Plants, Volume 1a* [7] and *Volume 1b*. [8]) The old case numbers are provided here, paired with the new case numbers for reference

^B Trace amounts of sulfur emissions may exist in the flue gas stream to the stack in capture cases

Exhibit ES-5. Net plant efficiency (HHV basis)



The primary performance and environmental profile conclusions that can be drawn from the IGCC cases are:

- In the non-carbon capture cases, the Shell gasifier has the highest net plant efficiency (43.0 percent), followed by the two-stage E-Gas™ slurry fed gasifier (41.1 percent).
- The energy penalty associated with adding nominal 90 percent CO₂ capture is primarily due to steam extraction for use in the WGS reaction, the auxiliary load for the CO₂ separation and compression equipment, and a slight plant derate due to the higher moisture content of the syngas working fluid. The reduction in net plant efficiency ranges 6–10 percentage points (15–24 percent relative to non-capture) with the variability being due to the different gasifier designs (e.g., slurry versus dry feed, syngas quench versus syngas heat recovery), which may vary between the capture and non-capture plant configurations.
 - The lowest energy penalty (6 percentage points) corresponds to the GEP Radiant gasifier cases primarily due to the non-capture plant design (slurry feed, water quench), which results in a high moisture content in the syngas and thus the CO₂ capture design requires little additional shift steam for WGS.
 - The highest energy penalty (10 percentage points) corresponds to the Shell gasifier cases. The design uses a dry feed system and, in the non-capture configuration, has relatively high heat recovery in the syngas cooler with no water quench, resulting in very low moisture content in the syngas. For the capture configuration, a water quench is added, which increases the moisture content of the syngas for the WGS reaction but decreases the heat recovery in the syngas cooler.
- The non-capture CB&I E-Gas™ case using refrigerated methyldiethanolamine (MDEA) has the highest SO₂ emissions (0.192 lb/MWh-gross) of the seven cases because refrigerated MDEA has the lowest H₂S removal efficiency of the AGR technologies considered.
- For the IGCC cases, the syngas scrubber blowdown flow rate range to be treated by the vacuum flash, brine concentrator, and crystallizer ZLD system spans 277–635 gpm, with Case B5B-Q having the highest flow rate for treatment. The other six IGCC cases span a tighter range of 277–332 gpm. The approximate performance impact of implementing the ZLD system across the seven IGCC cases is a 0.1–0.2 percentage point (absolute) decrease in the HHV net plant efficiency, with six of the seven IGCC cases falling at or around a 0.1 percentage point decrease. This is due primarily to the steam extraction and auxiliary load required for the total ZLD system, which is significantly larger than the auxiliary load required for the spray dryer evaporator applied in PC cases.
- Emissions of Hg, HCl, PM, NO_x, and SO₂ are all below the applicable federal regulatory limits currently in effect for IGCC technology.

The primary performance and environmental profile conclusions that can be drawn from the PC cases are:

- For the PC cases, adding CO₂ capture results in a HHV efficiency penalty of 8–9 percentage points (22–23 percent relative to non-capture) for Sub PC cases and 9 percentage points (21–22 percent relative to non-capture) for SC PC cases.
 - The addition of higher CO₂ capture rates, comparing B11B.90 and B11B.95, results in an HHV efficiency penalty of 0.5 percentage points (1.6 percent relative to B11B.90). For the SC PC cases, comparing B12B.90 and B12B.95, the addition of higher CO₂ capture rates results in an HHV efficiency penalty of 0.5 percentage points (1.5 percent relative to B12B.90).
- For the PC cases, the FGD wastewater blowdown flow rate range to be treated by the spray dryer evaporator spans 55–75 gpm. The approximate performance impact of implementing the spray dryer evaporator across the six PC cases is a 0.25–0.27 percentage point (absolute) decrease in the HHV net plant efficiency. This is due primarily to the diversion of warm flue gas away from the air preheater and to the evaporator, with an additional minor impact resulting from the small auxiliary load required by the spray dryer evaporator.
- Emissions of Hg, HCl, PM, NO_x, and SO₂ are all at or below the applicable federal regulatory limits currently in effect for PC technology.

The primary performance and environmental profile conclusions that can be drawn from the NGCC cases are:

- The NGCC H-class cases have the highest net efficiency of all the technologies, both without CO₂ capture (55.1 percent) and with CO₂ capture (49.0 percent at a 90 percent capture rate). The next non-NGCC case highest efficiency is the non-capture Shell IGCC case, with an efficiency of 43.0 percent.
- For the NGCC cases, adding CO₂ capture results in a HHV efficiency penalty of 6 percentage points (11–12 percent relative to non-capture) for both the F-frame cases and H-frame cases.
 - The addition of higher CO₂ capture rates to the F-frame cases, comparing B31B.90 and B31B.95, results in an HHV efficiency penalty of 0.3 percentage points (0.7 percent relative to B31B.90). For the H-frame cases, comparing B32B.90 and B32B.95, the addition of higher CO₂ capture rates results in an HHV efficiency penalty of 0.3 percentage points (0.7 percent relative to B32B.90).
- The NGCC penalty is less than the PC penalty because:
 - Natural gas is less carbon intensive than coal (based on the fuel compositions used in this study, natural gas contains 32 lb carbon/MMBtu (13.7 kg/GJ) [HHV] of heat input and coal contains 55 lb/MMBtu (23.6 kg/GJ) [HHV]).
 - The NGCC non-capture plant is more efficient, thus there is less total CO₂ to capture and compress (NGCC non-capture CO₂ emissions are approximately 56–59 percent lower than the PC cases) when normalized to equivalent net power outputs.

- These effects are offset slightly by the lower concentration of CO₂ in the NGCC flue gas (4 mol% versus 13 mol% for PC). Concentration of CO₂ is the driving force for capture from the flue gas in the amine system, and the lower concentration requires more energy (steam and auxiliary load) from the base plant to reach the capture target.
- Natural gas contains no Hg or chloride, and PM, NO_x, and SO₂ emissions are all at or below the applicable federal regulatory limits currently in effect for NGCC technology.

The cost results for IGCC cases are provided in Exhibit ES-6, for PC cases Exhibit ES-7, and for NGCC cases Exhibit ES-8. A graph of the LCOE is provided in Exhibit ES-9.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit ES-6. Cost summary for all IGCC cases

Case Name (Legacy Naming Convention) ^A	IGCC						
	Shell		E-Gas™ FSQ		GEP R+Q		
	B1A (5)	B1B (6)	B4A (3)	B4B (4)	B5A (1)	B5B (2)	B5B-Q (2a)
Cost							
Total Plant Cost (2018\$/kW)	4,087	6,545	3,656	5,501	4,105	5,568	5,212
Bare Erected Cost	2,837	4,487	2,548	3,788	2,854	3,834	3,595
Home Office Expenses	439	691	396	585	443	592	559
Project Contingency	588	967	534	828	594	826	795
Process Contingency	222	401	179	300	214	316	262
Total Overnight Cost (2018\$/MM)	3,194	4,175	2,867	3,773	3,189	3,810	3,206
Total Overnight Cost (2018\$/kW)	4,993	8,039	4,474	6,776	5,032	6,847	6,423
Owner's Costs	906	1,493	818	1,275	927	1,279	1,211
Total As-Spent Cost (2018\$/kW)	5,764	9,280	5,165	7,822	5,809	7,904	7,414
LCOE (\$/MWh) (excluding T&S)^B	111.5	173.7	103.2	150.1	114.0	151.3	147.1
Capital Costs	58.2	93.7	52.1	79.0	58.6	79.8	74.8
Fixed Costs	21.3	33.5	19.2	28.4	21.4	28.7	27.3
Variable Costs	14.3	23.2	13.3	20.3	14.9	20.3	19.8
Fuel Costs	17.7	23.4	18.5	22.5	19.0	22.5	25.1
LCOE (\$/MWh) (including T&S)^B	111.5	182.3	103.2	158.3	114.0	159.4	156.2
CO₂ T&S Costs	N/A	8.6	N/A	8.2	N/A	8.1	9.1
Cost of CO₂ Captured (ex. T&S), \$/tonne^C	N/A	127.7	N/A	104.3	N/A	106.7	91.1
Cost of CO₂ Avoided (incl. T&S), \$/tonne^C	N/A	172.8	N/A	136.6	N/A	137.9	135.3

^AFinancing structures are presented in NETL's "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance" [4]

^BVarying incentives, such as tax credits, could impact the economics of the system

^CBoth the cost of CO₂ captured and cost of CO₂ avoided were calculated based on the non-capture SC PC Case B12A for all coal cases

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit ES-7. Cost summary for all PC cases

Case Name (Legacy Naming Convention) ^A	PC					
	SubC PC			SC PC		
	B11A (9)	B11B.90 (10)	B11B.95	B12A (11)	B12B.90 (12)	B12B.95
Cost						
Total Plant Cost (2018\$/kW)	2,015	3,393	3,458	2,103	3,452	3,514
<i>Bare Erected Cost</i>	1,486	2,408	2,453	1,551	2,455	2,497
<i>Home Office Expenses</i>	260	421	429	271	430	437
<i>Project Contingency</i>	270	472	482	281	479	488
<i>Process Contingency</i>	0	91	95	0	88	92
Total Overnight Cost (2018\$/MM)	1,615	2,709	2,761	1,683	2,752	2,802
Total Overnight Cost (2018\$/kW)	2,484	4,165	4,245	2,588	4,233	4,309
<i>Owner's Costs</i>	468	772	787	485	781	795
Total As-Spent Cost (2018\$/kW)	2,867	4,808	4,900	2,988	4,886	4,974
LCOE (\$/MWh) (excluding T&S)^B	64.0	99.1	100.9	64.5	98.4	100.1
<i>Capital Costs</i>	27.2	45.7	46.6	28.4	46.4	47.3
<i>Fixed Costs</i>	9.2	14.6	14.9	9.5	14.8	15.1
<i>Variable Costs</i>	7.9	13.6	13.9	7.7	13.2	13.5
<i>Fuel Costs</i>	19.7	25.2	25.6	18.9	24.0	24.4
LCOE (\$/MWh) (including T&S)^B	64.0	108.4	110.9	64.5	107.3	109.7
<i>CO₂ T&S Costs</i>	N/A	9.3	10.0	N/A	8.9	9.5
Cost of CO₂ Captured (ex. T&S), \$/tonne^C	N/A	37.0	36.3	N/A	38.1	37.3
Cost of CO₂ Avoided (incl. T&S), \$/tonne^C	N/A	65.0	63.9	N/A	63.0	61.9

^AFinancing structures are presented in NETL's "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance" [4]

^BVarying incentives, such as tax credits, could impact the economics of the system

^CBoth the cost of CO₂ captured and cost of CO₂ avoided were calculated based on the non-capture SC PC Case B12A for all coal cases

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit ES-8. Cost summary for all NGCC cases

Case Name (Legacy Naming Convention) ^A	NGCC					
	State-of-the-art 2017 F-Class			State-of-the-art 2017 H-class		
	B31A (13)	B31B.90 (14)	B31B.95	B32A	B32B.90	B32B.95
Cost						
Total Plant Cost (2018\$/kW)	780	1,686	1,727	796	1,593	1,630
<i>Bare Erected Cost</i>	561	1,134	1,160	573	1,078	1,101
<i>Home Office Expenses</i>	112	227	232	115	216	220
<i>Project Contingency</i>	107	254	261	109	237	243
<i>Process Contingency</i>	0	71	74	0	62	65
Total Overnight Cost (2018\$/MM)	692	1,321	1,344	963	1,710	1,738
Total Overnight Cost (2018\$/kW)	952	2,049	2,099	970	1,936	1,980
<i>Owner's Costs</i>	172	363	372	174	343	351
Total As-Spent Cost (2018\$/kW)	1,040	2,239	2,293	1,060	2,115	2,164
LCOE (\$/MWh) (excluding T&S)^B	43.3	64.4	65.4	42.7	61.5	62.4
<i>Capital Costs</i>	9.9	21.3	21.8	10.1	20.1	20.6
<i>Fixed Costs</i>	3.6	7.4	7.6	3.5	6.8	7.0
<i>Variable Costs</i>	1.7	4.0	4.1	1.7	3.8	3.9
<i>Fuel Costs</i>	28.1	31.7	31.9	27.4	30.8	31.0
LCOE (\$/MWh) (including T&S)^B	43.3	67.9	69.1	42.7	64.9	66.0
<i>CO₂ T&S Costs</i>	N/A	3.5	3.7	N/A	3.4	3.6
Cost of CO₂ Captured (ex. T&S), \$/tonne^C	N/A	60.7	59.9	N/A	55.9	55.2
Cost of CO₂ Avoided (incl. T&S), \$/tonne^C	N/A	80.8	79.8	N/A	75.0	74.2

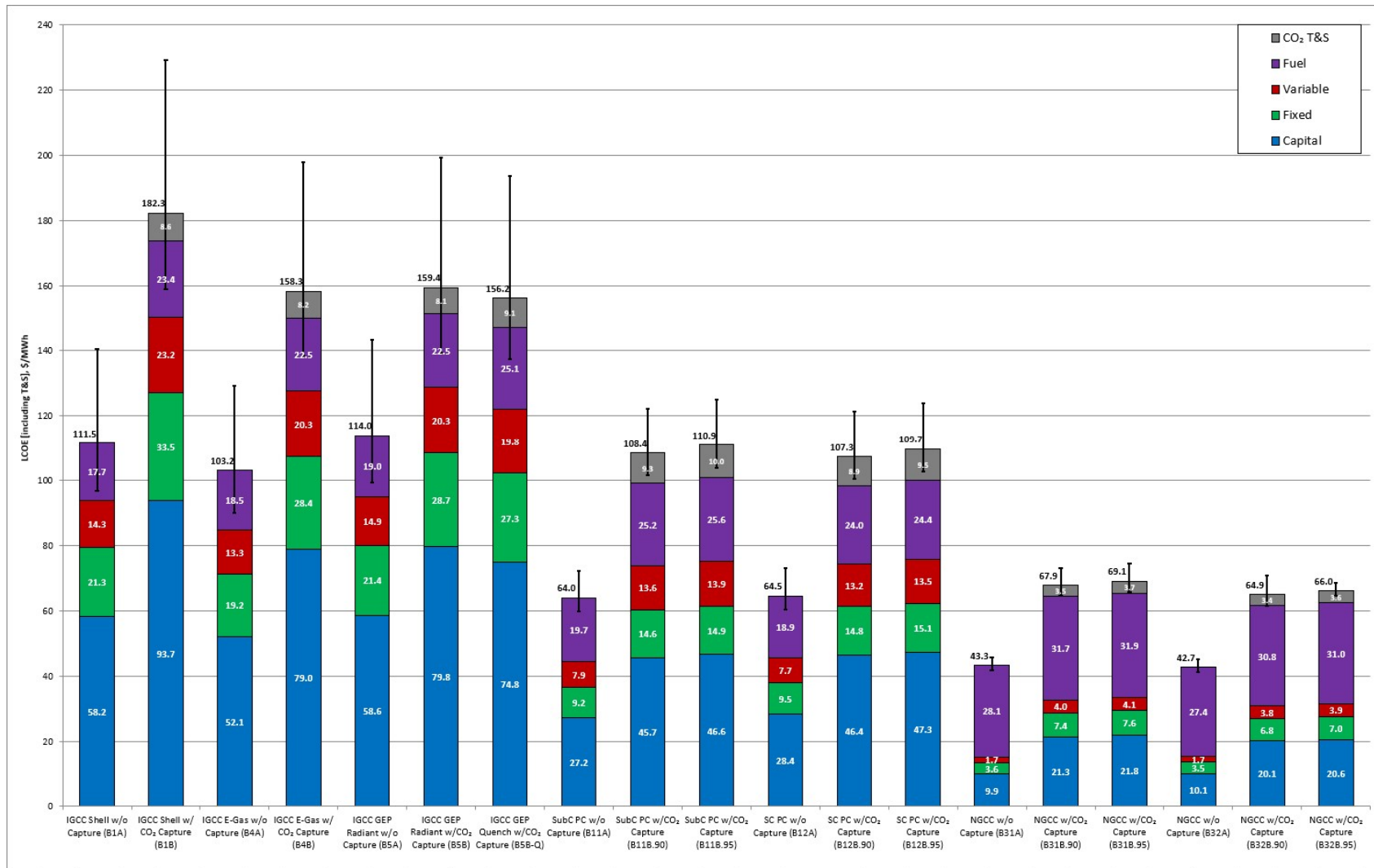
^AFinancing structures are presented in NETL's "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance" [4]

^BVarying incentives, such as tax credits, could impact the economics of the system

^CThe cost of CO₂ captured and cost of CO₂ avoided were calculated based on the analogous non-capture case (i.e. B31B cases use B31A as a reference and B32B cases use B32A)

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit ES-9. LCOE by cost component



Note: Financing structures are presented in NETL's "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance" [4]

Note: As discussed in the Special Considerations on Reported Costs section below, the capital cost estimates in this report reflect varying uncertainty ranges by technology type. The error bars represent the potential LCOE range relative to the maximum and minimum capital cost uncertainty ranges. The LCOE ranges presented are not reflective of other changes, such as variation in fuel price, labor price, CF, or other factors.

The primary cost conclusions that can be drawn from the IGCC cases are:

- E-GasTM has the lowest total overnight cost (TOC) cost among the non-capture cases. The E-GasTM technology has several features that lend to the lower cost, such as:
 - The firetube syngas cooler is much smaller and less expensive than a radiant section. E-GasTM can use a firetube boiler because the two-stage design reduces the syngas temperature (slurry quench) to a range where a radiant cooler is not needed.
 - The firetube syngas cooler sits next to the gasifier instead of above or below it, which reduces the height of the main gasifier structure. The E-GasTM proprietary slag removal system—used instead of lock hoppers below the gasifier—also contributes to the lower structure height.
- The normalized TOC of the GEP Radiant and Shell gasifier non-capture cases are approximately 12 percent greater than E-GasTM.
- The GEP Quench gasifier (GEP Radiant is 7 percent greater than GEP Quench) is the low-cost technology in the CO₂ capture cases, with E-GasTM normalized TOC approximately 6 percent higher and Shell approximately 25 percent higher.
- The ASU cost represents 3–4 percent of the TOC in all cases. The ASU cost includes oxygen (O₂) and N₂ compression. With N₂ dilution used to the maximum extent possible, N₂ compression costs are significant.
- The normalized TOC premium for adding CO₂ capture averages 44 percent, spanning a TOC increase range of \$1,391–3,046/kW.
- The LCOE is dominated by capital costs, comprising at least 50 percent of the total (excluding T&S costs) in all cases.
- In the non-capture cases the E-GasTM gasifier has the lowest LCOE, but the differential with Shell is reduced (relative to the normalized TOC comparison) primarily because of the higher efficiency of the Shell gasifier. The Shell LCOE is 8 percent higher than E-GasTM (compared to 12 percent higher normalized TOC). The GEP gasifier LCOE is about 10 percent higher than E-GasTM.
- In the capture cases, the order of the GEP Radiant and Shell gasifiers is reversed, with GEP Quench being the lowest LCOE option. As discussed in the performance results previously, Shell presents with the largest energy penalty as a result of the addition of capture. This penalty translates to a lower plant efficiency as compared to GEP Radiant, and results in the LCOE order reversing as compared to the non-capture cases. The range is from \$156.2/MWh for GEP Quench to \$182.3/MWh for Shell with E-GasTM and GEP Radiant intermediate at \$158.3/MWh and \$159.4/MWh, respectively, excluding T&S. The LCOE CO₂ capture premium for the cases averages 41 percent (a range of 29–56 percent).
- The CO₂ T&S LCOE component composes 5–6 percent of the total LCOE in all capture cases.

The primary cost conclusions that can be drawn from the PC cases are:

- Capital costs for SubC and SC PC are essentially equivalent within the accuracy of this report for a constant power output.
- The addition of CO₂ capture increases the capital portion of the LCOE by 64–71 percent across all PC cases.
- The difference between the SC PC and SubC PC LCOEs is minor, given the level of accuracy of the study estimate.
- The capital cost component represents the largest portion of the LCOE in PC cases (excluding T&S costs), ranging 43–47 percent of the total LCOE.
- The fuel cost component in PC cases represents 24–31 percent of the total LCOE (excluding T&S costs). This is higher, but comparable with IGCC cases, and significantly less than the fuel contribution shown in NGCC cases.
- CO₂ T&S costs add \$9–10/MWh to the LCOE, which accounts for approximately 8–9 percent of the total LCOE.
- The PC cases incur a 66–73 percent increase in LCOE (including T&S costs) due to the addition of CO₂ capture.
 - The addition of higher CO₂ capture rates to the SubC PC cases results in an LCOE penalty of \$2.5/MWh (2.3 percent) in Case B11B.95, compared to Case B11B.90. For the SCPC cases, the addition of higher CO₂ capture rates results in an LCOE penalty of \$2.3/MWh (2.2 percent) in Case B12B.95, compared to Case B12B.90.

The primary cost conclusions that can be drawn from the NGCC cases are:

- The addition of CO₂ capture increases the capital portion of the LCOE by 100–120 percent for NGCC.
- The capital cost component in NGCC cases represents 23–33 percent of the total LCOE (excluding T&S costs), a smaller percentage than in PC or IGCC cases.
- The fuel cost component represents the largest portion of the LCOE in NGCC cases, ranging 49–65 percent of the total LCOE (excluding T&S costs).
- CO₂ T&S costs add \$3–4/MWh to the LCOE, which accounts for approximately 5 percent of the total LCOE.
- The NGCC case incurs a 52–60 percent increase in LCOE due to the addition of CO₂ capture.
 - The addition of higher CO₂ capture rates to the F-frame cases results in an LCOE penalty of \$1.2/MWh (1.8 percent) in Case B31B.95, compared to Case B31B.90. For the H-frame cases, the addition of higher CO₂ capture rates results in an LCOE penalty of \$1.1/MWh (1.8 percent) in Case B32B.95, compared to Case B32B.90.

General cost conclusions that can be drawn between the three technology types are:

- Based on TOC in \$/kW, B31A is approximately 37 percent of B12A and B31B.90 is 48 percent of B12B.90.

- F-frame NGCC plant LCOEs are approximately 63–67 percent of the SC PC plant LCOEs when compared with and without capture, respectively.
- Despite the higher net plant efficiency and equivalent decrease in LCOE, both the cost of CO₂ captured and cost of CO₂ avoided are higher for NGCC cases than PC cases due to the lower concentration and amount of CO₂ available for capture.
- If future legislation assigns a cost to carbon emissions, all the technologies examined in this report will become more expensive. The technologies without carbon capture will be impacted to a larger extent than those with carbon capture, and coal-based technologies will be impacted more than natural gas-based technologies.

SENSITIVITIES

Exhibit ES-10 shows the LCOE sensitivity to natural gas costs for NGCC H-Frame and SC PC cases with 95 percent capture and without CCS, as well as the lowest LCOE IGCC cases with (GEP Quench) and without (E-Gas) CCS. The bands for the coal cases represent a variance in coal price from \$1.58–\$2.63/GJ (\$1.67–\$2.78/MMBtu) (±25 percent of the base study value of \$2.11/GJ [\$2.23/MMBtu]). This sensitivity highlights regions of competitiveness for NGCC with SC PC and the lowest cost IGCC options, with and without CCS, as a function of the delivered natural gas price. The base case assumed natural gas price is \$4.19/GJ (\$4.42/MMBtu).

Exhibit ES-11 shows the LCOE sensitivity to coal costs for NGCC H-Frame and SC PC cases with 95 percent capture and without CCS, as well as the lowest LCOE IGCC cases with (GEP Quench) and without (E-Gas) CCS. The bands for the natural gas cases represent a variance in natural gas price of \$3.15–5.24/GJ (\$3.32–5.53/MMBtu) (±25 percent of the base study value of \$4.19/GJ [\$4.42/MMBtu]). Similar to Exhibit ES-10, this sensitivity highlights regions of competitiveness for NGCC with SC PC and the lowest cost IGCC options, with and without CCS, as a function of the delivered coal price. The base case assumed coal price is \$2.11/GJ (\$2.23/MMBtu).

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit ES-10. LCOE sensitivity to natural gas costs

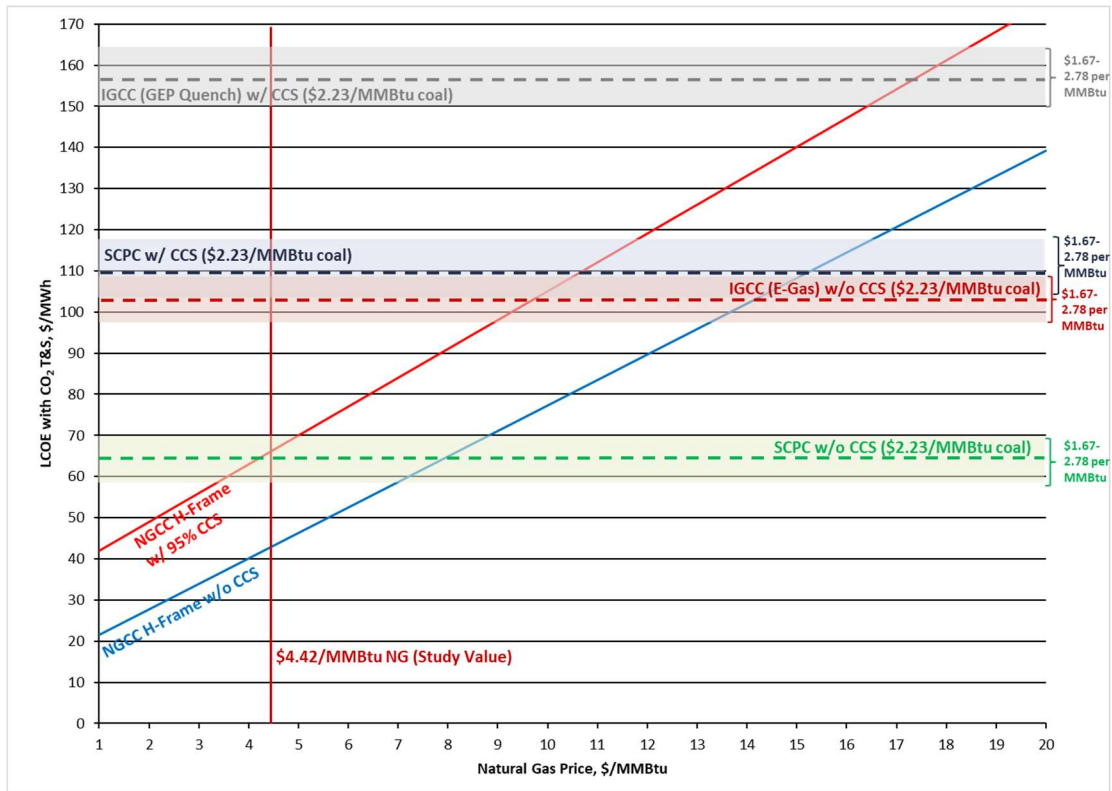
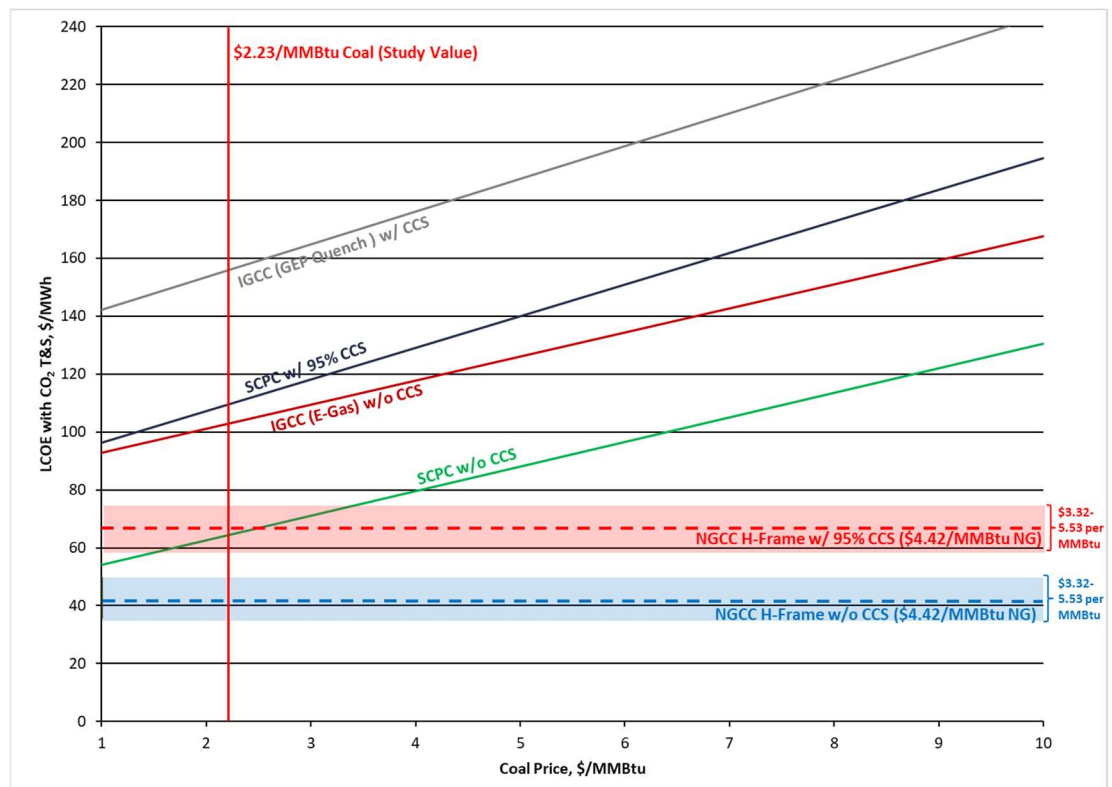


Exhibit ES-11. LCOE sensitivity to coal costs

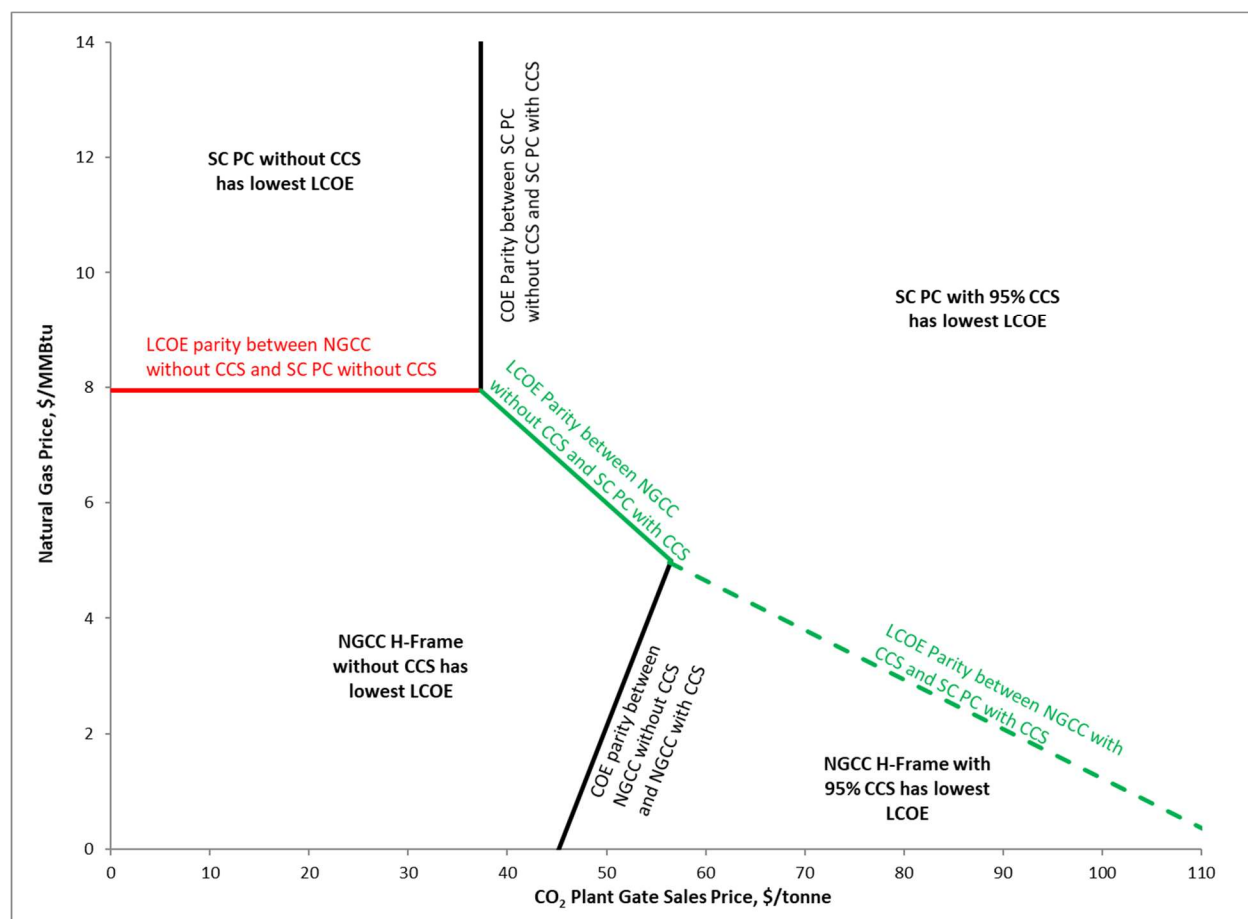


Sale of the captured CO₂ for utilization and storage in enhanced oil recovery (EOR) has the potential to provide a revenue stream for cases with CO₂ capture. The plant gate CO₂ sales price, or the cost of CO₂ captured, will ultimately depend on a number of factors including plant location and crude oil prices. The impact of CO₂ sales and the implications on the competitiveness of the capture technologies can be considered in a “phase diagram” type plot, as shown in Exhibit ES-12. The lines in the plot represent LCOE parity between different pairs of technologies.

The plot illustrates the following when comparing NGCC (B32A) and PC technologies:

- Capture cases include 95 percent CO₂ capture
- Non-capture plants are the low-cost option below a CO₂ price of \$38/tonne (\$34/ton).
- NGCC is preferred when natural gas prices are below \$7.9/MMBtu with a CO₂ sale price below \$37/tonne (\$34/ton) (and a CF of 85 percent). The natural gas price that provides parity between the various NGCC and PC cases drops off at higher CO₂ revenues reaching \$2/MMBtu at approximately \$91/tonne (\$83/ton).

Exhibit ES-12. Lowest cost technology options at various natural gas and CO₂ sales prices for NGCC and PC



SPECIAL CONSIDERATIONS ON REPORTED COSTS

Capital Costs

The capital cost estimates documented in this report reflect varying uncertainty ranges by technology type, as shown in Exhibit ES-13.

Exhibit ES-13. Capital cost uncertainty ranges

Technology	Uncertainty Range	AACE Classification
IGCC	-25/+50	Class 5
PC	-15/+30	Class 4
NGCC	-15/+25	Class 4

IGCC cases carry an uncertainty range of -25 percent/+50 percent, consistent with Association for the Advancement of Cost Engineering (AACE) Class 5 cost estimates (i.e., feasibility study) [4] [9] [10], based on the level of engineering design performed. This range is deemed reflective of recent commercial power IGCC experience. PC and NGCC cases carry smaller ranges, and both fall within AACE Class 4 estimates. Given recent experience with NGCC plants, the NGCC uncertainty range is slightly smaller than PC. In all cases, this report intends to represent the next commercial offering and relies on vendor cost estimates for component technologies. It also applies process contingencies at the appropriate subsystem levels in an attempt to account for expected but undefined costs, which can be a challenge for emerging technologies.

Costs of Mature Technologies and Designs

The cost estimates for plant designs that only contain fully mature technologies, which have been widely deployed at commercial scale (e.g., PC and NGCC power plants without CO₂ capture), reflect nth-of-a-kind (NOAK) on the technology commercialization maturity spectrum. The costs of such plants have dropped over time due to “learning by doing”, supply chain improvements, vendor competition, and risk reduction benefits that result from serial deployments as well as from continuing research and development (R&D).

Costs of Emerging Technologies and Designs

The cost estimates for plant designs that include technologies that are not yet fully mature (e.g., IGCC plants and any plant with CO₂ capture) use the same cost estimating methodology as for mature plant designs, which does not fully account for the unique cost premiums associated with the initial, complex integrations of emerging technologies in a commercial application. Thus, it is anticipated that initial deployments of these plants may incur costs higher than those reflected within this report.

Other Factors

Actual reported project costs for all the plant types are also expected to deviate from the cost estimates in this report due to project- and site-specific considerations (e.g., contracting

strategy, local labor costs and availability, seismic conditions, water quality, financing parameters, local environmental concerns, weather delays) that may make construction more costly. Such variations are not captured by the reported cost uncertainty.

Future Cost Trends

Continuing research, development, and demonstration (RD&D) is expected to result in designs that are more advanced than those assessed by this report, leading to costs that are lower than those estimated here.

CO₂ CAPTURE RATES ABOVE 95 PERCENT

Commercial-scale demonstration of solvent-based post-combustion CO₂ capture systems at power generation facilities (specifically PC plants) has shown the ability to capture 90 percent of the CO₂ in the flue gas stream. [11] [12] Moreover, field-testing of post-combustion CO₂ capture technology as well as vendor and industry feedback on projects currently in the planning stages (including FEED projects sponsored by DOE) indicates that capture rates as high as 95 percent are feasible for both coal- and natural gas-fueled electricity generating units. [13] [14] [15] [16] Given the breadth of publicly-available information supporting the capability for post-combustion capture systems to remove greater than 90 percent of the CO₂ in the treated stream, cases for 90 percent and 95 percent capture on NGCC and PC are presented in the main body of this report.

It should be emphasized that technology suppliers (as reflected in vendor-supplied information provided to DOE for this study that included cost and performance estimates for >95 percent CCS (97 percent for NGCC and 99 percent for PC) study cases) as well as subject matter experts acknowledge and support that solvent-based post-combustion CO₂ capture technologies are capable of achieving CO₂ removal rates beyond 95 percent on low-purity streams representative of fossil-fueled combustion. Although technoeconomic analyses of deep decarbonization (≥ 99 percent) of combustion flue gas have been published by others, [17] [18] the relatively limited experience with design and operation of capture systems that can routinely, reliably, and economically achieve very high removal rates requires further study. Technoeconomic analysis of the higher capture rates (97% NGCC and 99% PC) are included in the Appendices to this report. The performance and environmental profile summaries for PC and NGCC cases with CO₂ capture rates greater than 95 percent are shown in Exhibit ES-14; the primary conclusions that can be drawn are:

- The emissions of Hg, HCl, PM, NO_x, and SO₂ are all at or below the applicable federal regulatory limits currently in effect for PC and NGCC technologies (natural gas contains no Hg or chloride).
- For the PC cases, adding a CO₂ capture system with a 99 percent removal rate results in a 9 percentage point (24 percent) reduction in efficiency, compared to the non-capture PC cases. For the NGCC cases, the addition of a CO₂ capture system with a 97 percent removal rate results in a 7 percentage point (12 percent) reduction in efficiency, compared to non-capture NGCC cases.

The cost results for PC and NGCC cases with CO₂ capture rates greater than 95 percent are shown in Exhibit ES-15; the primary cost conclusions that can be drawn are:

- The addition of CO₂ capture increases the capital portion of the LCOE by 70–75 percent for PC cases and 107–124 percent for NGCC cases and increases the total LCOE by 74–78 percent for PC cases and 56–61 percent for NGCC cases.
- For PC cases, CO₂ T&S costs add \$10–11/MWh to the LCOE, which accounts for approximately 9 percent of the total LCOE. For NGCC cases, CO₂ T&S costs add \$4/MWh to the LCOE, which accounts for approximately 5–6 percent of the total LCOE.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit ES-14. Performance summary and environmental profile for PC and NGCC cases with CO₂ capture rates greater than 95 percent

Case Name	PC				NGCC			
	SubC PC		SC PC		State-of-the-art 2017 F-Class		State-of-the-art 2017 H-class	
	B11A	B11B.99	B12A	B12B.99	B31A	B31B.97	B32A	B32B.97
Performance								
CO ₂ Capture Rate (%)	0	99	0	99	0	97	0	97
Capacity Factor (%)	85	85	85	85	85	85	85	85
Gross Power Output (MWe)	688	780	686	774	740	687	1,009	939
Auxiliary Power Requirement (MWe)	38	130	36	123	14	51	17	66
Net Power Output (MWe)	650	650	650	650	727	637	992	873
Coal Flow Rate (lb/hr)	493,115	651,832	473,055	619,732	N/A	N/A	N/A	N/A
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	205,630	205,630	273,429	273,429
HHV Thermal Input (kWt)	1,685,945	2,228,591	1,617,359	2,118,843	1,354,905	1,354,905	1,801,631	1,801,631
Net Plant HHV Efficiency (%)	38.6	29.2	40.2	30.7	53.6	47.0	55.1	48.4
Net Plant HHV Heat Rate (Btu/kWh)	8,849	11,691	8,490	11,116	6,363	7,260	6,196	7,045
Raw Water Withdrawal (gpm/MWnet)	10.0	16.1	9.3	15.0	4.0	7.1	3.6	6.6
Process Water Discharge (gpm/MWnet)	2.1	4.2	1.9	3.9	0.9	2.3	0.8	2.2
Raw Water Consumption (gpm/MWnet)	8.0	11.9	7.4	11.1	3.1	4.8	2.8	4.4
CO ₂ Emissions (lb/MMBtu)	202	2	202	2	119	4	119	4
CO ₂ Emissions (lb/MWh-gross)	1,693	20	1,628	19	741	24	723	23
CO ₂ Emissions (lb/MWh-net)	1,790	24	1,718	23	755	26	735	25
SO ₂ Emissions (lb/MMBtu) ^A	0.081	0.000	0.081	0.000	0.001	0.000	0.001	0.000
SO ₂ Emissions (lb/MWh-gross)	0.675	0.000	0.649	0.000	0.006	0.000	0.006	0.000
NO _x Emissions (lb/MMBtu)	0.084	0.072	0.087	0.075	0.004	0.003	0.004	0.003
NO _x Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.022	0.022	0.022	0.022
PM Emissions (lb/MMBtu)	0.011	0.009	0.011	0.010	0.002	0.000	0.002	0.000
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.012	0.000	0.011	0.000
Hg Emissions (lb/TBtu)	0.359	0.308	0.373	0.321	0.000	0.000	0.000	0.000
Hg Emissions (lb/MWh-gross) ^B	3.00E-06	3.00E-06	3.00E-06	3.00E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00

^A Trace amounts of sulfur emissions may exist in the flue gas stream to the stack in capture cases

^B The mercury capture units used in the PC cases were designed to attain the emissions target of 3.00x10⁻⁶ lb/MWh-gross

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit ES-15. Cost summary for PC and NGCC cases with CO₂ capture rates greater than 95 percent

Case Name ^A	PC				NGCC			
	SubC PC		SC PC		State-of-the-art 2017 F-Class		State-of-the-art 2017 H-class	
	B11A	B11B.99	B12A	B12B.99	B31A	B31B.97	B32A	B32B.97
Cost								
Total Plant Cost (2018\$/kW)	2,015	3,543	2,103	3,596	780	1,754	796	1,654
Bare Erected Cost	1,486	2,510	1,551	2,552	561	1,177	573	1,117
Home Office Expenses	260	439	271	447	112	235	115	223
Project Contingency	270	494	281	500	107	265	109	247
Process Contingency	0	100	0	97	0	77	0	67
Total Overnight Cost (2018\$/MM)	1,615	2,829	1,683	2,868	692	1,358	963	1,754
Total Overnight Cost (2018\$/kW)	2,484	4,349	2,588	4,409	952	2,132	970	2,010
Owner's Costs	468	805	485	813	172	378	174	356
Total As-Spent Cost (2018\$/kW)	2,867	5,020	2,988	5,090	1,040	2,329	1,060	2,196
LCOE (\$/MWh) (excluding T&S)	64.0	103.1	64.5	102.3	43.3	66.1	42.7	63.1
Capital Costs	27.2	47.7	28.4	48.4	9.9	22.1	10.1	20.9
Fixed Costs	9.2	15.2	9.5	15.4	3.6	7.7	3.5	7.1
Variable Costs	7.9	14.2	7.7	13.8	1.7	4.2	1.7	4.0
Fuel Costs	19.7	26.0	18.9	24.8	28.1	32.1	27.4	31.1
LCOE (\$/MWh) (including T&S)	64.0	113.8	64.5	112.4	43.3	69.9	42.7	66.8
CO₂ T&S Costs	N/A	10.6	N/A	10.1	N/A	3.8	N/A	3.7
Cost of CO₂ Captured (ex. T&S), \$/tonne^B	N/A	36.4	N/A	37.4	N/A	60.2	N/A	55.5
Cost of CO₂ Avoided (incl. T&S), \$/tonne^B	N/A	64.1	N/A	62.2	N/A	80.4	N/A	74.8

^AFinancing structures are presented in NETL's "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance" [4]

^BBoth the cost of CO₂ captured and cost of CO₂ avoided were calculated based on the non-capture SC PC Case B12A for all coal cases, and the non-capture NGCC Cases B31A/B32A for natural gas cases.

1 INTRODUCTION

This report presents an independent assessment of the cost and performance of select fossil energy power systems – specifically, integrated gasification combined cycle (IGCC), pulverized coal (PC), and natural gas combined cycle (NGCC) plants – using a systematic, transparent technical and economic approach. This is Volume 1 of a four-volume series, comprised as follows:

- Volume 1: Bituminous Coal and Natural Gas to Electricity
- Volume 2: Coal to Synthetic Natural Gas and Ammonia (Various Coal Ranks)
- Volume 3: Low Rank Coal and Natural Gas to Electricity
- Volume 4: Bituminous Coal to Liquid Fuels

The cost and performance of fossil fuel-based generation technologies represented in this report (and the series at large) are important inputs to assessments and determinations of technology combinations to be utilized to meet the projected demands of future power markets. In addition to informing technology comparisons, the reference plant configurations found in this report provide perspective for regulators and policy makers. From a research & development perspective, this report is used to assess goals and metrics and to provide a consistent basis for comparing developing technologies.

Selection of new generation technologies will depend on many factors, including:

- Capital and operating costs
- Overall energy efficiency
- Operational flexibility (e.g., ramp rate, turndown, start-up time)
- Fuel prices
- Project financial requirements
- Availability, reliability, and environmental performance
- Current and potential regulations governing air, water, and solid waste discharges from fossil-fueled power plants
- Specific site and application constraints and requirements
- Market penetration of clean coal technologies that have matured and improved as a result of recent commercial-scale demonstrations under the Department of Energy's (DOE) Clean Coal and Carbon Management Program

Nineteen power plant configurations are analyzed in this report:

- Seven IGCC configurations—two Shell Global Solutions (Shell) gasifiers (with and without carbon dioxide [CO₂] capture), two Chicago Bridge and Iron (CB&I) E-Gas™ full-slurry quench (FSQ) gasifiers (with and without CO₂ capture), and three General Electric Power (GEP) gasifiers (one without [radiant] and two with [one radiant and one quench] CO₂ capture), all with two state-of-the-art 2008 F-Class combustion turbines.

- Six PC power plant configurations—three subcritical (SubC) and three supercritical (SC) (with [one 90% and one 95%] and without CO₂ capture).
- Six NGCC power plant configurations—three state-of-the-art 2017 F-Class combustion turbine and three state-of-the-art 2017 H-Class combustion turbine (with [one 90% and one 95%] and without CO₂ capture).

The Shell CANSOLV CO₂ capture system utilized for PC and NGCC capture plants is an amine-based solvent system based on a 2021 quote. The IGCC capture case configurations remained consistent with Revision 4 of this report (Fossil Energy Baseline Revision 4 [FEBR4]).

This revision reflects varying degrees of updated technology vendor input. The majority of modeling inputs remained constant from FEBR4 except for those noted below. For IGCC plants, the performance was unchanged. However, the air separation unit (ASU) costs were updated to maintain greater consistency with Revision 3 of this report and other NETL reports. For PC and NGCC plants, the CO₂ capture system was updated to reflect a new 2021 vendor quote. The primary revision was the adjustment of the NGCC capture system to match more closely that of the PC system in terms of both solvent used and system layout. For both PC and NGCC, 95 percent capture cases were included. Aside from the capture system, new vendor quotes were not obtained for the balance of plant items. Rather, costs were scaled according to NETL's current Quality Guidelines for Energy System Studies (QGESS) methodology. [19] Finally, H-frame NGCC cases were included utilizing data from a 2017 vendor quote. The final assessment of performance and cost was determined independently by NETL and is not endorsed by the individual vendors.

1.1 CO₂ CAPTURE RATES ABOVE 95 PERCENT

Commercial-scale demonstration of solvent-based post-combustion CO₂ capture systems at power generation facilities (specifically PC plants) has shown the ability to capture 90 percent of the CO₂ in the flue gas stream. [11] [12] Moreover, field-testing of post-combustion CO₂ capture technology as well as vendor and industry feedback on projects currently in the planning stages (including FEED projects sponsored by DOE) indicates that capture rates as high as 95 percent are feasible for both coal- and natural gas-fueled electricity generating units. [13] [14] [15] [16] Given the breadth of publicly-available information supporting the capability for post-combustion capture systems to remove greater than 90 percent of the CO₂ in the treated stream, cases for 90 percent and 95 percent capture on NGCC and PC are presented in the main body of this report.

It should be emphasized that technology suppliers (as reflected in vendor-supplied information provided to DOE for this study that included cost and performance estimates for >95 percent CCS (97 percent for NGCC and 99 percent for PC) study cases) as well as subject matter experts acknowledge and support that solvent-based post-combustion CO₂ capture technologies are capable of achieving CO₂ removal rates beyond 95 percent on low-purity streams representative of fossil-fueled combustion. Although technoeconomic analyses of deep decarbonization (≥ 99 percent) of combustion flue gas have been published by others, [17] [18] the relatively limited experience with design and operation of capture systems that can routinely, reliably, and

economically achieve very high removal rates requires further study. Technoeconomic analysis of the higher capture rates (97% NGCC and 99% PC) are included in the Appendices to this report.

1.2 GENERATING UNIT CONFIGURATIONS

A summary of plant configurations considered in this report is presented in Exhibit 1-1. Components for each plant configuration are described in more detail in the corresponding report sections for each case.

The IGCC cases have different gross and net power outputs because of the combustion turbine (CT) size constraint. The state-of-the-art 2008 F-class CT used to model the cases comes in a standard size of 232 MW when operated on syngas at conditions set by the International Organization for Standardization (ISO). Each case uses two CTs for a combined gross output of 464 MW. In the combined cycle, a heat recovery steam generator (HRSG) extracts heat from the CT exhaust to power a steam turbine.

The IGCC CO₂ capture cases consume more extraction steam than the non-capture cases, thus reducing the steam turbine output. In addition, the capture cases have a higher auxiliary load requirement than non-capture cases, which serves to further reduce net plant output.

While the two CTs provide 464 MW gross output in all IGCC cases, the overall combined cycle gross output ranges 685–765 MW, which results in a range of net output from 499 (Case B5B-Q) to 641 MW (Case B4A). The coal feed rate required to achieve the gross power output is also different between the six cases, ranging 197,500–219,000 kg/hr (435,400–482,900 lb/hr).

The NGCC cases also have different gross and net power outputs because of the CT size constraint. The state-of-the-art 2017 F-class CT used to model the NGCC cases comes in a standard size of 238 MW when operated at conditions set by ISO. Each case uses two CTs for a combined gross output of 477 MW. In the combined cycle, a HRSG extracts heat from the CT exhaust to power a steam turbine. The state-of-the-art 2017 H-class CT comes in a standard size of 343 MW when operated at conditions set by ISO. Each case uses two CTs for a combined gross output of 686 MW. In the combined cycle, an HRSG extracts heat from the CT exhaust to power a steam turbine.

The net output in the NGCC CO₂ capture case is significantly reduced compared to the non-capture case due to the high auxiliary power load and significant extraction steam requirement of the CO₂ capture system.

While the two F-frame CTs provide 477 MW gross output, the overall combined cycle gross output ranges 690–740 MW, which results in a range of net output from 640 MW (Case B31B.95) to 727 MW (Case B31A). The natural gas feed rate is the same in both cases at 93,272 kg/hr (205,630 lb/hr). While the two H-class CTs provide 686 MW gross output, the overall combined cycle gross output ranges 942–1,009 MW, which results in a range of net output from 877 MW (Case B32B.95) to 992 MW (Case B32A). The natural gas feed rate is the same in both cases at 124,025 kg/hr (273,429 lb/hr).

All six PC cases have a net output of 650 MW. When considering the NGCC and IGCC cases net output, PC net output selection of 650 MW represents the most optimal midpoint for cross-technology results comparison to F-frame NGCC with CO₂ capture (640–645 MW-net) and IGCC without CO₂ capture (634–641 MW-net). H-frame NGCC without CO₂ capture (992 MW-net) and IGCC with CO₂ capture (499–557 MW-net) represent the maximum and minimum net plant outputs for the cases considered in this report, respectively. The boiler and steam turbine industry's ability to match unit size to a custom specification has been commercially demonstrated enabling a common net output comparison of the PC cases in this report. The coal feed rate was increased in the CO₂ capture cases to increase the gross steam turbine output and account for the higher auxiliary load as well as the required extraction steam, resulting in a constant net output.

The balance of this report is organized as follows:

- Section 2 provides the basis for technical, environmental, and cost evaluations.
- Section 3 describes the IGCC technologies modeled and presents the results for the seven cases.
- Section 4 describes the PC technologies modeled and presents the results for the six PC cases.
- Section 5 describes the NGCC technologies modeled and presents the results for the six NGCC cases.
- Section 6 provides a cross comparison of IGCC, PC, and NGCC cases.
- Section 7 includes a record of report revisions.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 1-1. Case descriptions

Case ^A	Plant Type	Steam Cycle, psig/°F/°F	Combustion Turbine	Gasifier/Boiler Technology	H ₂ S Separation	Sulfur Removal	PM Control	CO ₂ Separation	Capture Rate ^D	Process Water Treatment
B1A	IGCC	1800/1050/1050	2 x State-of-the-art 2008 F-Class ^B	Shell	Sulfinol-M	Claus Plant/Sulfur	Cyclone, candle filter, and water scrubber	N/A	N/A	Vacuum flash, brine concentrator, crystallizer
B1B		1800/1000/1000			Selexol			Selexol 2 nd stage	90%	
B4A		1800/1050/1050		CB&I E-Gas™	Refrigerated MDEA			N/A	N/A	
B4B		1800/1000/1000			Selexol			Selexol 2 nd stage	90%	
B5A		1800/1050/1050		GEP Radiant	Selexol		Quench, water scrubber, and AGR adsorber	N/A	N/A	
B5B		1800/1000/1000			Selexol			Selexol 2 nd stage	90%	
B5B-Q		1800/1000/1000		GEP Quench	Selexol			Selexol 2 nd stage	90%	
B11A	PC	2400/1050/1050	N/A	SubC PC	N/A	Wet FGD/ Gypsum	Baghouse	N/A	N/A	Spray dryer evaporator
B11B.90								CANSOLV	90%	
B11B.95								95%		
B12A		3500/1100/1100		SC PC ^C				N/A	N/A	
B12B.90								CANSOLV	90%	
B12B.95									95%	
B31A	NGCC	2378/1085/1084	2 x State-of-the-art 2017 F-Class	HRSG	N/A	N/A	N/A	N/A	N/A	N/A
B31B.90								CANSOLV	90%	
B31B.95									95%	
B32A		2668/1085/1044	2 x State-of-the-art 2017 H-Class					N/A	N/A	
B32B.90								CANSOLV	90%	
B32B.95									95%	

^AAll plants in this report are assumed to be located at a generic plant site in the midwestern United States

^BThe IGCC F-class combustion turbines represent the same technology considered in the previous version of this report. There have not been significant recent advances in high-H₂ syngas turbine technology; consequently, these turbines are still considered state-of-the-art.

^CWhile labeled as SC conditions, the SC steam cycle conditions utilized in this report are also generally representative of commercial plants characterized as ultra-supercritical (USC), particularly with respect to temperature (593°C [1,100°F]). Because efficiency is more sensitive to steam cycle temperature than pressure, the resulting performance is at or near that of top-performing commercially-available USC PC plants.

^DThe capture rate for IGCC cases is based on the total feedstock minus unburned carbon in slag. The capture rate for PC and NGCC cases is based on the total feedstock minus unburned carbon in ash (PC cases). The rate of CO₂ capture from the flue gas in the CANSOLV systems and from syngas in the Selexol systems varies. An explanation for the difference is provided in Section 2.4.4. All cases sequester the CO₂ offsite.

2 GENERAL EVALUATION BASIS

For each of the plant configurations analyzed in this report, an Aspen Plus® (Aspen) model was developed and used to generate material and energy balances which were, in turn, used to provide a design basis for items in the major equipment list. The equipment list and material balances were used as the basis for generating the capital and operating cost estimates. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgment. Capital and operating costs were estimated by Black & Veatch based on simulation results using an in-house database and conceptual estimating models. The estimating models are based on a United States (U.S.) Gulf Coast location and the labor cost was factored to reflect a Midwest location. Costs were further calibrated using a combination of adjusted vendor-furnished data and scaled estimates from previous design/build projects. Legacy costs were established in 2007 dollars in prior reports, and subsequently updated to 2011 dollars and again to 2018 dollars in FEBR4. The present revision also reports costs in 2018 dollars^e. Ultimately, a levelized cost of electricity (LCOE) was calculated for each of the cases and is reported as the revenue requirement figure-of-merit.

The balance of this section discusses the design basis common to all technologies, as well as environmental targets and cost assumptions used in this report. Technology specific design criteria are covered in subsequent chapters.

2.1 SITE CHARACTERISTICS

All plants in this report are assumed to be located at a generic plant site in the midwestern United States, with site characteristics and ambient conditions as presented in Exhibit 2-1 and Exhibit 2-2. The ambient conditions are the same as ISO conditions.

Exhibit 2-1. Site characteristics

Parameter	Value
Location	Greenfield, Midwestern U.S.
Topography	Level
Size (IGCC and PC), acres	300
Size (NGCC), acres	100
Transportation	Rail or Highway
Slag (IGCC) and Ash (PC) Disposal	Off-Site
Water	50% Municipal and 50% Ground Water

^e The Chemical Engineering Plant Cost Index [49] indicates relatively high volatility for capital and labor costs, with the cost index rising by 30 percent between December 2018 and March 2022. As these fluctuations are not captured by the reported cost uncertainty, the reader should adjust the reported costs if required by the end use of the data.

Exhibit 2-2. Site ambient conditions

Parameter	Value
Elevation, m (ft)	0 (0)
Barometric Pressure, MPa (psia)	0.101 (14.696)
Average Ambient Dry Bulb Temperature, °C (°F)	15 (59)
Average Ambient Wet Bulb Temperature, °C (°F)	10.8 (51.5)
Design Ambient Relative Humidity, %	60
Cooling Water Temperature, °C (°F) ^A	15.6 (60)
Air composition based on published psychrometric data, mass %	
N ₂	75.055
O ₂	22.998
Ar	1.280
H ₂ O	0.616
CO ₂	0.050
Total	100.00

^AThe cooling water temperature is the cooling tower cooling water exit temperature.
This is set to 4.8°C (8.5°F) above ambient wet bulb conditions in ISO cases.

The land area for IGCC and PC cases assumes that 30 acres are required for the plant proper, and the balance provides a buffer of approximately 0.4 km (0.25 mi) to the fence line. The extra land could also provide for a rail loop if required (rail loop is not included in this report). In the NGCC cases it was assumed the plant proper occupies about 10 acres leaving a buffer of 0.24 km (0.15 mi) to the plant fence line.

The quality of plant makeup water will vary dramatically from source-to-source (municipal versus groundwater), as well as from site to site, and can be expected to vary significantly throughout any given site, particularly if ground water is utilized. In this study, 50 percent of the makeup water to the plants is sourced from a publicly owned treatment works, with the balance of the makeup water sourced from groundwater. The assumed design makeup water composition is provided in Exhibit 2-3.

The makeup water composition reported in the following table is based on water qualities from actual operations. The design concentration of each constituent is individually representative of a plant configuration comparable to those in this study. However, due to the interaction and interdependencies of each constituent and the multitude of potential species, the makeup water quality cannot be considered representative as a whole. The makeup water quality is intended to inform users of the contaminants likely present, and at what concentrations they may be expected, to facilitate appropriate equipment selection and design.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 2-3. Design makeup water quality

Parameter	Groundwater (Range)	POTW Water (Range)	Makeup Water (Design Basis)
pH	6.6 – 7.9	7.1 – 8.0	7.4
Specific Conductance, $\mu\text{S}/\text{cm}$	1,096 – 1,484	1,150 – 1,629	1312
Turbidity, NTU		<50	<50
Total Dissolved Solids, ppm			906
M-Alkalinity as CaCO_3 , ppm ^A	200 – 325	184 – 596	278
Sodium as Na, ppm	102 – 150	172 – 336	168
Chloride as Cl, ppm	73 – 100	205 – 275	157
Sulfate as SO_4 , ppm	100 – 292	73 – 122	153
Calcium as Ca, ppm	106 – 160	71 – 117	106
Magnesium as Mg, ppm	39 – 75	19 – 33	40
Potassium as K, ppm	15 – 41	11 – 21	18
Silica as SiO_2 , ppm	5 – 12	21 – 26	16
Nitrate as N, ppm	0.1 – 0.8	18 – 34	12
Total Phosphate as PO_4 , ppm	0.1 – 0.2	1.3 – 6.1	1.6
Strontium as Sr, ppm	2.48 – 2.97	0.319 – 0.415	1.5
Fluoride as F, ppm	0.5 – 1.21	0.5 – 0.9	0.8
Boron as B, ppm	0.7 – 0.77		0.37
Iron as Fe, ppm	0.099 – 0.629	0.1	0.249
Barium as Ba, ppm	0.011 – 0.52	0.092 – 0.248	0.169
Aluminum as Al, ppm	0.068 – 0.1	0.1 – 0.107	0.098
Selenium as Se, ppm	0.02 – 0.15	0.0008	0.043
Lead as Pb, ppm	0.002 – 0.1		0.026
Arsenic as As, ppm	0.005 – 0.08		0.023
Copper as Cu, ppm	0.004 – 0.03	0.012 – 0.055	0.018
Nickel as Ni, ppm	0.02 – 0.05		0.018
Manganese as Mn, ppm	0.007 – 0.015	0.005 – 0.016	0.009
Zinc as Zn, ppm	0.005 – 0.024		0.009
Chromium as Cr, ppm	0.01 – 0.02		0.008
Cadmium as Cd, ppm	0.002 – 0.02		0.006
Silver as Ag, ppm	0.002 – 0.02		0.006
Mercury as Hg, ppm	0.0002 – 0.001		3E-04

^AAlkalinity is reported as CaCO_3 equivalent, rather than the concentration of HCO_3 . The concentration of HCO_3 can be obtained by dividing the alkalinity by 0.82.

In all cases, it was assumed that the steam turbine is enclosed in a turbine building; in the PC cases, the boiler is also enclosed. The gasifier and combustion turbines are not enclosed.

The following design parameters are considered site-specific and are not quantified for this report. Allowances for normal conditions and construction are included in the cost estimates.

- Flood plain considerations
- Existing soil/site conditions
- Water discharges and reuse
- Rainfall/snowfall criteria
- Seismic design
- Buildings/enclosures
- Local code height requirements
- Weather delays
- Other local environmental concerns
- Noise regulations

2.2 COAL CHARACTERISTICS

The design coal is Illinois No. 6 with characteristics presented in Exhibit 2-4. The coal properties are from the 2019 revision of the Quality Guidelines for Energy System Studies (QGESS) document “Detailed Coal Specifications.” [1]

Exhibit 2-4. Design coal

Rank	Bituminous	
Seam	Illinois No. 6	
Proximate Analysis (weight %) ^A		
	As Received	Dry
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
HHV, kJ/kg (Btu/lb)	27,113 (11,666)	30,506 (13,126)
LHV, kJ/kg (Btu/lb)	26,151 (11,252)	29,544 (12,712)
Ultimate Analysis (weight %)		
	As Received	Dry
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.15	0.17
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen ^B	7.02	7.91
Total	100.00	100.00

^AThe proximate analysis assumes sulfur as volatile matter.

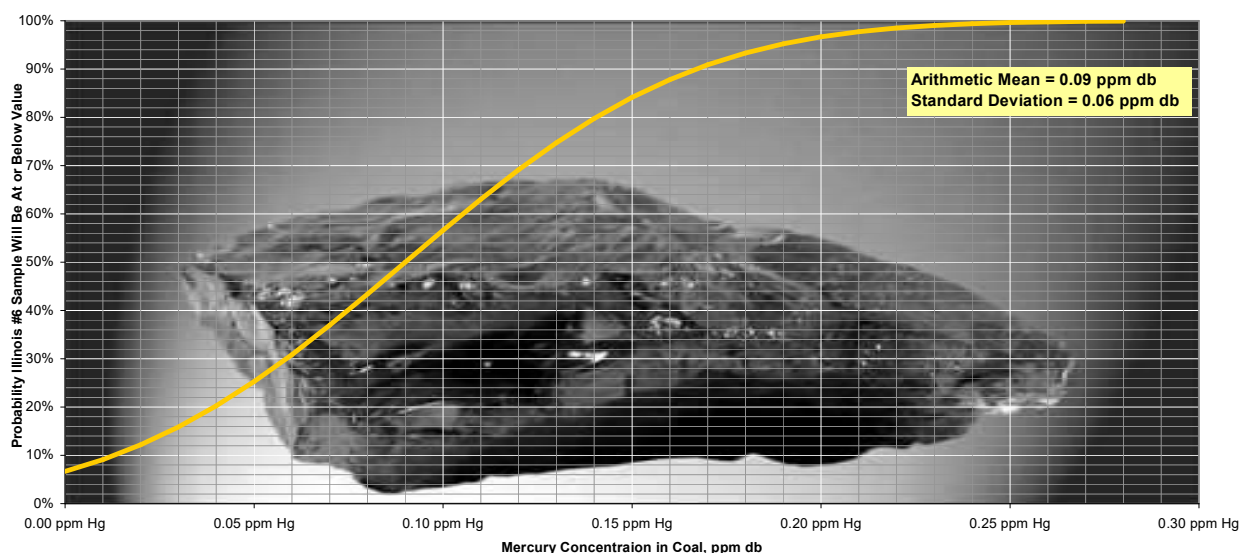
^BBy difference.

The chlorine content of 34 samples of Illinois No. 6 coal has an arithmetic mean value of 1,671 ppmwd with a standard deviation of 1,189 ppmwd based on coal samples shipped by Illinois mines. [20]

Based on the location of the Illinois No. 6 mine, along with the Herrin coal chlorine map published by the Illinois State Geological Survey [21], it was determined that Illinois No. 6 coal could be expected to have a chlorine content between 0.1 and 0.2 percent, on a dry basis. Therefore, the coal chloride content for this report was assumed to be the arithmetic mean value of 1,671 ppmwd.

The mercury (Hg) content of 34 samples of Illinois No. 6 coal has an arithmetic mean value of 0.09 ppmwd with standard deviation of 0.06 based on coal samples shipped by Illinois mines. [20] Hence, as illustrated in Exhibit 2-5, there is a 50 percent probability that the Hg content in the Illinois No. 6 coal would not exceed 0.09 ppmwd. The coal Hg content for this report was assumed to be 0.15 ppmwd, which corresponds to the mean plus one standard deviation and encompasses about 84 percent of the samples. It was further assumed that all the coal Hg enters the gas phase and none leaves with the slag in IGCC cases, or bottom ash in PC cases. [22]

Exhibit 2-5. Probability distribution of mercury concentration in the Illinois No. 6 coal



Fuel costs used in this report are specified according to the 2019 QGESS document “Fuel Prices for Selected Feedstocks in NETL Studies.” [5] The current levelized coal price is \$2.11/GJ (\$2.23/MMBtu) on a higher heating value (HHV) basis for Illinois No. 6 bituminous coal delivered to the Midwest and reported in 2018 dollars. Fuel costs are levelized over an assumed 30-year plant operational period with an assumed on-line year of 2023.

2.3 NATURAL GAS CHARACTERISTICS

The composition of natural gas used as fuel in all NGCC cases is presented in Exhibit 2-6. The natural gas properties are from the 2019 revision of the QGESS document “Specification for Selected Feedstocks” [2] including the addition of methanethiol (mercaptan). [23]

Exhibit 2-6. Natural gas composition

Component		Volume Percentage
Methane	CH ₄	93.1
Ethane	C ₂ H ₆	3.2
Propane	C ₃ H ₈	0.7
<i>n</i> -Butane	C ₄ H ₁₀	0.4
Carbon Dioxide	CO ₂	1.0
Nitrogen	N ₂	1.6
Methanethiol ^A	CH ₄ S	5.75x10 ⁻⁶
	Total	100.0
	LHV	HHV
kJ/kg (Btu/lb)	47,201 (20,293)	52,295 (22,483)
MJ/scm (Btu/scf)	34.52 (927)	38.25 (1,027)

^AThe sulfur content of natural gas is primarily composed of added Mercaptan (methanethiol [CH₄S]) with trace levels of hydrogen sulfide (H₂S) [23]

Note: Fuel composition is normalized, and heating values are calculated using Aspen

The current levelized natural gas price is \$4.19/GJ (\$4.42/MMBtu) on an HHV basis, delivered to the Midwest, and reported in 2018 U.S. dollars.^f Fuel costs are levelized over an assumed 30-year plant operational period with an assumed on-line year of 2023.

2.4 ENVIRONMENTAL TARGETS

2.4.1 Air Emissions Targets

Environmental targets were established for each of the technologies as follows:

- Hg and hydrochloric acid (HCl) limits were set by the March 2013 update to the Utility Mercury and Air Toxics Standards (MATS) for IGCC and PC technologies. [24], [25]
- Particulate matter (PM), sulfur dioxide (SO₂), and nitrogen oxide (NO_x) limits were set by the February 2013 update to the New Source Performance Standards (NSPS) for all technologies. [25], [26]

The regulations differentiate between low rank and non-low rank coal types based on their heating value. Coals with an HHV of greater than 19,300 kJ/kg (8,300 Btu/lb) on a moist, mineral-matter free basis are considered non-low rank. Therefore, Illinois No. 6 coal, with an HHV (moist, mineral-matter free) of 30,000 kJ/kg (12,900 Btu/lb), is considered a non-low rank coal.

^f As specified in the 2019 QGESS document on "Fuel Prices for Selected Feedstocks in NETL Studies." [5] The Energy Information Administration [138] indicates relatively high volatility for natural gas, with the Henry hub spot price increasing to \$7.83/GJ (\$8.26/MMBtu) in May 2022. As these fluctuations are not captured by the reported cost uncertainty, the reader should adjust the reported costs if required by the end use of the data.

The emission limits imposed by MATS and NSPS that apply to each technology in this report are provided in Exhibit 2-7.

Exhibit 2-7. MATS and NSPS emission limits for SO₂, NO_x, PM, Hg, and HCl

Pollutant ^A	IGCC (lb/MWh-gross)	PC (lb/MWh-gross)	NGCC (lb/MWh-gross)
SO ₂	0.40	1.00	0.90
NO _x	0.70	0.70	0.43
PM (Filterable)	0.07	0.09	N/A
Hg	3x10 ⁻⁶	3x10 ⁻⁶	N/A
HCl	0.002	0.010	N/A

^A Carbon monoxide (CO) emissions are reported for NGCC cases.

These new regulations apply to IGCC, PC, and NGCC technologies that begin construction after May 3, 2011. Furthermore, these regulations state that [25], [27]:

Fossil fuel is defined as natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Electric utility steam generating units (EGU) are defined as a fossil fuel-fired combustion unit of more than 25 MWe that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Fossil fuel-fired means an EGU that is capable of combusting more than 25 MW of fossil fuels. To be capable of combusting fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers; oil storage facilities).

Coal-fired electric utility steam generating units are defined as an EGU and meet the definition of “fossil fuel-fired,” which is that it burns coal for more than 10 percent of the average annual heat input during any three consecutive calendar years or for more than 15 percent of the annual heat input during any one calendar year.

Integrated gasification combined cycle electric utility steam generating units are defined as an EGU and meet the definition of “fossil fuel-fired,” which is that it burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10 percent of the average annual heat input during any three consecutive calendar years or for more than 15 percent of the annual heat input during any one calendar year in a combined-cycle combustion turbine. No solid coal or solid oil-derived fuel is directly burned in the unit during operation.

Unit designed for low-rank virgin coal subcategory is defined as any coal-fired EGU that is designed to burn, and that is burning, non-agglomerating virgin coal having a calorific value

(moist, mineral matter-free basis) of less than 19,300 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed for coal $\geq 19,300$ kJ/kg ($\geq 8,300$ Btu/lb) subcategory is defined as any coal-fired EGU that is not a coal-fired EGU in the “unit designed for low rank virgin coal” subcategory.

Other regulations that could affect emissions limits from a new plant include the New Source Review (NSR) permitting process and Prevention of Significant Deterioration (PSD). The NSR process requires installation of emission control technology meeting either the Best Available Control Technology (BACT) determinations for new sources located in areas meeting ambient air quality standards (attainment areas) or Lowest Achievable Emission Rate (LAER) technology for sources located in areas not meeting ambient air quality standards (non-attainment areas). Environmental area designation varies by county and can be established only for a specific site location. Based on the Environmental Protection Agency’s (EPA) Green Book Non-attainment Area Map, relatively few areas in the midwestern United States are classified as “non-attainment,” so the plant site for this report was assumed to be in an attainment area. [26]

2.4.2 Water Emissions Targets

EPA issued updated Effluent Limitation Guidelines (ELG) and standards for the steam electric power generation point source category in November 2015, to strengthen controls on wastewater discharges.⁹ [28] The ELG are national technology-based NSPS derived from data collected from industry. They are intended to provide flexibility in implementation through use of technologies already installed and operating in the power industry. The federal standards established by this rule are the minimum discharge standards. As ELG are enforced under the National Pollutant Discharge Elimination System [29], more stringent water quality-based standards may be established by the local permitting authority; however, these additional requirements were not considered in this report.

The final ELG rule established new wastewater categories and discharge limits and updated discharge requirements for existing wastewater categories. The following are the new or updated categories in the rule:

- Flue gas desulfurization (FGD) wastewater
- Fly ash transport water
- Bottom ash transport water
- Landfill leachate
- Flue gas mercury control wastewater
- Non-chemical metal cleaning wastewater
- Wastewater from gasification of fuels such as coal and petroleum coke

⁹In April 2017, EPA announced plans to reconsider the power plant ELG rule—as they apply to existing sources—and their intent to request a stay of the regulations, pending litigation. [29]

Non-chemical metal cleaning wastewater was established as a new wastewater category in the updated ELG. However, new limits were not established for this category; therefore, treatment of this stream has not been evaluated in this report.

The landfill of plant byproducts is assumed to be outside the scope of the plants considered in this study; therefore, landfill leachate is not evaluated in this report.

For the PC cases considered in this study, both fly ash and bottom ash handling systems are dry and do not result in a water stream requiring treatment under ELG. Similarly, the flue gas mercury control approach of combined sorbent injection followed by carbon injection does not generate a water stream for treatment. Therefore, only the FGD wastewater blowdown stream requires treatment in PC cases.

For the IGCC cases in this study, the gasification wastewater from the balance of plant is recycled within the gasification and syngas cleanup process, ultimately being utilized as makeup to the syngas scrubber. Therefore, only the syngas scrubber blowdown requires treatment in IGCC cases.

Intermittent discharges (e.g., chemical metal cleaning wastewater), coal pile runoff, low volume waste (e.g., boiler blowdown), and cooling tower blowdown were assumed to be compliant with all applicable regulations with no additional treatment beyond conventional considerations.

Under the assumptions established in this section, no additional control technology considerations are required for NGCC compliance with the ELG rule.

The applicable wastewater discharge limits for PC and IGCC cases are shown in Exhibit 2-8 and Exhibit 2-9, respectively.

Exhibit 2-8. New source treated FGD wastewater discharge limits [28]

Effluent Characteristic	Long-Term Average	Daily Maximum Limit	Monthly Average Limit ^A
Arsenic, ppb	4.0	4	-
Mercury, ppt	17.8	39	24
Selenium, ppb	5.0	5	-
Total Dissolved Solids, ppm	14.9	50	24

^AMonthly Average Limit refers to the highest allowable average of daily discharges over 30 consecutive days.

Exhibit 2-9. New source treated gasification wastewater discharge limits [28]

Effluent Characteristic	Long-Term Average	Daily Maximum Limit	Monthly Average Limit ^A
Arsenic, ppb	4.0	4	-
Mercury, ppt	1.08	1.8	1.3
Selenium, ppb	147	453	227
Total Dissolved Solids, ppm	15.2	38	22

^AMonthly Average Limit refers to the highest allowable average of daily discharges over 30 consecutive days.

For both the PC and IGCC wastewater treatment systems, the limits are applied at the discharge, prior to commingling with other plant water systems.

2.4.3 Study Cases

2.4.3.1 IGCC

Exhibit 2-10 provides the emissions limits for IGCC plants as well as a summary of the control technology utilized to satisfy the limits.

Exhibit 2-10. Environmental targets for IGCC cases [24] [25] [26]

Pollutant	IGCC (lb/MWh-gross)	Control Technology
SO ₂	0.40	Selexol, Methyldiethanolamine (MDEA), or Sulfinol (depending on gasifier technology) ^A
NO _x	0.70	Low NO _x burners and syngas N ₂ dilution
PM (Filterable)	0.07	Quench, water scrubber, and/or cyclones and candle filters (depending on gasifier technology)
Hg	3x10 ⁻⁶	Dual carbon bed
HCl	0.002	Quench, water scrubber, sodium hydroxide treatment, SWS

^AThe sulfur control technologies are used to remove H₂S formed in the gasifier to ultimately limit SO₂ emissions after the syngas is combusted in the CT.

Based on published vendor literature, it was assumed that low NO_x burners (LNBs) and nitrogen (N₂) dilution can achieve 15 ppmvd at 15 percent oxygen (O₂); this value was used for all cases. [30], [31]

The SO₂ limit is met via an AGR process, which captures sulfur as H₂S before it is oxidized to SO₂ later in the process train. Carbonyl sulfide (COS) hydrolysis is employed in non-capture cases to convert COS to the more capture-friendly compound H₂S, but not in capture cases where WGS is utilized and also serves to convert COS to H₂S. As the emissions limit is based on the gross power production of the plant, the actual removal efficiency is dependent on the net plant efficiency. Therefore, the required AGR H₂S removal efficiency varies from 75 to 98 percent in the cases without CO₂ capture. Vendor data on the AGR processes used in the non-capture cases indicate that the required level of sulfur removal in each technology is possible. The sulfur removal efficiency of the CO₂ capture cases is approximately 99.9 percent. The high rate of H₂S removal is a function of the CO₂ capture rate requirement (described in Section 2.4.4) of the two-stage Selexol process.

Most of the coal ash is removed from the gasifier as slag. The ash that remains entrained in the syngas is captured in the downstream equipment, including the syngas scrubber, cyclone, and either ceramic or metallic candle filters (E-Gas™ and Shell). Each combination of particulate control devices can achieve the environmental target.

The Eastman Chemical plant, where syngas from a GEP gasifier is treated, achieved a Hg removal efficiency of 95 percent. Sulfur-impregnated activated carbon is used by Eastman as the adsorbent in the packed beds operated at 30°C (86°F) and 6.2 MPa (900 psig). Hg removal between 90 and 95 percent has been reported with a bed life of 18–24 months. Removal efficiencies may be even higher, but, at 95 percent, the measurement precision limit was reached. Eastman has yet to experience any Hg contamination in its product. [32] As a Hg removal efficiency of up to 97 percent is required to meet the Hg emissions limit, a dual sulfur-impregnated carbon bed system (i.e., two beds in series) is required, which is capable of achieving greater than 99 percent Hg removal. It was assumed that the Hg removal efficiency is linearly related to bed depth; therefore, the bed depths were chosen to meet the emission limit.

The HCl is removed primarily (96 percent or greater) in the syngas scrubber and reacted with sodium hydroxide (NaOH) to form sodium chloride (NaCl). The remaining chloride in the syngas eventually drops out with condensed water downstream.

Exhibit 2-11 provides the water discharge limits for IGCC plants, and a brief description of the control technology utilized to satisfy the limits follows.

Exhibit 2-11. Water discharge targets for IGCC cases [28]

Effluent Characteristic	Long-term Average	Daily Maximum Limit	Monthly Average Limit ^A
Arsenic, ppb	4.0	4	-
Mercury, ppt	1.08	1.8	1.3
Selenium, ppb	147	453	227
Total Dissolved Solids, ppm	15.2	38	22

^AMonthly Average Limit refers to the highest allowable average of daily discharges over 30 consecutive days.

The gasification wastewater from the balance of plant is recycled within the gasification and syngas cleanup process, ultimately being utilized as makeup to the syngas scrubber. Therefore, all streams detailed in the updated ELG are included in the syngas scrubber blowdown and can be treated by a single system. The blowdown from the syngas scrubber is sent to a process water treatment plant, as discussed in Section 3.1.12, where a brine concentrator and crystallizer sequentially increase the concentration of NaCl through evaporation until a solid precipitate is formed, which is separated from the stream in a centrifuge. The treated streams are mixed with other process water in the process water drum and utilized throughout the plant as makeup water.

2.4.3.2 PC

Exhibit 2-12 provides the emissions limits for PC plants as well as a summary of the control technology utilized to satisfy the limits.

Exhibit 2-12. Environmental targets for PC cases [24] [25] [26]

Pollutant	PC (lb/MWh-gross)	Control Technology
SO ₂	1.00	Wet limestone scrubber
NO _x	0.70	Low NO _x burners, overfire air and SCR
PM (Filterable)	0.09	Fabric filter
Hg	3x10 ⁻⁶	Co-benefit capture, dry sorbent injection ^A , activated carbon injection
HCl	0.010	SO ₂ surrogate ^B

^ALimits sulfur trioxide (SO₃) levels and their detrimental effects on activated carbon injection.

^BSO₂ may be utilized as a surrogate for HCl measurement if the EGU utilizes wet FGD. [33]

It was assumed that LNBs and staged overfire air (OFA) would limit NO_x production to 0.15 kg/GJ (0.35 lb/MMBtu) and that selective catalytic reduction (SCR) technology would be 75–79 percent efficient. By adjusting the NH₃ flow rate and/or catalyst bed depth in the SCR, the NO_x emissions limit was able to be met exactly.

The wet limestone scrubber was assumed to be 98 percent efficient, which results in SO₂ emissions below the NSPS SO₂ limit. Current technology allows wet FGD removal efficiencies in excess of 99 percent, but based on NSPS requirements, such high removal efficiency is not necessary.

The fabric filter was assumed to be capable of achieving an efficiency of greater than 99.9 percent. As the required efficiency was approximately 99.9 percent for each case, the efficiency was varied in order to meet the PM emissions limit exactly.

The Hg removal efficiency required to meet the emission limit is approximately 97 percent in each case. It was assumed that the total Hg removal rate resulting from the combination of pollution control technologies used (SCR, dry sorbent injection [DSI], activated carbon injection [ACI], fabric filters, and FGD) would meet the limit exactly. DSI is required to limit the effects of SO₃ on Hg capture due to the high sulfur content of the coal in this study. Section 4.1.6 provides a detailed discussion regarding Hg removal and the various systems involved.

Exhibit 2-13 provides the water discharge limits for PC plants, and a brief description of the control technology utilized to satisfy the limits follows.

Exhibit 2-13. Water discharge targets for PC cases [28]

Effluent Characteristic	Long-term Average	Daily Maximum Limit	Monthly Average Limit ^A
Arsenic, ppb	4.0	4	-
Mercury, ppt	17.8	39	24
Selenium, ppb	5.0	5	-
Total Dissolved Solids, ppm	14.9	50	24

^AMonthly Average Limit refers to the highest allowable average of daily discharges over 30 consecutive days.

A spray dryer is a technology commonly used in the power industry for FGD, which can be applied as a thermal evaporation process to treat wastewater. The feasibility of using a spray dryer evaporator as the sole treatment system in PC cases is limited by the flow rate of wastewater, as the cost and performance impact of the spray dryer increases with increasing wastewater flow rate. Section 4.1.10 provides a detailed discussion regarding the spray dryer as applied to the PC cases in this report.

2.4.3.3 NGCC

Exhibit 2-14 provides the emissions limits for NGCC plants as well as a summary of the control technology utilized to satisfy the limits.

Exhibit 2-14. Environmental targets for NGCC cases [24] [25] [26]

Pollutant	NGCC (lb/MWh-gross)	Control Technology
SO ₂	0.90	Low sulfur content fuel
NO _x	0.43	Dry low NO _x burners and SCR
PM (Filterable)	N/A	N/A
Hg	N/A	N/A
HCl	N/A	N/A

The NGCC cases were designed to achieve approximately 1.8 ppmv NO_x emissions (referenced to 15 percent O₂) through the use of a dry low NO_x (DLN) burner in the combustion turbine-generator (CTG)—the DLN burners reduce the emissions to about 9 ppmvd [34] (referenced to 15 percent O₂)—and an SCR. [35]

While state-of-the-art 2017 F-class and H-class CTs alone produce NO_x emissions below the limit shown in Exhibit 2-14, an SCR was included to ensure the plant met EPA's PSD program by installing BACT. The SCR system is designed for 85–87 percent NO_x reduction while firing natural gas.

The total sulfur content of natural gas is typically limited by contract terms and industry practice to between 0.25 and 1.00 gr/100 scf with the average total sulfur content being 0.34 gr/100 scf. [23] For this report, the natural gas was assumed to contain the average value of total sulfur of 0.34 gr/100 scf (4.71×10^{-4} lb-S/MMBtu). It was also assumed that the added mercaptan (CH₄S) was the sole contributor of sulfur to the natural gas. The CH₄S concentration of the natural gas is provided in Exhibit 2-6 as 5.75×10^{-6} percent by mole (mol%) (7.06×10^{-4} lb-CH₄S/MMBtu).

The natural gas sulfur content results in SO₂ emissions for the non-capture case of 0.006 lb/MWh-gross. The CO₂ capture system removes virtually all SO₂ from the flue gas, resulting in zero (reported) emissions in the capture case.

The pipeline natural gas was assumed to contain no PM, Hg, or HCl.

Under the assumptions established in Section 2.4.2, no additional control technology considerations are required for compliance with the ELG rule.

2.4.4 Carbon Dioxide

EPA promulgated a New Source Performance Standard on October 23, 2015, for emissions of CO₂ for new fossil fuel-fired electric utility generating units. [36] The limit set by the regulation was 1,000 lb-CO₂/MWh-gross for NGCC, and 1,400 lb-CO₂/MWh-gross for PC and IGCC plants. As of the publication of this report, EPA has proposed changes that increase the CO₂ emissions limit for the PC and IGCC plants considered in this study to 1,900 lb-CO₂/MWh-gross. [37] The changes do not impact the previously established emissions limit for NGCC plants.

For the IGCC cases that have CO₂ capture, the basis is a nominal 90 percent carbon removal rate based on carbon input from the coal and excluding carbon that exits the gasifier with the slag. In the GEP and Shell cases, this was accomplished by using two WGS reactors in series to convert CO to CO₂ and a two-stage Selexol process with a CO₂ removal efficiency of 93.6 percent, a removal rate that was supported by vendor quotes. All gasifiers, except E-GasTM, achieve a nominal carbon removal rate of 90 percent. In the E-GasTM case, a third shift reactor was added to increase the CO conversion because the relatively high amount of methane (CH₄) present in the syngas (1.61 percent by volume [vol%] compared to 0.09 vol% in the GEP Radiant gasifier and 0.03 vol% in the Shell gasifier) would otherwise prevent this case from achieving the target of 90 percent carbon capture. The IGCC cases with CO₂ capture report CO₂ emissions ranging 151–163 lb-CO₂/MWh-gross, and the non-capture cases report CO₂ emissions ranging 1,328–1,396 lb-CO₂/MWh-gross.

The PC and NGCC cases both assume that all fuel-based carbon that is combusted (i.e., excluding unburned carbon in PC cases) is converted to CO₂ in the flue gas. Carbon dioxide is also generated from limestone in the FGD system. The nominal capture rate of each plant is defined by the amount of CO₂ capture that enters the capture plant (i.e., exiting the FGD system in PC cases and exiting the HRSG in NGCC cases). The non-capture plants report CO₂ emissions of 1,628–1,693 lb-CO₂/MWh-gross for PC cases, and 723–741 lb-CO₂/MWh-gross for the NGCC cases. The CO₂ capture plant designs result in emissions ranging 94–195 lb-CO₂/MWh-gross and 39–79 lb-CO₂/MWh-gross for PC and NGCC plants, respectively.

2.5 CAPACITY FACTOR

2.5.1 Capacity Factor Assumptions

Availability is the percent of time during a specific period that a generating unit is capable of producing electricity. This report assumes that each new plant would be dispatched any time it is available and would be capable of generating the nameplate capacity when online. Therefore, the capacity factor (CF) and availability are equal. The operating period selected is also important. The calculations assume that the CF and availability are constant over the life of the plant, but in actual operation may require that a plant have a higher peak availability to counter lower availability in the first several years of operation.

2.5.2 Existing Plant Data

The North American Electric Reliability Council (NERC) Generating Availability Data System (GADS) [38] provides information on existing plants (e.g., Generating Analysis Reports, Generating Availability Reports, Generating Unit Statistical Brochure, Historical Availability Statistics). These data for coal plants (e.g., PC, CFB, and IGCC technology) include average availability and plant CF data, by fuel type and plant capacity.

The GADS database provides data on many plant operating characteristics. Two metrics are used in this report to evaluate existing plant availability and CFs (availability factor [AF] and equivalent availability factor [EAF]). The metrics are defined by the following equations.

$$AF = \frac{PH - (POH + FOH + MOH)}{PH}$$

Where:

PH – Period Hours (number of hours a unit was in the active state)

POH – Planned Outage Hours (sum of all hours experienced during Planned Outages and Planned Outage Extensions [the extension of maintenance or planned outage beyond initial Planned Outages])

FOH – Forced Outage Hours (sum of all hours experienced during Forced Outages)

MOH – Maintenance Outage Hours (sum of all hours experienced during Maintenance Outages and Maintenance Outage Extensions [the extension of Maintenance Outages])

$$EAF = \frac{(PH - (POH + FOH + MOH)) - (EUDH + EPDH + ESEDH)}{PH}$$

Where:

EUDH – Equivalent Unplanned Derated Hours (the product of Unplanned Derated Hours [sum of all hours during Forced Deratings] and Size of Reduction [megawatts of derate], divided by Net Maximum Capacity [unit net megawatt output without derating])

EPDH – Equivalent Planned Derated Hours (the product of Planned Derated Hours [sum of all hours experienced during Planned Deratings and Scheduled Derating Extensions] and Size of Reduction, divided by Net Maximum Capacity)

ESEDH – Equivalent Seasonal Derated Hours (Net Maximum Capacity less Net Dependable Capacity [equivalent to the Net Maximum Capacity modified for seasonal limitations], multiplied by Available Hours [sum of all Service Hours, Reserve Shutdown Hours, Pumping Hours, and Synchronous Condensing Hours] and divided by Net Maximum Capacity)

The EAF is essentially a measure of the plant CF, assuming there is always a demand for the output. The EAF accounts for planned and scheduled derated hours as well as seasonal derated hours. As such, the EAF matches this report's definition of CF.

2.5.3 Capacity Factor for Coal Units without Carbon Capture

Exhibit 2-15 presents GADS “coal primary” EAF data from the Units Reporting Events data files for the years 2011, 2014, 2015, and 2016. The number of generating units included in the 2011 and 2016 data is presented in Exhibit 2-16. As previously noted, the EAF is a representation of this study’s definition of CF.

Exhibit 2-15. Coal unit equivalent availability factor

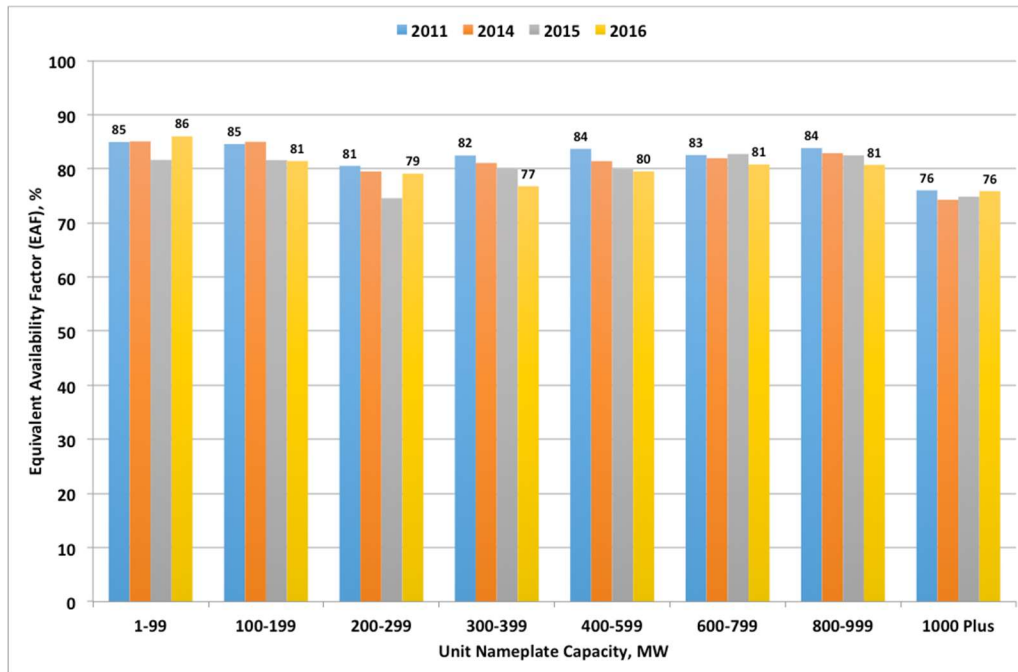
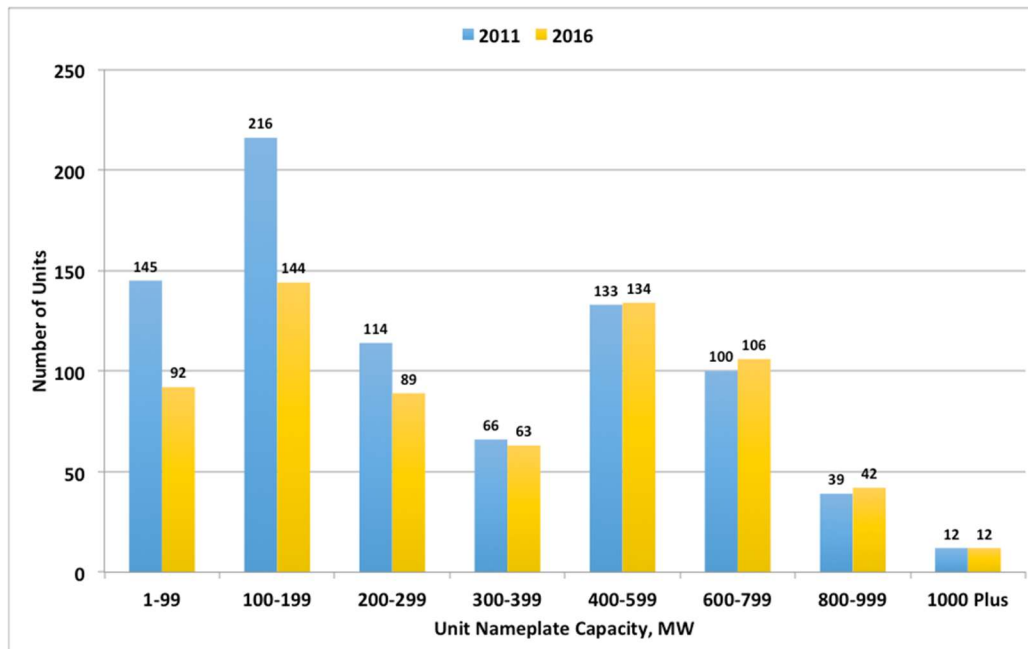


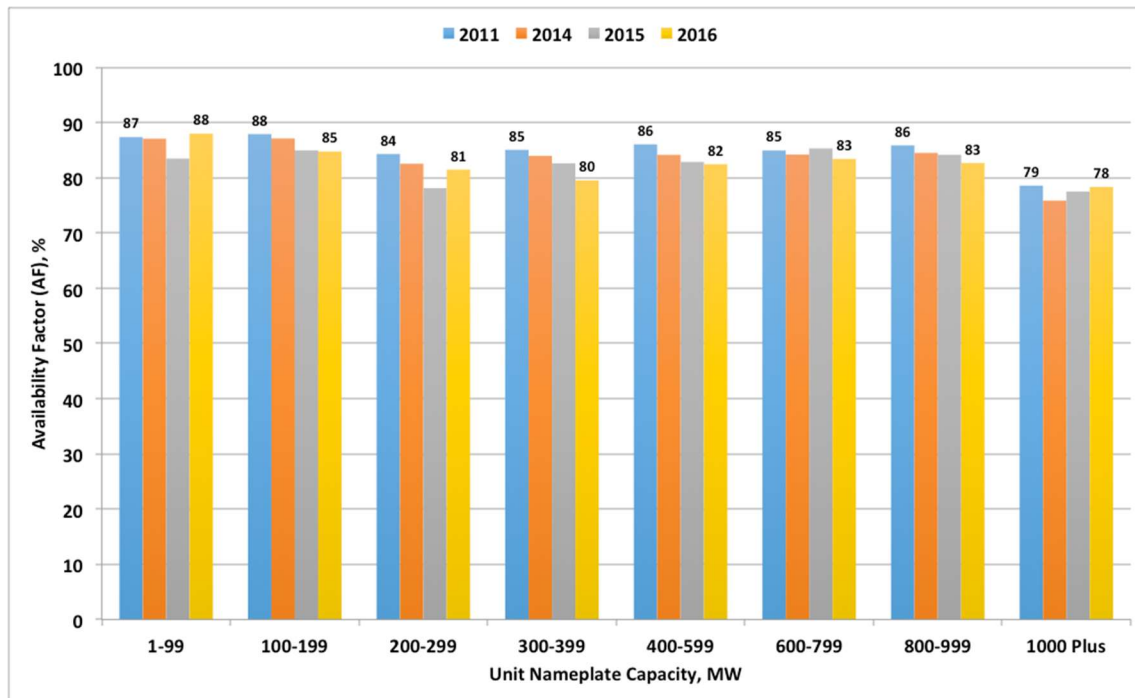
Exhibit 2-16. Number of coal units reporting in the 2011 and 2016 data



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 2-17 presents the GADS AF data for the same years (2011 through 2016).

Exhibit 2-17. Coal unit availability factor



The baseline study net PC unit capacity is 650 MW. The average EAF for coal-fired plants in the 600–799 MW size range was 83 percent in 2011 and declined to 81 percent in 2016.

While the assumption for this report is that a unit will be dispatched when it is available, it is useful to have perspective on the ability of coal units, and plants, to achieve high CFs.

Exhibit 2-18 presents coal plants, with capacities greater than 300 MW, that achieved high CFs in 2017. [39]

Exhibit 2-18. Reported high capacity factor coal units

Plant Name	Owner	State	Capacity, MW	Capacity Factor, %	Heat Rate, Btu/kWh
Dry Fork Station	Basin Electric	WY	393	94	10,593
Oak Grove	Luminant	TX	1,665	92	10,341
Twin Oaks	Luminant	TX	306	89	11,529
Milton R. Young	Minnkota Power Coop	ND	688	88	11,507
Wyodak	BHE	WY	336	87	12,249
Bonanza	Deseret G&T	UT	458	85	9,795
Rush Island	Ameren	MO	1,201	84	10,207
John W. Turk Jr.	SWEP CO	AR	609	83	9,089

In 2017 the top twenty coal plants, irrespective of nameplate capacity, achieved CFs in excess of 82 percent, with the top fifteen units achieving CFs of 85 percent or higher. [39]

The GADS data show an average coal unit availability for all unit sizes greater than 80 percent and the 2017 plant level data show that coal units have demonstrated CFs greater than 85 percent. The current study costs are based on mature plant technology and market conditions that enable baseload operation. Based on a review of the available data, an 85 percent CF is selected for the PC units.

2.5.4 Capacity Factor for IGCC Plants

The Electric Power Research Institute (EPRI) has reported an availability goal for IGCC plants of 85 percent. [40] Plants built before 2000 have achieved availability of 80 percent for limited periods. Common projections from technology suppliers and EPRI are that IGCC plants are capable of 80–85 percent availability without a spare gasifier and could achieve greater than 90 percent availability with a spare gasifier. [41], [42], [43], [44], [45], [46] While an availability of 85 percent is the goal, given the IGCC technology experience and the commercialization status compared with the more conventional plants (e.g., PC), a CF of 80 percent was selected for IGCC plants with no spare gasifier.

2.5.5 Capacity Factor for NGCC Plants

Similar data as used for coal units were reviewed for NGCC units. The GADS database reports an AF of 87.8 percent for 160 NGCC units in 2011, and the same AF value for 277 NGCC units in 2016. The EAF reported for NGCC units in 2011 is 84.0 percent, and in 2016 the EAF increased to 85.2 percent. [38] In 2017 the top twenty NGCC plants achieved CFs in excess of 85 percent, with an average CF of 89 percent. [39] An 85 percent CF is selected for NGCC plants.

2.5.6 Capacity Factor for Plants with Carbon Capture

The addition of carbon capture and storage adds extra equipment to the power plant. Preliminary reliability analyses show small reductions in reliability if the reliability of the base plant components is kept constant. A solvent-based carbon capture technology is used in this report for all capture configurations. The capture and CO₂ compression technologies have commercial operating experience, albeit at smaller scale in the case of solvent systems, with demonstrated ability for high reliability. Given the report basis and use of commercial technology, the assumption is made that the CFs for a given plant with and without carbon capture are the same. Thus, the CF for IGCC plants with capture is 80 percent; the CF for PC and NGCC plants with capture is 85 percent.

2.5.7 Perspective

Reported unit data and reported plant experience support the capability to achieve the selected AFs for the plants. Important factors required to achieve these availability projections include a quality plant design that utilizes lessons learned from similar plant designs, a focus on life cycle costs, a smart predictive maintenance program with sufficient maintenance budget, a trained

plant staff, and an economic demand for unit power. An illustration of lessons learned and the resulting high plant availability that can be obtained is reported by Richwine. [47]

Plant availability is determined by the plant technology, the capital cost invested in the plant (e.g., what is the design approach with respect to minimizing scheduled and unplanned maintenance), the maintenance requirements, the operating profile of the plant, and the customer requirements for the electricity (e.g., customer costs due to a unit not being available). Since the unavailability cost will decrease with increasing unit availability and the maintenance and capital costs increase with increasing unit availability, there will be an optimum economic unit availability for a given application. This report assumes that the plant design, plant maintenance, and electricity demand are consistent with the selected availability. Black & Veatch review of the maintenance allocation for the plants considered concluded that it was in accordance with expected maintenance allocations for comparable units in terms of the specified sizes and CF. It is acknowledged that fewer fossil energy plants operate baseloaded in today's energy markets; however, the objective of the report is to compare technologies based on their performance and cost merits without imposing market forces that would impact CF.

The existing plant data have not been analyzed with regard to the performance of individual plant availability over the life of the plant. As stated, this report assumes a constant availability of 80 percent for IGCC and 85 percent for PC and NGCC each year over the life of the plant. It is recognized that the availability of a given plant will vary over the life of the plant. As demonstrated by existing plant data, coal plants can be designed and operated with yearly availability ranging 85–100 percent. It is assumed that the plants in this report will have yearly AFs above and below the selected value with the effective or leveled availability for the life of the plant being the selected value. The sensitivity of LCOE to CF is plotted in Exhibit 6-23.

2.6 RAW WATER WITHDRAWAL AND CONSUMPTION

A water balance was performed for each case on the major water consumers in the process. The total water demand for each subsystem was determined, and internal recycle water available from various sources like condensate from syngas (in IGCC CO₂ capture cases), or from flue gas (in PC CO₂ capture cases) was applied to offset the water demand. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is the water removed from the ground or diverted from a municipal source for use in the plant. Raw water consumption is also accounted for as the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products, or otherwise not returned to the water source from which it was withdrawn.

Raw water makeup was assumed to be provided 50 percent by a publicly owned treatment works (POTW) and 50 percent from groundwater. Raw water withdrawal is defined as the water metered from a raw water source and used in the plant processes for all purposes, such as cooling tower makeup, boiler feedwater (BFW) makeup, slurry preparation makeup, syngas humidification, quench system makeup, and FGD system makeup, depending on the technology examined. The difference between withdrawal and process water returned to the source is consumption. Consumption represents the net impact of the process on the water source.

BFW blowdown and ASU knockout were assumed to be treated and recycled to the cooling tower. The cooling tower blowdown was assumed to be treated and 90 percent returned to the water source. The largest consumer of raw water in all cases is cooling tower makeup. It was assumed that all cases utilized a mechanical draft, evaporative cooling tower. The design ambient wet bulb temperature of 11°C (51.5°F) (Exhibit 2-1 and Exhibit 2-2) was used to achieve a cooling water temperature of 16°C (60°F) using an approach of 5°C (8.5°F). The cooling water range was assumed to be 11°C (20°F). The cooling tower makeup rate was determined using the following [48]:

- Evaporative losses of 0.8 percent of the circulating water flow rate per 5.5°C (10°F) of range
- Drift losses of 0.001 percent of the circulating water flow rate
- Blowdown losses (BDL) were calculated as follows:

$$BDL = \frac{EL}{CC - 1}$$

Where:

EL – Evaporative Losses

CC – Cycles of concentration

The cycles of concentration are a measure of water quality and a mid-range value of four was chosen for this report.

The water balances presented in subsequent sections include the water demand of the major water consumers within the process, the amount provided by internal recycle, the amount of raw water withdrawal by difference, the amount of process water returned to the source, and the raw water consumption, again by difference.

2.7 COST ESTIMATING METHODOLOGY

Detailed information pertaining to topics such as contracting strategy; engineering, procurement, and construction (EPC) contractor services; estimation of capital cost contingencies; owner's costs; cost estimate scope; economic assumptions; finance structures; and LCOEs are available in the 2019 revision of the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance." [4] Select portions are repeated in this report for completeness.

Capital Costs:

The capital cost estimates documented in this report reflect different uncertainty ranges depending on the technology considered as shown in Exhibit 2-19.

Exhibit 2-19. Capital cost uncertainty ranges

Technology	Uncertainty Range	AACE Classification
IGCC	-25/+50	Class 5
PC	-15/+30	Class 4
NGCC	-15/+25	Class 4

IGCC cases carry an uncertainty range of -25 percent/+50 percent, consistent with Association for the Advancement of Cost Engineering (AACE) Class 5 cost estimates (i.e., feasibility study) [4] [9] [10], based on the level of engineering design performed. This range is deemed reflective of recent commercial power IGCC experience. PC and NGCC cases carry smaller uncertainty ranges, and both fall within AACE Class 4 estimates. Given recent experience with NGCC plants, the NGCC uncertainty range is slightly smaller than PC. In all cases, this report intends to represent the next commercial offering and relies on vendor cost estimates for component technologies. It also applies process contingencies at the appropriate subsystem levels in an attempt to account for expected but undefined costs, which can be a challenge for emerging technologies.

Costs of Mature Technologies and Designs:

The cost estimates for plant designs that only contain fully mature technologies, which have been widely deployed at commercial scale (e.g., PC and NGCC power plants without CO₂ capture), reflect NOAK on the technology commercialization maturity spectrum. The costs of such plants have dropped over time due to “learning by doing”, supply chain improvements, vendor competition, and risk reduction benefits that result from serial deployments as well as from continuing research and development (R&D).

Costs of Emerging Technologies and Designs:

The cost estimates for plant designs that include technologies that are not yet fully mature (e.g., IGCC plants and any plant with CO₂ capture) use the same cost estimating methodology as for mature plant designs, which does not fully account for the unique cost premiums associated with the initial, complex integrations of emerging technologies in a commercial application. Thus, it is anticipated that early deployments of IGCC plants—both with and without CO₂ capture—as well as PC and NGCC plants with CO₂ capture, may incur costs higher than those reflected within this report.

Other Factors:

Actual reported project costs for all the plant types are also expected to deviate from the cost estimates in this report due to project- and site-specific considerations (e.g., contracting strategy, local labor costs, seismic conditions, water quality, financing parameters, local environmental concerns, weather delays) that may make construction more costly. Such variations are not captured by the reported cost uncertainty.

Future Cost Trends:

Continuing research, development, and demonstration (RD&D) is expected to result in designs that are more advanced than those assessed by this report, leading to costs that are lower than those estimated here.

2.7.1 Capital Costs

As illustrated in Exhibit 2-20, this report defines capital cost at five levels: BEC, EPCC, TPC, TOC, and TASC. BEC, EPCC, TPC, and TOC are “overnight” costs and are expressed in “base-year” dollars. The base year is the first year of capital expenditure. TASC is expressed in mixed, current-year dollars over the entire capital expenditure period, which is assumed in most NETL studies to last five years for coal plants and three years for natural gas plants.

The Bare Erected Cost (BEC) comprises the cost of process equipment, on-site facilities and infrastructure that support the plant (e.g., shops, offices, labs, road), and the direct and indirect labor required for its construction and/or installation. The cost of EPC services and contingencies are not included in BEC.

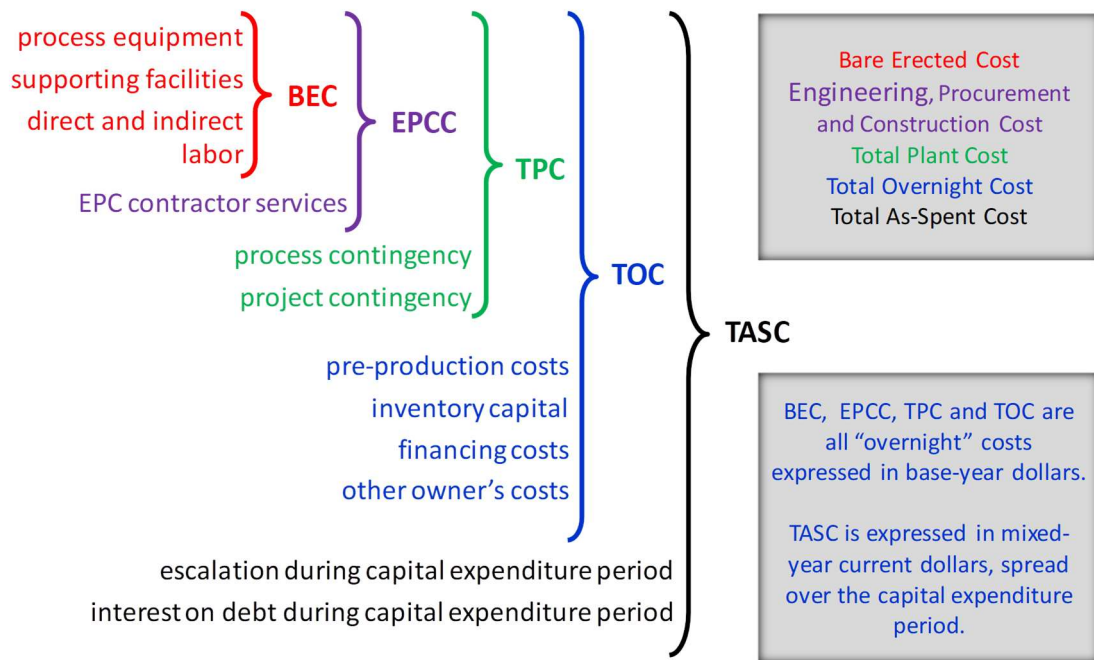
The Engineering, Procurement and Construction Cost (EPCC) comprises the BEC plus the cost of services provided by the EPC contractor. EPC services include: detailed design, contractor permitting (i.e., those permits that individual contractors must obtain to perform their scopes of work, as opposed to project permitting, which is not included here), and project/construction management costs.

The Total Plant Cost (TPC) comprises the EPCC plus project and process contingencies.

The Total Overnight Cost (TOC) comprises the TPC plus all other overnight costs, including owner’s costs. TOC does not include escalation during construction or interest during construction.

The Total As-Spent Cost (TASC) is the sum of all capital expenditures as they are incurred during the capital expenditure period including their escalation. TASC also includes interest during construction, comprising interest on debt and a return on equity.

Exhibit 2-20. Capital cost levels and their elements



2.7.1.1 Cost Estimate Basis and Classification

The TPC and operation and maintenance (O&M) costs for each of the cases in the report were estimated by Black & Veatch using an in-house database and conceptual estimating models. Costs were further calibrated using a combination of adjusted vendor-furnished data and scaled estimates from previous design/build projects.

2.7.1.2 System Code-of-Accounts

The costs are grouped according to a process/system-oriented code of accounts. This type of code-of-account structure has the advantage of grouping all reasonably allocable components of a system or process, so they are included in the specific system account. (This would not be the case had a facility, area, or commodity account structure been chosen instead).

2.7.1.3 Estimate Scope

The estimates represent a complete power plant facility on a generic site. The plant boundary limit is defined as the total plant facility within the "fence line" including coal receiving and water supply system but terminating at the high voltage side of the main power transformers. CO₂ transport and storage (T&S) cost is not included in the reported capital cost or O&M costs but is treated separately and added to the LCOE.

2.7.1.4 Capital Cost Assumptions

Black & Veatch developed the capital cost estimates for each plant using the company's in-house database and conceptual estimating methodology for each of the specific technologies. This database and approach are maintained by Black & Veatch as part of a commercial power plant design base of experience for similar equipment in the company's range of power and

process projects. A reference bottom-up estimate for each major component provides the basis for the estimating models.

Other key estimate considerations include the following:

- Labor costs are based on Midwest, Merit Shop. The estimating models are based on a U.S. Gulf Coast location and the labor cost has been factored to a Midwest location. Labor cost data were sourced from recent projects and proprietary Black & Veatch in-house references/cost databases.
- The estimates are based on a competitive bidding environment, with adequate skilled craft labor available locally.
- Labor is based on a 50-hour workweek (5-10s). No additional incentives such as per-diem allowances or bonuses have been included to attract craft labor.
- While not included at this time, labor incentives may ultimately be required to attract and retain skilled labor depending on the amount of competing work in the region, and the availability of skilled craft in the area at the time the projects proceed to construction.
- The estimates are based on a greenfield site.
- The site is considered to be Seismic Zone 1, relatively level, and free from hazardous materials, archeological artifacts, or excessive rock. Soil conditions are considered adequate for spread footing foundations. The soil bearing capability is assumed adequate such that piling is not needed to support the foundation loads.
- Engineering and Construction Management are estimated based on Black & Veatch's historical experience in designing and building power projects. The cost, as a percentage of BEC, varies by technology; 15 percent for IGCC, 17.5 percent for PC, and 20 percent for NGCC. The percentages were selected such that the final total cost calculated is representative of Black & Veatch's historical engineering/construction management costs for similar plant types. These costs consist of all home office engineering and procurement services as well as field construction management costs. Site staffing generally includes construction manager, resident engineer, scheduler, and personnel for project controls, document control, materials management, site safety, and field inspection.

2.7.1.5 Price Fluctuations

During the writing of this report, the prices of equipment and bulk materials fluctuated as a result of various market forces. Some reference quotes pre-dated the 2018-year cost basis while others may be considered more historical. All vendor quotes used to develop these estimates were adjusted to December 2018 dollars accounting for the price fluctuations. Price indices, e.g., The Chemical Engineering Plant Cost Index [49] and the Gross Domestic Product Chain-type Price Index [50], were used as needed for these adjustments. While these overall indices are nearly constant, it should be noted that the cost of individual equipment types may still deviate from the December 2018 reference point.

2.7.1.6 Cross-comparisons

In technology comparison studies, the relative differences in costs are often more significant than the absolute level of TPC. This requires cross-account comparison between technologies to review the consistency of the cost trends.

In performing such a comparison, it is important to reference the technical parameters for each item, as these are the basis for establishing the costs. Scope or assumption differences can quickly explain any apparent anomalies. There are a number of cases where differences in design philosophy occur. Some key examples are:

- The IGCC CT account in the GEP cases includes a syngas expander, which is not required for the E-Gas™ or Shell cases.
- The IGCC CTs for the capture cases include an additional cost for firing a high-H₂ content fuel.
- The Shell gasifier syngas cooling configuration is different between the CO₂-capture and non-CO₂-capture cases, resulting in a significant differential in thermal duty between the syngas coolers for the two cases.
- In PC cases, the CANSOLV unit includes a pre-scrubber tower to reduce flue gas SO₂ content to 0.37 ppmv to limit solvent degradation. In NGCC cases, there is little SO₂ present in the flue gas, and thus, a pre-scrubber is not required, or included in the NGCC CANSOLV capital cost.

2.7.1.6.1 Process Contingency

Process contingencies were applied to the IGCC estimates in this report, with justification provided, as follows:

- Gasifiers and Syngas Coolers: 14 percent on all cases—next-generation commercial offering and integration with the power island
- Two-Stage Selexol: 20 percent on all capture cases—unproven technology at commercial scale in IGCC service
- Mercury Removal: 5 percent on all cases—minimal commercial scale experience in IGCC applications
- CTG: 5 percent on all non-capture cases—syngas firing; 10 percent on all capture cases—high-H₂ firing
- Instrumentation and Controls: 5 percent on most accounts—integration issues

Process contingencies were applied to the PC and NGCC estimates in this report as follows:

- CANSOLV System: 17 percent on PC capture cases; 18 percent on NGCC capture cases—post-combustion capture process unproven at commercial scale for power plant applications

- Instrumentation and Controls: 5 percent on most line-items in the PC and NGCC capture cases—integration issues

2.7.1.7 Owner's Costs

Detailed explanation of the owner's costs is available in the 2019 revision of the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance." [4] Owner's costs are split into three categories: pre-production costs, inventory capital, and other costs.

Pre-production allocations are expected to carry the specific plants through substantial completion, and to commercial operation. Substantial completion is intended to represent the transfer point of the facility from the EPC contractor (development entity) to the end user or owner, and is typically contingent on mutually acceptable equipment closeout, successful completion of facility-wide performance testing, and full closeout of commercial items.

Two examples of what could be included in the "other" owner's costs are rail spur and switch yard costs. Rail spur costs would only be applied to the IGCC and PC cases; however, the switch yard costs would be included in all cases.

Switch yard costs are dependent on voltage, configuration, number of breakers, layout, and air-insulated versus gas-insulated. As a rule of thumb, a 345-kV switchyard (air-insulated, ring bus) would cost roughly \$890,000 per breaker.

On-site only rails (excludes long runs) would be expected to cost in the range of \$890,000 to \$990,000 per mile (relatively flat level terrain) plus the costs of any switches/turnouts (approximately \$50,000 each) and road crossings (approximately \$300 per linear foot).

2.7.2 Operation and Maintenance Costs

The production costs or operating costs and related maintenance expenses (O&M) pertain to those charges associated with operating and maintaining the power plants over their expected life. These costs include:

- Operating labor
- Maintenance – material and labor
- Administrative and support labor
- Consumables
- Fuel
- Waste disposal
- Co-product or by-product credit (that is, a negative cost for any by-products sold)

There are two components of O&M costs: fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation. Taxes and insurance are included as fixed O&M costs, totaling 2 percent of the TPC.

2.7.2.1 Operating Labor

Operating labor cost was determined based on the number of operators required for each technology. The average base labor rate used to determine annual cost is \$38.50/hour. The associated labor burden is estimated at 30 percent of the base labor rate.

2.7.2.2 Maintenance Material and Labor

Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost. This represents a weighted analysis in which the individual cost relationships were considered for each major plant component or section.

2.7.2.3 Administrative and Support Labor

Labor administration and overhead charges are assessed at a rate of 25 percent of the burdened O&M labor.

2.7.2.4 Consumables

The cost of consumables, including fuel, was determined on the basis of individual rates of consumption, the unit cost of each specific consumable commodity, and the plant annual operating hours.

Quantities for major consumables such as fuel and sorbent were taken from technology-specific energy and mass balance diagrams developed for each plant application. Other consumables were evaluated on the basis of the quantity required using reference data.

The quantities for initial fills and daily consumables were calculated on a 100 percent operating capacity basis. The annual cost for the daily consumables was then adjusted to incorporate the annual plant operating basis, or CF.

Initial fills of the consumables, fuels, and chemicals may be accounted for directly in the O&M tables or included with the equipment pricing in the capital cost. Where applicable, the O&M tables state where this cost is included on a case-by-case basis.

2.7.2.5 Waste Disposal

Waste quantities and disposal costs were determined/evaluated similarly to the consumables. In prior iterations of this report, the disposal cost for catalyst and chemicals was assumed to be included in the unit replacement cost, and thus, not explicitly shown. Only major waste streams, such as slag, or fly and bottom ash, were reported. In the current revision, chemical and catalyst waste streams are individually reported, in addition to others. Waste disposal costs were separated into two categories: non-hazardous and hazardous waste. Non-hazardous waste is disposed of at a rate of \$41.88/tonne (\$38.00/ton). Hazardous waste is disposed of at a rate of \$88.16/tonne (\$80.00/ton).

2.7.2.6 Co-Products and By-Products

By-product quantities were also determined similarly to the consumables. However, due to the variable marketability of these by-products, specifically gypsum and sulfur, no credit was taken for their potential salable value.

It should be noted that by-product credits and/or disposal costs could potentially be an additional determining factor in the choice of technology for some companies and in selecting some sites. A high local value of the product can establish whether added capital should be included in the plant costs to produce a particular co-product. Slag is a potential by-product in certain markets. Similarly, ash may also be a potential by-product in certain markets; however, due to the ACI in the PC cases, the fly ash may not be marketable. As stated above, these material streams are considered waste in this report with a concomitant disposal cost.

2.7.3 CO₂ Transport and Storage

The cost of CO₂ T&S in a deep saline formation is estimated using the Fossil Energy (FE)/NETL CO₂ Transport Cost Model (CO₂ Transport Cost Model) and the FE/NETL CO₂ Saline Storage Cost Model (CO₂ Storage Cost Model). Additional detail on development of these costs is available in the 2019 revision of the QGESS document “Carbon Dioxide Transport and Storage Costs in NETL Studies.” [51]

Due to the variances in the geologic formations that make up saline formations across the United States, the cost to store CO₂ will vary depending on location. Storage cost results from the CO₂ Storage Cost Model align with generic plant locations from the NETL studies that utilize the coal found in those particular basins:

- Midwest plant location – Illinois Basin
- Texas plant location – East Texas Basin
- North Dakota plant location – Williston Basin
- Montana plant location – Powder River Basin

The far-right column of Exhibit 2-21 shows the total T&S costs used in NETL system studies for each plant location rounded to the nearest whole dollar. Only the \$10/tonne (\$9/ton) value is used in this volume of the baseline study report since all cases are in the Midwest.

Exhibit 2-21. CO₂ transport and storage costs

Plant Location	Basin	Transport (2018 \$/tonne)	Storage Cost at 25 Gt (2018 \$/tonne)	T&S Value for System Studies ^A (2018 \$/tonne)
Midwest	Illinois	2.07	8.32	10
Texas	East Texas		8.66	11
North Dakota	Williston		12.98	15
Montana	Powder River		19.84	22

^AThe sum of transport and storage costs rounded to the nearest whole dollar

2.7.4 LCOE and Cost of CO₂ Captured/Avoided

The LCOE is the amount of revenue required per net megawatt-hour during the power plant's operational life to meet all capital and operational costs. The real LCOE can be obtained from the following formula:

$$LCOE = LCC + LOM + LFP$$

Where:

LCOE – the levelized cost of electricity, reported in \$/MWh

LCC – the levelized capital cost

LOM – the levelized operating and maintenance cost

LFP – the levelized fuel price

The method used to determine capital recovery factor and levelization factors for operating and maintenance and fuel costs is found in the Cost Estimating Quality Guideline.

The cost of CO₂ captured represents the minimum CO₂ plant gate sales price that will incentivize carbon capture relative to a defined reference non-capture plant. The cost of CO₂ captured is calculated using the following formula:

$$\text{Cost of CO}_2 \text{ Captured} \left(\frac{\$}{\text{tonne}} \right) = \frac{(LCOE_{CCS} - LCOE_{Non\ CCS})}{CO_2 \text{ Captured}}$$

The cost of CO₂ avoided represents the minimum CO₂ emissions price, when applied to both the capture and non-capture plant, that will incentivize carbon capture relative to a defined reference non-capture plant. The cost of CO₂ avoided is calculated using the following formula:

$$\text{Cost of CO}_2 \text{ Avoided} \left(\frac{\$}{\text{tonne}} \right) = \frac{(LCOE_{CCS\ with\ T\ \&\ S} - LCOE_{Non\ CCS})}{CO_2 \text{ Emissions}_{Non\ CCS} - CO_2 \text{ Emissions}_{CCS}}$$

Where:

CCS – the capture plant for which the cost of CO₂ captured/avoided is being calculated (excluding T&S unless otherwise noted)

Non-CCS – the reference non-capture plant, as described below

LCOE – the levelized cost of electricity, reported in \$/MWh

The CCS plant includes CO₂ compression to 15.3 MPa (2,215 psia)

For CO₂ Sales Price, the LCOE excludes T&S costs

For CO₂ Emissions Penalty, the LCOE includes T&S costs

CO₂ Captured – the rate of CO₂ captured, reported in tonne/MWh

CO₂ Emissions – the rate of CO₂ emitted out the stack, reported in tonne/MWh

For today's greenfield coal with CCS plants, the reference non-capture plant used to calculate the cost of CO₂ captured/avoided is an SC PC plant without capture.

For a greenfield natural gas-based power system, the reference plant used to calculate the cost of CO₂ captured/avoided is a non-capture natural gas-based plant.

INTEGRATED GASIFICATION COMBINED CYCLE PLANTS

3 INTEGRATED GASIFICATION COMBINED CYCLE PLANTS

Seven IGCC power plant configurations were evaluated, and the results are presented in this section. Each design is based on a market-ready technology that is assumed to be commercially available to support startup.

In 2018 there were multiple mergers and acquisitions of gasifier technology business units, and each of the gasifier technologies considered in this report was impacted. In May of 2018, McDermott International, Inc. announced that it had completed a merger with Chicago Bridge & Iron Company. As a result, the formerly CB&I E-Gas™ gasifier has become the Lummus Technology E-Gas™ gasification technology. [52] Air Products announced in May 2018 the completion of the acquisition of the Coal Gasification Technology licensing business from Royal Dutch Shell. [53] Both the gasifier technology options previously offered by Shell included in this report are now presented as the Air Products Gasification-Dry Syngas Cooler (DSC) and Air Products Gasification-Dry Bottom Quench (DBQ) technologies. [54] Air Products also announced in November 2018 their agreement to acquire General Electric Company's gasification business. [55] A timeline to finalization of this acquisition was not identified at the time of this report. Given the timing of this recent market activity, and that all relevant acquisitions are not yet final as of the writing of this report, the legacy vendor and technology names previously used to describe the IGCC cases considered have been maintained for this report revision.

The seven IGCC cases evaluated are based on the GEP gasifier, the CB&I E-Gas™ gasifier, and the Shell gasifier, each with and without CO₂ capture. As discussed in Section 1, all plants were sized based on the constraints imposed by the fixed CT output; the net output from each plant varies due to differences in auxiliary power and utility demands.

The CT is based on a state-of-the-art 2008 F-class design. The HRSG/steam turbine cycle varies based on the CT exhaust conditions. Steam conditions are nominally 12.4 MPa/566°C/566°C (1800 psig/1050°F/1050°F) for all the non-CO₂ capture cases and 12.4 MPa/536°C/536°C (1800 psig/996°F/996°F) for all the CO₂ capture cases. The capture cases have a lower main and reheat steam temperature primarily because the turbine firing temperature is reduced to allow for a parts' life equivalent to NGCC operation with a high-H₂ content fuel, which results in a lower turbine exhaust temperature.

The evaluation scope included developing energy and mass balances and estimating plant performance. Equipment lists were developed for each design. Section 3.1 covers general information that is common to all of the cases; case-specific information is subsequently presented in sections 3.2, 3.3, and 3.4.

3.1 IGCC COMMON PROCESS AREAS

The cases have process areas, which are common to each plant configuration, such as coal receiving and storage, O₂ supply, gas cleanup, power generation, etc. As detailed descriptions of these process areas for each case would be repetitious, they are presented in this section for

general background information. Where there is case-specific performance information, the performance features are presented in the relevant case sections.

3.1.1 Coal Receiving and Storage

The function of the coal receiving and storage system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to and including the slide gate valves at the outlet of the coal storage silos. Coal receiving and storage is identical in design for all seven cases; however, coal preparation and feed are gasifier-specific.

Operation Description – The coal is delivered to the site by 100-car unit trains comprising 91 tonne (100 ton) rail cars. The unloading is done by a trestle bottom dumper, which unloads the coal into two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 8 cm x 0 (3" x 0) coal from the feeder is discharged onto a belt conveyor. Two conveyors with an intermediate transfer tower are assumed to convey the coal to the coal stacker, which transfer the coal to either the long-term storage pile or to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

The reclaimers load the coal into two vibratory feeders located in the reclaim hopper under the pile. The feeders transfer the coal onto a belt conveyor that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3 cm x 0 (1½" x 0) by the crusher. A conveyor then transfers the coal to a transfer tower. In the transfer tower, the coal is routed to the tripper, which loads the coal into one of three silos. Two sampling systems are supplied: the as-received sampling system and the as-fired sampling system. Data from the analyses are used to support the reliable and efficient operation of the plant.

3.1.2 Air Separation Unit Selection

In order to efficiently support IGCC projects, air separation equipment has been modified and improved in response to production requirements and the consistent need to increase single train output. “Elevated pressure” air separation designs have been implemented that result in distillation column operating pressures that are over twice as high as traditional plants. In this report, the main air compressor (MAC) discharge pressure was set at 1.6 MPa (236 psia) compared to a traditional ASU plant operating pressure of about 0.7 MPa (105 psia). [56] For IGCC designs, the elevated pressure ASU process minimizes power consumption and decreases the size of some of the equipment items. The ASU power requirement assumed for this report is 420 kWh/ton-O₂ (including the MAC, booster compressor, and auxiliaries, on a 100 percent pure O₂ basis).

3.1.2.1 Residual Nitrogen Injection

The residual N₂ that is available after gasifier O₂ and N₂ requirements have been met is compressed and sent to the CT. Since all product streams are being compressed, the ASU air feed pressure is optimized to reduce the total power consumption and to provide a good match with available compressor frame sizes.

Increasing the diluent flow to the CT by injecting residual N_2 from the ASU can have several benefits, depending on the design of the CT:

- Increased diluent increases mass flow through the turbine, thus increasing the power output of the CT while maintaining optimum firing temperatures for syngas operation. This is particularly beneficial for locations where the ambient temperature and/or elevation are high and the CT would normally operate at reduced output.
- By mixing with the syngas or by being injected directly into the combustor, the diluent N_2 lowers the firing temperature (relative to natural gas) and reduces the formation of thermal NO_x .

In this report, power augmentation was accomplished by diluting the fuel gas with excess N_2 from the ASU and in some cases, also with steam, until a combustion turbine output of 232 MWe was attained.

3.1.2.2 Air Integration

Air integration can provide a modest overall plant efficiency benefit. However, there are ASU operability complications introduced by air integration, particularly at startup. Based on discussions with several ASU vendors, it was decided that the operability issues outweigh the potential efficiency benefits; for this study, air integration is not used for any cases.

3.1.2.3 Elevated Pressure ASU Experience in Gasification

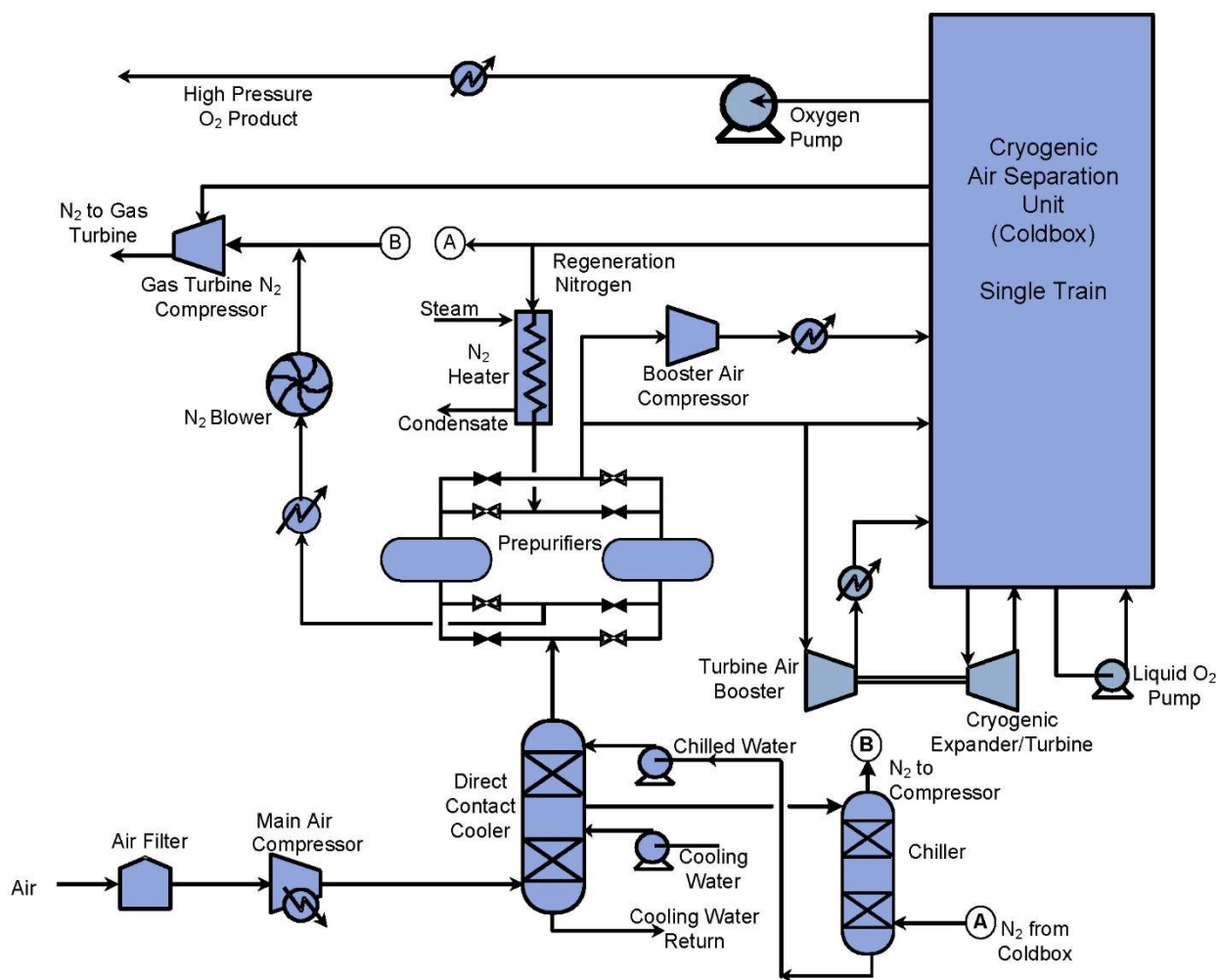
The Buggenum, Netherlands, unit built for Demkolec was the first elevated-pressure, fully integrated ASU to be constructed. It was designed to produce up to 1,796 tonnes/day (1,980 tpd) of 95 percent purity O_2 for a Shell coal-based gasification unit that fuels a Siemens V94.2 CT. In normal operation at the Buggenum plant, the ASU receives all its air supply from and sends all residual N_2 to the CT. [44]

The Polk County, Florida, ASU for the Tampa Electric IGCC is also an elevated-pressure, 95 percent purity O_2 design that provides 1,832 tonnes/day (2,020 tpd) of O_2 to a GEP coal-based gasification unit, which fuels a GEP 7FA CT. All the N_2 produced in the ASU is used in the CT. The original design did not allow for air extraction from the CT. After a CT air compressor failure in January 2005, a modification was made to allow air extraction, which, in turn, eliminated a bottleneck in ASU capacity and increased overall power output. [57]

3.1.2.4 Air Separation Plant Process Description

The air separation plant is designed to produce 95 vol% O_2 for use in the gasifier and Claus plant. The ASU is designed with two production trains, one for each gasifier. The air compressor is powered by an electric motor. N_2 , containing less than 2 vol% of O_2 , is recovered, compressed, and used as a diluent in the CT combustor. A process schematic of a typical elevated pressure ASU, which is based on vendor discussions and quotes, is shown in Exhibit 3-1. [58]

Exhibit 3-1. Typical ASU process schematic



The air feed to the ASU is supplied from the stand-alone MAC. Air to the compressor is first filtered in a suction filter upstream of the compressor. This air filter removes particulates, which tend to cause compressor wheel erosion and foul intercoolers. The filtered air is then compressed in the centrifugal compressor, with intercooling and aftercooling.

Air from the MAC is cooled in a two-stage direct contact cooler. Cooling for the first stage is provided with plant-cooling water. Cooling/chilling for the second stage is provided by chilled water generated by contact with cold N₂ exiting the cold box.

Chilled air is fed to a molecular sieve adsorber pre-purifier system. The adsorbent removes water, CO₂, and C₄+ saturated hydrocarbons in the air. After passing through the adsorption beds, the air is filtered with a dust filter to remove any adsorbent fines that may be present. Downstream of the dust filter a small stream of air is withdrawn to supply the instrument air requirements of the ASU.

Regeneration of the adsorbent in the pre-purifiers is accomplished by passing a hot N₂ stream through the off-stream bed(s) in a direction counter current to the normal airflow. The N₂ is heated against extraction steam (1.7 MPa [250 psia]) in a shell and tube heat exchanger (HX).

[58] The regeneration N_2 drives off the adsorbed contaminants. Following regeneration, the heated bed is cooled to near normal operating temperature by passing a cool N_2 stream through the adsorbent beds. The bed is re-pressurized with air and placed on stream so that the current on-stream bed(s) can be regenerated.

The air from the pre-purifier is then split into three streams. About 70 percent of the air is fed directly to the cold box. About 25 percent of the air is compressed in an air booster compressor. This boosted air is then cooled in an aftercooler against cooling water. The remaining five percent of the air is fed to a turbine-driven, single-stage, centrifugal booster compressor. This stream is cooled in a shell and tube aftercooler against cooling water before it is fed to the cold box. [58]

All three air feeds are cooled in the cold box to cryogenic temperatures against returning product O_2 and N_2 streams in plate-and-fin HXs. The large air stream is fed directly to the first distillation column to begin the separation process. The second largest air stream is liquefied against boiling liquid O_2 before it is fed to the distillation columns. The third, smallest air stream is fed to the cryogenic expander to produce refrigeration to sustain the cryogenic separation process.

Inside the cold box the air is separated into O_2 and N_2 products. The O_2 product is withdrawn from the distillation columns as a liquid and is pressurized by a cryogenic pump. The pressurized liquid O_2 is then vaporized against the high-pressure (HP) air feed before being warmed to ambient temperature. The HP liquid O_2 exits the cold box and is pumped to the desired pressure before being heated to 27°C (80°F) and fed to the gasification unit.

N_2 is produced from the cold box at two pressure levels. Low-pressure (LP) N_2 is split into two streams, the first of which is used as the regeneration gas for the pre-purifiers before being recombined with the balance of the LP N_2 prior to the compressor; the second LP N_2 product stream is used in the direct contact coolers chiller. HP N_2 is also produced from the cold box and is further compressed. The majority of the compressed N_2 is fed to the CT as diluent N_2 . However, depending on plant configuration, N_2 may also be utilized in the AGR and coal feed systems.

3.1.3 Water Gas Shift Reactors

3.1.3.1 Selection of Technology

In the cases with CO_2 separation and capture, the gasifier product must be converted to a CO_2 and H_2 -rich syngas. The syngas CO is converted to CO_2 by reacting with water over a bed of catalyst, producing H_2 . The exit steam to dry gas ratio of the shift reaction, shown below, is maintained above a lower limit of 0.25 to prevent carbon deposition and deactivation of the catalyst. The required steam extraction and associated penalty to the steam cycle is balanced with the catalyst cost while achieving the necessary conversion to achieve 90 percent overall carbon capture. [59] There is also a loss of chemical energy associated with the exothermic conversion of water (H_2O) and CO to CO_2 and H_2 . In the WGS configuration employed, intercooling is applied between stages and the recovered heat is used to generate steam for use

elsewhere in the plant, thus offsetting some of this loss. In the cases without CO₂ separation and capture, CO shift convertors are not required.



The CO shift converter can be located either upstream of the AGR step (sour gas shift) or immediately downstream (sweet gas shift). The WGS must be located upstream of the AGR to achieve high levels of carbon capture. If the CO converter is located downstream of the AGR, then the metallurgy of the unit is less stringent but additional equipment must be added to the process. This is because the CO converter promotes COS hydrolysis without a separate catalyst bed. Products from the gasifier are humidified with steam or water and contain a portion of the water vapor necessary to meet the water-to-gas criterion. If the CO converter is located downstream of the AGR, then the gasifier product would first have to be cooled and the free water separated and treated. Then additional steam would have to be generated and re-injected into the CO converter feed to meet the required water-to-gas ratio. Therefore, for this study, a sour gas shift is included, and the CO converter was located upstream of the AGR.

3.1.3.2 Process Description

The WGS consists of two paths of parallel fixed-bed reactors arranged in series. Two reactors in series are used in each parallel path to achieve conversion up to approximately 95 percent, while higher conversions necessary to meet the 90 percent carbon capture target require three reactors. In the E-Gas™ case, a third shift reactor is added to each parallel train to increase the CO conversion because of the relatively high amount of CH₄ present in the syngas. Steam injection upstream of the shift reactors is extracted from the steam cycle and is used to drive the reaction and control the outlet steam to dry gas ratio. Quench cases and cases with more direct contact syngas water cooling require little or no additional steam injection.

Cooling is provided between the series of reactors to control the exothermic temperature rise. In all four CO₂ capture cases, the HXs are used to raise steam for injection or otherwise integrated into the plant, such as for syngas reheating. Between 93 and 95 percent conversion of the CO is achieved in the GEP and Shell cases, and over 97 percent conversion is achieved in the E-Gas™ case.

3.1.4 Mercury Removal

An IGCC power plant has the potential of removing mercury in a simpler manner than conventional plants (e.g., PC). This is because mercury can be removed from the syngas at elevated pressure and prior to combustion where syngas volumes are much smaller than combusted flue gas volumes in conventional plants. A conceptual design for a sulfur-impregnated, activated carbon bed adsorption system was developed for mercury control, where mercury is captured in the reduced state. Data on the performance of carbon bed systems were obtained from the Eastman Chemical Company, which uses carbon beds at its syngas facility in Kingsport, Tennessee. [32] The coal mercury content (0.15 ppmvd) and carbon bed removal efficiency (approximately 97 percent) were discussed previously in Section 2.2 and Section 2.4.3.1, respectively.

3.1.4.1 Carbon Bed Location

The packed carbon bed vessels are located upstream of the AGR process. Syngas is preheated from temperatures between 27°C (80°F) and 29°C (85°F), to temperatures of 37°C (98°F) and 38°C (100°F) before entering the bed. The preheating is necessary to avoid condensation within the bed. Consideration was given to locating the beds further upstream before the COS hydrolysis unit (in non-CO₂ capture cases) at a temperature near 204°C (400°F). However, while the mercury removal efficiency of carbon has been found to be relatively insensitive to pressure variations, temperature adversely affects the removal efficiency. [60] Eastman Chemical operates their beds ahead of their sulfur recovery unit (SRU) at a temperature of 30°C (86°F). [32]

Consideration was also given to locating the beds downstream of the AGR. However, it was felt that removing the mercury and other contaminants before the AGR would enhance the performance of the AGR and increase the life of the various solvents.

3.1.4.2 Process Parameters

An empty vessel basis gas residence time of approximately 20 seconds was used based on Eastman Chemical's experience. [32] Allowable gas velocities are limited by considerations of particle entrainment, bed agitation, and pressure drop. One-foot-per-second superficial velocity is in the middle of the range normally encountered [60] and was selected for this application.

The bed density of 480 kg/m³ (30 lb/ft³) was based on the Calgon Carbon Corporation HGR®-P sulfur-impregnated pelleted activated carbon offering as of 2002. [61] These parameters determined the size of the vessels and the amount of carbon required. Each gasifier train has two sequential mercury removal beds; the first bed achieves 90 percent of the necessary removal, with the second bed removing the balance of the mercury necessary to meet the emissions limit of 3.0x10⁻⁶ lb/MWh-gross. Since there are two gasifier trains per case, each case has four total carbon beds.

3.1.4.3 Carbon Replacement Time

Eastman Chemicals replaces its bed every 18 to 24 months. [32] However, bed replacement is not due to mercury loading, but rather from:

- A buildup in pressure drop
- A buildup of water in the bed
- A buildup of other contaminants

For this report, a 24-month carbon replacement cycle was assumed. Under these assumptions, the mercury loading in the bed would build up to 0.6–1.1 percent by weight (wt%). Mercury capacity of sulfur-impregnated carbon can be as high as 30 wt%. [62] The mercury laden carbon is considered to be a hazardous waste.

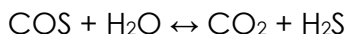
3.1.5 AGR Process Selection

Gasification of coal to generate power produces a syngas that must be treated prior to further utilization. A portion of the treatment consists of AGR and sulfur recovery. This includes all sulfur species, but in particular the total of COS and H₂S, thereby resulting in stack gas emissions of less than 4 ppmv SO₂.

3.1.5.1 COS Hydrolysis

The use of COS hydrolysis pretreatment in the feed to the AGR process converts the COS to a more easily capturable H₂S species. This method was first commercially proved at the Buggenum plant and was also used at both the Tampa Electric and Wabash River IGCC projects. Several catalyst manufacturers, including Haldor Topsøe, Porocel, and Johnson Matthey, offer a catalyst that promotes the COS hydrolysis reaction. The non-carbon capture COS hydrolysis reactor designs are based on information from Johnson Matthey [63] and Porocel. The Porocel activated alumina-based catalyst, designated as Hydrocel 640 catalyst, promotes the COS hydrolysis reaction without promoting reaction of H₂S and CO to form COS and H₂. In cases with CO₂ capture, the WGS reactors reduce COS to H₂S as discussed in Section 3.1.3; therefore, a separate COS hydrolysis unit is not required.

The COS hydrolysis reaction is equimolar with a slightly exothermic heat of reaction, as shown in the following reaction:



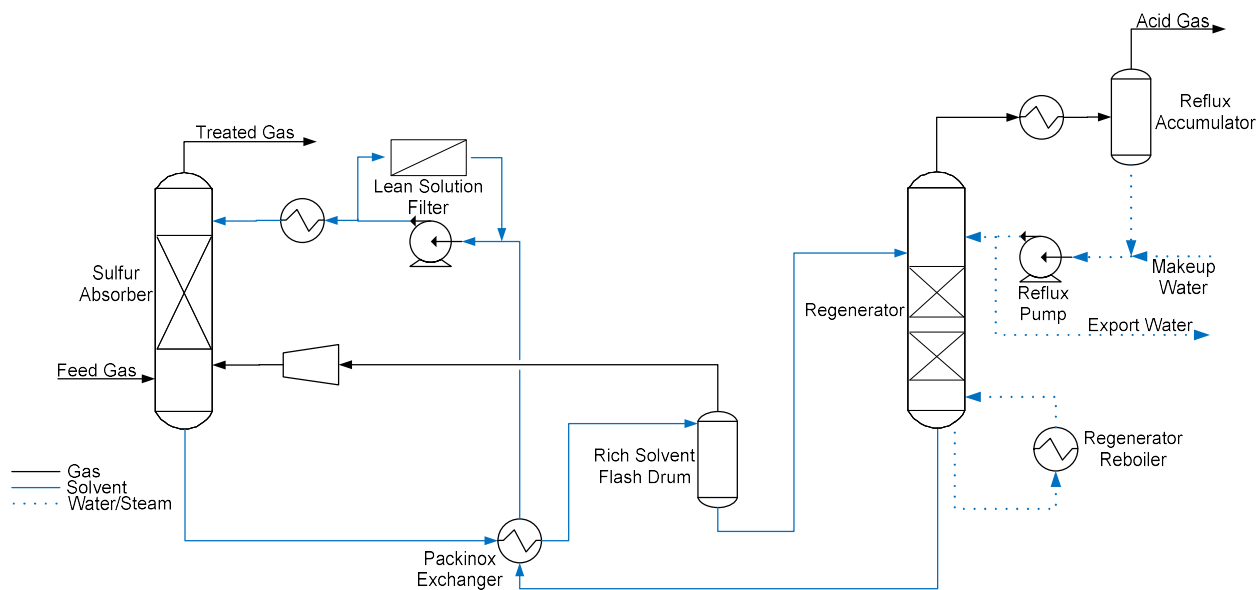
Since the reaction is exothermic, higher conversion is achieved at lower temperatures. However, at lower temperatures the reaction kinetics are slower. Based on the feed gas for this evaluation, Johnson Matthey recommended maintaining a 14°C (25°F) margin above the dew point, with a minimum operating temperature of 120°C (250°F) [63] (Porocel recommended an optimum operating temperature of 177 to 204°C [350 to 400°F]). For low temperature operations, increasing the feed stream's moisture concentration or utilizing additional reactor stages with H₂S removal between stages may be used to promote a higher equilibrium conversion of COS. [63] A retention time of approximately 10 seconds was used to achieve 95.0 percent conversion of the COS. [63]

Although the reaction is exothermic, the heat of reaction is dissipated among the large amount of non-reacting components. Therefore, the reaction is essentially isothermal. The product gas, containing between 6 and 35 ppmv of COS, is cooled prior to entering the mercury removal process and the AGR.

3.1.5.2 Sulfur Removal

H₂S removal generally consists of absorption by a regenerable solvent. The most commonly used technique is based on counter current contact with the solvent. Acid-gas-rich solution from the absorber is stripped of its acid gas in a regenerator, usually by application of heat. The regenerated lean solution is then cooled and recirculated to the top of the absorber, completing the cycle. Exhibit 3-2 is a simplified diagram of the AGR process. [64]

Exhibit 3-2. Flow diagram for a conventional single-stage AGR unit



There are well over 30 AGR processes in common commercial use throughout the oil, chemical, and natural gas industries. However, in a 2002 report by SFA Pacific a list of 42 operating and planned gasifiers shows that only six AGR processes are represented: Rectisol, Sulfinol-M, MDEA, Selexol, aqueous di-isopropanol (ADIP) amine, and FLEXSORB. [65] These processes can be separated into three general types: chemical reagents, physical solvents, and hybrid solvents.

3.1.5.3 AGR Technology Selection in Non-Capture Cases

There are numerous commercial AGR processes that could meet the sulfur environmental target of this report. The most frequently used AGR systems (Selexol, Sulfinol-M, MDEA, and Rectisol) have all been used with the Shell and GEP gasifiers in various applications. Both existing E-GasTM gasifiers use MDEA but could in theory use any of the existing AGR technologies. [64] The following selections were made for the AGR process in non-CO₂ capture cases:

- GEP gasifier: Selexol was chosen based on the GEP gasifier operating at the highest pressure (5.6 MPa [815 psia] versus 4.2 MPa [615 psia] for E-GasTM and Shell), which favors the physical solvent used in the Selexol process.
- E-GasTM gasifier: Refrigerated MDEA was chosen because the two operating E-GasTM gasifiers use MDEA and because CB&I lists MDEA as the selected AGR process on their website. [65] Refrigerated MDEA was chosen over conventional MDEA because the sulfur emissions environmental target chosen is just outside of the range of conventional (higher temperature) MDEA.
- Shell gasifier: The Sulfinol-M process was chosen for this case because it is a Shell owned technology. While the Shell gasifier can and has been used with other AGR processes, it was concluded the most likely pairing would be with the Sulfinol-M process.

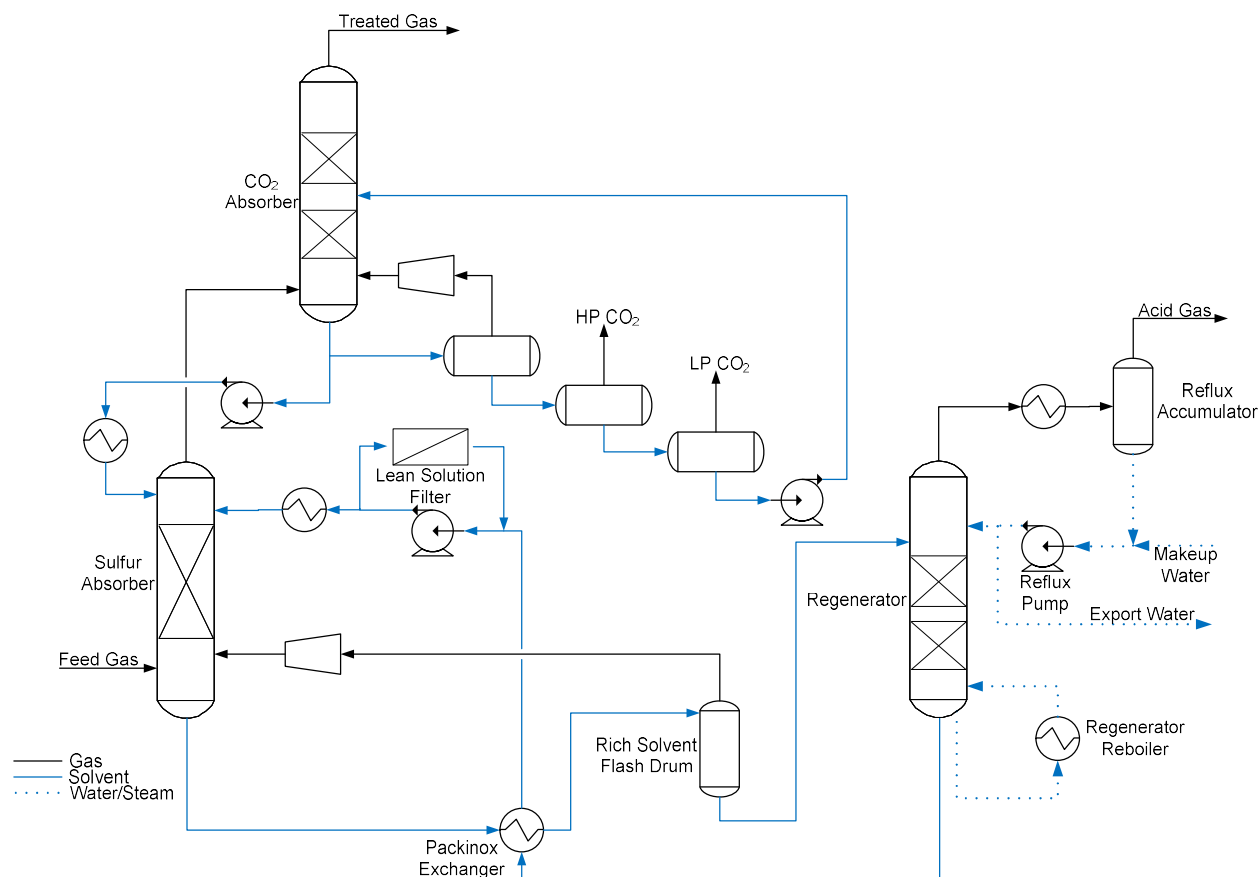
3.1.5.4 AGR Technology Selection in CO₂ Capture Cases

The two-stage Selexol process is used in all four cases that require CO₂ capture. According to the previously referenced SFA Pacific report, “For future IGCC with CO₂ removal for sequestration, a two-stage Selexol process presently appears to be the preferred AGR process – as indicated by ongoing engineering studies at EPRI and by various engineering firms with IGCC interests.” [66]

As several vendors have indicated that Selexol is sensitive to NH₃ and have specified that NH₃ should be reduced to a concentration below 10 ppmv in the syngas feed, a water wash column is included upstream of the AGR for NH₃ control, as detailed in Section 3.1.12.1.4.

As shown in Exhibit 3-3, syngas enters the bottom of the first of two absorbers and flows upward through packed beds where it contacts chilled solvent—loaded with CO₂—entering at the top of the column, which preferentially removes H₂S from the gas phase.

Exhibit 3-3. Flow diagram for a conventional two-stage AGR unit



The gas from the H₂S absorber flows upward through the packed beds of the second absorber. CO₂ is removed from the gas phase first by semi-lean, flash-regenerated solvent entering near the middle of the tower, followed by chilled, lean solvent entering at the top of the tower. The treated gas passes through de-entrainment devices at the top of the tower before exiting the

absorber and being sent directly to the CT. A portion of the gas can also be used for coal drying, when required.

The CO₂ loaded solvent exits the CO₂ absorber. A portion is sent to the H₂S absorber, which is pumped up to pressure and then chilled prior to reaching the H₂S absorber, and the remainder is sent to a series of flash drums for regeneration.

The portion sent to the flash regeneration is expanded in the HP CO₂ recycle flash drum at 2.0 MPa (289.7 psia) where H₂, CH₄, CO₂, and other dissolved gases are transferred to the gas phase. The flashed off gas is compressed and returned to the CO₂ absorber, minimizing product losses to the CO₂ stream.

The amount of H₂ recovered from the syngas stream is dependent on the Selexol process design conditions. In this report, H₂ recovery is 99.5 percent per pass. The minimal H₂ slip to the CO₂ sequestration stream maximizes the overall plant efficiency.

The semi-rich solvent from the HP CO₂ recycle flash drum is routed to two sequential CO₂ flash drums. The MP CO₂ stream is flashed at 0.55 MPa (80 psia) and the LP CO₂ stream is flashed at 0.1 MPa (16.7 psia). The flashed CO₂ gas is sent to the CO₂ compressors and the semi-lean solvent is pumped back to the CO₂ absorber.

The rich solvent exiting the H₂S absorber is heated using the lean solvent from the stripper. The hot, rich solvent enters the H₂S concentrator and partially flashes. The gas exiting the concentrator is compressed and recycled back to the H₂S absorber. The H₂S-rich solvent from the concentrator is sent to the regenerator for thermal regeneration.

The regenerator is composed of a lower section containing packed beds and an upper section containing several reflux trays used to contact the overhead vapor with the reflux water. The solvent from the concentrator enters the regenerator above the packed bed and flows downward, releasing H₂S, CO₂, and other components as it passes an upflow of hot vapor generated in the reboiler.

The combined gases and hot vapor flow upward through a demister and the trayed section, where it is contacted with downflowing reflux water, which cools and condenses the hot vapor and reduces solvent entrainment. The overhead stream passes through a de-entrainment device and exits the top of the column. The overhead gas then passes through the reflux condenser in order to recover the overhead liquid. The cooled liquid and vapor phases are separated in the reflux drum. The reflux liquid is pumped to the trayed section of the regenerator and the acid gas stream is sent to the Claus plant for further processing, as discussed in Section 3.1.7. The lean solvent exiting the stripper is first cooled by providing heat to the rich solvent, then further cooled by exchange with the product gas and finally chilled in the lean chiller before returning to the top of the CO₂ absorber.

The Selexol process unit can be constructed primarily out of killed carbon steel, which is a deoxidized steel that provides limited or no ageing, and a harder material. High severity areas of the Selexol process require stainless steel.

High severity areas are defined as:

- High temperature

- CO₂/H₂S evolution
- High turbulence
- Areas not normally wetted by Selexol solvent

The reboiler, absorber and regenerator packing and internals, regenerator column and reflux circuit, water wash section of the absorbers, and reflux pump impellers and casings are considered high severity areas.

3.1.6 CO₂ Compression and Drying System

All the CO₂ capture cases use two-stage Selexol with internal recycle of the high-pressure flash, as referenced in Section 3.1.5.4. As a result, the CO₂ discharge pressures from the AGR for each capture case are identical, as are the suction pressures at the CO₂ compressor inlets. Therefore, the CO₂ compressor specifications, stage pressure ratios and outlet stage pressures are identical for each of the CO₂ capture cases with the major differentiator being the inlet CO₂ flow rates.

The compression system was modeled based on vendor supplied data and using elements of the compressor design presented in the Carbon Capture Simulation Initiative's paper "Centrifugal Compressor Simulation User Manual." [67] The design was assumed to be an eight-stage front-loaded integrally geared centrifugal compressor with feed streams at stage one and stage three. The stage discharge pressures are presented in Exhibit 3-4.

Exhibit 3-4. CO₂ compressor interstage pressures

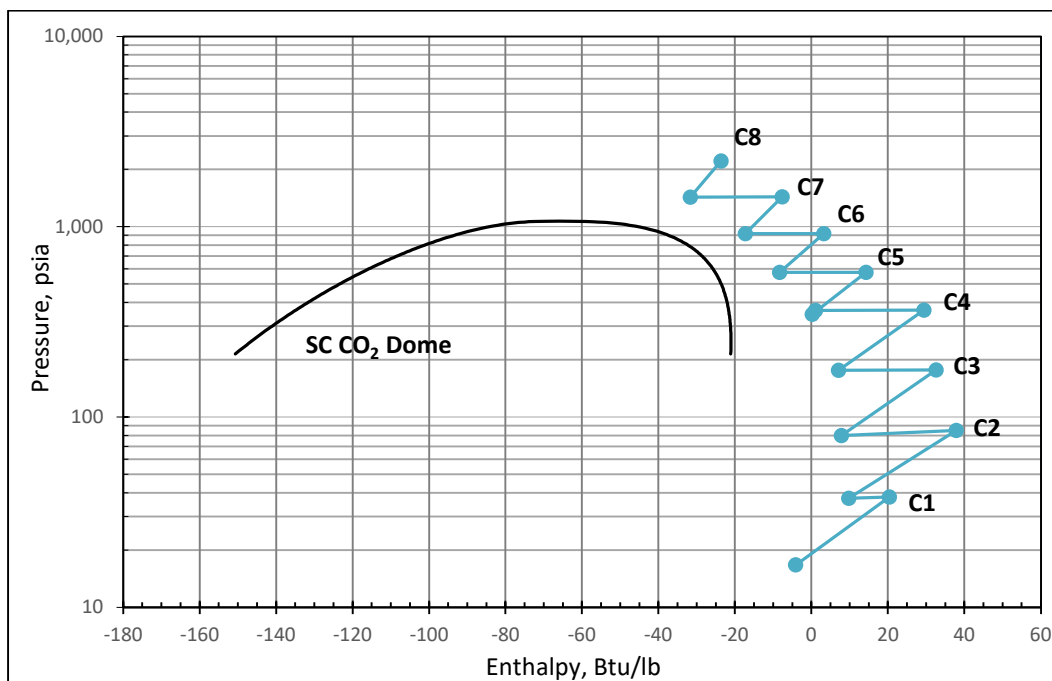
Stage	Outlet Pressure, MPa (psia)	Stage Pressure Ratio
1	0.26 (38)	2.28
2	0.59 (85)	2.28
3	1.22 (177)	2.21
4	2.51 (364)	2.07
5	3.97 (576)	1.66
6	6.34 (919)	1.60
7	9.87 (1,432)	1.56
8	15.27 (2,215)	1.55

The AGR produces CO₂ at two pressure levels and contains approximately 99 percent CO₂. The LP CO₂ stream enters the first stage of the CO₂ compressor at 0.1 MPa (16.7 psia) and is compressed to 0.59 MPa (85 psia) in the first two compression stages with intercooling. The LP CO₂ stream exiting stage two of compression is flashed to 0.55 MPa (80 psia) and is combined with the MP CO₂ stream prior to stage three of compression. The combined stream is compressed in the following two stages to 2.51 MPa (364 psia) with intercooling, after which the combined stream is dehydrated using a triethylene glycol (TEG) dryer. The dried CO₂ stream

is then further compressed in the final four stages, with intercooling, to the target product pressure of 15.27 MPa (2,215 psia).

Intercooling is included for each stage with the first three stages including water knockout. The first five intercoolers cool the CO₂ to 29°C (85°F), the sixth intercooler cools the CO₂ to 40°C (104°F), and the final intercooler cools the CO₂ to 55°C (131°F). The increased temperature is utilized in the final two stages of intercooling to provide a suitable buffer between the compressor operating profile and SC CO₂ dome. A CO₂ product aftercooler is also included to cool the CO₂ 30°C (86°F). CO₂ transportation and storage costs assume that the CO₂ enters the transport pipeline as a dense phase liquid; thus, a pipeline inlet temperature of 30°C (86°F) is considered. Exhibit 3-5 shows the enthalpy versus pressure plot for the CO₂ compressor modeled in Case B1B. Reference conditions for the data are 0.01°C (32.02°F) and 0.0006 MPa (0.089 psia), the same as those used for stream table results. Data points representing compression stage discharge pressures are labeled with the compression stage number (e.g., C1). Given that all four IGCC cases with CO₂ capture utilize the same AGR, and thus, have the same CO₂ discharge pressures, the operating profile is identical across all four IGCC cases with CO₂ capture. The CO₂ aftercooler is not represented in the compressor operating profile plot.

Exhibit 3-5. IGCC CO₂ compressor enthalpy versus pressure operating profile



A TEG dehydration unit is included between stages 4 and 5, operating at 2.39 MPa (347 psia), to reduce the moisture concentration of the CO₂ stream to 500 ppmv. The dryer was designed based on a paper published by the Norwegian University of Science and Technology. [68]

In an absorption process, such as in a TEG dehydration unit, the gas containing water flows up through a column while the TEG flows downward. The solvent preferentially binds the water by physical absorption. The dried gas exits at the top of the column, while the solvent rich in water

exits at the bottom. After depressurization to around atmospheric pressure, the solvent is regenerated by heating it and passing it through a regeneration column where the water is boiled off. A TEG unit is capable of reducing water concentrations to meet the QGESS design point of 500 ppmv. [69]

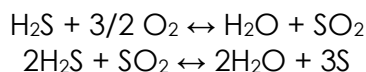
3.1.7 Sulfur Recovery/Tail Gas Cleanup Process Selection

Currently, most of the world's sulfur is produced from petroleum refining, natural gas processing, and coking plants. Sulfur compounds in syngas need to be removed in most gasification applications due to environmental regulations or to avoid catalyst poisoning. The Claus process is still the industry standard for sulfur recovery. Conventional three-stage Claus plants, with indirect reheat and feeds with a high H₂S content, can approach 98 percent sulfur recovery efficiency. However, since environmental regulations have become more stringent, sulfur recovery plants are required to recover sulfur with over 99.8 percent efficiency. To meet these stricter regulations, the Claus process underwent various modifications and add-ons. [66]

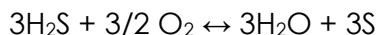
The add-on modification to the Claus plant selected for this report can be considered a separate option from the Claus process. In this context, it is often called a tail gas treating unit (TGTU) process.

The Claus Process

The Claus process converts H₂S to elemental sulfur via the following reactions:



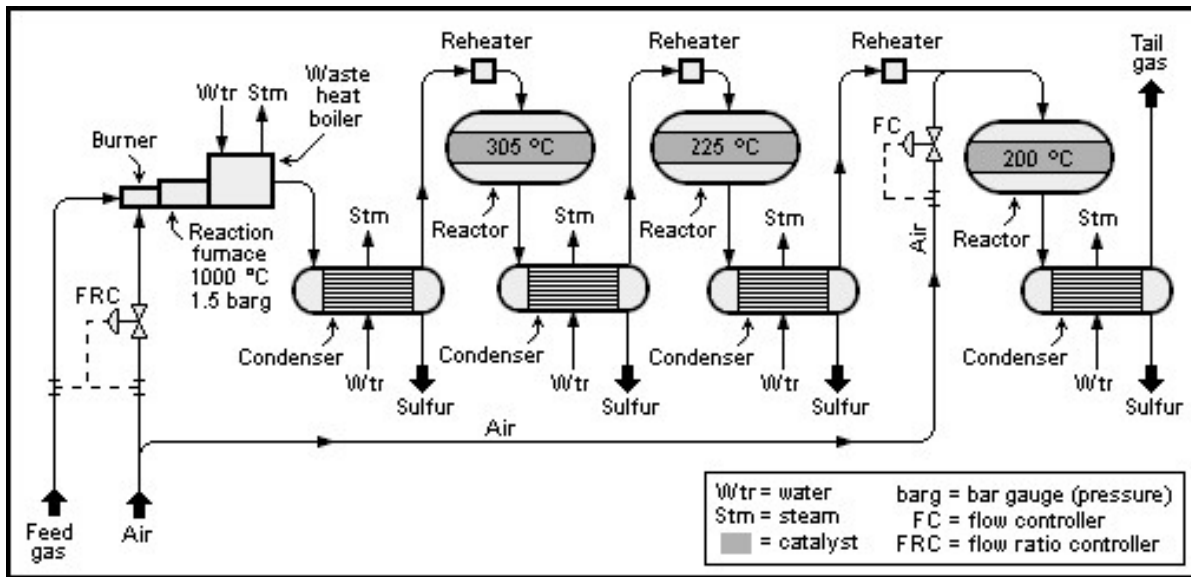
The second reaction, the Claus reaction, is equilibrium limited. The overall reaction is:



The sulfur in the vapor phase exists as S₂, S₆, and S₈, with the S₂ predominant at higher temperatures, and S₈ predominant at lower temperatures.

A simplified process flow diagram of a typical three-stage Claus plant is shown in Exhibit 3-6. [66] One-third of the H₂S is burned in the furnace with O₂ from the air to give sufficient SO₂ to react with the remaining H₂S. Since these reactions are highly exothermic, a boiler that recovers this heat to generate HP steam usually follows the furnace. Sulfur is condensed in a condenser that follows the HP steam recovery section. LP steam is raised in the condenser. The tail gas from the first condenser then goes to several catalytic conversion stages, usually two to three, where the remaining sulfur is recovered via the Claus reaction. Each catalytic stage consists of gas preheat, a catalytic reactor, and a sulfur condenser. The liquid sulfur goes to the sulfur pit, while the tail gas proceeds to the incinerator or for further processing in a TGTU.

Exhibit 3-6. Typical three-stage Claus sulfur plant



Used with permission from Beychok [70]

3.1.7.1 Claus Plant Sulfur Recovery Efficiency

The Claus reaction is equilibrium limited, and sulfur conversion is sensitive to the reaction temperature. The highest sulfur conversion in the thermal zone is limited to about 75 percent. Typical furnace temperatures are in the range of 1,093–1,427°C (2,000–2,600°F), and as the temperature decreases, conversion increases dramatically.

Claus plant sulfur recovery efficiency depends on many factors:

- H₂S concentration of the feed gas
- Number of catalytic stages
- Gas reheat method

In order to keep Claus plant recovery efficiencies approaching 94 to 96 percent for feed gases that contain about 20 to 50 percent H₂S, a split-flow design is often used. In this version of the Claus plant, part of the feed gas is bypassed around the furnace to the first catalytic stage, while the rest of the gas is oxidized in the furnace to mostly SO₂. This results in a more stable temperature in the furnace.

3.1.7.2 Oxygen-Blown Claus

One way to reduce diluent flows through the Claus plant and to obtain stable temperatures in the furnace for dilute H₂S streams is the O₂-blown Claus process.

The O₂-blown Claus process was originally developed to increase capacity at existing conventional Claus plants and to increase flame temperatures of low H₂S content gases. The process has also been used to provide the capacity and operating flexibility for sulfur plants where the feed gas is variable in flow and composition such as often found in refineries. The application of the process has now been extended to greenfield installations, even for rich H₂S

feed streams, to provide operating flexibility compared to conventional Claus units. At least four of the gasification plants in Europe use O₂-enriched Claus units.

O₂ enrichment results in higher temperatures in the front-end furnace, potentially reaching temperatures as high as 1,593–1,649°C (2,900–3,000°F) as the enrichment moves beyond 40–70 vol% O₂ in the oxidant feed stream. Although O₂ enrichment has many benefits, its primary benefit for lean H₂S feeds is a stable furnace temperature. O₂ enrichment also allows for tailgas recycle without N₂ diluent, which would be needed for an air-blown Claus system. Sulfur recovery is not significantly enhanced by O₂ enrichment. Because the IGCC process already requires an ASU, the O₂-blown Claus plant was chosen for all cases.

3.1.7.3 Tail Gas Treating

In many refinery and other conventional Claus applications, tail gas treating involves the removal of the remaining sulfur compounds from gases exiting the SRU. Tail gas from a typical Claus process, whether a conventional Claus or one of the extended versions of the process, usually contains small but varying quantities of COS, CS₂, H₂S, SO₂, and elemental sulfur vapors. In addition, there may be H₂, CO, and CO₂ in the tail gas. In order to remove the rest of the sulfur compounds from the tail gas, all the sulfur-bearing species must first be converted to H₂S. Then, the resulting H₂S is absorbed into a solvent and the clean gas vented or recycled for further processing. The clean gas resulting from the hydrolysis step can undergo further cleanup in a dedicated absorption unit or be integrated with an upstream AGR unit. The latter option is particularly suitable with physical absorption solvents. The approach of treating the tail gas in a dedicated amine absorption unit and recycling the resulting acid gas to the Claus plant is the one used by the Shell Claus Off-gas Treating (SCOT) process. With tail gas treatment, Claus plants can achieve overall removal efficiencies in excess of 99.9 percent.

In the case of IGCC applications, the tail gas from the Claus plant can be catalytically hydrogenated and then recycled back into the system with the choice of location being technology dependent, or it can be treated with a SCOT-type process. In each of the seven cases the Claus plant tail gas is hydrogenated, water is separated, the tail gas is compressed and then returned to the AGR process for further treatment.

3.1.7.4 Flare Stack

In most Claus plants, a self-supporting, refractory-lined, carbon steel (CS) flare stack is typically provided to combust and dispose of unreacted gas during startup, shutdown, and upset conditions. However, in all seven IGCC cases, a flare stack was included for syngas dumping during startup, shutdown, etc. Hence, a separate dedicated Claus plant flare was not required.

3.1.8 Slag Handling

The slag handling system conveys, stores, and disposes of slag removed from the gasification process. Spent material drains from the gasifier bed into a water bath in the bottom of the gasifier vessel. A slag crusher receives slag from the water bath and grinds the material into pea-sized fragments. A slag/water slurry that is between 5 and 10 percent solids leaves the

gasifier pressure boundary through either a proprietary pressure letdown device (E-Gas™) or using lockhoppers (GEP and Shell) to a series of dewatering bins.

The general aspects of slag handling are the same for all three gasification technologies. The slag is dewatered, the water is clarified and recycled, and the dried slag is transferred to a storage area for disposal. The specifics of slag handling vary among the gasification technologies regarding how the water is separated and the end uses of the water recycle streams.

In this report, the slag bins were sized for a nominal holdup capacity of 72 hours of full-load operation. At periodic intervals, a convoy of slag-hauling trucks will transit the unloading station underneath the hopper and remove a quantity of slag for disposal. Approximately ten truckloads per day are required to remove the total quantity of slag produced by the plant operating at nominal rated power. While the slag is suitable for use as a component of road paving mixtures, or potentially as a landfill cover material, it was assumed in this report that the slag would be landfilled with a disposal cost.

3.1.9 Power Island

3.1.9.1 Combustion Turbine

The CT generator selected for this application is representative of the state-of-the-art 2008 F-class turbines. This machine is an axial flow, single spool, and constant speed unit, with variable inlet guide vanes (IGVs). The turbine includes advanced bucket cooling techniques, compressor aerodynamic design and advanced alloys, enabling a higher firing temperature than the previous generation machines. The standard production version of this machine is fired with natural gas and is also commercially offered for use with IGCC derived syngas, such as at the Duke Edwardsport IGCC plant. Performance typical of a state-of-the-art 2008 F-class turbine on natural gas at ISO conditions is presented in Exhibit 3-7.

Exhibit 3-7. State-of-the-art 2008 F-class combustion turbine performance characteristics using natural gas [71]

State-of-the-art 2008 F-Class	
Firing Temperature Class, °C (°F)	1,371+ (2,500+)
Airflow, kg/s (lb/s)	431 (950)
Pressure Ratio	18.5
Simple Cycle Output, MW	185
Combined cycle performance	
Net Output, MW	280
Net Efficiency (LHV), %	57.3
Net Heat Rate (LHV), kJ/kWh (Btu/kWh)	6,284 (5,956)

In this service, with syngas from an IGCC plant, the machine requires some modifications to the burner and turbine nozzles in order to properly combust the low-calorific value gas and expand the combustion products in the turbine section of the machine. Syngas and high H₂ fuel combustion introduce unique concerns such as flame stability, flashback, and NO_x formation.

The modifications to the machine include a redesign of the original can-annular combustors. A second modification involves increasing the nozzle areas of the turbine to accommodate the volume flow of low-calorific value fuel gas combustion products, which are increased relative to those produced when firing natural gas. Other modifications include rearranging the various auxiliary skids that support the machine to accommodate the spatial requirements of the plant's general arrangement. The generator is a standard H₂-cooled machine with static exciter.

The combustion turbine considered for IGCC cases is of 2008 vintage but considered state-of-the-art for syngas applications. It is the same technology as presented in previous revisions of this report. In the NGCC section (Section 0), a 2017 F-class combustion turbine is considered for natural gas applications. There are significant differences between these two machines. The output for the natural gas combustion turbine is increased over syngas (232 MW per CT in IGCC versus 238 MW per CT in NGCC; the Revision 3 NGCC CT has an output of 211 MW). The efficiency of the 2017 vintage turbine is also improved. Per Exhibit 3-7 above, the 2008 vintage F-class firing natural gas would achieve a net plant efficiency (lower heating value [LHV] basis) of approximately 57.3 percent. The 2017 F-class applied in NGCC cases is reported to achieve a net plant efficiency (LHV basis) of 59.4 percent. These efficiency increases, and other design improvements, represent advances in F-class technology. However, in discussion with the vendor, there hasn't been significant recent advances in syngas-fired combustion turbine technology; therefore, the IGCC F-class combustion turbines in this report do not benefit from advances in output, efficiency, or other improvements. If a syngas application were to be developed today, the design for that machine would likely be based on the 2017 F-class frame or newer, and adjustments made to accommodate the syngas fuel, which would improve upon the 2008 vintage output and efficiency. However, per the vendor, such a design is not currently commercially offered. Therefore, the 2008 vintage syngas combustion turbine continues to be applied for IGCC cases.

3.1.9.2 Combustion Turbine Package Scope of Supply

The CT is typically supplied in several fully shop-fabricated modules, complete with all mechanical, electrical, and control systems as required for CT operation. Site CT installation involves module inter-connection and linking CT modules to the plant systems.

3.1.9.3 CT Firing Temperature Control Issue for Low Calorific Value Fuel

A CT fired on low calorific value (LCV) syngas has the potential to increase power output due to the increase in flow rate through the turbine. The higher turbine flow and moisture content of the combustion products can contribute to overheating of turbine components, affect rating criteria for the parts lives, and require a reduction in syngas firing temperatures (compared to the natural gas firing) to maintain design metal temperature. [72] Uncontrolled syngas firing temperature could result in more than 50 percent life cycle reduction of stage 1 buckets.

Control systems for syngas applications include provisions to compensate for these effects by maintaining virtually constant generation output for the range of the specified ambient conditions. IGVs and firing temperature are used to maintain the turbine output at the maximum torque rating, producing a flat rating up to the IGV full open position. Beyond the IGV full open position, flat output may be extended to higher ambient air temperatures by steam/N₂ injection.

In this report, the approximate firing temperature (defined as inlet rotor temperature) in the non-capture cases is 1,371°C (2,500°F) and in the CO₂ capture cases is 1,343°C (2,450°F). The reduction in firing temperature in the CO₂ capture cases is done to maintain equivalent parts life as the H₂O content of the combustion products increases from 5 to 7 vol% in the non-capture cases to 12 vol% in the capture cases. The decrease in temperature also results in a lower temperature steam cycle range in the CO₂ capture cases, 12.4 MPa/533°C to 536°C (1,800 psig/991°F to 996°F) compared to the non-CO₂ capture cases, which range from 12.4 MPa/562°C to 566°C (1,800 psig/1,043°F to 1,051°F).

3.1.9.4 Combustion Turbine Syngas Fuel Requirements

Typical fuel specifications and contaminant levels for successful CT operation are provided in GEP's "Specification for Fuel Gases for Combustion in Heavy-Duty Turbines" and presented for state-of-the-art 2008 F-class machines in Exhibit 3-8. [73] The vast majority of published CT performance information is specific to natural gas operation. Turbine performance using syngas requires vendor input as was obtained for this report.

Exhibit 3-8. Typical fuel specification for state-of-the-art 2008 F-class machines

	Max	Min
LHV, kJ/m ³ (Btu/scf)	None	3.0 (100)
Gas Fuel Pressure, MPa (psia)	3.1 (450)	
Gas Fuel Temperature, °C (°F)	^A	Varies with gas pressure ^B
Flammability Limit Ratio, Rich-to-Lean, Volume Basis	^C	2.2:1 ^D
Sulfur	N/A ^E	

^A The maximum fuel temperature is defined in GEK-4189 [74]

^B To ensure that the fuel gas supply to the CT is 100 percent free of liquids the minimum fuel gas temperature must meet the required superheat over the respective dew point. This requirement is independent of the hydrocarbon and moisture concentration. Superheat calculation shall be performed as described in GEI-4140G [73]

^C Maximum flammability ratio limit is not defined. Fuel with flammability ratio significantly larger than those of natural gas may require start-up fuel

^D Below the minimum flammability ratio of 2.2:1, combustion instability over the full operating range of the turbine may be experienced

^E The quantity of sulfur in syngas is not limited by specification. Experience has shown that fuel sulfur levels up to 1 vol% do not significantly affect oxidation/corrosion rates

3.1.9.5 Normal Operation

Inlet air is compressed in a single spool compressor to a pressure ratio of approximately 17.8:1 relative to ambient air intake. This pressure ratio was vendor specified and less than the 18.5:1

ratio used in natural gas applications. The majority of compressor discharge air remains on board the machine and passes to the burner section to support combustion of the syngas. Compressed air is also used in burner, transition, and film cooling services.

Pressurized syngas is combusted in 14 parallel diffusion combustors, and syngas dilution is used to limit NO_x formation. As described in Section 3.1.2, power augmentation was accomplished by diluting the fuel gas with excess N₂ from the ASU and in some cases, also with N₂ humidification, until a turbine output of 232 MWe was attained. The advantages of using N₂ as the primary diluent include:

- N₂ from the ASU is already partially compressed and using it for dilution eliminates wasting the compression energy.
- Limiting the water content reduces the need to derate firing temperature, particularly in the high-H₂ (CO₂ capture) cases.
- Low-quality heat not otherwise useful for other applications can be used to preheat water for the N₂ humidification process.

There are some disadvantages to using N₂ as the primary diluent, and these include:

- There is a significant auxiliary power requirement to further compress the large N₂ flow from the ASU pressures of 0.5 MPa (65 psia) to the CT pressure of approximately 3.2 MPa (465 psia).
- N₂ is not as efficient as water in limiting NO_x emissions.

It is not clear that one dilution method provides a significant advantage over the other. However, in this report N₂ was chosen as the primary diluent based on suggestions by turbine industry experts during peer review of the report.

Hot combustion products are expanded in the three-stage turbine-expander. Given the assumed ambient conditions, back-end loss, and HRSG pressure drop, the CT exhaust temperature is nominally 593°C (1,099°F) for non-CO₂ capture cases and 563°C (1,046°F) for capture cases. Gross turbine power, as measured after the generator terminals, is 232 MW per train.

3.1.10 Steam Generation Island

3.1.10.1 Heat Recovery Steam Generator

The HRSG is a horizontal gas flow, drum-type, multi-pressure design that is matched to the characteristics of the CT exhaust gas. High-temperature flue gas exiting the CT is conveyed through the HRSG to recover the large quantity of thermal energy that remains. Flue gas travels through the HRSG gas path and exits at 132°C (270°F) for all 7 cases.

The HP drum produces steam at main steam pressure, while the LP drum produces process steam. The HRSG drum pressures are nominally 12.4/0.3 MPa (1,800/50 psig) for the HP/LP turbine sections, respectively. In addition to generating and superheating steam, the HRSG

performs reheat duty for the cold/hot reheat steam for the steam turbine, provides condensate and feedwater (FW) heating, and provides deaeration of the condensate.

Natural circulation of steam is accomplished in the HRSG by utilizing differences in densities due to temperature differences of the steam. The natural circulation HRSG provides the most reliable design.

The HRSG drums include moisture separators, internal baffles, and piping for FW/steam. All tubes, including economizers, superheaters, and headers and drums, are equipped with drains.

Safety relief valves are furnished in order to comply with appropriate codes and ensure a safe workplace.

Superheater, boiler, and economizer sections are supported by shop-assembled structural steel. Inlet and outlet ducts are provided to route the gases from the CT outlet to the HRSG inlet and the HRSG outlet to the stack. A diverter valve is included in the inlet duct to bypass the gas when appropriate. Suitable expansion joints are also included.

3.1.10.2 Steam Turbine Generator and Auxiliaries

The steam turbine consists of an HP section, an intermediate-pressure (IP) section, and one double-flow LP section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single-span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine has a last stage bucket length of 76 cm (30 in.).

Main steam from the HRSG and gasifier island is combined in a header, and then passes through the stop valves and control valves and enters the turbine at stream conditions shown in Exhibit 3-9. The steam initially enters the turbine near the middle of the HP span, flows through the turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at stream conditions shown in Exhibit 3-9.

Exhibit 3-9. IGCC steam conditions

Steam Conditions		
Steam Parameter	Capture	Non-Capture
Main Pressure, MPa (psig)	12.4 (1,800)	12.4 (1,800)
Main Temperature, °C (°F)	533-536 (991-996)	562-566 (1,043-1,051)
Reheat Pressure, MPa (psig)	3.3 (477)	3.3 (477)
Reheat Temperature, °C (°F)	533-536 (991-996)	562-566 (1,043-1,051)

After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections, exhausting downward into the condenser.

Turbine bearings are lubricated by a closed loop (CL), water-cooled, pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip, an

emergency oil pump mounted on the reservoir pumps the oil. When the turbine reaches 95 percent of synchronous speed, the main pump mounted on the turbine shaft pumps oil. The oil flows through water-cooled HXs prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to an LP steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure-regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any collected steam is condensed in the packing exhauster and returned to the condensate system.

The generator is a H₂-cooled synchronous type, generating power at 24 kV. A static, transformer type exciter is provided. The generator is cooled with a H₂ gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Gas is prevented from escaping at the rotor shafts by a CL oil seal system. The oil seal system consists of storage tank, pumps, filters, and pressure controls, all skid mounted.

The steam turbine generator (STG) is controlled by a triple-redundant, microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, operator interface, and datalink interfaces to the balance-of-plant distributed control system (DCS) and incorporates on-line repair capability.

3.1.10.3 Condensate System

The condensate system transfers condensate from the condenser hotwell, through a series of economizers, to the deaerator. The economizers may exchange heat with either the tail-gas recycle coolers, low temperature heat recovery (LTHR) system, and/or the low-temperature economizer section in the HRSG, depending on the case. The system consists of one main condenser; two 50 percent capacity, motor-driven, vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG. Condensate is delivered to a common discharge header through separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

3.1.10.4 Feedwater System

The function of the FW system is to pump the various FW streams from the deaerator storage tank in the HRSG to the respective steam drums. Two 50 percent capacity boiler feed pumps are provided for each pressure level (HP and LP). Each pump is provided with inlet and outlet isolation valves, and outlet check valve. Minimum flow recirculation to prevent overheating and cavitation of the pumps during startup and low loads is provided by an automatic recirculation

valve and associated piping that discharges back to the deaerator storage tank. Pneumatic flow control valves control the recirculation flow.

The FW pumps are supplied with instrumentation to monitor and alarm on low oil pressure, or high-bearing temperature. FW pump suction pressure and temperature are also monitored. In addition, the suction of each boiler feed pump is equipped with a startup strainer.

3.1.10.5 Main and Reheat Steam Systems

The function of the main steam system is to convey main steam generated in the synthesis gas cooler (SGC) and HRSG from the HRSG superheater outlet to the HP turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater (RH), and to the turbine reheat stop valves.

Main steam at conditions shown previously in Exhibit 3-9 exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve and is routed to the HP turbine. Cold reheat steam at approximately 3.4 MPa/344°C to 367°C (487 psig/651°F to 692°F) exits the HP turbine, flows through a motor-operated isolation gate valve, to the HRSG reheater. Hot reheat steam at the conditions shown previously in Exhibit 3-9 exits the HRSG RH through a motor-operated gate valve and is routed to the IP turbines.

Steam piping is sloped from the HRSG to the drip pots located near the steam turbine for removal of condensate from the steam lines. Condensate collected in the drip pots and in low-point drains is discharged to the condenser through the drain system.

Steam flow is measured by means of flow nozzles in the steam piping. The flow nozzles are located upstream of any branch connections on the main headers.

Safety valves are installed to comply with appropriate codes and to ensure the safety of personnel and equipment.

3.1.10.6 Circulating Water System

The circulating water system (CWS) is a closed-cycle cooling water system that supplies cooling water to the condenser to condense the main turbine exhaust steam. The system also supplies cooling water to the AGR plant as required, and to the auxiliary cooling system. The auxiliary cooling system is a CL process that utilizes a higher quality water to remove heat from compressor intercoolers, oil coolers, and other ancillary equipment and transfers that heat to the main circulating cooling water system in plate and frame HXs. The heat transferred to the circulating water in the condenser and other applications is removed by a mechanical draft cooling tower.

The system consists of two 50 percent capacity vertical circulating water pumps (CWP), a mechanical draft evaporative cooling tower, and CS cement-lined interconnecting piping. The pumps are single-stage vertical pumps. The piping system is equipped with butterfly isolation valves and all required expansion joints. The cooling tower is a multi-cell wood frame counterflow mechanical draft cooling tower.

The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or for plugging tubes. This can be done during normal operation at reduced load.

The condenser is equipped with an air extraction system to evacuate the condenser steam space for removal of non-condensable gases during steam turbine operation and to rapidly reduce the condenser pressure from atmospheric pressure before unit startup and admission of steam to the condenser.

3.1.10.7 Raw Water, Fire Protection, and Cycle Makeup Water Systems

The raw water system supplies cooling tower makeup, cycle makeup, service water and potable water requirements. The water source is 50 percent from a POTW and 50 percent from groundwater (makeup water quality is provided in Section 2.1). Booster pumps within the plant boundary provide the necessary pressure.

The fire protection system provides water under pressure to the fire hydrants, hose stations, and fixed water suppression system within the buildings and structures. The system consists of pumps, underground and aboveground supply piping, distribution piping, hydrants, hose stations, spray systems, and deluge spray systems. One motor-operated booster pump is supplied on the intake structure of the cooling tower with a diesel engine backup pump installed on the water inlet line.

The cycle makeup water system provides high-quality demineralized water for makeup to the HRSG cycle, for steam injection ahead of the WGS reactors in CO₂ capture cases, and for N₂ humidification, if required. The demineralizer is sized based on the requirements of the startup boiler.

The cycle makeup system consists of two 100 percent trains, each with a full-capacity activated carbon filter, primary cation exchanger, primary anion exchanger, mixed bed exchanger, recycle pump, and regeneration equipment. The equipment is skid-mounted and includes a control panel and associated piping, valves, and instrumentation.

3.1.11 Accessory Electric Plant

The accessory electric plant consists of switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, and wire and cable. It also includes the main power transformer, all required foundations, and standby equipment.

3.1.12 Process Water Systems

3.1.12.1 Process Water Sources

This section provides brief technology descriptions of equipment that produces process wastewater from IGCC plants, including the syngas scrubber, LTHR, sour water stripper (SWS), NH₃ wash, and process water drum.

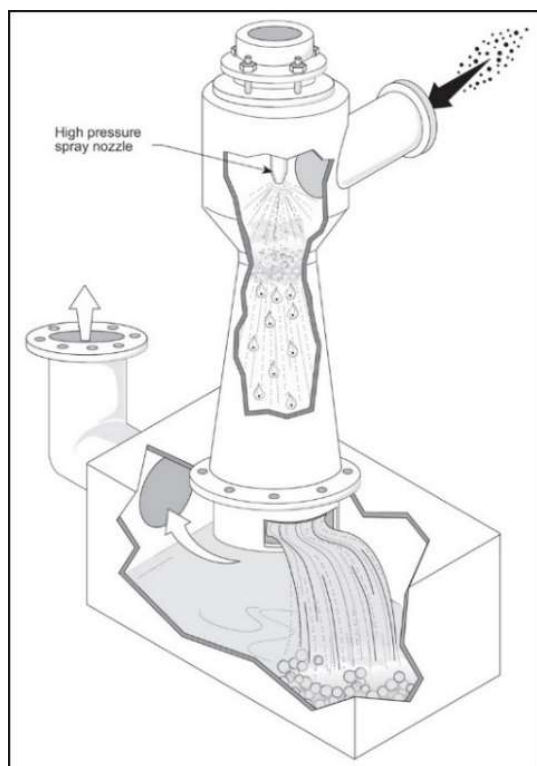
3.1.12.1.1 Syngas Scrubber

The majority of PM is removed from the syngas by upstream equipment, leaving only the finest particulates remaining prior to the syngas scrubber. Most of the remaining particulate is removed in the scrubber, although the primary concern of the syngas scrubber is to facilitate high efficiency gas cleaning by maximizing the contact surface area between liquid and gas, as gases such as HCl are eliminated through absorption into the scrubbing liquid, which in this case is an alkali solution of water and NaOH.

An HP ejector venturi scrubber is particularly suitable for high efficiency gas cleaning in HP operations and is frequently selected to facilitate this process, with expected HCl removal efficiencies in excess of 95 percent. [75] [76]

Exhibit 3-10 provides a diagram of an ejector type venturi scrubber. The gas enters the top section of the system where it comes into contact with a spray of fine water droplets, the spray is directed into a chamber that is shaped to conduct the gas through the atomized droplets, [77] where the HCl and other soluble gases are absorbed. The majority of the remaining particulates are removed from the gas stream by impingement against the relative high velocity droplets. The liquid is collected in a reservoir and the gas exits the side of the reservoir opposite the entrance. The liquid is pumped from the reservoir through a settling tank for particulate removal before being recycled.

Exhibit 3-10. Example diagram of an ejector type venturi scrubber



Source: EPA [78]

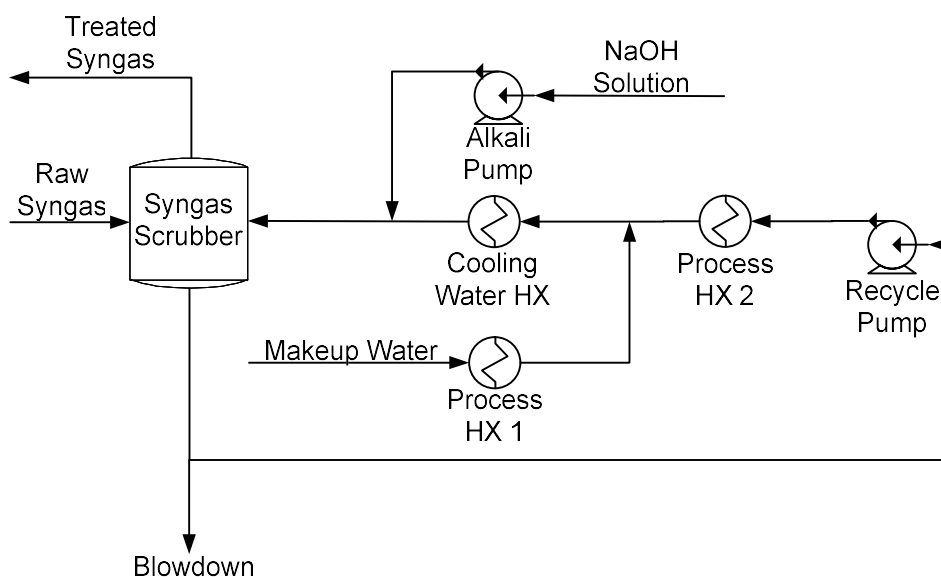
The ejector type venturi scrubbers are typically constructed of 316L stainless steel, operate with a relatively low pressure drop (approximately 2–3 percent of the inlet pressure) [79], have a liquid injection pressure of around 0.83 MPa (120 psi) above that of the inlet gas stream [77], and require between 30 and 100 gallons per 1,000 ft³ of inlet gas. [75]

While 316L stainless steel has a very high tolerance to alkali solutions without concern for corrosion (concentrations of NaOH of up to 50 wt% can be used with negligible corrosion rates [80]), it can only withstand up to 2,000 ppmw of chloride ions (Cl⁻). Considering the cost of the downstream ZLD equipment, priority was given to maximizing the chloride concentration and minimizing the process water discharge flow rate. Because 317L stainless steel can withstand up to 5,000 ppmw Cl⁻, it was selected as the material of choice for the scrubber system. [81] The blowdown from the syngas scrubber is adjusted to maintain a Cl⁻ concentration of 5,000 ppmw, or lower.

While the tolerance of both 316L and 317L to alkali solutions is very high, the pitting rate of both steels rapidly increases with decreasing pH. At a pH of 5, severe pitting occurs with chloride concentrations as low as 500 ppmw. [82] In order to prevent excessive pitting, it is recommended that sufficient NaOH be added in the makeup water to maintain an alkali solution in the effluent. [75] [83]

Exhibit 3-11 provides a simplified block flow diagram (BFD) of the syngas scrubber system, including the alkali injection, makeup water, blowdown, and recycle. The alkali solution is assumed to be 50 wt% NaOH in water. The final cooling water HX cools the injection water to 21.1°C (70°F). The two process HXs are integrated with the syngas preheating system prior to the combustion turbine and the WGS FW preheating system. The makeup water to the syngas scrubber is sourced from either raw water, ZLD condensate, or process wastewater, depending on the selection of technologies utilized in each case. For cases that utilize raw water as the source of the makeup water, the first process HX is excluded.

Exhibit 3-11. Simplified syngas scrubber block flow diagram

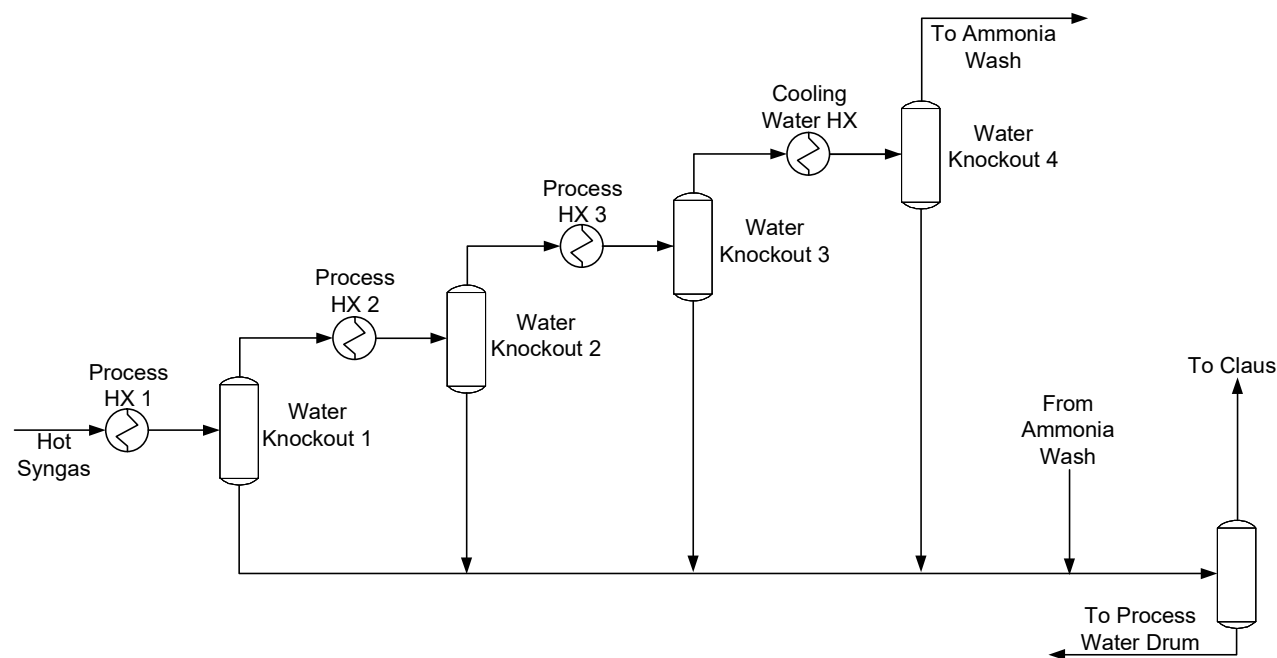


3.1.12.1.2 Low Temperature Heat Recovery

The gas exiting the WGS, or COS hydrolysis reactors enters the LTHR system before entering the NH_3 wash. The purpose of the LTHR system is to cool the syngas to the required operating temperature of the mercury control system, the NH_3 wash and the AGR system, while recovering low grade heat.

As shown in Exhibit 3-12, LTHR consists of a series of shell-and-tube HXs; [84] depending on the inlet temperature, the LTHR system consists of one to three process integrated HXs, followed by a final heat exchange with cooling water. [85]

Exhibit 3-12. Simplified low temperature heat recovery system



During cooling, a significant amount of water is condensed, along with between 35 and 65 percent of the NH_3 present at the inlet and nearly all the remaining HCl , leaving only trace amounts. Small amounts of CO_2 , H_2 , and H_2S are also removed. Knockout drums are located after each HX to remove condensed water.

The effluent from the LTHR system is combined with that of the NH_3 wash and is flashed to 0.5 MPa (65 psia). The vapor product is combined with the compressed sour gas from the SWS and sent to the Claus plant for incineration. The effluent from the flash drum is sent to the process water collection drum for use as process water recycle.

The first of the LTHR HXs is used to produce low pressure steam, which is used in the steam cycle, and the second of the LTHR HXs is used in several systems, depending on the plant configuration, and can include WGS steam preheat, slurry water preheat, gasifier water preheat, syngas preheat prior to the combustion turbine, N_2 humidifier water preheat, and steam cycle FW preheat. The third LTHR HX is used to preheat steam cycle FW.

To withstand the NH_3 concentration in the effluent, which can approach 60,000 ppmw, 316L stainless steel was selected as the material of construction for its high tolerance to NH_3 , as discussed in Section 3.1.12.1.4.

3.1.12.1.3 Sour Water Stripper

As NH_3 is a highly soluble gas, it has a tendency to build-up in the plant process water. The primary solution is to utilize process water as makeup water to the gasifier (slurry water) where it will be destroyed; however, several cases utilize combinations of technologies that result in the presence of excess water from the process water collection drum that necessitates the utilization of a SWS to remove NH_3 , H_2S , and other dissolved gases, so that the process water can be utilized as makeup water to downstream systems such as the NH_3 wash.

The presence of acids, chlorides, sulfates, and formates suppress NH_3 stripping. [86] Since small quantities of HCl are present in the sour water as a result of the LTHR effluent (discussed in 3.1.12.1.2), which reacts with NH_3 to form ammonium chloride (NH_4Cl), small amounts of NaOH may be added to react with the NH_4Cl , releasing the NH_3 and producing the heat stable salt (HSS) sodium chloride (NaCl). [86] The caustic would be fed onto a tray far enough down the column that most of the H_2S has already been stripped out (tray 35 of 40). No more NaOH should be injected than is necessary to maintain pH, as it will chemically bind H_2S into the solution. [86] Other alkaline contaminants that can trap H_2S include sodium, potassium, and magnesium; however, they were assumed to be present in negligible quantities in this report.

HSS can cause the protonation of NH_3 and, therefore, cause a residual amount of NH_3 that cannot be removed (as little as 300 ppmw of HSS can prevent the treated water from reaching NH_3 concentrations of below 100 ppmw), which limits the usefulness of the effluent as recycle water. However, HSS can significantly improve H_2S removal rates, as they are weak acids. [86]

Despite the reasons presented above for adding caustic to the SWS, there are also potential adverse consequences, including a negative impact on the removal of H_2S , the fact that NaOH reacts with HCl to form NaCl, and the beneficial role that the presence of HCl can have on H_2S removal. Based on the net impacts, it was determined that the addition of NaOH would not be necessary and would not be utilized in this report.

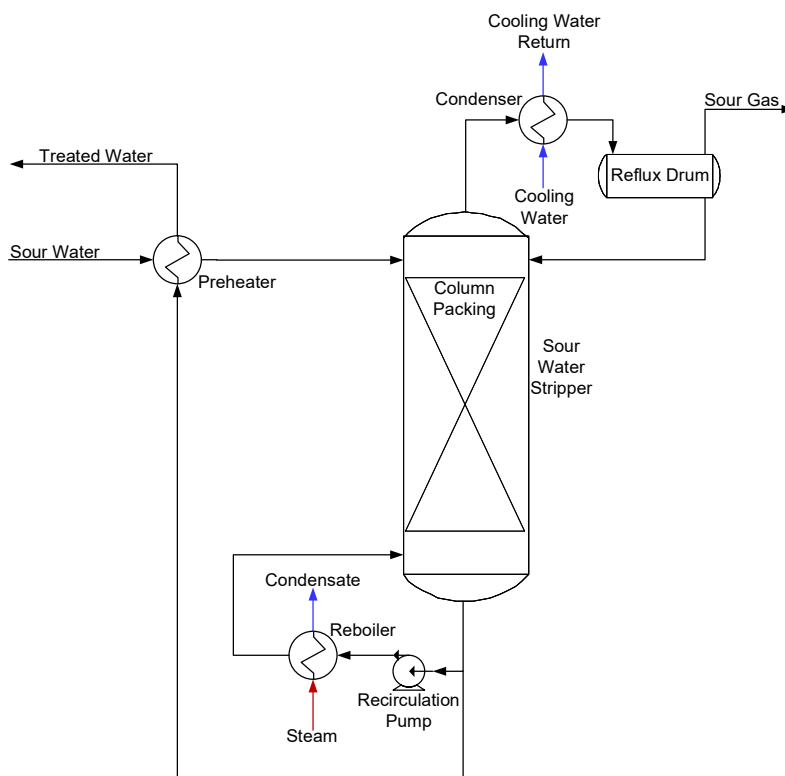
A selection of typical values for key operating parameters for a SWS are provided in Exhibit 3-13.

Exhibit 3-13. Typical operating parameters for sour water strippers

Parameter	Typical
Column Stages [86]	35-45
NH_3 in Effluent, ppmw [86]	30-80
H_2S in Effluent, ppmw [87]	<<1
Steam/Sour Water Feed, kg/m^3 (lb/ft^3) [87]	60-300 (3.7-18.7)
Column Operating Pressure, MPa (psia) [87]	0.1-0.5 (16-65)
pH of Sour Water Feed [86]	~9

Exhibit 3-14 provides a diagram of an SWS column. The excess water from the process water collection drum (described in Section 3.1.12.1.5) constitutes the sour water feed stream to the SWS. The sour water feed is preheated against the treated water product effluent prior to being injected at the top of the column. The sour water flows downward through the column packing [87] against an up-flow of sour gases and steam. A portion of the bottom water is recycled through the reboiler back to the column to increase the rate of recovery of the sour gases. The vapor product is passed through a partial-vapor condenser with the sour gases being separated from the condensate in the reflux drum. The condensate is returned to the column to increase the retention rate of water in the column.

Exhibit 3-14. Simplified sour water stripper diagram



To withstand the NH_3 concentration in the sour water feed stream, which can exceed 20,000 ppmw, 316L stainless steel was selected as the material of construction for its high tolerance to NH_3 , as discussed in Section 3.1.12.1.4.

The sour water is fed to the SWS above the first stage at 0.4 MPa (65 psia), with the sour gas produced at 0.11 MPa (16 psia) and the effluent produced at stage 40 at 0.15 MPa (22 psia). The SWS utilizes an external kettle-type reboiler with 0.4 MPa (65 psia) process steam used as its heat source. [86] The partial-vapor condenser receives cold water from the cooling tower at 16°C (60°F) and the water is returned to the cooling tower at 27°C (80°F).

The SWS is designed to recover 99.5 mol% of NH_3 while retaining 99.6 mol% of water. Only trace amounts of other dissolved gases remain, including H_2S . The sour gas is sent to the Claus plant for incineration, and the clean effluent is used as wash water in the NH_3 wash system.

3.1.12.1.3.1 Secondary Sour Water Stripper

In several cases, the selected combination of plant technologies resulted in excess process wastewater that required disposal. However, to qualify for ZLD, this wastewater needed to be utilized as process makeup water. As several gasifier technologies require steam addition at elevated pressure (~ 5.1 MPa [~ 740 psia]), it was determined that the production of mid-grade steam from process water would be beneficial, rather than extracting high-grade steam and letting it down to the required pressure.

The use of raw process water presents multiple design and operation issues, as these streams contain appreciable quantities of dissolved solids, which would cause fouling on the surface of the boiler tubes. Of particular concern is the presence of NaCl, which is typically limited to 10 ppmw in the boiler water feed. [88] In order to avoid this, the feed to the secondary SWS was sourced from the condensate of the ZLD processes (discussed in Section 3.1.12.2). This effluent is free from suspended solids, and contains less than 20 ppm of dissolved solids, consisting primarily of sodium- and calcium-based constituents. It is assumed that the sodium-based constituents comprise less than half of the total dissolved solids. Therefore, the only contaminant of concern is NH_3 , which is limited to 200 ppmw at the desired operating pressure. [88]

The design of the secondary SWS is nearly identical to that of the primary SWS. The only two differences being that the secondary SWS operates with a feed pressure of 0.18 MPa (26.4 psia) and the column is designed to achieve an effluent with an NH_3 concentration of 200 ppmw. The sour gas from the secondary SWS is compressed and sent to the Claus plant for incineration.

3.1.12.1.4 NH_3 Wash

The operation of solvent based AGR systems is sensitive to the presence of NH_3 , which has a tendency to concentrate in the CO_2 reflux loop. [89] NH_3 forms ammonium sulfide with H_2S that is a contaminant in the product CO_2 and the off gas, and it can form ammonium carbamate with CO_2 that can cause plugging of equipment. [90] If concentrations are allowed to build-up to the point that performance starts to be impacted, the conventional recovery measure would consist of blowing down a portion of the reflux stream, which would then be disposed. [89]

In order to minimize the loss of solvent and to maximize performance of the AGR, a pre-scrubber for NH_3 control is typically utilized to maintain NH_3 concentrations at or below 10 ppmv in the syngas. [89] [91] [92] A spray tower absorption column is often the scrubber of choice for highly soluble gases, such as NH_3 , in systems that operate at low temperatures. [93] [89] [85]

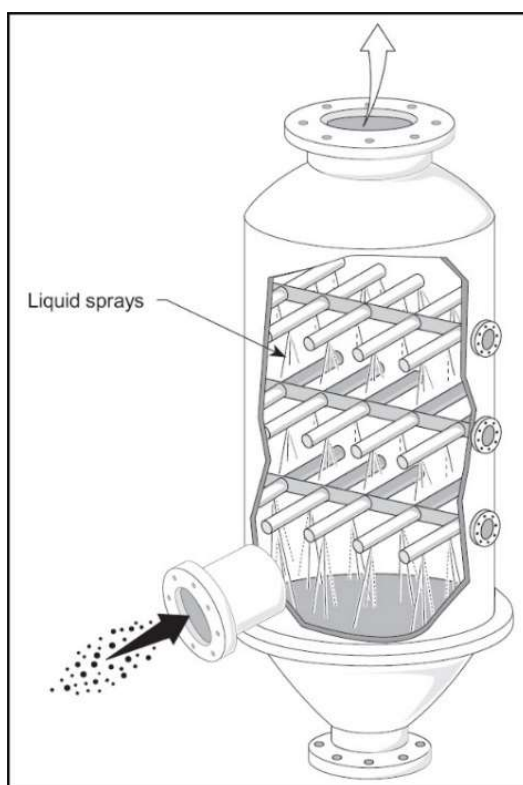
NH_3 , like HCl, is eliminated through absorption into the scrubbing liquid, [76] and as such, the efficiency of scrubbers increases with decreasing temperature; typical scrubber operating temperatures are around 26.7–29.4°C (80–85°F). [94] In order to achieve this, a cooling stage is included in the low temperature HX design (discussed in Section 3.1.12.1.2) that lowers the

temperature to 29.4°C (85°F) and the wash water is cooled to 21.1°C (70°F) in a HX prior to injection.

A single-stage system can expect to achieve between 70 [89] and 85 [94] percent NH_3 reduction, with a typical configuration consisting of approximately 5 stages, [94] which can achieve total NH_3 reduction of over 99 percent. [94] To achieve the target concentration of NH_3 in the clean syngas of 10 ppm, 4 stages were required.

Exhibit 3-15 provides a diagram of an example spray tower absorption column. The spray tower operates by having a counter-current raw gas flow upward against a downward fine-mist spray of water. The water functions to both cool the syngas and absorb the NH_3 , along with other soluble gases. The cleaned gas exits the top of the column and the water exits the bottom. To maximize NH_3 removal, the water is not recycled but is instead sent to a process water collection drum (discussed in Section 3.1.12.1.5) to be utilized as process water makeup. The water demand for the spray tower is primarily sourced from the effluent of the SWS, [95] [94] with raw water making up the balance, as necessary.

Exhibit 3-15. Example diagram of a spray tower absorption column



Source: EPA [78]

The NH_3 water wash column has the same relative pressure drop and water to gas ratio as the syngas scrubber, described in Section 3.1.12.1.1.

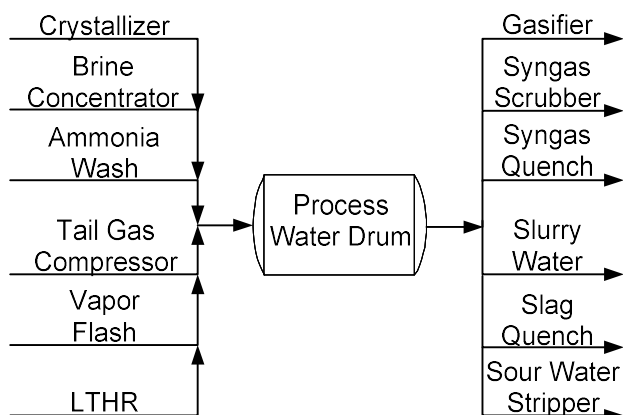
While spray scrubbers are generally constructed of carbon steel, [95] 316L stainless steel is recommended for high NH_3 concentration applications. [96] Considering the concentration of

NH₃ can exceed 20,000 ppmw in the scrubber effluent, 316L stainless steel was the material of choice for this study (no significant deterioration occurs in the presence of NH₃ at concentrations as high as 6 percent [60,000 ppmw]). [97]

3.1.12.1.5 Process Water Drum

The process water drum, depicted in Exhibit 3-16, is a collection tank and distribution point for process wastewater. The process water from various sources such as the Claus plant, ZLD process water treatment system, and NH₃ wash are collected together before being distributed to processes with a water demand, such as the syngas scrubber, coal slurry, and gasifier.

Exhibit 3-16. Example diagram of a process water drum



As is the case with the process wastewater sources, the process water drum would be subjected to a high concentration of NH₃ in the process water (greater than 20,000 ppmw). Therefore, 316L stainless steel is utilized as the material of construction, due to its high tolerance for NH₃, as discussed in Section 3.1.12.1.4.

3.1.12.1.6 Gasification Wastewater Quality

Gasification wastewater quality, summarized in Exhibit 3-17, represents the assumed quality of the water exiting the syngas scrubber that must be treated under the ELG rule, as stated earlier in Section 2.4.2. The gasification water quality is based on internal information from Black & Veatch IGCC projects utilizing a GE gasifier and discussions with GEP regarding their experience with gasification wastewater. Exhibit 3-17 includes a range of values, an average, and the final selected gasification wastewater quality.

The wastewater composition reported in the following table is based on water qualities from actual operations and adjusted to account for chloride. The design concentration of each constituent is individually representative of a plant configuration comparable to those in this study. However, due to the interaction and interdependencies of each constituent and the multitude of potential species, the wastewater quality cannot be considered representative as a whole. The wastewater quality is intended to inform users of the contaminants likely present, and at what concentrations they may be expected at, to facilitate appropriate equipment selection and design.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-17. Gasification wastewater quality

Parameter	Gasification Wastewater (Range)	Gasification Wastewater (Average)	Gasification Wastewater (Final)
pH	5.5–7.0		7.0
Chemical O ₂ demand, ppm		1,500	1,500
Biological O ₂ demand, ppm		1,000	1,000
Specific Conductance, µS/cm			14,000
Ammonia as N, ppm		<80	<80
Suspended Solids, ppm		<50	5
Total Dissolved Solids, ppm			14,995
Chloride as Cl, ppm		5,000	5,000
Sodium as Na, ppm		3,250	3,250
Formate, ppm		3,200	5,333
M-Alkalinity as CaCO ₃ , ppm ^A	600–2,000		700
Calcium as Ca, ppm	20–270		270
Sulfate as SO ₄ , ppm	25–100		100
Silica as SiO ₂ , ppm	25–50		50
Barium (total), ppm	0.20–40	20	40
Magnesium as Mg, ppm	4–20		20
Aluminum, ppm			20
Boron (total), ppm	2.5–10	5	10
Iron (total), ppm	2.5–10	5	10
Selenium (total), ppm	2.5–10	5	10
Sulfide, ppm		<10	<10
Cyanide, ppm		<5	<5
Chromium (total), ppm	0.5–2.0	1	2
Phosphorus, ppm	0.5–2.0	1	2
Potassium, ppm			2
Fluorine, ppm			2
Nickel (total), ppm	0.1–1.0	0.5	1
Molybdenum (total), ppm	0.2–0.8	0.4	0.8
Titanium (total), ppm	0.2–0.8	0.4	0.8
Lithium, ppm			0.3
Antimony (total), ppm	0.005–0.200	0.1	0.2
Arsenic (total), ppm	0.005–0.200	0.1	0.2
Lead (total), ppm	0.05–0.2	0.1	0.2
Thallium (total), ppm	0.05–0.2	0.1	0.2

Parameter	Gasification Wastewater (Range)	Gasification Wastewater (Average)	Gasification Wastewater (Final)
Vanadium (total), ppm	0.025–0.1	0.05	0.1
Uranium, ppm			0.1
Cobalt, ppm			0.1
Manganese (total), ppm	0.015–0.06	0.03	0.06
Beryllium (total), ppm	0.01–0.04	0.02	0.04
Copper (total), ppm	0.01–0.04	0.02	0.04
Zinc (total), ppm	0.01–0.04	0.02	0.04
Thorium, ppm			0.04
Cadmium (total), ppm	0.005–0.02	0.01	0.02
Tin, ppm			0.02
Mercury (total), ppm	0.002–0.008	0	0.01

^aAlkalinity is reported as CaCO₃ equivalent, rather than the concentration of HCO₃⁻. The concentration of HCO₃⁻ can be obtained by dividing the alkalinity by 0.82

The gasification wastewater composition will be dependent on several factors, including composition of the coal, makeup water quality, syngas treatment systems that recycle water to the syngas scrubber, and other factors. The wastewater quality defined above will form the basis for discussion of the process water treatment systems, discussed in the following section.

3.1.12.2 Process Water Treatment

The updated ELG rule established gasification wastewater as a new category, with discharge limits that must be met. The gasification wastewater from the balance of plant is recycled within the gasification and syngas cleanup process, ultimately being utilized as makeup to the syngas scrubber. Therefore, all streams detailed in the updated ELG rule are included in the syngas scrubber blowdown (primary sources are described in Section 3.1.12.1) and can be treated by a single system with a composition described in Section 3.1.12.1.6.

It was a goal of this study to eliminate process water discharge in all the IGCC cases presented in this report. Process water discharge is defined as any water discharged from systems that provide direct contact with contaminants foreign to the source-water (syngas scrubber, NH₃ wash, LTHR) to local waterways. Under these boundaries, blowdown from both the steam cycle and cooling tower are exempt from ZLD classification, provided that no process wastewater is utilized as makeup to either of these systems.

The equipment utilized to achieve ZLD is varied and dependent on several factors, such as contaminants being treated (e.g., selenium or chlorine), general water quality (e.g., pH), end use of product (e.g., process makeup or drinking water), land availability (evaporative ponds), geology characteristics (e.g., deep-well injection), and site characteristics (e.g., wetlands).

Wabash River, Kemper County, and Duke Edwardsport were designed with, and use, vapor-compression evaporation systems to treat their gasification wastewater as part of a ZLD operating practice. [28]

While multiple process configurations were assessed for feasibility of complying with the ELG rule, given this study's intention of maintaining general applicability of the cases presented, and the prevalence of utilizing ZLD operating practices in existing IGCC plants, systems that would achieve ZLD were selected in all cases.

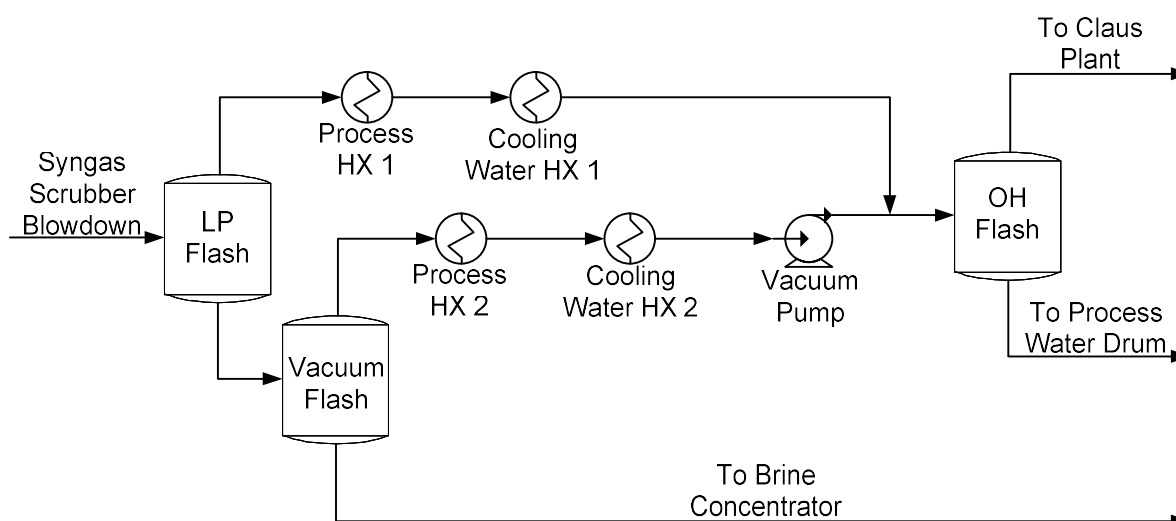
The process water treatment system for IGCC cases includes a vacuum flash, brine concentrator, and crystallizer.

3.1.12.2.1 Vacuum Flash

The primary purpose of the vacuum flash system is to remove dissolved gases, such as NH_3 , CO , H_2 , and H_2S . The separation of dissolved gases prior to the brine concentrator aids in maintaining stable operation and avoiding upsets. Considering the desire to utilize the ZLD system condensate as FW to the auxiliary boiler, and the sensitivity of the auxiliary boiler to NH_3 (discussed in 3.1.12.1.3), it is particularly desirable to remove as much NH_3 as possible prior to the brine concentrator.

Exhibit 3-18 provides a diagram of a vacuum flash system. The blowdown from the syngas scrubber enters the LP drum where it is flashed to 0.5 MPa (70 psia). [98] The effluent of the LP drum enters the vacuum drum, where it is flashed to 0.05 MPa (7.5 psia). The effluent from the vacuum drum is then sent to the brine concentrator. The vapor overhead from both the LP and vacuum drums is cooled in a process integrated HX first, and then a cooling water HX. The vacuum flash is compressed in a vacuum pump before both overhead (OH) streams are sent to the overhead drum, where they are flashed to 0.24 MPa (35 psia). [98] The vapor overhead from the OH drum is sent to the Claus plant for incineration, and the effluent is sent to the process water drum.

Exhibit 3-18. Simplified diagram of vacuum flash system



Both process HXs are integrated with the syngas preheater prior to the combustion turbine. Both cooling water HXs condense the vapor overhead streams by cooling them to 29.4°C (85°F).

While the syngas scrubber limits the chloride concentration of the blowdown stream to 5,000 ppmw, a portion of the water present in the blowdown will be lost with the NH_3 in the LP and vacuum flash drums, resulting in an increased chloride concentration in the effluent of the LP and vacuum flash drums.

Excluding Case B5B-Q, which has a maximum chloride concentration at the vacuum effluent of 3,634 ppmw, both the effluent from the LP flash drum (5,621 ppmw in Case B5B) and vacuum flash drum (6,410 ppmw in Case B5B) exceed the chloride tolerance of 317L stainless steel (5,000 ppmw). Therefore, a more advanced stainless steel will be required in both the LP and vacuum flash drum, such as 317LM or 317LMN. [99] The OH flash drum is required to be constructed of 316L stainless steel due to the high concentration of NH_3 (greater than 40,000 ppmw), as discussed in Section 3.1.12.1.2.

3.1.12.2.2 Brine Concentrator

A brine concentrator is a thermal evaporation process that is often selected as a component of a wastewater treatment system and is utilized as the first step in this study. There are two primary categories of evaporators used in the wastewater treatment industry: thin film and forced circulation. Most brine concentrators in operation are thin film evaporators configured to use a mechanical vapor compression vertical tube evaporation process, which partially evaporates water from the incoming waste stream and leaves behind a concentrated salt solution.

As NaOH is used for HCl scrubbing (discussed in Section 3.1.12.1.1), the wastewater contains primarily sodium-based salts, which are easy to crystallize compared to calcium- and magnesium-based salts, which are highly soluble and difficult to evaporate to a solid product. Therefore, the system can achieve full ZLD without a purge from the crystallizer.

Due to the nature of the salts and the low total suspended solids^h (5 ppmw) in gasification wastewater, pretreatment upstream of the brine concentrator is not required. However, gasification wastewater typically contains constituents that will precipitate from solution within the brine concentrator when heated, adhering to the evaporator surface. While a seeded slurry process can be used to reduce precipitation on tube walls (calcium sulfate is added as a precipitation surface for low solubility salts), scaling cannot be completely eliminated through this method. Therefore, antiscalant addition was selected over seeding, which is fed at multiple points in the system.

To minimize carryover into downstream equipment, an antifoam is added to prevent foaming caused by biological O_2 demand, chemical O_2 demand, and other organics.

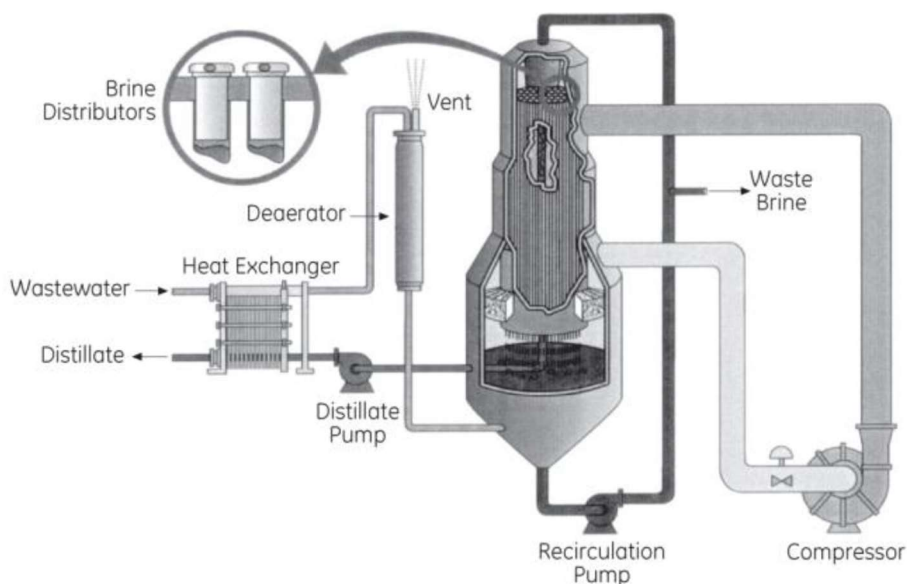
Lastly, sulfuric acid is added to prevent fouling and corrosion, as well as maintain consistent brine properties.

Exhibit 3-19 provides a depiction of a brine concentrator [100] and consists of a HX, heat transfer tubes, sump, sump pump, and compressor. The process water (depicted as

^h The feedwater to the brine concentrator is limited to 50 ppmw TSS to prevent plugging the inlet plate and frame heat exchanger.

“Wastewater”) from the vacuum flash is pumped (not shown) through a HX, where its temperature is raised to the boiling point by the distillate product of the brine concentrator. While the depiction shows a deaerator following the HX, it is not included in the design utilized in this study as the vacuum flash serves the same purpose of removing dissolved gases. From the HX, the process water enters the brine concentrator and is combined with the brine slurry in the sump. The brine slurry is recirculated from the sump to a floodbox at the top of a bundle of heat transfer tubes. [101] As the brine falls through the heat transfer tubes to the sump, a portion of the water evaporates and passes through a mist eliminator (not shown) before entering the vapor compressor. [101] The compressed vapor is sent to the outside of the heat transfer tubes where it is condensed against the brine falling inside the tubes. The condensed distillate is pumped back through the HX, where it heats the incoming process water. A small amount of waste brine is blown down from the sump to control the total dissolved solids (TDS). [101]

Exhibit 3-19. Example diagram of a brine concentrator



Copyright General Electric Company; used with permission. [100]

The brine concentrator is expected to produce an effluent with up to 500,000 TDS [102], with typical performance achieving between 200,000 and 300,000 TDS. [103] Given the elevated operating temperature and the use of NaOH in the upstream syngas scrubber for salt conversion, along with the high solubility of NaCl, it was assumed that 250,000 TDS would be achievable.

The brine concentrator operates at ambient pressure, and the vapor compressor varies the outlet pressure to ensure that sufficient heat is available to preheat the incoming process wastewater (~0.14 MPa [~20 psia]).

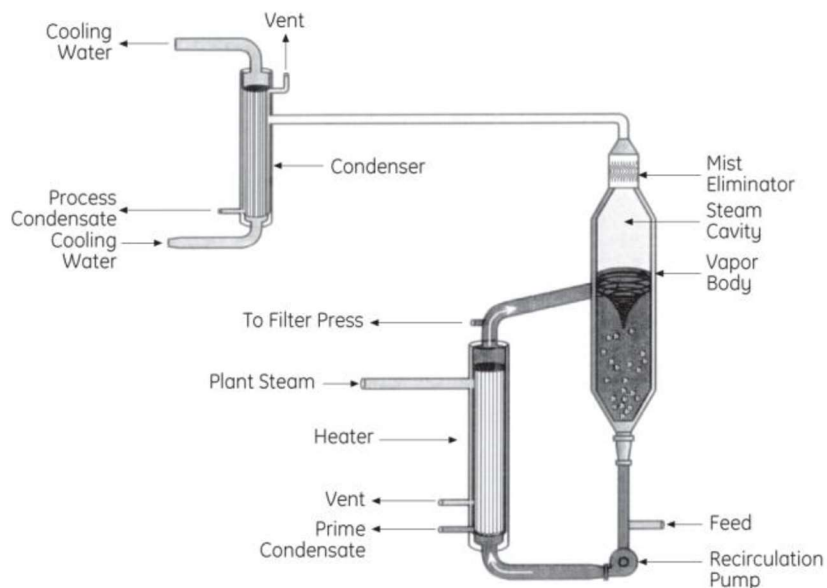
The brine concentrator must be constructed out of exotic materials to withstand the corrosive nature of the highly concentrated product stream. Either Inconel 625 or Hastelloy C276 can be

used for piping and equipment construction; however, titanium would be required for the HX tubes.

3.1.12.2.3 Crystallizer

A crystallizer is often selected as a component of a wastewater treatment system and is utilized as the second step in this study. Exhibit 3-20 provides a depiction of a forced-circulation, steam-driven crystallizer [100] and consists of two HXs and a pump.

Exhibit 3-20. Example diagram of a forced-circulation, steam-driven crystallizer



Copyright General Electric Company; used with permission. [100]

The process water (depicted as feed) from the brine concentrator is sent to the crystallizer sump, where the sump pump circulates the brine through a shell and tube HX. Because the tubes are flooded, the brine is under pressure and will not boil, which prevents scaling in the tubes. [100] The brine enters the crystallizer vapor body at an angle, where it swirls in a vortex. [100] As the water in the brine evaporates, crystals begin to form. The majority of the brine is recirculated back to the heater; however, approximately 20 percent [100] is blown down to the centrifuge/filter press for dewatering (depicted as “To Filter Press”, but not shown). The water from the centrifuge and filter press is returned and mixed with the process water feed from the brine concentrator (not shown). The vapor from evaporation passes through a mist eliminator to remove entrained particles. [101] The product vapor is sent to a HX to be condensed against cooling water. The hot cooling water is returned to the cooling tower and the resulting condensate is utilized as process water makeup. An antifoam chemical feed is required to control foaming within the crystallizer.

An alternative configuration is to use a vapor compressor, rather than plant process steam, to provide heat to the system. In this alternative configuration, the compressed vapor heats the recirculating brine as it condenses. [101] The advantages of this process are the elimination of the condensing HX and process steam extraction in exchange for an electrical auxiliary load.

Considering the energy penalties of using an electrical compressor versus process steam, along with the concern of sufficient vapor product to provide heat to the system, it was determined that a steam-driven crystallizer was most suitable for the cases in this study.

As with the brine concentrator, the crystallizer operates at ambient pressures and requires exotic materials of construction to withstand the corrosive concentrations of brine. Either Inconel 625 or Hastelloy C276 can be used for piping and equipment construction; however, titanium would be required for HX tubes.

The use of sulfuric acid for pH control in the brine concentrator results in the elimination of NaOH and the production of Na_2SO_4 , which is removed as a dissolved solid in the moisture of the salt cake. It is assumed that the impurities present in the gasification wastewater result in a waste product, rather than a salable product, which is transported off-site to a waste-disposal site.

The combined distillate stream from the brine concentrator and crystallizer has a TDS level of less than 20 ppmw, generally consisting primarily of sodium and calcium as carryovers. For the purposes of this study, it is assumed that the combined distillate consists of less than 10 ppmw NaCl.

3.1.12.2.4 Alternative Treatment Methods

In addition to the purification and recycling approach applied to IGCC cases in this report, deep-well injection and evaporating ponds were also considered, and discussion is provided below.

Deep-well injection is a proven technology in municipal and industrial applications which discharges wastewater under pressure into underground porous rock formations through Class 1 wells. Strata of impermeable rock are used to protect underground sources of drinking water from the injected wastewater. A survey of the local geology is, therefore, required to determine the depth to which the well must be drilled and ultimately operated. Capital cost for the equipment and the electrical power consumed by the system would depend on the depth of the well. Disposal of wastewater by this method is regulated and requires that the facility apply for and receive a permit.

Based on the potentially adverse impacts to surface water and groundwater, geological and legal restrictions, and increasing disposal costs, deep well injection was excluded from further evaluation as a viable treatment option in this study.

Evaporation ponds can be constructed to dispose of wastewater if sufficient plot space is available, which is greatly impacted by local ambient conditions. A key determining factor in assessing the viability of an evaporation pond at a specific location is the difference between average rainfall and average evaporation at that location, as the pond needs to be large enough to contain the volume of the discharged wastewater, as well as rain water. In addition, the pond must have enough surface area to allow for average evaporation rates to be equal to or greater than the total inflow of water.

Parts of the Midwest region could be considered a cold, semi-arid climate, which indicates that the summers can be either warm or hot, but the winters tend to be colder, compared to hot, semi-arid or hot, arid climates. Therefore, winter evaporation would be less available.

Moreover, other parts of the Midwest region fall into humid, subtropical and humid, continental climate types. The humidity and higher rainfall averages compared to the arid climates are not favorable for the installation of evaporation ponds. Therefore, evaporation ponds were excluded from further evaluation as a viable treatment option in this study.

While both evaporating ponds and deep-well injection offer low-cost solutions with low auxiliary loads, neither option addresses water consumption, and in many regions of the country the availability of fresh water is limited—therefore, it is desirable to restrict the consumption of, and discharge into the available fresh water. By recycling what would otherwise be water discharge, the amount of water withdrawal required can be reduced considerably.

3.1.13 Waste Treatment/Miscellaneous Systems

An onsite water treatment facility treats all runoff, cleaning wastes, blowdown, and backwash. It is anticipated that the treated water will be suitable for discharge into existing systems and be within EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals.

The waste treatment system is minimal and consists, primarily, of neutralization and oil/water separators (along with the associated pumps, piping, etc.).

A natural gas supply line has been included in all cases for start-up or emergency fuel.

Miscellaneous systems consisting of natural gas, service air, instrument air, and service water are provided. All truck roadways and unloading stations inside the fence area are provided.

3.1.14 Instrumentation and Control

An integrated plant wide DCS is provided. The DCS is a redundant microprocessor based, functional DCS. The control room houses an array of multiple video monitors and keyboard units. The monitor/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to be operational and accessible 99.5 percent of the time that it is required (99.5 percent availability). The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are manually implemented, with operator selection of modular automation routines available. The exception to this, and an important facet of the control system for gasification, is the critical controller system, which is a part of the license package from the gasifier supplier and is a dedicated and distinct hardware segment of the DCS.

This critical controller system is used to control the gasification process. The partial oxidation of the fuel feed and O₂ feed streams to form a syngas product is a stoichiometric, temperature- and pressure-dependent reaction. The critical controller utilizes a redundant microprocessor executing calculations and dynamic controls at 100- to 200-millisecond intervals. The enhanced execution speeds as well as evolved predictive controls allow the critical controller to mitigate process upsets and maintain the reactor operation within a stable set of operating parameters.

3.1.15 Performance Summary Metrics

This section details the methodologies of several metrics reported in the performance summaries.

3.1.15.1 Cold Gas Efficiency

The cold gas efficiency is calculated by subtracting the heating value of any gas recycled to the gasifier from the heating value of the gas exiting the gasifier and dividing that difference by the thermal input to the gasifier. This calculation is represented by the equation:

$$CGE = \frac{(GO - RI)}{TI}$$

Where:

CGE – cold gas efficiency, percent

GO – heating value of gas exiting the gasifier, Btu

RI – heating value of gas recycled to gasifier, Btu

TI – thermal input to the gasifier, Btu

The thermal input to the gasifier is calculated by taking the coal feed rate and multiplying by the heating value.

The components considered for the heating value of the gasifier exit gas and recycle gas are CO, H₂, CH₄, H₂S, NH₃, and COS. Their mole fraction is extracted from the model, multiplied by the molar flow of the stream, and then multiplied by their individual heating values.

3.1.15.2 Combustion Turbine Efficiency

The combustion turbine efficiency is calculated by taking the combustion turbine power produced and dividing it by the thermal input to the turbines. This calculation is represented by the equation:

$$CTE = \frac{CTP}{TI}$$

Where:

CTE – combustion turbine efficiency, percent

CTP – combustion turbine power, kWh

TI – thermal input to the turbine, kWh

The thermal input is calculated by taking the mole fraction of the individual gases (CO, H₂, CH₄, H₂S, NH₃, and COS) multiplied by the molar flow rate of the total stream entering the combustion turbine and then multiplying each by their individual heating values.

3.1.15.3 *Steam Turbine Efficiency*

The steam turbine efficiency is calculated by taking the steam turbine power produced and dividing it by the difference between the thermal input and thermal output. This calculation is represented by the equation:

$$STE = \frac{STP}{(TI - TO)}$$

Where:

STE – steam turbine efficiency, percent

STP – steam turbine power, after generator losses, kWh

TI – thermal input, kWh

TO – thermal output, kWh

Depending on the case, the thermal input is considered to include the main steam, makeup water, energy added during reheat, LP steam from the HRSG, and/or IP steam from the WGS.

The IP blowdown, HP blowdown, and superheater losses are also credited to the thermal input as they are extracted from the cycle prior to the main steam but after the condensate boiler FW.

The thermal output is considered to be the BFW from the condenser and any extractions, such as the gasifier steam and the 1.7 MPa (250 psia) header.

3.1.15.4 *Steam Turbine Heat Rate*

The steam turbine heat rate is calculated by taking the inverse of the steam turbine efficiency. This calculation is represented by the equation:

$$STHR = \frac{1}{STE} * 3,412$$

Where:

STHR – steam turbine heat rate, Btu/kWh

STE – steam turbine efficiency, fraction

3.2 SHELL GLOBAL SOLUTIONS IGCC CASES

This section contains an evaluation of plant designs for cases B1A and B1B, which are based on the Shell gasifier. Cases B1A and B1B are very similar in terms of process, equipment, scope and arrangement, except that Case B1B employs a syngas quench and includes WGS reactors, CO₂ absorption/regeneration, and compression/transport systems. There are no provisions for CO₂ removal in Case B1A.

The balance of this section is organized as follows:

- Gasifier Background – provides information on the development and status of the Shell gasification technology

- Process System Description – provides an overview of the technology operation as applied to Case B1A. The systems that are common to all gasifiers were covered in Section 3.1 and only features that are unique to Case B1A are discussed further in this section
- Key Assumptions – provides a summary of study and modeling assumptions relevant to cases B1A and B1B
- Sparing Philosophy – provided for cases B1A and B1B
- Performance Results – provides the main modeling results from Case B1A, including the performance summary, environmental performance, carbon balance, sulfur balance, water balance, mass and energy balance diagrams, and mass and energy balance tables
- Equipment List – provides an itemized list of major equipment for Case B1A
- Cost Estimates – provides a summary of capital and operating costs for Case B1A.

Process and System Description, Performance Results, and Equipment List and Cost Estimates are repeated for Case B1B.

3.2.1 Gasifier Background

The “Coal Gasification Guidebook: Status, Application, and Technologies” report published by EPRI provides a detailed history of the development of several types of gasifier technology, including the Shell gasifier, as well as gasifier capacity, distinguishing characteristics, and important coal characteristics. [104]

As of 2009, Shell reported ten gasifiers in operation, producing 100,000–150,000 Nm³/hr of syngas and three of the same size in construction. Another three ranging 150,000–250,000 Nm³/hr are also in construction. [105] The large gasifier operating in the Netherlands has a bituminous coal-handling capacity of 1,633 tonnes/day (1,800 tpd) and produces dry gas at a rate of 158,575 Nm³/hr (5.6 million scf/hr) with an energy content of about 1,792 GJ/hr (1,700 MMBtu/hr) (HHV). This gasifier was sized to match the fuel gas requirements for the Siemens/Kraftwerk Union V-94.2 CT and could easily be scaled up to match state-of-the-art 2008 F-class turbine requirements. [105]

Shell gasifiers are capable of utilizing a wide variety of coal types, and compared to slurry fed gasifiers, the dry-fed, cooled-refractory lined, Shell gasifier has a lower O₂ requirement and produces a gas with a higher H₂S/CO₂ ratio, which improves sulfur recovery. [104]

While the use of dry feed allows for lower O₂ consumption, the feed system—which includes the coal drying system—is more complicated. [104]

Coal characteristics that are favorable when selecting a coal type for use with a Shell gasifier include low concentrations of ash with a moderate fusion temperature. If a coal is selected that has a high ash fusion temperature, flux addition may be necessary. The negative impact that high ash coals have on the operation of gasifiers are reduced in dry feed systems in comparison to slurry fed gasifiers. [104]

3.2.2 Key System Assumptions

System assumptions for cases B1A and B1B (Shell IGCC with and without CO₂ capture) are compiled in Exhibit 3-21.

Exhibit 3-21. Shell IGCC plant study configuration matrix

Case	B1A	B1B
Gasifier Pressure, MPa (psia)	4.2 (615)	
O ₂ :Coal Ratio, kg O ₂ /kg As-Received coal	0.720	
Carbon Conversion, %	99.5	
Syngas HHV at Gasifier Outlet, kJ/Nm ³ (Btu/scf) ^A	10,805 (290)	9,948 (267)
Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/561/561 (1,800/1,043/1,043)	12.4/533/533 (1,800/991/991)
Condenser Pressure, mm Hg (in. Hg)	51 (2.0)	
CT	2x State-of-the-art 2008 F-Class (232 MW output each)	
Gasifier Technology	Shell	
Oxidant	95 vol% O ₂	
Coal	Illinois No. 6	
Coal Feed Moisture Content, %	5	
COS Hydrolysis	Yes	Occurs in WGS
WGS	No	Yes
H ₂ S Separation	Sulfinol-M	Selexol 1 st Stage
Sulfur Removal, %	99.5	~100.0
Sulfur Recovery	Claus Plant with Tail Gas Treatment/Elemental Sulfur	
Particulate Control	Cyclone, Candle Filter, Scrubber, and AGR Absorber	Cyclone, Candle Filter, Scrubber, Quench, and AGR Absorber
Chloride Control	Venturi Scrubber, Vacuum Flash, Brine Concentrator, Crystallizer	
Mercury Control	Carbon Bed	
NO _x Control	MNQC (LNB), N ₂ Dilution, and Humidification	
CO ₂ Separation	N/A	Selexol 2 nd Stage
Overall Carbon Capture, %	N/A	90.0
CO ₂ Sequestration	N/A	Off-site Saline Formation

^ASyngas measurement is reflected post-syngas recycle, but before syngas quench (if applicable). In B1B with CO₂ capture and WGS, syngas recycle is taken after WGS, resulting in an increased moisture content and lower syngas heating value

3.2.2.1 Balance of Plant – Case B1A and Case B1B

The balance of plant assumptions are common to both cases and presented in Exhibit 3-22.

Exhibit 3-22. Balance of plant assumptions

Parameters	Values
Cooling System	Recirculating Wet Cooling Tower
Fuel and Other Storage	
Coal	30 days
Slag	30 days
Sulfur	30 days
Sorbent	30 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 V
Motors between 1 hp and 250 hp	480 V
Motors between 250 hp and 5,000 hp	4,160 V
Motors above 5,000 hp	13,800 V
Steam and Combustion Turbine Generators	24,000 V
Grid Interconnection Voltage	345 kV
Water and Wastewater	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater and is assumed to be in sufficient quantities to meet plant makeup requirements Makeup for potable, process, and de-ionized (DI) water is drawn from municipal sources
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant was sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	Blowdown from the cooling tower is softened and passed through a two-stage RO with pre-treatment and demineralizer before being discharged

3.2.3 Sparing Philosophy

The sparing philosophy for cases B1A and B1B is provided below. Dual trains are used to accommodate the size of commercial CTs. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- Two ASUs (2 x 50 percent)
- Two trains of coal drying and dry feed systems (2 x 50 percent)
- Two trains of gasification, including gasifier, SGC, cyclone, and barrier filter (2 x 50 percent)
- Two trains of syngas clean-up process (2 x 50 percent)
- Two trains of Sulfinol-M AGR in Case B1A and (2 x 50 percent)
- One train of two-stage Selexol in Case B1B (1 x 100 percent)
- One train of CO₂ compression systems (1 x 100 percent) in Case B1B
- Two trains of process water treatment systems (2 x 50 percent)
- One train of Claus-based sulfur recovery (1 x 100 percent)
- Two CT/HRSG tandems (2 x 50 percent)
- One steam turbine (1 x 100 percent)

3.2.4 Case B1A – Shell IGCC Power Plant Without CO₂ Capture Process Description

In this section, the Shell gasification process for Case B1A is described. The system descriptions follow the BFD provided in Exhibit 3-23 with the associated stream tables—providing process data for the numbered streams in the BFD—provided in Exhibit 3-24.

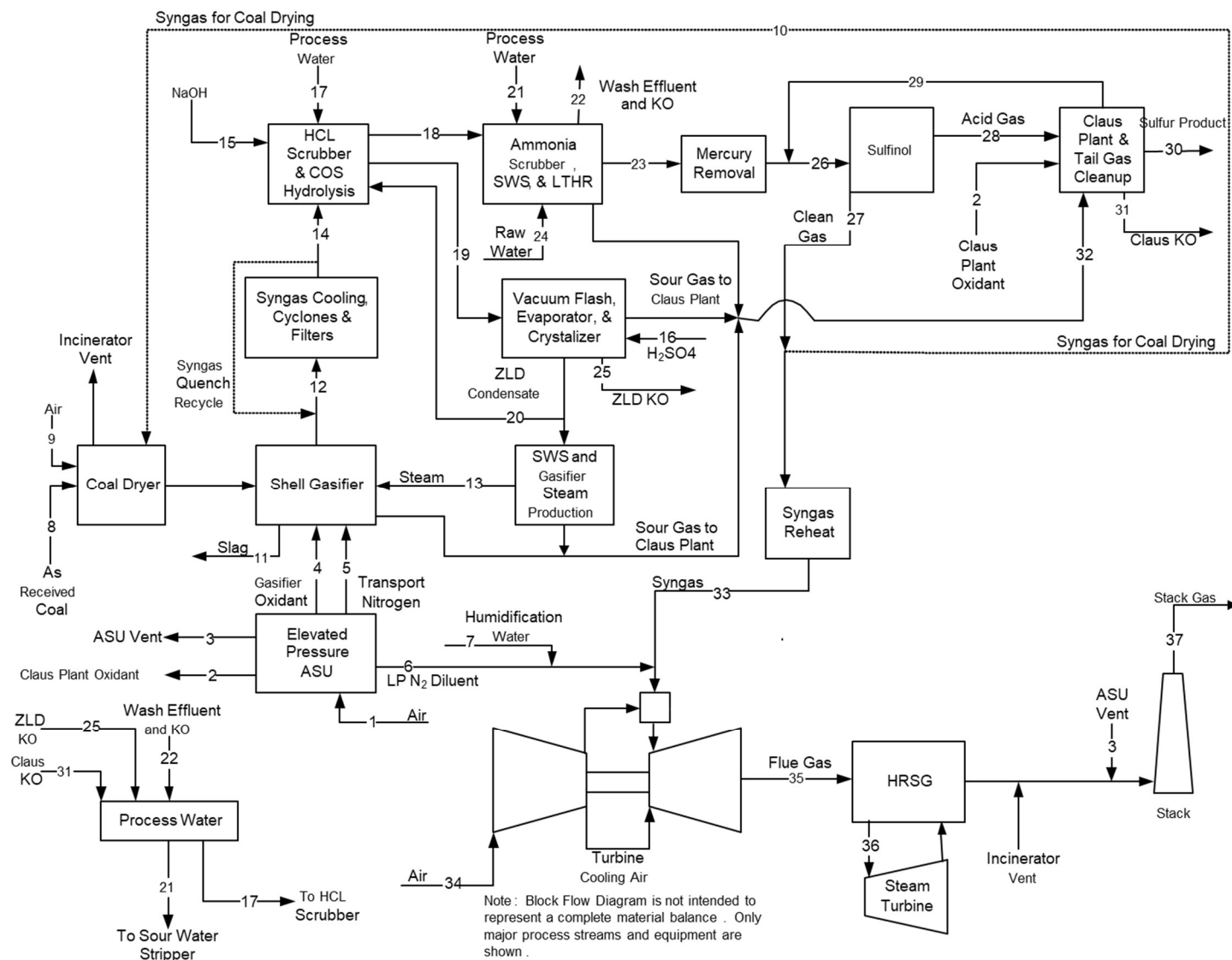
3.2.4.1 Coal Preparation and Feed Systems

Coal receiving and handling is common to all cases and was covered in Section 3.1.1. The receiving and handling subsystem ends at the coal silo. The Shell process uses a dry feed system, which is sensitive to the coal moisture content. Coal moisture consists of two parts, surface moisture and inherent moisture. For coal to flow smoothly through the lock hoppers, the surface moisture must be removed. The Illinois No. 6 coal used in this report contains 11.12 percent total moisture on an as-received basis (stream 8). It was assumed that the coal must be dried to 5 percent moisture to allow for smooth flow through the dry feed system.

The coal is simultaneously crushed and dried in the coal mill then delivered to a surge hopper with an approximate two-hour capacity. A slipstream of clean syngas (stream 10) is combusted with air (stream 9) in an incinerator, which produces a flue gas with an O₂ content of 6 vol%. The incinerator's flue gas is used to dry the coal in the mill.

The coal is drawn from the surge hoppers and fed through a pressurization lock hopper system to a dense phase pneumatic conveyor, which uses N₂ from the ASU (stream 5) to convey the coal to the gasifiers.

Exhibit 3-23. Case B1A block flow diagram, Shell IGCC without CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-24. Case B1A stream table, Shell IGCC without capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0343	0.2078	0.0343	0.0000	0.0000	0.0000	0.0000	0.0092	0.0097	0.0000	0.0091
CH ₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000	0.0004
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.5970	0.0000	0.5753
CO ₂	0.0003	0.0000	0.0365	0.0000	0.0000	0.0000	0.0000	0.0000	0.0003	0.0206	0.0000	0.0188
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0007
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3093	0.0000	0.2937
H ₂ O	0.0099	0.0000	0.7535	0.0000	0.0000	0.0000	1.0000	0.0000	0.0099	0.0013	0.0000	0.0323
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005
H ₂ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0081
N ₂	0.7732	0.0157	0.0023	0.0157	0.9964	0.9964	0.0000	0.0000	0.7732	0.0616	0.0000	0.0575
NH ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0035
O ₂	0.2074	0.9501	0.0000	0.9501	0.0036	0.0036	0.0000	0.0000	0.2074	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	0.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	22,143	94	198	4,675	880	16,225	96	0	835	253	0	25,032
V-L Flowrate (kg/hr)	638,970	3,042	4,670	150,577	24,677	454,760	1,723	0	24,107	5,159	0	513,012
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	197,502	0	0	19,781	0
Temperature (°C)	15	27	29	27	129	196	38	15	15	45	1,427	1,080
Pressure (MPa, abs)	0.10	0.86	0.45	5.10	5.41	2.80	0.90	0.10	0.10	3.36	4.24	4.24
Steam Table Enthalpy (kJ/kg) ^A	30.23	21.53	18.93	9.82	127.56	202.54	161.90	---	30.23	60.36	---	1,759.42
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-0.97	-9,805.48	-12.68	101.59	176.57	-15,818.39	-2,119.02	-97.58	-3,627.19	2,165.43	-2,216.09
Density (kg/m ³)	1.2	11.2	16.9	68.6	44.9	19.9	993.1	---	1.2	25.8	---	7.7
V-L Molecular Weight	28.857	32.209	23.543	32.209	28.028	28.028	18.015	---	28.857	20.398	---	20.494
V-L Flowrate (lb _{mol} /hr)	48,816	208	437	10,307	1,941	35,771	211	0	1,842	558	0	55,186
V-L Flowrate (lb/hr)	1,408,688	6,707	10,296	331,965	54,403	1,002,573	3,799	0	53,146	11,373	0	1,130,999
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	435,418	0	0	43,609	0
Temperature (°F)	59	80	83	80	263	385	101	59	59	112	2,600	1,977
Pressure (psia)	14.7	125.0	65.0	740.0	785.0	406.1	130.0	14.7	14.7	487.4	615.0	615.0
Steam Table Enthalpy (Btu/lb) ^A	13.0	9.3	8.1	4.2	54.8	87.1	69.6	---	13.0	26.0	---	756.4
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-0.4	-4,215.6	-5.5	43.7	75.9	-6,800.7	-911.0	-42.0	-1,559.4	931.0	-952.7
Density (lb/ft ³)	0.076	0.700	1.053	4.283	2.802	1.245	61.999	---	0.076	1.612	---	0.478

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-24. Case B1A stream table, Shell IGCC without capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0091	0.0000	0.0000	0.0000	0.0090	0.0000	0.0000	0.0000	0.0000	0.0095	0.0000
CH ₄	0.0000	0.0004	0.0000	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000
CO	0.0000	0.5753	0.0000	0.0000	0.0000	0.5635	0.0002	0.0000	0.0000	0.0000	0.5958	0.0000
CO ₂	0.0000	0.0188	0.0000	0.0000	0.0002	0.0191	0.0001	0.0000	0.0002	0.0002	0.0201	0.0000
COS	0.0000	0.0007	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.2937	0.0000	0.0000	0.0000	0.2877	0.0001	0.0000	0.0000	0.0000	0.3042	0.0000
H ₂ O	0.9998	0.0323	0.6895	0.1000	0.9779	0.0508	0.9904	0.9969	0.9779	0.9784	0.0014	0.9999
HCl	0.0000	0.0005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0000	0.0081	0.0000	0.0000	0.0004	0.0086	0.0001	0.0000	0.0004	0.0004	0.0090	0.0000
N ₂	0.0000	0.0575	0.0000	0.0000	0.0000	0.0563	0.0000	0.0000	0.0000	0.0000	0.0596	0.0000
NH ₃	0.0002	0.0035	0.0000	0.0000	0.0215	0.0046	0.0063	0.0031	0.0215	0.0208	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0026	0.0000	0.0000	0.0000	0.0000	0.0001
NaOH	0.0000	0.0000	0.3105	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	0.1000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	1,051	17,522	27	0	1,651	17,889	3,248	1,936	2,723	3,964	16,916	340
V-L Flowrate (kg/hr)	18,936	359,109	681	12	29,736	365,547	58,857	34,878	49,041	71,384	348,025	6,122
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	343	191	16	15	37	131	118	87	37	38	28	15
Pressure (MPa, abs)	5.10	3.93	4.76	0.13	0.47	3.70	3.83	0.13	0.47	0.45	3.51	0.10
Steam Table Enthalpy (kJ/kg) ^A	3,083.36	343.38	-338.83	-8,206.86	112.14	295.72	478.58	358.65	112.14	116.61	36.40	62.75
AspenPlus Enthalpy (kJ/kg) ^B	-12,884.30	-3,632.14	-13,665.04	-8,526.27	-15,573.36	-3,889.34	-15,327.49	-15,573.09	-15,573.36	-15,575.60	-3,613.73	-15,905.25
Density (kg/m ³)	19.9	20.6	1,531.7	1,791.5	979.4	22.4	934.8	964.3	979.4	979.4	28.8	999.4
V-L Molecular Weight	18.015	20.494	24.842	90.073	18.007	20.434	18.120	18.012	18.007	18.009	20.574	18.019
V-L Flowrate (lb _{mol} /hr)	2,317	38,630	60	0	3,641	39,439	7,161	4,269	6,004	8,739	37,293	749
V-L Flowrate (lb/hr)	41,746	791,699	1,502	27	65,558	805,893	129,758	76,892	108,117	157,376	767,263	13,497
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	650	375	61	59	99	267	244	189	99	100	83	59
Pressure (psia)	740.0	570.2	690.2	18.2	67.7	537.1	555.3	19.3	67.7	65.0	509.1	14.7
Steam Table Enthalpy (Btu/lb) ^A	1,325.6	147.6	-145.7	-3,528.3	48.2	127.1	205.8	154.2	48.2	50.1	15.7	27.0
AspenPlus Enthalpy (Btu/lb) ^B	-5,539.3	-1,561.5	-5,874.9	-3,665.6	-6,695.3	-1,672.1	-6,589.6	-6,695.2	-6,695.3	-6,696.3	-1,553.6	-6,838.0
Density (lb/ft ³)	1.240	1.289	95.621	111.841	61.141	1.397	58.358	60.198	61.141	61.140	1.799	62.391

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-24. Case B1A stream table, Shell IGCC without capture (continued)

	25	26	27	28	29	30	31	32	33	34	35	36	37
V-L Mole Fraction													
Ar	0.0000	0.0094	0.0097	0.0004	0.0083	0.0000	0.0000	0.0005	0.0097	0.0092	0.0087	0.0000	0.0090
CH ₄	0.0000	0.0004	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.5817	0.5970	0.0147	0.0048	0.0000	0.0000	0.0238	0.5970	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0002	0.0334	0.0206	0.5110	0.5805	0.0000	0.0000	0.0157	0.0206	0.0003	0.0760	0.0000	0.0761
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.3015	0.3093	0.0083	0.1888	0.0000	0.0000	0.0132	0.3093	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.9480	0.0014	0.0013	0.0053	0.0022	0.0000	1.0000	0.1815	0.0013	0.0099	0.0469	1.0000	0.0531
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0007	0.0089	0.0000	0.3393	0.0043	0.0000	0.0000	0.0188	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0632	0.0616	0.1207	0.2110	0.0000	0.0000	0.0017	0.0616	0.7732	0.7551	0.0000	0.7495
NH ₃	0.0510	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000	0.7447	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2074	0.1133	0.0000	0.1122
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	222	17,328	16,875	454	413	0	189	82	16,622	110,253	135,663	39,458	137,546
V-L Flowrate (kg/hr)	3,990	361,439	344,215	17,224	13,414	0	3,410	1,486	339,056	3,181,556	3,977,095	710,850	4,023,832
Solids Flowrate (kg/hr)	0	0	0	0	0	4,928	0	0	0	0	0	0	0
Temperature (°C)	30	37	45	45	38	184	51	204	193	15	592	561	122
Pressure (MPa, abs)	0.24	3.39	3.36	3.36	3.39	0.29	0.27	0.45	3.23	0.10	0.10	12.51	0.10
Steam Table Enthalpy (kJ/kg) ^A	24.88	47.09	60.36	15.47	21.37	---	116.08	863.94	280.22	30.23	712.14	3,504.64	207.25
AspenPlus Enthalpy (kJ/kg) ^B	-15,280.98	-3,730.87	-3,627.19	-5,569.13	-7,073.03	147.58	-15,853.53	-4,472.51	-3,407.34	-97.58	-792.26	-12,475.66	-1,363.60
Density (kg/m ³)	964.2	27.4	25.8	56.4	45.7	5,266.4	968.4	2.1	16.8	1.2	0.4	35.1	0.9
V-L Molecular Weight	17.984	20.858	20.398	37.978	32.496	---	18.016	18.048	20.398	28.857	29.316	18.015	29.255
V-L Flowrate (lb _{mol} /hr)	489	38,203	37,203	1,000	910	0	417	181	36,645	243,065	299,086	86,990	303,236
V-L Flowrate (lb/hr)	8,797	796,836	758,864	37,972	29,573	0	7,517	3,275	747,491	7,014,130	8,767,994	1,567,156	8,871,030
Solids Flowrate (lb/hr)	0	0	0	0	0	10,863	0	0	0	0	0	0	0
Temperature (°F)	86	98	112	112	100	364	124	400	380	59	1,098	1,043	252
Pressure (psia)	35.0	492.0	487.4	487.4	492.0	41.7	39.5	65.0	468.1	14.7	15.1	1,814.7	14.8
Steam Table Enthalpy (Btu/lb) ^A	10.7	20.2	26.0	6.7	9.2	---	49.9	371.4	120.5	13.0	306.2	1,506.7	89.1
AspenPlus Enthalpy (Btu/lb) ^B	-6,569.6	-1,604.0	-1,559.4	-2,394.3	-3,040.9	63.4	-6,815.8	-1,922.8	-1,464.9	-42.0	-340.6	-5,363.6	-586.2
Density (lb/ft ³)	60.191	1.712	1.612	3.520	2.856	328.773	60.453	0.129	1.047	0.076	0.026	2.190	0.057

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

3.2.4.2 Gasifier

There are two Shell dry feed, pressurized, upflow, entrained, slagging gasifiers, operating at 4.2 MPa (615 psia) and processing a total of 4,740 tonnes/day (5,225 tpd) of as-received coal. The air separation plant supplies 3,614 tonnes/day (3,984 tpd) of 95 percent O₂ to the gasifiers (stream 4). Coal reacts with O₂ and steam at a temperature of 1,427°C (2,600°F) in the gasifier to produce principally H₂ and CO with little CO₂ formed.

The gasifier's refractory-lined water wall is protected by molten slag that solidifies on the cooled walls.

3.2.4.3 Raw Gas Cooling and Particulate Removal

High-temperature heat recovery in each gasifier train is accomplished in three steps, including the gasifier jacket, which cools and solidifies slag touching the gasifier walls and maintains the syngas temperature at 1,427°C (2,600°F). The product gas from the gasifier is cooled below 1,093°C (2,000°F) by adding cooled recycled syngas to lower the temperature below the ash melting point. The mixed gas (stream 12) then goes through a duct cooler, which lowers the gas temperature to 899°C (1,650°F), and a subsequent syngas cooler, which further lowers the gas temperature to 375°C (675°F). Both the duct cooler and syngas cooler produce HP steam at 12.8 MPa (1,852 psia) for use in the steam cycle.

The majority of the fine particulates in the cooled gas from the syngas cooler are removed by passing through a cyclone collector, followed by an array of raw gas metallic candle filter elements in a pressure vessel (recycled syngas is used as the pulse gas to clean the candle filters). A carbon conversion of 99.5 percent is achieved by recycling the recovered fines, which are returned to the gasifier with the coal fuel.

The ash that is not carried out with the gas forms slag and runs down the interior walls, exiting the gasifier in liquid form. The slag is solidified in a quench tank for disposal (stream 11). Lockhoppers are used to reduce the pressure of the solids from 4.2 to 0.1 MPa (615 to 15 psia). The syngas scrubber removes additional PM further downstream (covered in Section 3.2.4.5).

The syngas from the candle filter is further cooled to 191°C (375°F) by producing IP steam at 5.1 MPa (740 psia) for use in the gasifier (stream 13), preheating the N₂ diluent (stream 6) prior to the CT, and producing LP steam at 0.4 MPa (65 psia).

3.2.4.4 Quench Gas Compressor

Thirty percent of the cooled syngas is recycled back to the gasifier exit as quench gas. A single-stage compressor is utilized to boost the pressure of the cooled syngas stream to 4.3 MPa (625 psia).

3.2.4.5 Syngas Scrubber

The ejector-type venturi scrubber is common to all cases and was covered in Section 3.1.12.1.1. The raw syngas exiting the final raw gas cooler at 191°C (375°F) (stream 14) enters the scrubber for removal of HCl and remaining PM. The treated syngas leaves the scrubber saturated at a

temperature of 117°C (242°F). Process water (stream 17) is mixed with ZLD condensate (stream 20) before being cooled to 58°C (137°F) by preheating syngas prior to the CT and subsequently cooled further to 21°C (70°F) with cooling water. The cooled water is then used to remove 99.9 percent of entering HCl, along with essentially all traces of entrained particles (principally unconverted carbon, slag, and metals). The rate of process water injection into the scrubber is controlled to maintain a concentration of chloride in the blowdown (stream 19) of 5,000 ppmw. Due to the dry nature of the syngas in this case (3 vol%), no effluent recycle is required to achieve the desired chloride concentration in the blowdown.

A 50 wt% solution of NaOH (stream 15) is added at a rate of 1,502 lb/hr to the scrubber to maintain pH and form the HSS NaCl.

The blowdown from the syngas scrubber is sent to the process water treatment system for chloride removal and recycle.

3.2.4.6 COS Hydrolysis

The COS hydrolysis unit is common to all non-CO₂ capture cases and was covered in Section 3.1.5.1. Following the syngas scrubber, the gas is reheated to 130°C (266°F) and fed to the COS hydrolysis reactor where 95 percent of the COS is hydrolyzed with steam over a catalyst bed to H₂S and CO₂. Before the raw syngas can be treated in the AGR process, it must be cooled and treated for NH₃.

3.2.4.7 Low Temperature Heat Recovery

The raw syngas from the COS unit is cooled through a series of two shell and tube HXs (covered in Section 3.1.12.1.2). The first stage cools the syngas from 131°C (268°F) to 59°C (138°F) by preheating FW to the HRSG and the second stage cools the syngas to 29°C (85°F) with cooling water. During cooling, part of the water vapor condenses, along with significant amounts of NH₃, and is combined with the effluent of the NH₃ wash.

3.2.4.8 Sour Water Stripper and Ammonia Wash

The primary SWS removes NH₃, H₂S, and other dissolved gases from the remaining water from the process water drum (stream 19), as was covered in Section 3.1.12.1.3. Process water flows from the drum to the SWS, which consists of a packed column with a steam-heated reboiler. Sour gas is stripped from the liquid and sent to the SRU. The remaining water is combined with raw water makeup (stream 24) and cooled to 21°C (70°F) with cooling water prior to being used as feed to the NH₃ wash.

The cooled syngas from the LTHR is sent to the NH₃ wash (covered in Section 3.1.12.1.4) where it flows upward against a counter-current spray of water from the SWS. The rate of raw water makeup addition to the NH₃ wash is controlled to achieve a concentration of NH₃ in the treated gas (stream 23) of 10 ppm. The effluent from the NH₃ wash contains high concentrations of NH₃ and is combined with the effluent from the LTHR system before being flashed and sent to the process water drum (stream 22). The vapor product of the flash is sent to the SRU.

A secondary SWS is included in this case to reduce the concentration of NH_3 in the condensate from the brine concentrator and crystallizer to 200 ppmw prior to being fed into a steam generator for production of steam injected into the gasifier (stream 13).

3.2.4.9 Process Water Treatment

The process water treatment system—which consists of a vacuum flash, brine concentrator, and crystallizer—is common to all cases and was covered in Section 3.1.12.2. The blowdown (stream 19) from the syngas scrubber is first flashed to 0.5 MPa (70 psia) with the effluent subsequently vacuum flashed to 0.05 MPa (7.5 psia). The vapor products from both the LP and vacuum flash stages are first cooled to 72°C (162°F), by preheating syngas prior to the CT, before being cooled further to 29°C (85°F) using cooling water. The cooled streams are sent to an overhead flash to 0.2 MPa (35 psia) with the sour gas compressed to 0.4 MPa (65 psia) and sent to the SRU for incineration. The effluent from the overhead flash and condensate from the sour gas compressor are collected and sent to the process water drum for distribution (stream 25).

The effluent from the vacuum flash is sent to the brine concentrator, which evaporates sufficient water to produce an effluent containing approximately 250,000 TDS. The vapor product from the brine concentrator is compressed to 0.14 MPa (20.5 psia) and cooled to provide heat to the brine concentrator for evaporation. The vapor product is condensed in a heat exchanger, which provides preheat to the brine concentrator feed.

The effluent from the brine concentrator then enters the steam-driven crystallizer, where 2,776 kg/hr (6,120 lb/hr) of 0.45 MPa (65 psia) steam is utilized to evaporate sufficient water to produce a super-saturated solution in the effluent. A portion of the effluent is extracted and sent to a centrifuge to separate solids. The centrifuge effluent is returned to the crystallizer.

The vapor product from the brine concentrator is condensed with cooling water and combined with the condensate from the brine concentrator before being recycled to the syngas scrubber (stream 20) or further treated in the secondary SWS (covered in Section 3.1.12.1.3 and 3.2.4.8).

3.2.4.10 Mercury Removal and AGR

The cooled syngas (stream 23) passes through a series of two carbon beds to remove approximately 97 percent of the Hg (covered in Section 3.1.4).

The Sulfinol process, developed by Shell in the early 1960s, is a combination process that uses a mixture of amines and a physical solvent. The solvent consists of an aqueous amine and sulfolane. Sulfinol-D uses diisopropanolamine (DIPA), while Sulfinol-M uses MDEA. The mixed solvents allow for better solvent loadings at high acid gas partial pressures and higher solubility of COS and organic sulfur compounds than pure aqueous amines. Sulfinol-M was selected for this application.

The sour syngas (stream 26) is fed directly into an HP contactor. The HP contactor is an absorption column in which the H_2S , COS, CO_2 , and small amounts of H_2 and CO are removed from the gas by the Sulfinol-M solvent. The overhead gas stream from the HP contactor is then washed with water in the sweet gas scrubber before leaving the unit as the feed gas to the sulfur polishing unit.

The rich solvent from the bottom of the HP contactor flows through a hydraulic turbine and is flashed in the rich solvent flash vessel. The flashed gas is then scrubbed in the LP contactor with lean solvent to remove H_2S and COS . The overhead from the LP contactor is flashed in the LP KO drum. This gas can be used as a utility fuel gas, consisting primarily of H_2 and CO , at 0.8 MPa (118 psia) and 38°C (101°F). The solvent from the bottom of the LP contactor is returned to the rich solvent flash vessel.

Hot, lean solvent in the lean/rich solvent exchanger then heats the flashed rich solvent before entering the stripper. The stripper strips the H_2S , COS , and CO_2 from the solvent at LP with heat supplied through the stripper reboiler. The acid gas stream (stream 28) to sulfur recovery/tail gas cleanup is recovered as the flash gas from the stripper accumulator. The lean solvent from the bottom of the stripper is cooled in the lean/rich solvent exchanger and the lean solvent cooler. Most of the lean solvent is pumped to the HP contactor. A small amount goes to the LP contactor.

The Sulfinol-M process removes 60 percent of the CO_2 along with the H_2S and COS . The acid gas fed to the SRU contains 34 vol% H_2S and 51 vol% CO_2 . The CO_2 passes through the SRU, the TGTU and is recycled to the AGR (stream 29), ultimately exiting the AGR with the clean syngas (stream 27).

3.2.4.11 Claus Unit

Acid gas (stream 28) from the Sulfinol-M unit is preheated to 219°C (427°F). A portion of the acid gas, along with all the sour gas (stream 32) and some O_2 from the ASU (stream 2), is fed to the SRU (a Claus bypass type). In the furnace, molten sulfur is produced by catalytically oxidizing approximately one third of the H_2S in the feed to SO_2 at a furnace temperature of $1,316^\circ\text{C}$ ($2,400^\circ\text{F}$), which must be maintained in order to thermally decompose all the NH_3 present in the sour gas stream. The remaining H_2S is then reacted with SO_2 to produce sulfur and water. Following the thermal stage and condensation of sulfur, three reheaters and three sulfur converters are used to obtain a per-pass H_2S conversion of 99.4 percent. The Claus plant tail gas is hydrogenated and recycled back to the AGR (stream 29).

The total elemental sulfur production from the SRU (stream 30) is approximately 118 tonnes/day (130 tpd).

The waste heat from the Claus unit is used to satisfy all Claus process preheating and reheating requirements, as well as to provide some medium-pressure (1.7 MPa [250 psia]) steam to the ASU.

3.2.4.12 Incinerator

A slipstream of clean syngas (stream 10) from the AGR is passed through an incinerator and combusted with air. The hot, nearly inert incinerator off gas is used to dry coal (covered in Section 3.2.4.1) before being vented to the atmosphere.

3.2.4.13 Power Block

The remaining clean syngas exiting the Sulfinol-M absorber (stream 27) that is not used for coal drying is reheated (stream 33) to 193°C (380°F) and diluted with LP N₂ from the ASU (stream 6). The diluted syngas enters the state-of-the-art 2008 F-class CT burner. The CT compressor provides combustion air (stream 34) to the burner. The exhaust gas exits the CT at 592°C (1,098°F) (stream 35) and enters the HRSG where additional heat is recovered until the flue gas exits the HRSG at 132°C (270°F) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced, commercially available steam turbine using a 12.4 MPa/561°C/561°C (1,800 psig/1,043°F/1,043°F) steam cycle.

3.2.4.14 Air Separation Unit

The ASU is designed to produce a nominal output of 3,614 tonnes/day (3,984 tpd) of 95 mol% O₂ for use in the gasifier (stream 4) and SRU (stream 2). The plant is designed with two production trains. The air compressor is powered by an electric motor. Approximately 11,508 tonnes/day (12,686 tpd) of N₂ is also recovered, compressed, and used as dilution in the CT combustor and coal transportation.

3.2.5 Case B1A – Performance Results

The plant produces a net output of 640 MW at a net plant efficiency of 43.0 percent (HHV basis). Shell has reported expected efficiencies using bituminous coal of around 44–45 percent (HHV basis), although this value excluded the net power impact of coal drying. [106] Accounting for coal drying would reduce the efficiency by about 0.5–1 percentage point, which results in a reasonable match between the reported and modeled values.

Overall performance for the entire plant is summarized in Exhibit 3-25. Exhibit 3-26 provides a detailed breakdown of the auxiliary power requirements. The ASU accounts for approximately 80 percent of the total auxiliary load distributed between the MAC, booster compressor, N₂ compressor, O₂ pump, and ASU auxiliaries. The cooling water system, including the circulating water pumps and cooling tower fan, accounts for approximately 5 percent of the auxiliary load, and the BFW pumps account for an additional 3 percent. All other systems together constitute the remaining 12 percent of the auxiliary load.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-25. Case B1A plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	464
Sweet Gas Expander Power, MWe	–
Steam Turbine Power, MWe	301
Total Gross Power, MWe	765
Air Separation Unit Main Air Compressor, kWe	61,360
Air Separation Unit Booster Compressor, kWe	4,830
N ₂ Compressors, kWe	32,500
CO ₂ Compression, kWe	–
Acid Gas Removal, kWe	680
Balance of Plant, kWe	26,110
Total Auxiliaries, MWe	125
Net Power, MWe	640
HHV Net Plant Efficiency, %	43.0
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,377 (7,940)
HHV Cold Gas Efficiency, %	82.9
HHV Combustion Turbine Efficiency, %	39.0
LHV Net Plant Efficiency, %	44.6
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,080 (7,659)
LHV Cold Gas Efficiency, %	81.3
LHV Combustion Turbine Efficiency, %	41.2
Steam Turbine Cycle Efficiency, %	46.7
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,702 (7,300)
Condenser Duty, GJ/hr (MMBtu/hr)	1,532 (1,452)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	96 (91)
As-Received Coal Feed, kg/hr (lb/hr)	197,502 (435,418)
HHV Thermal Input, kWt	1,488,680
LHV Thermal Input, kWt	1,435,850
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.024 (6.5)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.019 (5.0)
O ₂ :As-Received Coal	0.720

Exhibit 3-26. Case B1A plant power summary

Power Summary	
Combustion Turbine Power, MWe	464
Sweet Gas Expander Power, MWe	–
Steam Turbine Power, MWe	301
Total Gross Power, MWe	765
Auxiliary Load Summary	
Acid Gas Removal, kWe	680
Air Separation Unit Auxiliaries, kWe	1,000
Air Separation Unit Main Air Compressor, kWe	61,360
Air Separation Unit Booster Compressor, kWe	4,830
Ammonia Wash Pumps, kWe	70
Circulating Water Pumps, kWe	3,980
Claus Plant TG Recycle Compressor, kWe	1,030
Claus Plant/TGTU Auxiliaries, kWe	250
CO ₂ Compression, kWe	–
Coal Dryer Air Compressor, kWe	60
Coal Handling, kWe	440
Coal Milling, kWe	2,030
Combustion Turbine Auxiliaries, kWe	1,000
Condensate Pumps, kWe	230
Cooling Tower Fans, kWe	2,060
Feedwater Pumps, kWe	4,260
Gasifier Water Pump, kWe	40
Ground Water Pumps, kWe	370
Miscellaneous Balance of Plant ^A , kWe	3,000
N ₂ Compressors, kWe	32,500
N ₂ Humidification Pump, kWe	–
O ₂ Pump, kWe	310
Quench Water Pump, kWe	–
Shift Steam Pump, kWe	–
Slag Handling, kWe	510
Slag Reclaim Water Recycle Pump, kWe	–
Slurry Water Pump, kWe	–
Sour Gas Compressors, kWe	120
Sour Water Recycle Pumps, kWe	–

Power Summary	
Auxiliary Load Summary	
Steam Turbine Auxiliaries, kWe	200
Syngas Recycle Compressor, kWe	950
Syngas Scrubber Pumps, kWe	120
Process Water Treatment Auxiliaries, kWe	1,350
Transformer Losses, kWe	2,730
Total Auxiliaries, MWe	125
Net Power, MWe	640

^AIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

3.2.5.1 Environmental Performance

The environmental targets for emissions of Hg, HCl, NO_x, SO₂, and PM were presented in Section 2.3. A summary of the plant air emissions for Case B1A is presented in Exhibit 3-27.

Exhibit 3-27. Case B1A air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.008 (0.020)	317 (349)	0.059 (0.130)
NO _x	0.025 (0.059)	949 (1,046)	0.177 (0.390)
Particulate	0.003 (0.007)	115 (126)	0.021 (0.047)
Hg	1.94E-7 (4.52E-7)	0.007 (0.008)	1.36E-6 (3.00E-6)
HCl	0.000 (0.000)	0.00 (0.00)	0.000 (0.000)
CO ₂	86 (200)	3,230,068 (3,560,540)	602 (1,328)
CO ₂ ^C	—	—	720 (1,588)

^ACalculations based on an 80 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

The low level of SO₂ emissions is achieved by capturing the sulfur in the gas by the Sulfinol-M AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 6 ppmv. This results in a concentration in the HRSG flue gas of less than 2 ppmv. The H₂S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is compressed and recycled back to the AGR to capture most of the remaining sulfur. The SO₂ emissions in Exhibit 3-27 include both the stack emissions and the coal dryer emissions.

NO_x emissions are limited by the use of N₂ dilution to 15 ppmvd (as NO at 15 percent O₂). NH₃ in the syngas is removed with process condensate prior to the low-temperature AGR process and destroyed in the Claus plant burner. This helps lower NO_x levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Approximately 97 percent of the mercury is captured from the syngas by dual activated carbon beds.

CO₂ emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 3-28. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag and as CO₂ in the stack gas (includes the coal dryer vent gas and ASU vent gas).

Exhibit 3-28. Case B1A carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	125,897 (277,556)	Stack Gas	125,790 (277,320)
Air (CO ₂)	523 (1,153)	CO ₂ Product	–
		Slag	629 (1,388)
Total	126,420 (278,709)	Total	126,420 (278,709)

Exhibit 3-29 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant and sulfur emitted in the stack gas (includes the coal drying vent). Sulfur in the slag is considered to be negligible.

Exhibit 3-29. Case B1A sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	4,950 (10,913)	Stack Gas	23 (50)
		CO ₂ Product	–
		Elemental Sulfur	4,928 (10,863)
Total	4,950 (10,913)	Total	4,950 (10,913)

Exhibit 3-30 shows the overall water balance for the plant.

Exhibit 3-30. Case B1A water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
Slag Handling	0.43 (113)	0.43 (113)	–	–	–
Slurry Water	–	–	–	–	–
Gasifier Water	–	–	–	–	–
Quench	–	–	–	–	–
HCl Scrubber	1.08 (285)	1.08 (285)	–	–	–
NH ₃ Scrubber	0.90 (238)	0.80 (211)	0.10 (27)	–	0.10 (27)
Gasifier Steam	0.32 (83)	0.32 (83)	–	–	–
Condenser Makeup	0.24 (63)	–	0.24 (63)	–	0.24 (63)
BFW Makeup	0.21 (55)	–	0.21 (55)	–	0.21 (55)
Gasifier Steam	–	–	–	–	–
Shift Steam	–	–	–	–	–
N ₂ Humidification	0.03 (8)	–	0.03 (8)	–	0.03 (8)
Cooling Tower	15.51 (4,098)	0.23 (61)	15.28 (4,038)	3.49 (922)	11.79 (3,116)
BFW Blowdown	–	0.21 (55)	-0.21 (-55)	–	-0.21 (-55)
ASU Knockout	–	0.02 (5)	-0.02 (-5)	–	-0.02 (-5)
Total	18.47 (4,880)	2.85 (753)	15.62 (4,127)	3.49 (922)	12.13 (3,206)

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and is re-used as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a municipal source for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from groundwater. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for all purposes, such as cooling tower makeup, BFW makeup, quench system makeup, and slag handling makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products, or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

An overall plant energy balance is provided in tabular form in Exhibit 3-31. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a combined generator efficiency of 98.5 percent.

Exhibit 3-31. Case B1A overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, MMBtu/hr (GJ/hr)				
Coal	5,359 (5,080)	4.5 (4.2)	–	5,364 (5,084)
Air	–	116.2 (110.1)	–	116.2 (110.1)
Raw Water Makeup	–	58.7 (55.7)	–	58.7 (55.7)
Auxiliary Power	–	–	451.7 (428.2)	451.7 (428.2)
TOTAL	5,359 (5,080)	179.4 (170.1)	451.7 (428.2)	5,990 (5,678)
Heat Out, MMBtu/hr (GJ/hr)				
Misc. Process Steam	–	5.0 (4.7)	–	5.0 (4.7)
Slag	20.6 (19.6)	33.4 (31.6)	–	54.0 (51.2)
Stack Gas	–	834 (790)	–	834 (790)
Sulfur	45.7 (43.3)	0.6 (0.6)	–	46.2 (43.8)
Motor Losses and Design Allowances	–	–	54.5 (51.6)	54.5 (51.6)
Cooling Tower Load ^A	–	2,026 (1,920)	–	2,026 (1,920)
CO ₂ Product Stream	–	–	–	–
Blowdown Streams	–	33.4 (31.7)	–	33.4 (31.7)
Ambient Losses ^B	–	137.1 (129.9)	–	137.1 (129.9)
Power	–	–	2,755 (2,611)	2,755 (2,611)
TOTAL	66.3 (62.8)	3,069 (2,909)	2,809 (2,663)	5,945 (5,635)
Unaccounted Energy ^C	–	–	–	45.7 (43.3)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers

^CBy difference

3.2.5.2 Energy and Mass Balance Diagrams

Energy and mass balance diagrams are shown for the following subsystems in Exhibit 3-32 through Exhibit 3-34:

- Coal gasification and ASU
- Syngas cleanup, sulfur recovery, and tail gas recycle
- Combined cycle power generation, steam, and FW

This page intentionally left blank

Exhibit 3-32. Case B1A coal gasification and ASU energy and mass balance

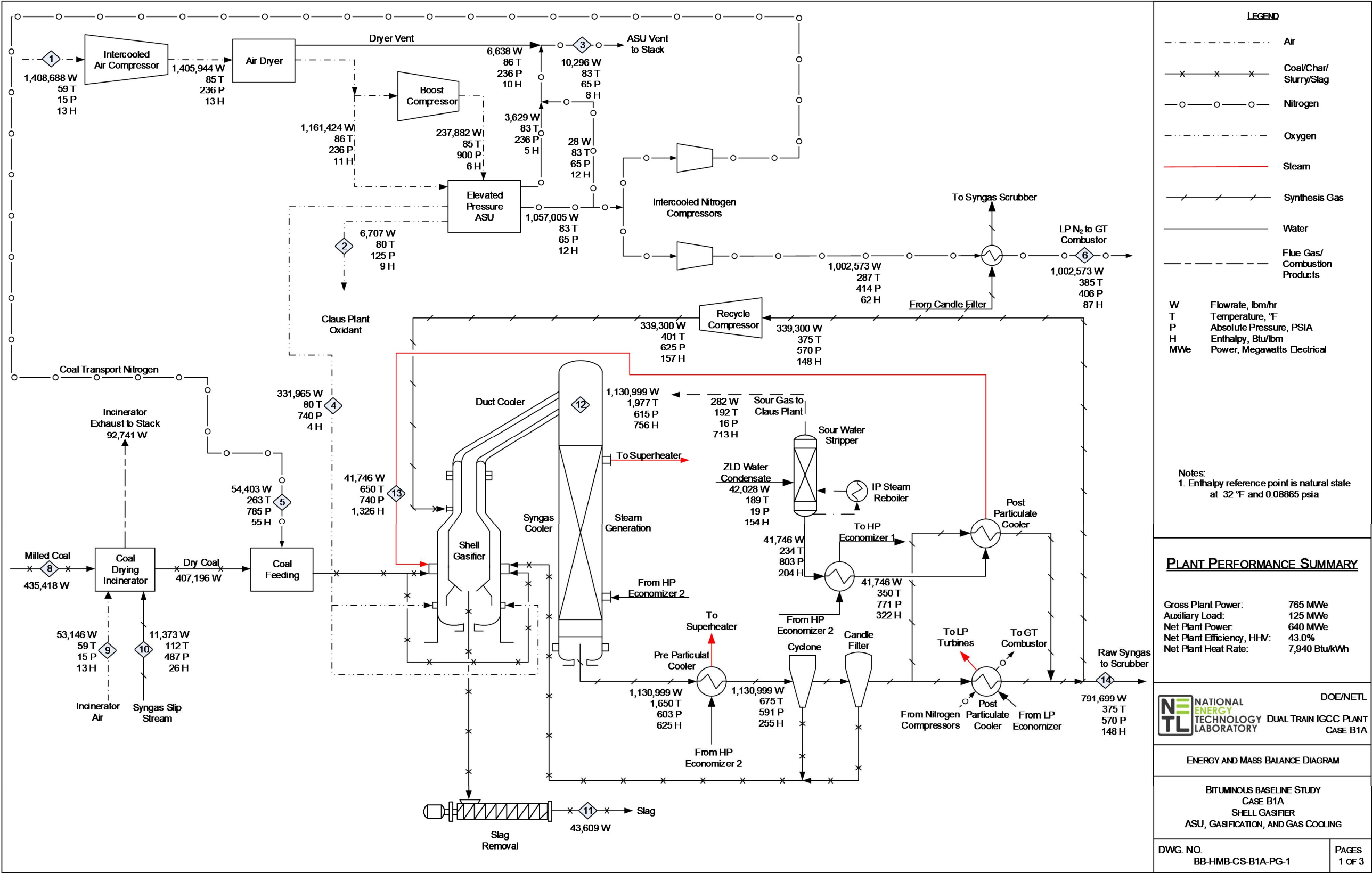


Exhibit 3-33. Case B1A syngas cleanup energy and mass balance

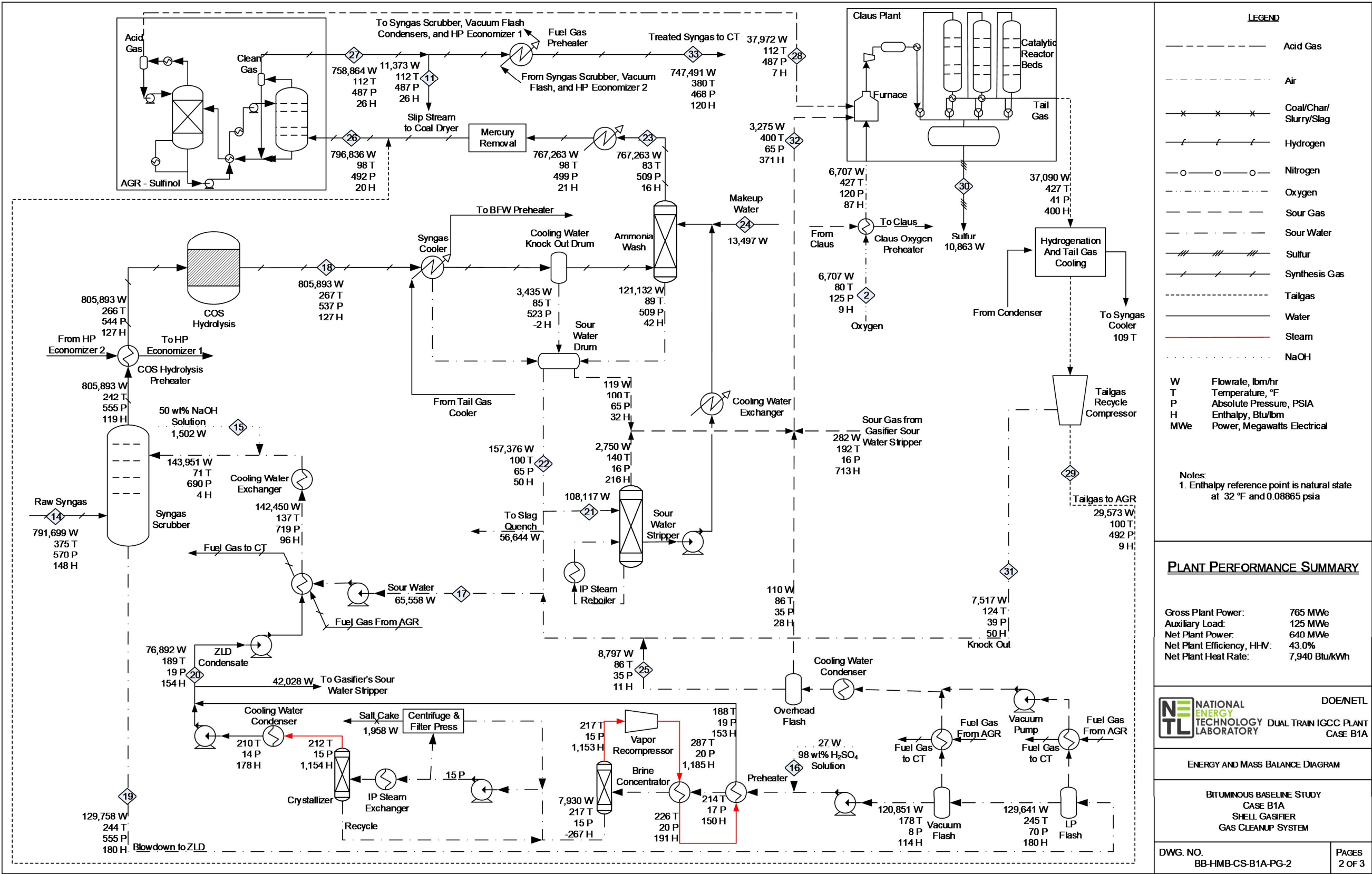
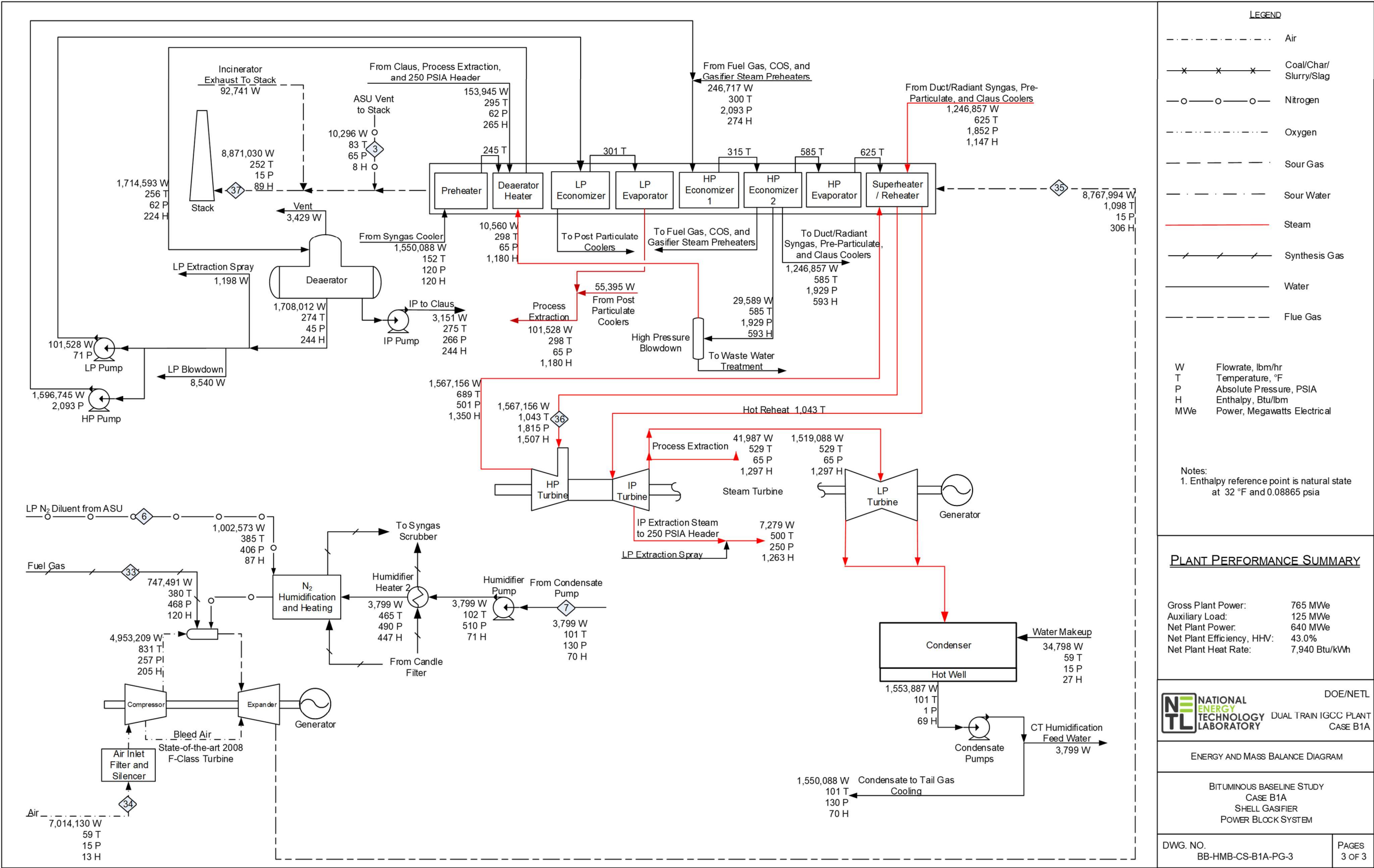


Exhibit 3-34. Case B1A combined cycle power generation energy and mass balance



This page intentionally left blank

3.2.6 Case B1A – Major Equipment List

Major equipment items for the Shell gasifier with no CO₂ capture are shown in the following tables. In general, the design conditions include a 10 percent design allowance for flows and heat duties and a 21 percent design allowance for heads on pumps and fans.

Case B1A – Account 1: Coal Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
5	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
6	Reclaim Hopper	N/A	40 tonne (50 ton)	2	1
7	Feeder	Vibratory	160 tonne/hr (180 tph)	2	1
8	Conveyor No. 3	Belt w/ tripper	330 tonne/hr (360 tph)	1	0
9	Coal Surge Bin w/ Vent Filter	Dual outlet	160 tonne (180 ton)	2	0
10	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
11	Conveyor No. 4	Belt w/trippper	330 tonne/hr (360 tph)	1	0
12	Conveyor No. 5	Belt w/ tripper	330 tonne/hr (360 tph)	1	0
13	Coal Silo w/ Vent Filter and Slide Gates	Field erected	720 tonne (800 ton)	3	0

Case B1A – Account 2: Coal Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	70 tonne/hr (80 tph)	3	0
2	Conveyor No. 6	Belt w/trippper	220 tonne/hr (240 tph)	1	0
3	Roller Mill Feed Hopper	Dual Outlet	430 tonne (480 ton)	1	0
4	Weigh Feeder	Belt	110 tonne/hr (120 tph)	2	0
5	Coal Dryer and Pulverizer	Rotary	110 tonne/hr (120 tph)	2	0
6	Coal Dryer Feed Hopper	Vertical Hopper	220 tonne (240 ton)	2	0

Case B1A – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,042,000 liters (275,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,510 lpm @ 90 m H ₂ O (1,720 gpm @ 300 ft H ₂ O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	428,000 kg/hr (943,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	440 lpm @ 20 m H ₂ O (120 gpm @ 70 ft H ₂ O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,910 lpm @ 1,700 m H ₂ O (1,820 gpm @ 5,700 ft H ₂ O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,070 lpm @ 210 m H ₂ O (280 gpm @ 670 ft H ₂ O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
8	Service Air Compressors	Flooded Screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	219 GJ/hr (208 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	78,600 lpm @ 20 m H ₂ O (20,800 gpm @ 70 ft H ₂ O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
14	Municipal Water Pumps	Stainless steel, single suction	3,580 lpm @ 20 m H ₂ O (950 gpm @ 60 ft H ₂ O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,390 lpm @ 270 m H ₂ O (630 gpm @ 880 ft H ₂ O)	3	1
16	Filtered Water Pumps	Stainless steel, single suction	220 lpm @ 50 m H ₂ O (60 gpm @ 160 ft H ₂ O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	107,000 liter (28,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	170 lpm (40 gpm)	2	0
19	Liquid Waste Treatment System	N/A	10 years, 24-hour storm	1	0
20	Process Water Treatment	Vacuum flash, brine concentrator, and crystallizer	Vacuum Flash - Inlet: 32,000 kg/hr (71,000 lb/hr) Outlet: 5,369 ppmw Cl- Brine Concentrator Inlet - 30,000 kg/hr (66,000 lb/hr) Crystallizer Inlet - 2,000 kg/hr (4,000 lb/hr)	2	0

Case B1A – Account 4: Gasifier, ASU, and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized dry-feed, entrained bed	2,600 tonne/day, 4.2 MPa (2,900 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Convective spiral-wound tube boiler	282,000 kg/hr (622,000 lb/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	282,000 kg/hr (622,000 lb/hr) Design efficiency 90%	2	0
4	HCl Scrubber	Ejector Venturi	198,000 kg/hr (435,000 lb/hr)	2	0
5	Ammonia Wash	Counter-flow spray tower	192,000 kg/hr (423,000 lb/hr) @ 3.6 MPa (523 psia)	2	0
6	Primary Sour Water Stripper	Counter-flow with external reboiler	27,000 kg/hr (59,000 lb/hr)	2	0
7	Secondary Sour Water Stripper	Counter-flow with external reboiler	10,000 kg/hr (23,000 lb/hr)	2	0
8	Low Temperature Heat Recovery Coolers	Shell and tube with condensate drain	201,000 kg/hr (443,000 lb/hr)	6	0
9	Low Temperature Heat Recovery Knockout Drum	Vertical with mist eliminator	193,000 kg/hr, 59°C, 3.6 MPa (425,000 lb/hr, 138°F, 526 psia)	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
10	Saturation Water Economizers	Shell and tube	N/A	4	0
11	HP Nitrogen Gas Saturator	Direct Injection	N/A	2	0
12	LP Nitrogen Gas Saturator	Direct Injection	250,000 kg/hr, 196°C, 2.8 MPa (551,000 lb/hr, 385°F, 406 psia)	2	0
13	Saturator Water Pump	Centrifugal	0 lpm @ 324 m H ₂ O (0 gpm @ 1062 ft H ₂ O)	2	2
14	Saturated Nitrogen Reheaters	Shell and tube	N/A	4	0
15	Synthesis Gas Reheaters	Shell and tube	Reheater 1: N/A Reheater 2: 300 kg/hr (1,000 lb/hr) Reheater 3: 101,000 kg/hr (224,000 lb/hr) Reheater 4: 85,000 kg/hr (187,000 lb/hr) Reheater 5: 186,000 kg/hr (411,000 lb/hr) Reheater 6: 186,000 kg/hr (411,000 lb/hr)	2	0
16	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	201,000 kg/hr (443,000 lb/hr) syngas	2	0
17	ASU Main Air Compressor	Centrifugal, multi-stage	5,000 m ³ /min @ 1.6 MPa (170,000 scfm @ 236 psia)	2	0
18	Cold Box	Vendor design	2,000 tonne/day (2,200 tpd) of 95% purity O ₂	2	0
19	Gasifier O ₂ Pump	Centrifugal, multi-stage	1,000 m ³ /min (36,000 scfm) Suction - 1.0 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	2	0
20	AGR Nitrogen Boost Compressor	Centrifugal, multi-stage	N/A	2	0
21	High Pressure Nitrogen Diluent Compressor	Centrifugal, multi-stage	N/A	2	0
22	Low Pressure Nitrogen Diluent Compressor	Centrifugal, single-stage	3,520 m ³ /min (124,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - 2.9 MPa (410 psia)	2	0
23	Gasifier Nitrogen Boost Compressor	Centrifugal, single-stage	190 m ³ /min (7,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - 5.4 MPa (790 psia)	2	0

Case B1A – Account 5: Syngas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber 1	Sulfated carbon bed	191,000 kg/hr (422,000 lb/hr) 28°C (83°F) 3.5 MPa (509 psia)	2	0
2	Mercury Adsorber 2	Sulfated carbon bed	191,000 kg/hr (422,000 lb/hr) 37°C (98°F) 3.4 MPa (495 psia)	2	0
3	Sulfur Plant	Claus type	130 tonne/day (143 tpd)	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
4	COS Hydrolysis Reactor	Fixed bed, catalytic	201,000 kg/hr (443,000 lb/hr) 132°C (270°F) 3.7 MPa (540 psia)	2	0
5	COS Hydrolysis Heat Exchanger	Shell and Tube	4 GJ/hr (4 MMBtu/hr)	2	0
6	Acid Gas Removal Plant	Sulfinol	199,000 kg/hr (438,000 lb/hr) 37°C (98°F) 3.4 MPa (492 psia)	2	0
7	Hydrogenation Reactor	Fixed bed, catalytic	19,000 kg/hr (41,000 lb/hr) 219°C (427°F) 0.3 MPa (40.8425733 psia)	1	0
8	Tail Gas Recycle Compressor	Centrifugal	15,000 kg/hr (33,000 lb/hr) each	1	0
9	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0

Case B1A – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	State-of-the-art 2008 F-Class	232 MW	2	0
2	Combustion Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

Case B1A – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.4 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 390,968 kg/hr, 12.4 MPa/561°C (861,936 lb/hr, 1,800 psig/1,043°F) Reheat steam - 390,968 kg/hr, 3.3 MPa/561°C (861,936 lb/hr, 477 psig/1,043°F)	2	0

Case B1A – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	317 MW 12.4 MPa/561°C/561°C (1,800 psig/1,043°F/1,043°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	350 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,680GJ/hr (1,600 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B1A – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	400,000 lpm @ 30 m (106,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 2,230 GJ/hr (2,110 MMBtu/hr) heat duty	1	0

Case B1A – Account 10: Slag Recovery and Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	207,000 liters (55,000 gal)	2	0
2	Slag Crusher	Roll	11 tonne/hr (12 tph)	2	0
3	Slag Depressurizer	Lock Hopper	11 tonne/hr (12 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	125,000 liters (33,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	56,000 liters (15,000 gal)	2	0
6	Slag Conveyor	Drag chain	11 tonne/hr (12 tph)	2	0
7	Slag Separation Screen	Vibrating	11 tonne/hr (12 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	11 tonne/hr (12 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	177,000 liters (47,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	50 lpm @ 14 m H ₂ O (10 gpm @ 46 ft H ₂ O)	2	2
11	Grey Water Storage Tank	Field erected	57,000 liters (15,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	200 lpm @ 430 m H ₂ O (50 gpm @ 1,420 ft H ₂ O)	2	2
13	Slag Storage Bin	Vertical, field erected	800 tonne (900 tons)	2	0
14	Unloading Equipment	Telescoping chute	90 tonne/hr (100 tph)	1	0

Case B1A – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 320 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 55 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 27 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 4 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B1A – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.2.7 Case B1A – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 3-35 shows a detailed breakdown of the capital costs; Exhibit 3-36 shows the owner's costs, TOC, and TASC; Exhibit 3-37 shows the initial and annual O&M costs; and Exhibit 3-38 shows the LCOE breakdown.

The estimated TPC of the Shell gasifier with no CO₂ capture is \$4,087/kW. Process contingency represents 5.4 percent of the TPC, and project contingency represents 14.4 percent. The LCOE is \$111.5/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-35. Case B1A total plant cost details

Case: Plant Size (MW, net):		B1A 640	– Shell IGCC w/o CO ₂ Capture				Estimate Type: Cost Base:			Conceptual Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1 Coal Handling											
1.1	Coal Receive & Unload	\$929	\$0	\$448	\$0	\$1,377	\$206	\$0	\$317	\$1,900	\$3
1.2	Coal Stackout & Reclaim	\$3,037	\$0	\$726	\$0	\$3,763	\$564	\$0	\$866	\$5,193	\$8
1.3	Coal Conveyors & Yard Crush	\$28,971	\$0	\$7,375	\$0	\$36,346	\$5,452	\$0	\$8,360	\$50,157	\$78
1.4	Other Coal Handling	\$4,512	\$0	\$1,016	\$0	\$5,528	\$829	\$0	\$1,271	\$7,629	\$12
1.9	Coal & Sorbent Handling Foundations	\$0	\$81	\$212	\$0	\$294	\$44	\$0	\$68	\$405	\$1
	Subtotal	\$37,450	\$81	\$9,776	\$0	\$47,307	\$7,096	\$0	\$10,881	\$65,284	\$102
2 Coal Preparation & Feed											
2.1	Coal Crushing & Drying	\$2,242	\$135	\$322	\$0	\$2,700	\$405	\$0	\$621	\$3,726	\$6
2.2	Prepared Coal Storage & Feed	\$6,890	\$1,655	\$1,065	\$0	\$9,610	\$1,441	\$0	\$2,210	\$13,262	\$21
2.3	Dry Coal Injection System	\$8,792	\$101	\$805	\$0	\$9,698	\$1,455	\$0	\$2,231	\$13,384	\$21
2.4	Miscellaneous Coal Preparation & Feed	\$680	\$497	\$1,464	\$0	\$2,640	\$396	\$0	\$607	\$3,644	\$6
2.9	Coal & Sorbent Feed Foundation	\$0	\$1,655	\$1,420	\$0	\$3,075	\$461	\$0	\$707	\$4,243	\$7
	Subtotal	\$18,604	\$4,043	\$5,076	\$0	\$27,723	\$4,158	\$0	\$6,376	\$38,258	\$60
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$2,213	\$3,794	\$1,897	\$0	\$7,904	\$1,186	\$0	\$1,818	\$10,908	\$17
3.2	Water Makeup & Pretreating	\$4,489	\$449	\$2,544	\$0	\$7,482	\$1,122	\$0	\$2,581	\$11,186	\$17
3.3	Other Feedwater Subsystems	\$1,144	\$375	\$356	\$0	\$1,875	\$281	\$0	\$431	\$2,588	\$4
3.4	Service Water Systems	\$1,342	\$2,561	\$8,293	\$0	\$12,196	\$1,829	\$0	\$4,208	\$18,233	\$29
3.5	Other Boiler Plant Systems	\$297	\$108	\$270	\$0	\$675	\$101	\$0	\$155	\$932	\$1
3.6	Natural Gas Pipeline and Start-Up System	\$7,076	\$304	\$228	\$0	\$7,608	\$1,141	\$0	\$1,750	\$10,500	\$16
3.7	Waste Water Treatment Equipment	\$6,552	\$0	\$4,054	\$0	\$10,606	\$1,591	\$0	\$3,659	\$15,856	\$25
3.8	Vacuum Flash, Brine Concentrator, & Crystallizer	\$22,582	\$0	\$13,971	\$0	\$36,553	\$5,483	\$0	\$12,611	\$54,647	\$85
3.9	Miscellaneous Plant Equipment	\$15,068	\$1,976	\$7,657	\$0	\$24,701	\$3,705	\$0	\$8,522	\$36,928	\$58
	Subtotal	\$60,763	\$9,568	\$39,271	\$0	\$109,602	\$16,440	\$0	\$35,735	\$161,778	\$253
4 Gasifier, ASU, & Accessories											
4.1	Gasifier & Auxiliaries (Shell)	\$544,706	\$0	\$236,123	\$0	\$780,829	\$117,124	\$109,316	\$151,090	\$1,158,360	\$1,811
4.2	Syngas Cooler	\$51,993	\$0	\$22,538	\$0	\$74,532	\$11,180	\$10,434	\$14,422	\$110,568	\$173
4.3	Air Separation Unit/Oxidant Compression	\$120,252	\$27,522	\$28,620	\$0	\$176,394	\$35,279	\$17,639	\$34,397	\$263,709	\$412
4.5	Miscellaneous Gasification Equipment	\$4,021	\$0	\$1,743	\$0	\$5,765	\$865	\$0	\$994	\$7,624	\$12

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B1A	– Shell IGCC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		640					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
4.6	Low Temperature Heat Recovery & Flue Gas Saturation	\$43,966	\$0	\$16,704	\$0	\$60,670	\$9,100	\$0	\$13,954	\$83,724	\$131
4.7	Flare Stack System	\$1,835	\$0	\$324	\$0	\$2,158	\$324	\$0	\$496	\$2,979	\$5
4.15	Major Component Rigging	\$224	\$0	\$97	\$0	\$321	\$48	\$0	\$55	\$424	\$1
4.16	Gasification Foundations	\$0	\$454	\$271	\$0	\$725	\$109	\$0	\$208	\$1,042	\$2
	Subtotal	\$766,998	\$27,976	\$306,419	\$0	\$1,101,393	\$174,029	\$137,390	\$215,618	\$1,628,430	\$2,546
	5	Syngas Cleanup									
5.2	Sulfinol System	\$4,884	\$0	\$4,116	\$0	\$9,001	\$1,350	\$0	\$2,070	\$12,421	\$19
5.3	Elemental Sulfur Plant	\$45,308	\$8,832	\$58,054	\$0	\$112,194	\$16,829	\$0	\$25,805	\$154,827	\$242
5.6	Mercury Removal (Carbon Bed)	\$191	\$0	\$145	\$0	\$336	\$50	\$17	\$81	\$484	\$1
5.8	Carbonyl Sulfide (COS) Hydrolysis	\$7,887	\$0	\$10,230	\$0	\$18,117	\$2,718	\$0	\$4,167	\$25,001	\$39
5.9	Particulate Removal	\$1,316	\$0	\$571	\$0	\$1,887	\$283	\$0	\$326	\$2,496	\$4
5.10	Blowback Gas Systems	\$739	\$415	\$232	\$0	\$1,385	\$208	\$0	\$319	\$1,911	\$3
5.11	Fuel Gas Piping	\$0	\$2,686	\$1,756	\$0	\$4,441	\$666	\$0	\$1,021	\$6,129	\$10
5.12	Gas Cleanup Foundations	\$0	\$209	\$141	\$0	\$350	\$52	\$0	\$121	\$523	\$1
	Subtotal	\$60,326	\$12,141	\$75,243	\$0	\$147,710	\$22,156	\$17	\$33,908	\$203,792	\$319
	6	Combustion Turbine & Accessories									
6.1	Combustion Turbine Generator	\$74,945	\$0	\$5,399	\$0	\$80,343	\$12,051	\$4,017	\$14,462	\$110,873	\$173
6.3	Combustion Turbine Accessories	\$2,687	\$0	\$164	\$0	\$2,851	\$428	\$0	\$492	\$3,770	\$6
6.4	Compressed Air Piping	\$0	\$510	\$333	\$0	\$843	\$126	\$0	\$194	\$1,163	\$2
6.5	Combustion Turbine Foundations	\$0	\$216	\$250	\$0	\$466	\$70	\$0	\$161	\$697	\$1
	Subtotal	\$77,632	\$726	\$6,145	\$0	\$84,503	\$12,675	\$4,017	\$15,308	\$116,504	\$182
	7	HRSG, Ductwork, & Stack									
7.1	Heat Recovery Steam Generator	\$35,544	\$0	\$6,883	\$0	\$42,427	\$6,364	\$0	\$7,319	\$56,110	\$88
7.2	Heat Recovery Steam Generator Accessories	\$12,691	\$0	\$2,457	\$0	\$15,149	\$2,272	\$0	\$2,613	\$20,034	\$31
7.3	Ductwork	\$0	\$1,068	\$748	\$0	\$1,817	\$272	\$0	\$418	\$2,507	\$4
7.4	Stack	\$9,083	\$0	\$3,389	\$0	\$12,471	\$1,871	\$0	\$2,151	\$16,494	\$26
7.5	Heat Recovery Steam Generator, Ductwork & Stack Foundations	\$0	\$226	\$227	\$0	\$453	\$68	\$0	\$156	\$677	\$1
	Subtotal	\$57,318	\$1,294	\$13,704	\$0	\$72,316	\$10,847	\$0	\$12,657	\$95,821	\$150
	8	Steam Turbine & Accessories									
8.1	Steam Turbine Generator & Accessories	\$39,671	\$0	\$6,089	\$0	\$45,760	\$6,864	\$0	\$7,894	\$60,518	\$95
8.2	Steam Turbine Plant Auxiliaries	\$1,928	\$0	\$4,392	\$0	\$6,319	\$948	\$0	\$1,090	\$8,357	\$13

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B1A	– Shell IGCC w/o CO ₂ Capture				Estimate Type:		Conceptual		
Plant Size (MW, net):		640					Cost Base:		Dec 2018		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
8.3	Condenser & Auxiliaries	\$7,137	\$0	\$4,027	\$0	\$11,164	\$1,675	\$0	\$1,926	\$14,765	\$23
8.4	Steam Piping	\$7,401	\$0	\$3,210	\$0	\$10,611	\$1,592	\$0	\$3,051	\$15,254	\$24
8.5	Turbine Generator Foundations	\$0	\$301	\$531	\$0	\$832	\$125	\$0	\$287	\$1,243	\$2
	Subtotal	\$56,138	\$301	\$18,249	\$0	\$74,687	\$11,203	\$0	\$14,247	\$100,137	\$157
9		Cooling Water System									
9.1	Cooling Towers	\$10,457	\$0	\$3,157	\$0	\$13,614	\$2,042	\$0	\$2,348	\$18,004	\$28
9.2	Circulating Water Pumps	\$1,377	\$0	\$94	\$0	\$1,471	\$221	\$0	\$254	\$1,946	\$3
9.3	Circulating Water System Auxiliaries	\$9,483	\$0	\$1,329	\$0	\$10,812	\$1,622	\$0	\$1,865	\$14,299	\$22
9.4	Circulating Water Piping	\$0	\$5,355	\$4,850	\$0	\$10,205	\$1,531	\$0	\$2,347	\$14,083	\$22
9.5	Make-up Water System	\$545	\$0	\$748	\$0	\$1,293	\$194	\$0	\$297	\$1,784	\$3
9.6	Component Cooling Water System	\$193	\$231	\$159	\$0	\$583	\$87	\$0	\$134	\$804	\$1
9.7	Circulating Water System Foundations	\$0	\$443	\$788	\$0	\$1,231	\$185	\$0	\$425	\$1,841	\$3
	Subtotal	\$22,055	\$6,029	\$11,124	\$0	\$39,209	\$5,881	\$0	\$7,671	\$52,760	\$82
10		Slag Recovery & Handling									
10.1	Slag Dewatering & Cooling	\$1,848	\$0	\$905	\$0	\$2,754	\$413	\$0	\$475	\$3,642	\$6
10.2	Gasifier Ash Depressurization	\$1,047	\$0	\$513	\$0	\$1,560	\$234	\$0	\$269	\$2,063	\$3
10.3	Cleanup Ash Depressurization	\$471	\$0	\$231	\$0	\$701	\$105	\$0	\$121	\$927	\$1
10.6	Ash Storage Silos	\$1,061	\$0	\$1,146	\$0	\$2,208	\$331	\$0	\$381	\$2,920	\$5
10.7	Ash Transport & Feed Equipment	\$409	\$0	\$95	\$0	\$505	\$76	\$0	\$87	\$667	\$1
10.8	Miscellaneous Ash Handling Equipment	\$59	\$72	\$21	\$0	\$152	\$23	\$0	\$26	\$201	\$0
10.9	Ash/Spent Sorbent Foundation	\$0	\$416	\$550	\$0	\$966	\$145	\$0	\$333	\$1,444	\$2
	Subtotal	\$4,895	\$488	\$3,462	\$0	\$8,845	\$1,327	\$0	\$1,692	\$11,864	\$19
11		Accessory Electric Plant									
11.1	Generator Equipment	\$2,843	\$0	\$2,145	\$0	\$4,987	\$748	\$0	\$860	\$6,596	\$10
11.2	Station Service Equipment	\$3,566	\$0	\$306	\$0	\$3,872	\$581	\$0	\$668	\$5,120	\$8
11.3	Switchgear & Motor Control	\$21,516	\$0	\$3,733	\$0	\$25,249	\$3,787	\$0	\$4,356	\$33,392	\$52
11.4	Conduit & Cable Tray	\$0	\$95	\$275	\$0	\$370	\$56	\$0	\$106	\$532	\$1
11.5	Wire & Cable	\$0	\$1,305	\$2,333	\$0	\$3,639	\$546	\$0	\$1,046	\$5,231	\$8
11.6	Protective Equipment	\$241	\$0	\$837	\$0	\$1,078	\$162	\$0	\$186	\$1,426	\$2
11.7	Standby Equipment	\$865	\$0	\$798	\$0	\$1,663	\$249	\$0	\$287	\$2,199	\$3
11.8	Main Power Transformers	\$6,569	\$0	\$134	\$0	\$6,703	\$1,006	\$0	\$1,156	\$8,865	\$14
11.9	Electrical Foundations	\$0	\$76	\$193	\$0	\$268	\$40	\$0	\$93	\$401	\$1
	Subtotal	\$35,600	\$1,477	\$10,754	\$0	\$47,830	\$7,174	\$0	\$8,758	\$63,762	\$100
12		Instrumentation & Control									

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO
ELECTRICITY

Case:		B1A	– Shell IGCC w/o CO ₂ Capture				Estimate Type:		Conceptual		
Plant Size (MW, net):		640					Cost Base:		Dec 2018		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
12.1	Integrated Gasification and Combined Cycle Control Equipment	\$660	\$0	\$286	\$0	\$946	\$142	\$0	\$163	\$1,251	\$2
12.2	Combustion Turbine Control Equipment	\$652	\$0	\$47	\$0	\$699	\$105	\$0	\$121	\$924	\$1
12.3	Steam Turbine Control Equipment	\$602	\$0	\$92	\$0	\$695	\$104	\$0	\$120	\$919	\$1
12.4	Other Major Component Control Equipment	\$1,165	\$0	\$793	\$0	\$1,958	\$294	\$98	\$352	\$2,702	\$4
12.5	Signal Processing Equipment	\$904	\$0	\$29	\$0	\$933	\$140	\$0	\$161	\$1,234	\$2
12.6	Control Boards, Panels & Racks	\$262	\$0	\$172	\$0	\$434	\$65	\$22	\$104	\$625	\$1
12.7	Distributed Control System Equipment	\$9,484	\$0	\$309	\$0	\$9,794	\$1,469	\$490	\$1,763	\$13,515	\$21
12.8	Instrument Wiring & Tubing	\$472	\$378	\$1,510	\$0	\$2,360	\$354	\$118	\$708	\$3,540	\$6
12.9	Other Instrumentation & Controls Equipment	\$1,059	\$0	\$525	\$0	\$1,583	\$238	\$79	\$285	\$2,185	\$3
	Subtotal	\$15,260	\$378	\$3,764	\$0	\$19,402	\$2,910	\$806	\$3,777	\$26,896	\$42
	13	Improvements to Site									
13.1	Site Preparation	\$0	\$416	\$9,500	\$0	\$9,916	\$1,487	\$0	\$3,421	\$14,825	\$23
13.2	Site Improvements	\$0	\$1,888	\$2,669	\$0	\$4,557	\$684	\$0	\$1,572	\$6,813	\$11
13.3	Site Facilities	\$2,947	\$0	\$3,309	\$0	\$6,256	\$938	\$0	\$2,158	\$9,353	\$15
	Subtotal	\$2,947	\$2,304	\$15,478	\$0	\$20,729	\$3,109	\$0	\$7,152	\$30,991	\$48
	14	Buildings & Structures									
14.1	Combustion Turbine Area	\$0	\$314	\$177	\$0	\$491	\$74	\$0	\$85	\$649	\$1
14.3	Steam Turbine Building	\$0	\$2,784	\$3,964	\$0	\$6,748	\$1,012	\$0	\$1,164	\$8,924	\$14
14.4	Administration Building	\$0	\$886	\$643	\$0	\$1,529	\$229	\$0	\$264	\$2,022	\$3
14.5	Circulation Water Pump House	\$0	\$135	\$71	\$0	\$206	\$31	\$0	\$35	\$272	\$0
14.6	Water Treatment Buildings	\$0	\$297	\$289	\$0	\$586	\$88	\$0	\$101	\$775	\$1
14.7	Machine Shop	\$0	\$486	\$333	\$0	\$819	\$123	\$0	\$141	\$1,083	\$2
14.8	Warehouse	\$0	\$379	\$244	\$0	\$624	\$94	\$0	\$108	\$825	\$1
14.9	Other Buildings & Structures	\$0	\$278	\$216	\$0	\$494	\$74	\$0	\$85	\$653	\$1
14.10	Waste Treating Building & Structures	\$0	\$747	\$1,427	\$0	\$2,174	\$326	\$0	\$375	\$2,876	\$4
	Subtotal	\$0	\$6,306	\$7,365	\$0	\$13,670	\$2,051	\$0	\$2,358	\$18,079	\$28
	Total	\$1,215,985	\$73,110	\$525,832	\$0	\$1,814,927	\$281,059	\$142,230	\$376,139	\$2,614,355	\$4,087

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-36. Case B1A owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$21,541	\$34
1 Month Maintenance Materials	\$5,310	\$8
1 Month Non-Fuel Consumables	\$730	\$1
1 Month Waste Disposal	\$645	\$1
25% of 1 Months Fuel Cost at 100% CF	\$2,064	\$3
2% of TPC	\$52,287	\$82
Total	\$82,578	\$129
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	\$17,632	\$28
0.5% of TPC (spare parts)	\$13,072	\$20
Total	\$30,704	\$48
Other Costs		
Initial Cost for Catalyst and Chemicals	\$2,959	\$5
Land	\$900	\$1
Other Owner's Costs	\$392,153	\$613
Financing Costs	\$70,588	\$110
Total Overnight Costs (TOC)	\$3,194,235	\$4,993
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	\$3,687,463	\$5,764

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-37. Case B1A initial and annual operating and maintenance costs

Case:	B1A – Shell IGCC w/o CO ₂ Capture			Cost Base:	Dec 2018	
Plant Size (MW, net):	640	Heat Rate-net (Btu/kWh):	7,940		Capacity Factor (%):	80
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	% of base	Operator:	10.0	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	3.0	
				Total:	16.0	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$7,015,008	\$10.966
Maintenance Labor:					\$27,450,723	\$42.911
Administrative & Support Labor:					\$8,616,433	\$13.469
Property Taxes and Insurance:					\$52,287,092	\$81.734
Total:					\$95,369,257	\$149.080
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$50,979,915	\$11.37143
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (gal/1000):	0	2,972	\$1.90	\$0	\$1,648,664	\$0.36775
Makeup and Waste Water Treatment Chemicals (ton):	0	8.85	\$550.00	\$0	\$1,421,646	\$0.31711
Sulfur-Impregnated Activated Carbon (ton):	60.4	0.083	\$12,000.00	\$724,967	\$289,987	\$0.06468
COS Hydrolysis Catalyst (ft³):	1,347	0.923	\$1,300.00	\$1,750,996	\$350,199	\$0.07811
Sulfinol Solution (gal):	30,172	20.5	\$16.00	\$482,745	\$95,804	\$0.02137
Sodium Hydroxide (50 wt%, ton):	0	18.0	\$600.00	\$0	\$3,157,197	\$0.70424
Sulfuric Acid (98 wt%, ton):	0	0.320	\$210.00	\$0	\$19,598	\$0.00437
Claus Catalyst (ft³):	w/equip.	1.81	\$48.00	\$0	\$25,429	\$0.00567
Subtotal:				\$2,958,708	\$7,008,524	\$1.56330
Waste Disposal						
Sulfur-Impregnated Activated Carbon (ton):	0	0.083	\$80.00	\$0	\$1,933	\$0.00043
COS Hydrolysis Catalyst (ft³):	0	0.923	\$2.50	\$0	\$673	\$0.00015
Sulfinol Solution (gal):	0	20.5	\$0.35		\$2,096	\$0.00047
Claus Catalyst (ft³):	0	1.81	\$2.50		\$1,324	\$0.00030
Crystallizer Solids (ton):	0	34.0	\$38.00		\$377,258	\$0.08415
Slag (ton):	0	523	\$38.00	\$0	\$5,806,682	\$1.29522
Subtotal:				\$0	\$6,189,967	\$1.38072
By-Products						
Sulfur (tons):	0	130	\$0.00	\$0	\$0	\$0.00000
Subtotal:				\$0	\$0	\$0.00000
Variable Operating Costs Total:				\$2,958,708	\$64,178,406	\$14.31545
Fuel Cost						
Illinois Number 6 (ton):	0	5,225	\$51.96	\$0	\$79,272,599	\$17.68231
Total:				\$0	\$79,272,599	\$17.68231

Exhibit 3-38. Case B1A LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	58.2	52.2%
Fixed	21.3	19.1%
Variable	14.3	12.8%
Fuel	17.7	15.9%
Total (Excluding T&S)	111.5	100.0%
CO ₂ T&S	–	–
Total (Including T&S)	111.5	100.0%

3.2.8 Case B1B – Shell IGCC Power Plant with CO₂ Capture Process Description

In this section, the Shell gasification process for Case B1B is described. The plant configuration is nearly identical to that of Case B1A, with the exception that this case is configured to produce electric power with CO₂ capture.

The gross power output is constrained by the capacity of the two CTs, and since the CO₂ capture and compression process increases the auxiliary load on the plant, the net output is significantly reduced relative to Case B1A (519 MW versus 640 MW).

The process descriptions for Case B1B are similar to Case B1A with several notable exceptions to accommodate CO₂ capture. The system descriptions follow the BFD provided in Exhibit 3-39 with the associated stream tables—providing process data for the numbered streams in the BFD—provided in Exhibit 3-40. Rather than repeating the entire process description, only differences from Case B1A are reported here.

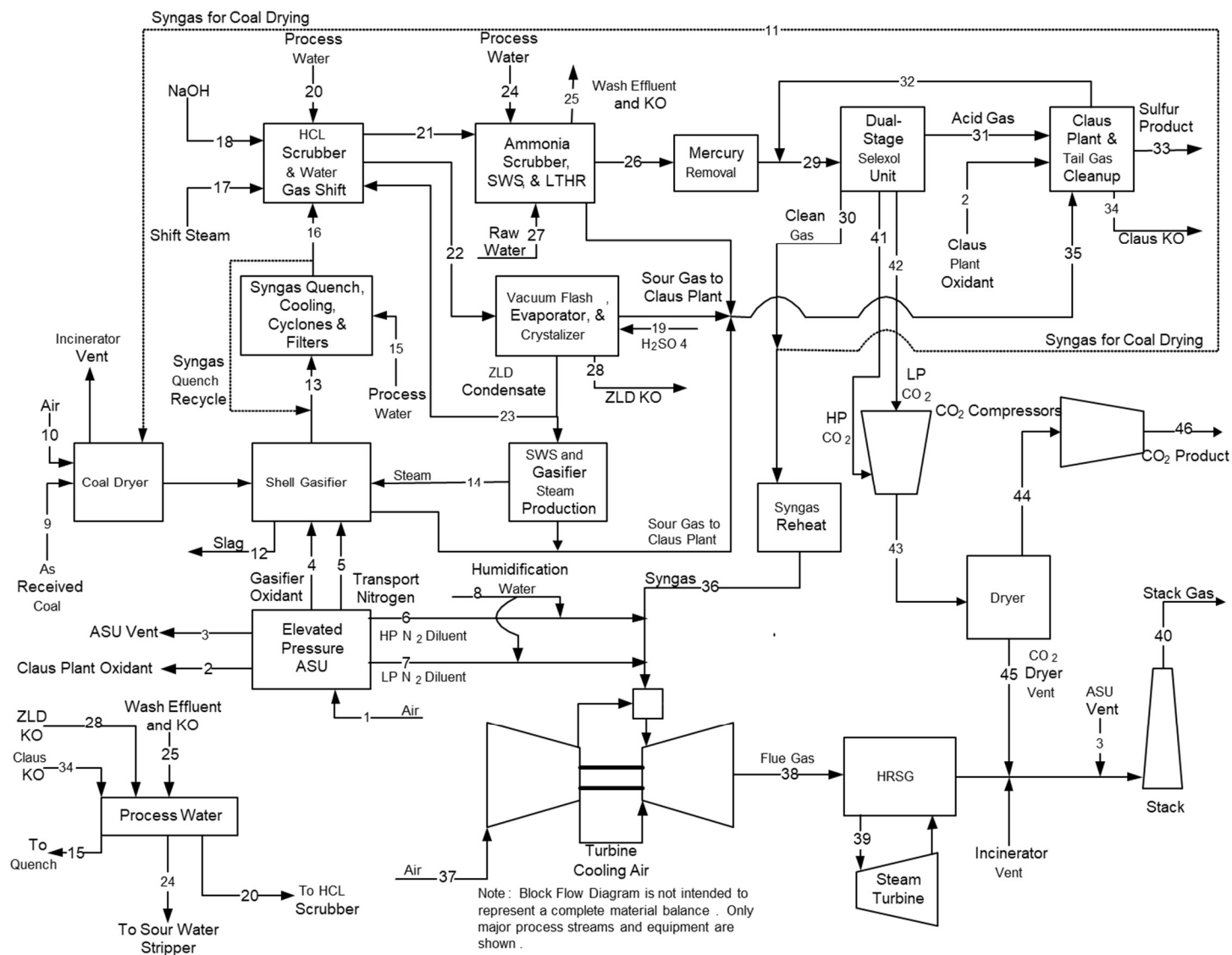
3.2.8.1 Coal Preparation and Feed Systems

No differences from Case B1A.

3.2.8.2 Gasifier

There are no differences in gasifier design from Case B1A. Downstream changes, such as syngas recycle, may impact overall syngas characteristics.

Exhibit 3-39. Case B1B block flow diagram, Shell IGCC with CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-40. Case B1B stream table, Shell IGCC with capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0343	0.2078	0.0343	0.0000	0.0000	0.0000	0.0000	0.0000	0.0092	0.0096	0.0000
CH ₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0328	0.0000
CO ₂	0.0003	0.0000	0.0365	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0003	0.0278	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.8678	0.0000
H ₂ O	0.0099	0.0000	0.7536	0.0000	0.0000	0.0000	0.0000	1.0000	0.0000	0.0099	0.0001	0.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7732	0.0157	0.0021	0.0157	0.9964	0.9964	0.9964	0.0000	0.0000	0.7732	0.0614	0.0000
NH ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.2074	0.9501	0.0000	0.9501	0.0036	0.0036	0.0036	0.0000	0.0000	0.2074	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	0.0000
V-L Flowrate (kg _{mol} /hr)	23,745	97	213	5,018	945	7,960	9,439	1,142	0	999	304	0
V-L Flowrate (kg/hr)	685,201	3,124	5,007	161,609	26,484	223,090	264,552	20,580	0	28,834	1,827	0
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	211,967	0	0	21,230
Temperature (°C)	15	27	29	27	130	196	196	38	15	15	18	1,427
Pressure (MPa, abs)	0.10	0.86	0.45	5.10	5.62	3.24	2.80	0.90	0.10	0.10	2.89	4.24
Steam Table Enthalpy (kJ/kg) ^A	30.23	21.53	18.93	9.82	129.22	202.25	202.54	161.90	---	30.23	87.76	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-0.97	-9,807.28	-12.68	103.25	176.29	176.57	-15,818.39	-2,119.02	-97.58	-2,468.67	2,165.43
Density (kg/m ³)	1.2	11.2	16.9	68.6	46.4	23.1	19.9	993.1	---	1.2	7.1	---
V-L Molecular Weight	28.857	32.209	23.542	32.209	28.028	28.028	28.028	18.015	---	28.857	6.006	---
V-L Flowrate (lb _{mol} /hr)	52,348	214	469	11,062	2,083	17,548	20,809	2,518	0	2,203	671	0
V-L Flowrate (lb/hr)	1,510,610	6,888	11,038	356,287	58,388	491,829	583,237	45,371	0	63,569	4,029	0
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	467,308	0	0	46,803
Temperature (°F)	59	80	83	80	267	385	385	101	59	59	65	2,600
Pressure (psia)	14.7	125.0	65.0	740.0	815.0	470.0	406.1	130.0	14.7	14.7	418.7	615.0
Steam Table Enthalpy (Btu/lb) ^A	13.0	9.3	8.1	4.2	55.6	87.0	87.1	69.6	---	13.0	37.7	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-0.4	-4,216.4	-5.5	44.4	75.8	75.9	-6,800.7	-911.0	-42.0	-1,061.3	931.0
Density (lb/ft ³)	0.076	0.700	1.054	4.283	2.894	1.439	1.245	61.999	---	0.076	0.441	---

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-40. Case B1B stream table, Shell IGCC with capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0082	0.0000	0.0000	0.0059	0.0000	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000	0.0000
CH ₄	0.0004	0.0000	0.0000	0.0003	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000
CO	0.5163	0.0000	0.0000	0.3727	0.0000	0.0000	0.0000	0.0000	0.0168	0.0002	0.0000	0.0000
CO ₂	0.0170	0.0000	0.0010	0.0125	0.0000	0.0000	0.0000	0.0007	0.2960	0.0001	0.0000	0.0007
COS	0.0006	0.0000	0.0000	0.0005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.2637	0.0000	0.0000	0.1904	0.0000	0.0000	0.0000	0.0000	0.4397	0.0001	0.0000	0.0000
H ₂ O	0.1293	0.9998	0.9791	0.3656	1.0000	0.6895	0.1000	0.9795	0.2001	0.9931	0.9993	0.9795
HCl	0.0004	0.0000	0.0000	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0073	0.0000	0.0001	0.0053	0.0000	0.0000	0.0000	0.0001	0.0046	0.0001	0.0000	0.0001
N ₂	0.0516	0.0000	0.0000	0.0373	0.0000	0.0000	0.0000	0.0000	0.0302	0.0000	0.0000	0.0000
NH ₃	0.0052	0.0002	0.0197	0.0092	0.0000	0.0000	0.0000	0.0197	0.0075	0.0039	0.0007	0.0197
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0026	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.3105	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.1000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	26,523	1,131	10,216	29,024	7,885	29	0	710	35,795	3,480	1,627	3,250
V-L Flowrate (kg/hr)	536,862	20,367	184,146	569,587	142,057	731	13	12,784	691,407	63,061	29,310	58,558
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	1,079	343	188	232	288	16	15	66	207	190	88	66
Pressure (MPa, abs)	4.24	5.10	4.98	3.98	3.88	4.81	0.13	0.47	3.49	3.88	0.13	0.47
Steam Table Enthalpy (kJ/kg) ^A	2,034.53	3,083.36	767.08	1,188.89	2,971.61	-338.78	-8,206.86	236.66	812.09	792.08	367.95	236.66
AspenPlus Enthalpy (kJ/kg) ^B	-3,011.58	-	-	-6,578.92	-	-	-8,526.27	-	-8,350.17	-	-	-
Density (kg/m ³)	7.6	19.9	835.0	19.0	16.9	1,531.7	1,791.5	964.5	17.0	873.7	965.6	964.5
V-L Molecular Weight	20.241	18.015	18.025	19.625	18.015	24.842	90.073	18.017	19.316	18.119	18.015	18.017
V-L Flowrate (lb _{mol} /hr)	58,474	2,492	22,523	63,987	17,384	65	0	1,564	78,915	7,673	3,587	7,166
V-L Flowrate (lb/hr)	1,183,578	44,900	405,973	1,255,724	313,182	1,612	29	28,183	1,524,293	139,026	64,618	129,099
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	1,974	650	371	450	550	61	59	151	404	373	191	151
Pressure (psia)	615.0	740.0	722.7	577.7	562.7	697.7	18.2	67.7	506.1	562.7	19.3	67.7
Steam Table Enthalpy (Btu/lb) ^A	874.7	1,325.6	329.8	511.1	1,277.6	-145.7	-3,528.3	101.7	349.1	340.5	158.2	101.7
AspenPlus Enthalpy (Btu/lb) ^B	-1,294.7	-5,539.3	-6,420.7	-2,828.4	-5,592.7	-5,874.9	-3,665.6	-6,651.4	-3,589.9	-6,469.9	-6,703.8	-6,651.4
Density (lb/ft ³)	0.473	1.240	52.127	1.183	1.055	95.623	111.841	60.212	1.064	54.544	60.280	60.212

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-40. Case B1B stream table, Shell IGCC with capture (continued)

	25	26	27	28	29	30	31	32	33	34	35	36
V-L Mole Fraction												
Ar	0.0000	0.0061	0.0000	0.0000	0.0061	0.0096	0.0000	0.0094	0.0000	0.0000	0.0004	0.0096
CH ₄	0.0000	0.0003	0.0000	0.0000	0.0003	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004
CO	0.0000	0.0212	0.0000	0.0000	0.0210	0.0328	0.0009	0.0053	0.0000	0.0000	0.0047	0.0328
CO ₂	0.0010	0.3718	0.0000	0.0002	0.3752	0.0278	0.5119	0.6379	0.0000	0.0000	0.3130	0.0278
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0009	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.5551	0.0000	0.0000	0.5512	0.8678	0.0121	0.2434	0.0000	0.0000	0.0283	0.8678
H ₂ O	0.9786	0.0016	0.9999	0.9829	0.0016	0.0001	0.0227	0.0024	0.0000	1.0000	0.1553	0.0001
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0001	0.0058	0.0000	0.0003	0.0058	0.0000	0.4505	0.0050	0.0000	0.0000	0.0124	0.0000
N ₂	0.0000	0.0382	0.0000	0.0000	0.0389	0.0614	0.0003	0.0966	0.0000	0.0000	0.0015	0.0614
NH ₃	0.0202	0.0000	0.0000	0.0166	0.0000	0.0000	0.0007	0.0000	0.0000	0.0000	0.4844	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	13,281	28,350	2,712	685	28,710	18,136	367	360	0	213	136	17,831
V-L Flowrate (kg/hr)	239,394	556,172	48,864	12,327	567,710	108,923	14,111	11,538	0	3,846	3,460	107,096
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	5,312	0	0	0
Temperature (°C)	69	29	15	30	37	18	27	38	184	50	160	193
Pressure (MPa, abs)	0.45	3.18	0.10	0.24	3.07	2.89	0.18	3.07	0.12	0.11	0.45	2.72
Steam Table Enthalpy (kJ/kg) ^A	246.21	39.46	62.75	90.19	50.99	87.76	40.89	23.53	---	109.93	503.16	948.97
AspenPlus Enthalpy (kJ/kg) ^B	-15,448.64	-7,608.63	-15,905.25	-15,660.66	-7,602.44	-2,468.67	-5,643.65	-7,887.11	147.56	-15,860.00	-7,013.83	-1,607.46
Density (kg/m ³)	962.1	25.2	999.4	985.4	23.9	7.1	2.9	40.7	5,266.4	968.5	3.2	4.2
V-L Molecular Weight	18.026	19.618	18.019	18.008	19.774	6.006	38.417	32.010	---	18.016	25.491	6.006
V-L Flowrate (lb _{mol} /hr)	29,279	62,500	5,979	1,509	63,295	39,982	810	795	0	471	299	39,312
V-L Flowrate (lb/hr)	527,774	1,226,150	107,727	27,176	1,251,586	240,134	31,110	25,436	0	8,479	7,628	236,105
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	11,711	0	0	0
Temperature (°F)	156	84	59	85	99	65	80	100	364	121	321	380
Pressure (psia)	65.0	460.7	14.7	35.0	445.2	418.7	26.7	445.2	16.8	15.9	65.0	394.1
Steam Table Enthalpy (Btu/lb) ^A	105.9	17.0	27.0	38.8	21.9	37.7	17.6	10.1	---	47.3	216.3	408.0
AspenPlus Enthalpy (Btu/lb) ^B	-6,641.7	-3,271.1	-6,838.0	-6,732.9	-3,268.5	-1,061.3	-2,426.3	-3,390.8	63.4	-6,818.6	-3,015.4	-691.1
Density (lb/ft ³)	60.061	1.573	62.391	61.518	1.492	0.441	0.180	2.540	328.772	60.463	0.200	0.260

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-40. Case B1B stream table, Shell IGCC with capture (continued)

	37	38	39	40	41	42	43	44	45	46
V-L Mole Fraction										
Ar	0.0092	0.0086	0.0000	0.0089	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0010	0.0002	0.0008	0.0008	0.0000	0.0008
CO ₂	0.0003	0.0081	0.0000	0.0082	0.9834	0.9983	0.9874	0.9903	0.0500	0.9903
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0107	0.0008	0.0080	0.0081	0.0000	0.0081
H ₂ O	0.0099	0.1279	1.0000	0.1346	0.0044	0.0007	0.0034	0.0005	0.9500	0.0005
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7732	0.7480	0.0000	0.7421	0.0004	0.0000	0.0003	0.0003	0.0000	0.0003
NH ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.2074	0.1074	0.0000	0.1062	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	110,253	138,595	28,002	140,769	7,445	2,762	10,207	10,176	31	10,176
V-L Flowrate (kg/hr)	3,181,556	3,796,875	504,469	3,846,887	323,283	121,393	444,676	444,071	605	444,071
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	563	533	121	-3	-11	29	29	29	30
Pressure (MPa, abs)	0.10	0.10	12.51	0.10	0.55	0.12	2.50	2.39	2.50	15.27
Steam Table Enthalpy (kJ/kg) ^A	30.23	847.95	3,429.64	353.74	-8.36	-9.59	2.39	0.57	138.13	-226.74
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-634.66	-12,550.65	-1,204.42	-8,973.30	-8,972.60	-8,962.21	-8,955.32	-15,225.03	-9,182.62
Density (kg/m ³)	1.2	0.4	36.8	0.8	11.2	2.3	49.8	47.2	319.0	837.3
V-L Molecular Weight	28.857	27.395	18.015	27.328	43.422	43.954	43.566	43.640	19.315	43.640
V-L Flowrate (lb _{mol} /hr)	243,065	305,551	61,734	310,341	16,414	6,089	22,503	22,434	69	22,434
V-L Flowrate (lb/hr)	7,014,130	8,370,676	1,112,164	8,480,933	712,716	267,626	980,342	979,009	1,333	979,009
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	1,046	991	250	26	12	85	85	85	86
Pressure (psia)	14.7	15.1	1,814.7	14.8	80.0	16.7	363.0	346.5	363.0	2,214.7
Steam Table Enthalpy (Btu/lb) ^A	13.0	364.6	1,474.5	152.1	-3.6	-4.1	1.0	0.2	59.4	-97.5
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-272.9	-5,395.8	-517.8	-3,857.8	-3,857.5	-3,853.1	-3,850.1	-6,545.6	-3,947.8
Density (lb/ft ³)	0.076	0.026	2.298	0.053	0.697	0.146	3.106	2.946	19.917	52.273

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

3.2.8.3 Raw Gas Cooling and Particulate Removal

The raw gas cooling system is identical to that of Case B1A's through the duct cooler. Following the duct cooler, the syngas cooler is replaced with a direct contact water quench, which cools the raw syngas from 899°C (1,650°F) to 399°C (750°F) while providing a portion of the water required for WGS and removing a significant portion of the PM from the syngas. The balance of the system is identical to Case B1A with the exception that the final stage of cooling produces a syngas at 232°C (450°F), rather than 191°C (375°F).

3.2.8.4 Quench Gas Compressor

Case B1B differs from Case B1A in that 21 percent of the cooled syngas is recycled back to the gasifier exit as quench gas, rather than 30 percent.

3.2.8.5 Syngas Scrubber

The design of the syngas scrubber used in Case B1B differs from Case B1A in that effluent recycle is required to achieve a chloride concentration in the blowdown (stream 22) of 5,000 ppmw.

The recycled effluent is cooled from 190°C (374°F) to 44°C (112°F) by preheating FW to the WGS steam generator before being mixed with cooled process water. Process water (stream 20) and ZLD condensate (stream 23) are cooled to 32°C (90°F) by preheating syngas prior to the CT and mixed with the cooled effluent before being cooled further to 21°C (70°F) with cooling water and injected into the scrubber.

Since the chloride concentration is maintained by adjusting the rate of effluent recycle, the rate of process water addition is used to maintain the HCl removal rate at 96 percent.

All other aspects of the syngas scrubber are identical to those described for Case B1A.

3.2.8.6 Water Gas Shift

The WGS process was described in Section 3.1.3. After the scrubber, the syngas is combined with steam (stream 17) to adjust the steam to dry gas ratio prior to the first WGS reactor. The rate of steam injection is controlled to maintain an exit steam to dry gas ratio of approximately 0.25. Two stages in total are used to convert 94.4 of the CO in the syngas to CO₂. The heat generated from the first reactor is used to produce more steam than is required (35,053 kg/hr [77,279 lb/hr] of 3.9 MPa (563 psia) steam is exported for use in the steam cycle) to maintain the desired steam to dry gas ratio while cooling the syngas to 253°C (487°F) prior to entering the second stage. Prior to the syngas being sent to the LTHR system (stream 21), the warm syngas from the second stage of WGS is cooled to 207°C (404°F) by preheating the FW of the WGS steam generator.

The WGS catalyst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor.

3.2.8.7 Low Temperature Heat Recovery

Since the exit temperature of the WGS system used in this case was significantly higher than the COS hydrolysis unit used in Case B1A, two additional HXs were required for the LTHR system. The first stage cools the syngas from 207°C (404°F) to 162°C (323°F) by raising 0.4 MPa (65 psia) process steam. The second stage cools the syngas to 134°C (274°F) by preheating the FW to the WGS steam generator, preheating both the N₂ humidification water and syngas prior to the CT, and preheating the FW to the HRSG. The balance of the section is unchanged from Case B1A.

3.2.8.8 Sour Water Stripper and Ammonia Wash

No differences from Case B1A.

3.2.8.9 Process Water Treatment

The process water treatment system is identical to that used in Case B1A, with the exception that the vapor products from both the LP and vacuum flash stages are cooled to 46°C (115°F) prior to the cooling water condensing HX. The lower temperature reached in this case (46°C [115°F] versus 72°C [162°F]) is due to the lower exit temperature of the Selexol system, compared to the Sulfinol-M system.

3.2.8.10 Mercury Removal and AGR

Mercury removal is the same as in Case B1A.

The AGR process in Case B1B is a two-stage Selexol process (covered in Section 3.1.5.4) where H₂S is removed in the first stage and CO₂ in the second stage of absorption. The process results in four product streams, the clean syngas (stream 30), two CO₂-rich streams (streams 41 and 42) and an acid gas feed to the Claus plant (stream 31). The acid gas contains 45 vol% H₂S and 51 vol% CO₂ with the balance primarily water and H₂. The raw CO₂ stream from the Selexol process contains over 99 vol% CO₂.

3.2.8.11 Claus Unit

No differences from Case B1A.

3.2.8.12 Incinerator

No differences from Case B1A.

3.2.8.13 Power Block

In Case B1B, N₂ alone is not sufficient to provide the dilution necessary for the CT. In this case, the preheated syngas is diluted with humidified HP and LP N₂ (streams 6 and 7). The moisture added to the N₂ streams provides sufficient dilution for operating the CT. The exhaust gas (stream 38) exits the CT at a lower temperature (563°C [1,046°F]) than Case B1A due to the higher moisture content.

3.2.8.14 Air Separation Unit

No differences from Case B1A.

3.2.9 Case B1B – Performance Results

The Case B1B modeling assumptions were presented previously in Section 3.2.2.

The plant produces a net output of 519 MW at a net plant efficiency of 32.5 percent (HHV basis). Overall performance for the plant is summarized in Exhibit 3-41. Exhibit 3-42 provides a detailed breakdown of the auxiliary power requirements. The ASU accounts for approximately 62 percent of the auxiliary load between the MAC, booster compressor, N₂ compressors, O₂ pump, and ASU auxiliaries. The two-stage Selexol process and CO₂ compression account for an additional 24 percent of the auxiliary power load. The BFW and circulating water system (circulating water pumps and cooling tower fan) composes approximately 4 percent of the load, with all other systems together constituting the remaining 10 percent of the auxiliary load.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-41. Case B1B plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	464
Sweet Gas Expander Power, MWe	–
Steam Turbine Power, MWe	232
Total Gross Power, MWe	696
Air Separation Unit Main Air Compressor, kWe	65,800
Air Separation Unit Booster Compressor, kWe	5,180
N ₂ Compressors, kWe	36,280
CO ₂ Compression, kWe	31,030
Acid Gas Removal, kWe	11,330
Balance of Plant, kWe	27,220
Total Auxiliaries, MWe	177
Net Power, MWe	519
HHV Net Plant Efficiency, %	32.5
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,075 (10,497)
HHV Cold Gas Efficiency, %	82.9
HHV Combustion Turbine Efficiency, %	36.4
LHV Net Plant Efficiency, %	33.7
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,682 (10,124)
LHV Cold Gas Efficiency, %	81.3
LHV Combustion Turbine Efficiency, %	42.7
Steam Turbine Cycle Efficiency, %	42.1
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	8,551 (8,105)
Condenser Duty, GJ/hr (MMBtu/hr)	1,345 (1,275)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	144 (137)
As-Received Coal Feed, kg/hr (lb/hr)	211,967 (467,308)
HHV Thermal Input, kWt	1,597,710
LHV Thermal Input, kWt	1,541,011
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.037 (9.8)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.029 (7.7)
O ₂ :As-Received Coal	0.720

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-42. Case B1B plant power summary

Power Summary	
Combustion Turbine Power, MWe	464
Sweet Gas Expander Power, MWe	–
Steam Turbine Power, MWe	232
Total Gross Power, MWe	696
Auxiliary Load Summary	
Acid Gas Removal, kWe	11,330
Air Separation Unit Auxiliaries, kWe	1,000
Air Separation Unit Main Air Compressor, kWe	65,800
Air Separation Unit Booster Compressor, kWe	5,180
Ammonia Wash Pumps, kWe	120
Circulating Water Pumps, kWe	4,640
Claus Plant TG Recycle Compressor, kWe	1,220
Claus Plant/TGTU Auxiliaries, kWe	250
CO ₂ Compression, kWe	31,030
Coal Dryer Air Compressor, kWe	80
Coal Handling, kWe	460
Coal Milling, kWe	2,180
Combustion Turbine Auxiliaries, kWe	1,000
Condensate Pumps, kWe	260
Cooling Tower Fans, kWe	2,400
Feedwater Pumps, kWe	3,220
Gasifier Water Pump, kWe	40
Ground Water Pumps, kWe	460
Miscellaneous Balance of Plant ^A , kWe	3,000
N ₂ Compressors, kWe	36,280
N ₂ Humidification Pump, kWe	20
O ₂ Pump, kWe	330
Quench Water Pump, kWe	330
Shift Steam Pump, kWe	300
Slag Handling, kWe	550
Slag Reclaim Water Recycle Pump, kWe	–
Slurry Water Pump, kWe	–

Power Summary	
Auxiliary Load Summary	
Sour Gas Compressors, kWe	140
Sour Water Recycle Pumps, kWe	–
Steam Turbine Auxiliaries, kWe	200
Syngas Recycle Compressor, kWe	880
Syngas Scrubber Pumps, kWe	120
Process Water Treatment Auxiliaries, kWe	1,310
Transformer Losses, kWe	2,710
Total Auxiliaries, MWe	177
Net Power, MWe	519

^AIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

3.2.9.1 Environmental Performance

The environmental targets for emissions of Hg, HCl, NO_x, SO₂, CO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B1B is presented in Exhibit 3-43.

Exhibit 3-43. Case B1B air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.021 (0.049)	846 (933)	0.173 (0.382)
Particulate	0.003 (0.007)	123 (136)	0.025 (0.056)
Hg	1.65E-7 (3.83E-7)	0.007 (0.007)	1.36E-6 (3.00E-6)
HCl	0.000 (0.000)	0.00 (0.00)	0.000 (0.000)
CO ₂	9 (21)	355,305 (391,656)	73 (161)
CO ₂ ^C	–	–	98 (215)

^ACalculations based on an 80 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

The low level of SO₂ emissions is achieved by capturing the sulfur in the gas by the two-stage Selexol AGR process. The CO₂ capture target results in more sulfur compounds being removed than required in the environmental targets of Section 2.4. The clean syngas exiting the AGR process has a sulfur concentration of approximately 4 ppmv. This results in a concentration in the HRSG flue gas of less than 1 ppmv. The H₂S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is compressed and recycled back to the AGR where most of the remaining sulfur is removed.

NO_x emissions are limited using N₂ dilution and humidification to 15 ppmvd (as NO at 15 percent O₂). NH₃ in the syngas is removed with process condensate prior to the low-

temperature AGR process and subsequently destroyed in the Claus plant burner. This helps lower NO_x levels as well.

Particulate discharge to the atmosphere is limited to extremely low values using a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Approximately 97 percent of mercury is captured from the syngas by dual activated carbon beds.

Ninety two percent of the CO₂ from the syngas is captured in the AGR system and compressed for sequestration. Because not all CO is converted to CO₂ in the shift reactors, the overall carbon removal is 90.0 percent.

The carbon balance for the plant is shown in Exhibit 3-44. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon leaves the plant as unburned carbon in the slag, the captured CO₂ product, and the CO₂ in the stack gas (includes the coal dryer vent gas and ASU vent gas). The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in less carbon contained in the slag, represented by the following fraction:

$$\left(1 - \left(\frac{\text{Carbon in Stack}}{(\text{Total Carbon In}) - (\text{Carbon in Slag})}\right)\right) * 100 = \left(1 - \left(\frac{30,505}{299,052 - 1,489}\right)\right) * 100 = 90\%$$

Exhibit 3-44. Case B1B carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	135,118 (297,884)	Stack Gas	13,837 (30,505)
Air (CO ₂)	530 (1,168)	CO ₂ Product	121,135 (267,058)
		Slag	676 (1,489)
Total	135,648 (299,052)	Total	135,648 (299,052)

Exhibit 3-45 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant and sulfur in the CO₂ product. Sulfur in the slag is considered negligible.

Exhibit 3-45. Case B1B sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	5,313 (11,713)	Stack Gas	—
		CO ₂ Product	1 (2)
		Elemental Sulfur	5,312 (11,711)
Total	5,313 (11,713)	Total	5,313 (11,713)

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-46 shows the overall water balance for the plant. The exhibit is presented in an identical manner as for Case B1A.

Exhibit 3-46. Case B1B water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
Slag Handling	0.46 (122)	0.46 (122)	–	–	–
Slurry Water	–	–	–	–	–
Gasifier Water	–	–	–	–	–
Quench	3.07 (812)	3.07 (812)	–	–	–
HCl Scrubber	1.88 (497)	1.88 (497)	–	–	–
NH ₃ Scrubber	1.77 (467)	0.95 (252)	0.82 (215)	–	0.82 (215)
Gasifier Steam	0.34 (90)	0.34 (90)	–	–	–
Condenser Makeup	0.52 (139)	–	0.52 (139)	–	0.52 (139)
BFW Makeup	0.18 (48)	–	0.18 (48)	–	0.18 (48)
Gasifier Steam	–	–	–	–	–
Shift Steam	–	–	–	–	–
N ₂ Humidification	0.34 (91)	–	0.34 (91)	–	0.34 (91)
Cooling Tower	18.09 (4,779)	0.20 (54)	17.89 (4,726)	4.07 (1,075)	13.82 (3,651)
BFW Blowdown	–	0.18 (48)	-0.18 (-48)	–	-0.18 (-48)
ASU Knockout	–	0.02 (6)	-0.02 (-6)	–	-0.02 (-6)
Total	26.14 (6,906)	6.91 (1,826)	19.23 (5,080)	4.07 (1,075)	15.16 (4,005)

An overall plant energy balance is provided in tabular form in Exhibit 3-47. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a combined generator efficiency of 98.5 percent.

Exhibit 3-47. Case B1B overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, MMBtu/hr (GJ/hr)				
Coal	5,752 (5,452)	4.8 (4.6)	–	5,757 (5,456)
Air	–	117.7 (111.6)	–	117.7 (111.6)
Raw Water Makeup	–	72.3 (68.5)	–	72.3 (68.5)
Auxiliary Power	–	–	636.6 (603.4)	636.6 (603.4)
TOTAL	5,752 (5,452)	194.9 (184.7)	636.6 (603.4)	6,583 (6,240)
Heat Out, MMBtu/hr (GJ/hr)				
Misc. Process Steam	–	4.8 (4.6)	–	4.8 (4.6)

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

	HHV	Sensible + Latent	Power	Total
Slag	22.1 (21.0)	35.8 (34.0)	–	58.0 (55.0)
Stack Gas	–	1,361 (1,290)	–	1,361 (1,290)
Sulfur	49.2 (46.7)	0.6 (0.6)	–	49.9 (47.3)
Motor Losses and Design Allowances	–	–	55.0 (52.1)	55.0 (52.1)
Cooling Tower Load ^A	–	2,362 (2,239)	–	2,362 (2,239)
CO ₂ Product Stream	–	-100.7 (-95.4)	–	-100.7 (-95.4)
Blowdown Streams	–	36.7 (34.8)	–	36.7 (34.8)
<i>Ambient Losses^B</i>	–	139.2 (131.9)	–	139.2 (131.9)
Power	–	–	2,506 (2,376)	2,506 (2,376)
TOTAL	71.4 (67.6)	3,839 (3,639)	2,561 (2,428)	6,472 (6,134)
Unaccounted Energy ^C	–	–	–	111.4 (105.5)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers

^CBy difference

3.2.9.2 Energy and Mass Balance Diagrams

Energy and mass balance diagrams are shown for the following subsystems in Exhibit 3-48 through Exhibit 3-50:

- Coal gasification and ASU
- Syngas cleanup including sulfur recovery and tail gas recycle
- Combined cycle power generation, steam, and FW

This page intentionally left blank

Exhibit 3-48. Case B1B coal gasification and ASU energy and mass balance

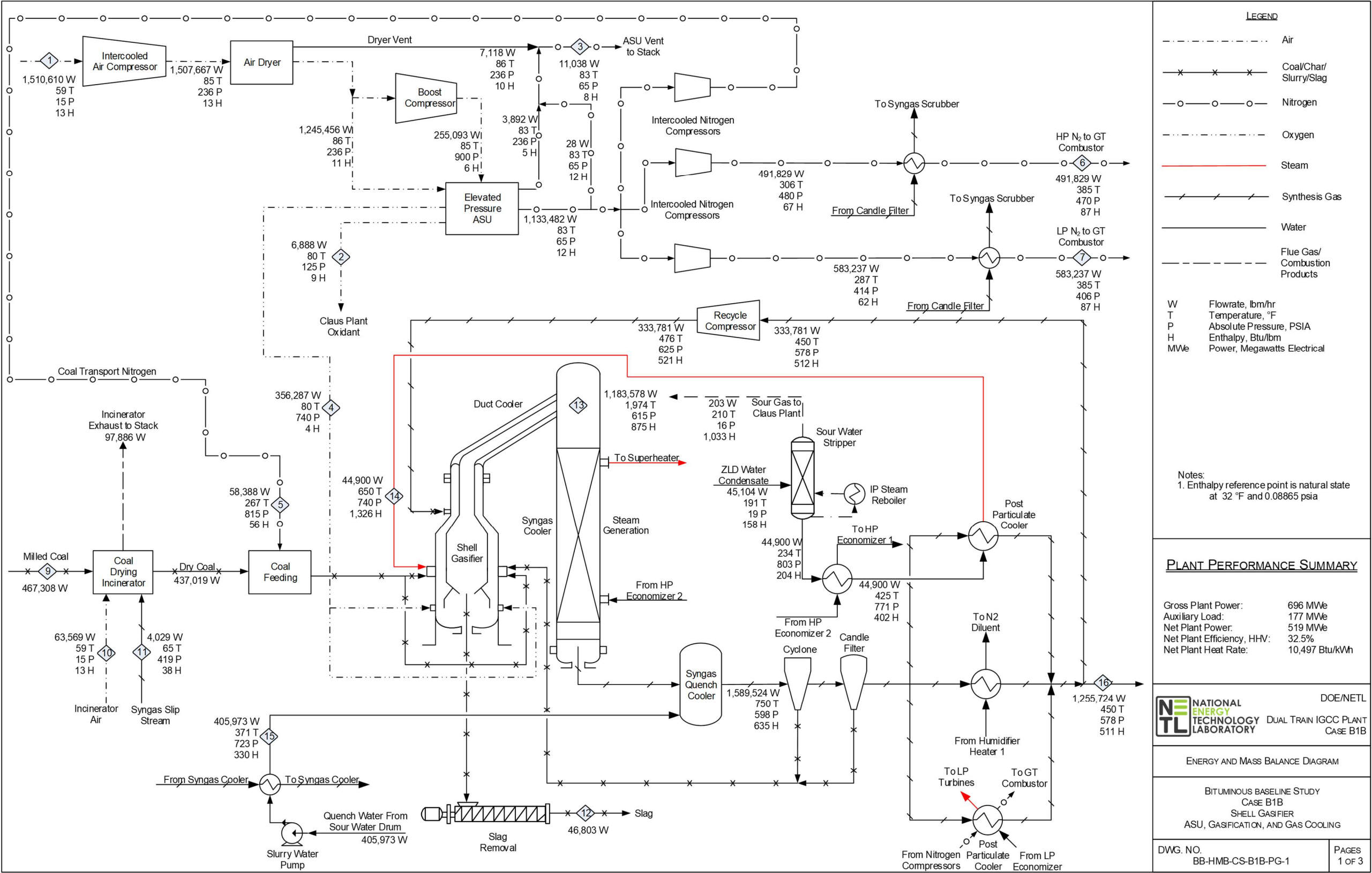


Exhibit 3-49. Case B1B syngas cleanup energy and mass balance

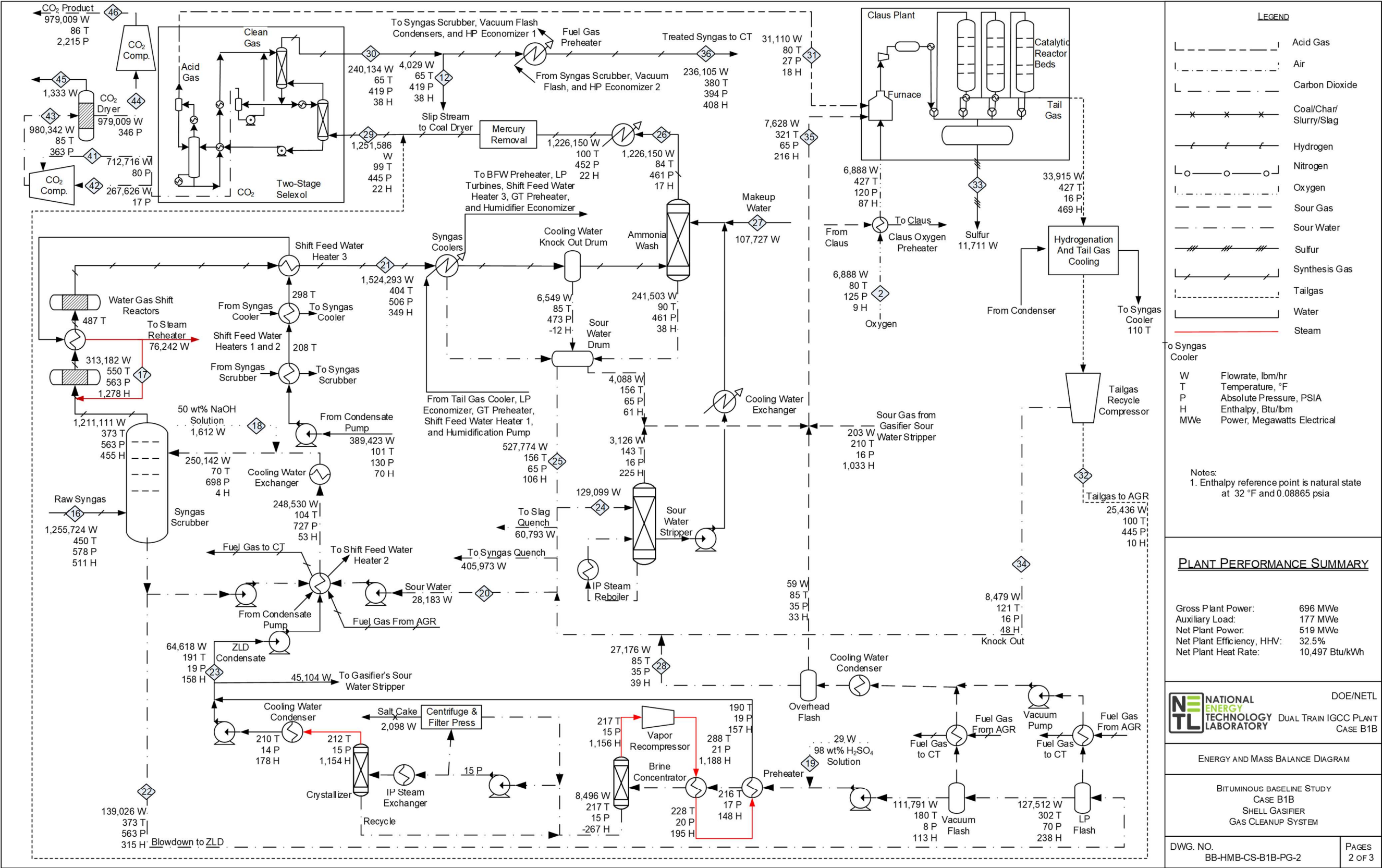
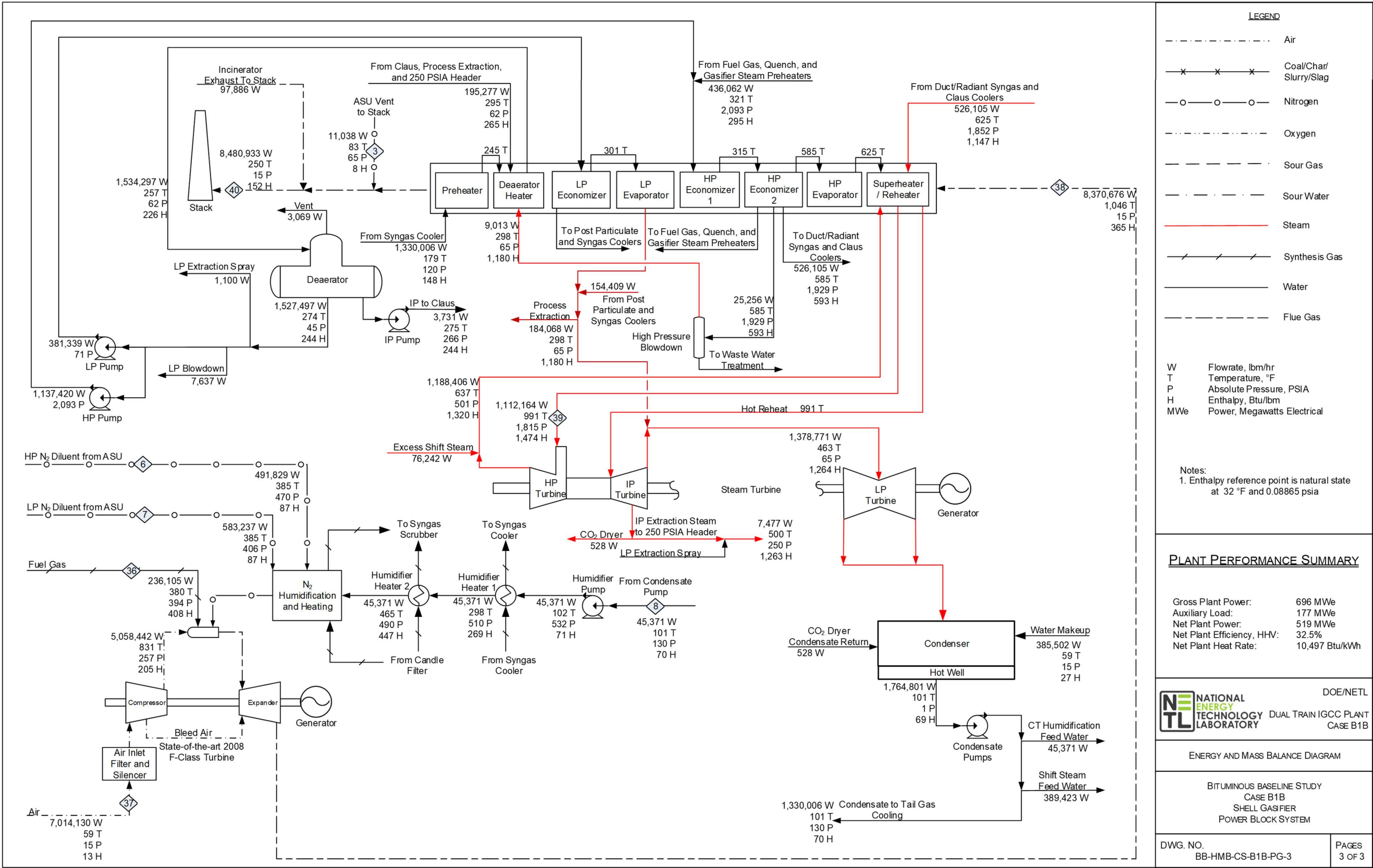


Exhibit 3-50. Case B1B combined cycle power generation energy and mass balance



This page intentionally left blank

3.2.10 Case B1B – Major Equipment List

Major equipment items for the Shell gasifier with CO₂ capture are shown in the following tables. In general, the design conditions include a 10 percent design allowance for flows and heat duties and a 21 percent design allowance for heads on pumps and fans.

Case B1B – Account 1: Coal Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
5	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
6	Reclaim Hopper	N/A	40 tonne (50 ton)	2	1
7	Feeder	Vibratory	170 tonne/hr (190 tph)	2	1
8	Conveyor No. 3	Belt w/ tripper	350 tonne/hr (390 tph)	1	0
9	Coal Surge Bin w/ Vent Filter	Dual outlet	170 tonne (190 ton)	2	0
10	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
11	Conveyor No. 4	Belt w/trippper	350 tonne/hr (390 tph)	1	0
12	Conveyor No. 5	Belt w/ tripper	350 tonne/hr (390 tph)	1	0
13	Coal Silo w/ Vent Filter and Slide Gates	Field erected	780 tonne (860 ton)	3	0

Case B1B – Account 2: Coal Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	80 tonne/hr (90 tph)	3	0
2	Conveyor No. 6	Belt w/trippper	230 tonne/hr (260 tph)	1	0
3	Roller Mill Feed Hopper	Dual Outlet	470 tonne (510 ton)	1	0
4	Weigh Feeder	Belt	120 tonne/hr (130 tph)	2	0
5	Coal Dryer and Pulverizer	Rotary	120 tonne/hr (130 tph)	2	0
6	Coal Dryer Feed Hopper	Vertical Hopper	230 tonne (260 ton)	2	0

Case B1B – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	11,548,000 liters (3,051,000 gal)	2	0
2	Condensate Pumps	Vertical canned	7,390 lpm @ 90 m H ₂ O (1,950 gpm @ 300 ft H ₂ O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	383,000 kg/hr (844,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	1,650 lpm @ 20 m H ₂ O (440 gpm @ 70 ft H ₂ O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 4,920 lpm @ 1,700 m H ₂ O (1,300 gpm @ 5,700 ft H ₂ O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,890 lpm @ 210 m H ₂ O (500 gpm @ 670 ft H ₂ O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
8	Service Air Compressors	Flooded Screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	480 GJ/hr (455 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	172,200 lpm @ 20 m H ₂ O (45,500 gpm @ 70 ft H ₂ O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
14	Municipal Water Pumps	Stainless steel, single suction	3,350 lpm @ 20 m H ₂ O (880 gpm @ 60 ft H ₂ O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	3,350 lpm @ 270 m H ₂ O (880 gpm @ 880 ft H ₂ O)	2	1
16	Filtered Water Pumps	Stainless steel, single suction	2,050 lpm @ 50 m H ₂ O (540 gpm @ 160 ft H ₂ O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	985,000 liter (260,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	1,610 lpm (420 gpm)	2	0
19	Liquid Waste Treatment System	N/A	10 years, 24-hour storm	1	0
20	Process Water Treatment	Vacuum flash, brine concentrator, and crystallizer	Vacuum Flash - Inlet: 35,000 kg/hr (76,000 lb/hr) Outlet: 6,218 ppmw Cl- Brine Concentrator Inlet - 28,000 kg/hr (61,000 lb/hr) Crystallizer Inlet - 2,000 kg/hr (5,000 lb/hr)	2	0

Case B1B – Account 4: Gasifier, ASU, and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized dry-feed, entrained bed	2,800 tonne/day, 4.2 MPa (3,100 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Convective spiral-wound tube boiler	295,000 kg/hr (651,000 lb/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	397,000 kg/hr (874,000 lb/hr) Design efficiency 90%	2	0
4	HCl Scrubber	Ejector Venturi	313,000 kg/hr (691,000 lb/hr)	2	0
5	Ammonia Wash	Counter-flow spray tower	308,000 kg/hr (679,000 lb/hr) @ 3.3 MPa (473 psia)	2	0
6	Primary Sour Water Stripper	Counter-flow with external reboiler	32,000 kg/hr (71,000 lb/hr)	2	0
7	Secondary Sour Water Stripper	Counter-flow with external reboiler	11,000 kg/hr (25,000 lb/hr)	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
8	Low Temperature Heat Recovery Coolers	Shell and tube with condensate drain	380,000 kg/hr (838,000 lb/hr)	6	0
9	Low Temperature Heat Recovery Knockout Drum	Vertical with mist eliminator	309,000 kg/hr, 59°C, 3.3 MPa (682,000 lb/hr, 138°F, 476 psia)	2	0
10	Saturation Water Economizers	Shell and tube	N/A	4	0
11	HP Nitrogen Gas Saturator	Direct Injection	123,000 kg/hr, 196°C, 3.2 MPa (271,000 lb/hr, 385°F, 470 psia)	2	0
12	LP Nitrogen Gas Saturator	Direct Injection	146,000 kg/hr, 196°C, 2.8 MPa (321,000 lb/hr, 385°F, 406 psia)	2	0
13	Saturator Water Pump	Centrifugal	200 lpm @ 342 m H ₂ O (100 gpm @ 1121 ft H ₂ O)	2	2
14	Saturated Nitrogen Reheaters	Shell and tube	N/A	4	0
15	Synthesis Gas Reheaters	Shell and tube	Reheater 1: N/A Reheater 2: 14,000 kg/hr (32,000 lb/hr) Reheater 3: 20,000 kg/hr (44,000 lb/hr) Reheater 4: 25,000 kg/hr (55,000 lb/hr) Reheater 5: 59,000 kg/hr (130,000 lb/hr) Reheater 6: 59,000 kg/hr (130,000 lb/hr)	2	0
16	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	302,000 kg/hr (666,000 lb/hr) syngas	2	0
17	ASU Main Air Compressor	Centrifugal, multi-stage	5,000 m ³ /min @ 1.6 MPa (182,000 scfm @ 236 psia)	2	0
18	Cold Box	Vendor design	2,200 tonne/day (2,400 tpd) of 95% purity O ₂	2	0
19	Gasifier O ₂ Pump	Centrifugal, multi-stage	1,000 m ³ /min (38,000 scfm) Suction - 1.0 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	2	0
20	AGR Nitrogen Boost Compressor	Centrifugal, multi-stage	N/A	2	0
21	High Pressure Nitrogen Diluent Compressor	Centrifugal, multi-stage	2,000 m ³ /min (61,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - 3.3 MPa (480 psia)	2	0
22	Low Pressure Nitrogen Diluent Compressor	Centrifugal, single-stage	2,050 m ³ /min (72,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - 2.9 MPa (410 psia)	2	0
23	Gasifier Nitrogen Boost Compressor	Centrifugal, single-stage	210 m ³ /min (7,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - 5.6 MPa (820 psia)	2	0

Case B1B – Account 5: Syngas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber 1	Sulfated carbon bed	306,000 kg/hr (674,000 lb/hr) 29°C (84°F) 3.2 MPa (461 psia)	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
2	Mercury Adsorber 2	Sulfated carbon bed	306,000 kg/hr (674,000 lb/hr) 37°C (99°F) 3.1 MPa (448 psia)	2	0
3	Sulfur Plant	Claus type	140 tonne/day (155 tpd)	1	0
4	Water Gas Shift Reactors	Fixed bed, catalytic	190,000 kg/hr (419,000 lb/hr) 216°C (420°F) 3.9 MPa (560 psia)	4	0
5	Shift Reactor Heat Recovery Exchangers	Shell and Tube	Exchanger 1: 205 GJ/hr (194 MMBtu/hr) Exchanger 2: 89 GJ/hr (85 MMBtu/hr) Exchanger 3: 68 GJ/hr (64 MMBtu/hr) Exchanger 4: 79 GJ/hr (75 MMBtu/hr)	8	0
6	Acid Gas Removal Plant	Two-stage Selexol	624,000 kg/hr (1,377,000 lb/hr) 37°C (99°F) 3.1 MPa (445 psia)	1	0
7	Hydrogenation Reactor	Fixed bed, catalytic	17,000 kg/hr (37,000 lb/hr) 219°C (427°F) 0.1 MPa (16.4388411 psia)	1	0
8	Tail Gas Recycle Compressor	Centrifugal	13,000 kg/hr (28,000 lb/hr) each	1	0
9	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0
10	CO ₂ Dryer	Triethylene glycol	Inlet: 149 m ³ /min @ 2.5 MPa (5,260 acfm @ 363 psia) Outlet: 2.4 MPa (346 psia) Water Recovered: 605 kg/hr (1,333 lb/hr)	1	0
11	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	10 m ³ /min @ 15.3 MPa (343 acfm @ 2,217 psia)	1	0
12	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 76 GJ/hr (72 MMBtu/hr)	1	0

Case B1B – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	State-of-the-art 2008 F-Class	232 MW	2	0
2	Combustion Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

Case B1B – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.5 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 277,458 kg/hr, 12.4 MPa/533°C (611,690 lb/hr, 1,800 psig/991°F) Reheat steam - 296,479 kg/hr, 3.3 MPa/533°C (653,623 lb/hr, 477 psig/991°F)	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B1B – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	244 MW 12.4 MPa/533°C/533°C (1,800 psig/991°F/991°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	270 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,480GJ/hr (1,400 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

Case B1B – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	466,000 lpm @ 30 m (123,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 2,600 GJ/hr (2,460 MMBtu/hr) heat duty	1	0

Case B1B – Account 10: Slag Recovery and Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	223,000 liters (59,000 gal)	2	0
2	Slag Crusher	Roll	12 tonne/hr (13 tph)	2	0
3	Slag Depressurizer	Lock Hopper	12 tonne/hr (13 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	134,000 liters (35,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	60,000 liters (16,000 gal)	2	0
6	Slag Conveyor	Drag chain	12 tonne/hr (13 tph)	2	0
7	Slag Separation Screen	Vibrating	12 tonne/hr (13 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	12 tonne/hr (13 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	190,000 liters (50,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	50 lpm @ 14 m H ₂ O (10 gpm @ 46 ft H ₂ O)	2	2
11	Grey Water Storage Tank	Field erected	61,000 liters (16,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	210 lpm @ 430 m H ₂ O (60 gpm @ 1,420 ft H ₂ O)	2	2
13	Slag Storage Bin	Vertical, field erected	800 tonne (900 tons)	2	0
14	Unloading Equipment	Telescoping chute	100 tonne/hr (110 tph)	1	0

Case B1B – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 230 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 77 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 40 MVA, 3-ph, 60 Hz	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 6 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B1B – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.2.11 Case B1B – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 3-51 shows a detailed breakdown of the capital costs; Exhibit 3-52 shows the owner's costs, TOC, and TASC; Exhibit 3-53 shows the initial and annual O&M costs; and Exhibit 3-54 shows the LCOE breakdown.

The estimated TPC of the Shell gasifier with CO₂ capture is \$6,545/kW. Process contingency represents 6.1 percent of the TPC, and project contingency represents 14.8 percent. The LCOE, including CO₂ T&S costs of \$8.6/MWh, is \$182.3/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-51. Case B1B total plant cost details

Case: B1B		– Shell IGCC w/ CO ₂ Capture					Estimate Type:		Conceptual		
Plant Size (MW, net): 519							Cost Base:		Dec 2018		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1 Coal Handling											
1.1	Coal Receive & Unload	\$971	\$0	\$468	\$0	\$1,438	\$216	\$0	\$331	\$1,985	\$4
1.2	Coal Stackout & Reclaim	\$3,173	\$0	\$758	\$0	\$3,931	\$590	\$0	\$904	\$5,425	\$10
1.3	Coal Conveyors & Yard Crush	\$30,270	\$0	\$7,704	\$0	\$37,974	\$5,696	\$0	\$8,734	\$52,404	\$101
1.4	Other Coal Handling	\$4,715	\$0	\$1,061	\$0	\$5,776	\$866	\$0	\$1,328	\$7,970	\$15
1.9	Coal & Sorbent Handling Foundations	\$0	\$85	\$222	\$0	\$307	\$46	\$0	\$71	\$424	\$1
	Subtotal	\$39,128	\$85	\$10,213	\$0	\$49,426	\$7,414	\$0	\$11,368	\$68,208	\$131
2 Coal Preparation & Feed											
2.1	Coal Crushing & Drying	\$2,349	\$142	\$338	\$0	\$2,829	\$424	\$0	\$651	\$3,904	\$8
2.2	Prepared Coal Storage & Feed	\$7,217	\$1,734	\$1,115	\$0	\$10,066	\$1,510	\$0	\$2,315	\$13,891	\$27
2.3	Dry Coal Injection System	\$9,212	\$106	\$844	\$0	\$10,162	\$1,524	\$0	\$2,337	\$14,023	\$27
2.4	Miscellaneous Coal Preparation & Feed	\$713	\$521	\$1,534	\$0	\$2,768	\$415	\$0	\$637	\$3,819	\$7
2.9	Coal & Sorbent Feed Foundation	\$0	\$1,734	\$1,488	\$0	\$3,221	\$483	\$0	\$741	\$4,446	\$9
	Subtotal	\$19,491	\$4,237	\$5,318	\$0	\$29,045	\$4,357	\$0	\$6,680	\$40,083	\$77
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$1,740	\$2,982	\$1,491	\$0	\$6,213	\$932	\$0	\$1,429	\$8,573	\$17
3.2	Water Makeup & Pretreating	\$5,203	\$520	\$2,948	\$0	\$8,672	\$1,301	\$0	\$2,992	\$12,964	\$25
3.3	Other Feedwater Subsystems	\$899	\$295	\$280	\$0	\$1,474	\$221	\$0	\$339	\$2,034	\$4
3.4	Service Water Systems	\$1,555	\$2,968	\$9,612	\$0	\$14,135	\$2,120	\$0	\$4,876	\$21,131	\$41
3.5	Other Boiler Plant Systems	\$232	\$84	\$211	\$0	\$527	\$79	\$0	\$121	\$728	\$1
3.6	Natural Gas Pipeline and Start-Up System	\$7,197	\$310	\$232	\$0	\$7,739	\$1,161	\$0	\$1,780	\$10,679	\$21
3.7	Waste Water Treatment Equipment	\$7,333	\$0	\$4,494	\$0	\$11,828	\$1,774	\$0	\$4,080	\$17,682	\$34
3.8	Vacuum Flash, Brine Concentrator, & Crystallizer	\$25,033	\$0	\$15,508	\$0	\$40,540	\$6,081	\$0	\$13,986	\$60,608	\$117
3.9	Miscellaneous Plant Equipment	\$15,325	\$2,010	\$7,788	\$0	\$25,124	\$3,769	\$0	\$8,668	\$37,560	\$72
	Subtotal	\$64,516	\$9,169	\$42,564	\$0	\$116,250	\$17,437	\$0	\$38,272	\$171,959	\$331
4 Gasifier, ASU, and Accessories											
4.1	Gasifier & Auxiliaries (Shell)	\$604,150	\$0	\$259,074	\$0	\$863,224	\$129,484	\$120,851	\$167,034	\$1,280,593	\$2,466
4.2	Syngas Cooler	\$61,109	\$0	\$26,205	\$0	\$87,314	\$13,097	\$12,224	\$16,895	\$129,530	\$249
4.3	Air Separation Unit/Oxidant Compression	\$125,400	\$28,700	\$29,845	\$0	\$183,945	\$36,789	\$18,395	\$35,869	\$274,998	\$529
4.5	Miscellaneous Gasification Equipment	\$4,180	\$0	\$1,792	\$0	\$5,972	\$896	\$0	\$1,030	\$7,898	\$15
4.6	Low Temperature Heat Recovery & Flue Gas Saturation	\$44,687	\$0	\$16,977	\$0	\$61,664	\$9,250	\$0	\$14,183	\$85,096	\$164
4.7	Flare Stack System	\$1,901	\$0	\$335	\$0	\$2,236	\$335	\$0	\$514	\$3,086	\$6
4.15	Major Component Rigging	\$233	\$0	\$100	\$0	\$332	\$50	\$0	\$57	\$439	\$1
4.16	Gasification Foundations	\$0	\$470	\$280	\$0	\$751	\$113	\$0	\$216	\$1,079	\$2

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B1B		– Shell IGCC w/ CO ₂ Capture			Estimate Type:		Conceptual		
Plant Size (MW, net):		519					Cost Base:		Dec 2018		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
	Subtotal	\$841,659	\$29,170	\$334,609	\$0	\$1,205,438	\$190,013	\$151,470	\$235,799	\$1,782,719	\$3,433
5 Syngas Cleanup											
5.1	Double Stage Selexol	\$169,382	\$0	\$69,184	\$0	\$238,567	\$35,785	\$47,713	\$64,413	\$386,478	\$744
5.2	Sulfur Removal	w/5.1	w/5.1	w/5.1	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5.3	Elemental Sulfur Plant	\$47,647	\$9,288	\$61,050	\$0	\$117,985	\$17,698	\$0	\$27,137	\$162,819	\$313
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$31,944	\$4,792	\$13,412	\$0	\$50,148	\$7,522	\$0	\$11,534	\$69,204	\$133
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$473	\$75	\$203	\$0	\$750	\$113	\$0	\$173	\$1,035	\$2
5.6	Mercury Removal (Carbon Bed)	\$527	\$0	\$398	\$0	\$925	\$139	\$46	\$222	\$1,332	\$3
5.7	Water Gas Shift (WGS) Reactors	\$97,500	\$0	\$38,978	\$0	\$136,477	\$20,472	\$0	\$31,390	\$188,339	\$363
5.9	Particulate Removal	\$1,842	\$0	\$790	\$0	\$2,631	\$395	\$0	\$454	\$3,480	\$7
5.10	Blowback Gas Systems	\$838	\$471	\$263	\$0	\$1,571	\$236	\$0	\$361	\$2,168	\$4
5.11	Fuel Gas Piping	\$0	\$1,169	\$765	\$0	\$1,934	\$290	\$0	\$445	\$2,669	\$5
5.12	Gas Cleanup Foundations	\$0	\$221	\$149	\$0	\$371	\$56	\$0	\$128	\$554	\$1
	Subtotal	\$350,152	\$16,015	\$185,192	\$0	\$551,360	\$82,704	\$47,760	\$136,256	\$818,079	\$1,575
6 Combustion Turbine & Accessories											
6.1	Combustion Turbine Generator	\$77,280	\$0	\$4,703	\$0	\$81,983	\$12,297	\$8,198	\$15,372	\$117,850	\$227
6.3	Combustion Turbine Accessories	\$2,687	\$0	\$164	\$0	\$2,851	\$428	\$0	\$492	\$3,770	\$7
6.4	Compressed Air Piping	\$0	\$509	\$334	\$0	\$843	\$126	\$0	\$194	\$1,163	\$2
6.5	Combustion Turbine Foundations	\$0	\$216	\$250	\$0	\$466	\$70	\$0	\$161	\$697	\$1
	Subtotal	\$79,967	\$725	\$5,450	\$0	\$86,143	\$12,921	\$8,198	\$16,218	\$123,480	\$238
7 HRSG, Ductwork, & Stack											
7.1	Heat Recovery Steam Generator	\$32,381	\$0	\$8,095	\$0	\$40,476	\$6,071	\$0	\$6,982	\$53,530	\$103
7.2	Heat Recovery Steam Generator Accessories	\$12,107	\$0	\$2,345	\$0	\$14,452	\$2,168	\$0	\$2,493	\$19,113	\$37
7.3	Ductwork	\$0	\$1,083	\$759	\$0	\$1,842	\$276	\$0	\$424	\$2,543	\$5
7.4	Stack	\$9,213	\$0	\$3,437	\$0	\$12,650	\$1,897	\$0	\$2,182	\$16,729	\$32
7.5	Heat Recovery Steam Generator, Ductwork & Stack Foundations	\$0	\$229	\$230	\$0	\$460	\$69	\$0	\$159	\$687	\$1
	Subtotal	\$53,701	\$1,312	\$14,867	\$0	\$69,881	\$10,482	\$0	\$12,240	\$92,602	\$178
8 Steam Turbine & Accessories											
8.1	Steam Turbine Generator & Accessories	\$33,578	\$0	\$4,563	\$0	\$38,141	\$5,721	\$0	\$6,579	\$50,442	\$97
8.2	Steam Turbine Plant Auxiliaries	\$1,604	\$0	\$3,651	\$0	\$5,254	\$788	\$0	\$906	\$6,949	\$13
8.3	Condenser & Auxiliaries	\$6,525	\$0	\$3,666	\$0	\$10,191	\$1,529	\$0	\$1,758	\$13,478	\$26
8.4	Steam Piping	\$5,837	\$0	\$2,531	\$0	\$8,369	\$1,255	\$0	\$2,406	\$12,030	\$23
8.5	Turbine Generator Foundations	\$0	\$249	\$440	\$0	\$690	\$103	\$0	\$238	\$1,031	\$2
	Subtotal	\$47,543	\$249	\$14,852	\$0	\$62,645	\$9,397	\$0	\$11,888	\$83,929	\$162
9 Cooling Water System											
9.1	Cooling Towers	\$11,675	\$0	\$3,532	\$0	\$15,208	\$2,281	\$0	\$2,623	\$20,112	\$39

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B1B		– Shell IGCC w/ CO ₂ Capture			Estimate Type:		Conceptual		
Plant Size (MW, net):		519					Cost Base:		Dec 2018		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
9.2	Circulating Water Pumps	\$1,519	\$0	\$112	\$0	\$1,631	\$245	\$0	\$281	\$2,157	\$4
9.3	Circulating Water System Auxiliaries	\$10,496	\$0	\$1,491	\$0	\$11,987	\$1,798	\$0	\$2,068	\$15,853	\$31
9.4	Circulating Water Piping	\$0	\$5,880	\$5,325	\$0	\$11,206	\$1,681	\$0	\$2,577	\$15,464	\$30
9.5	Make-up Water System	\$622	\$0	\$855	\$0	\$1,477	\$222	\$0	\$340	\$2,039	\$4
9.6	Component Cooling Water System	\$213	\$255	\$175	\$0	\$643	\$96	\$0	\$148	\$887	\$2
9.7	Circulating Water System Foundations	\$0	\$486	\$863	\$0	\$1,348	\$202	\$0	\$465	\$2,016	\$4
	Subtotal	\$24,526	\$6,621	\$12,354	\$0	\$43,500	\$6,525	\$0	\$8,503	\$58,528	\$113
10 Slag Recovery & Handling											
10.1	Slag Dewatering & Cooling	\$1,934	\$0	\$947	\$0	\$2,881	\$432	\$0	\$497	\$3,810	\$7
10.2	Gasifier Ash Depressurization	\$1,096	\$0	\$537	\$0	\$1,632	\$245	\$0	\$282	\$2,158	\$4
10.3	Cleanup Ash Depressurization	\$492	\$0	\$241	\$0	\$734	\$110	\$0	\$127	\$970	\$2
10.6	Ash Storage Silos	\$1,104	\$0	\$1,193	\$0	\$2,297	\$345	\$0	\$396	\$3,038	\$6
10.7	Ash Transport & Feed Equipment	\$425	\$0	\$99	\$0	\$524	\$79	\$0	\$90	\$693	\$1
10.8	Miscellaneous Ash Handling Equipment	\$61	\$75	\$22	\$0	\$158	\$24	\$0	\$27	\$209	\$0
10.9	Ash/Spent Sorbent Foundation	\$0	\$431	\$573	\$0	\$1,004	\$151	\$0	\$346	\$1,501	\$3
	Subtotal	\$5,112	\$506	\$3,612	\$0	\$9,230	\$1,384	\$0	\$1,765	\$12,380	\$24
11 Accessory Electric Plant											
11.1	Generator Equipment	\$2,470	\$0	\$1,863	\$0	\$4,334	\$650	\$0	\$748	\$5,731	\$11
11.2	Station Service Equipment	\$4,161	\$0	\$357	\$0	\$4,518	\$678	\$0	\$779	\$5,975	\$12
11.3	Switchgear & Motor Control	\$25,109	\$0	\$4,356	\$0	\$29,465	\$4,420	\$0	\$5,083	\$38,967	\$75
11.4	Conduit & Cable Tray	\$0	\$111	\$321	\$0	\$432	\$65	\$0	\$124	\$621	\$1
11.5	Wire & Cable	\$0	\$1,523	\$2,723	\$0	\$4,246	\$637	\$0	\$1,221	\$6,104	\$12
11.6	Protective Equipment	\$241	\$0	\$837	\$0	\$1,078	\$162	\$0	\$186	\$1,426	\$3
11.7	Standby Equipment	\$826	\$0	\$763	\$0	\$1,589	\$238	\$0	\$274	\$2,102	\$4
11.8	Main Power Transformers	\$6,143	\$0	\$125	\$0	\$6,268	\$940	\$0	\$1,081	\$8,290	\$16
11.9	Electrical Foundations	\$0	\$71	\$180	\$0	\$251	\$38	\$0	\$87	\$376	\$1
	Subtotal	\$38,950	\$1,706	\$11,526	\$0	\$52,181	\$7,827	\$0	\$9,583	\$69,591	\$134
12 Instrumentation & Control											
12.1	Integrated Gasification and Combined Cycle Control Equipment	\$692	\$0	\$297	\$0	\$989	\$148	\$0	\$171	\$1,308	\$3
12.2	Combustion Turbine Control Equipment	\$683	\$0	\$48	\$0	\$731	\$110	\$0	\$126	\$967	\$2
12.3	Steam Turbine Control Equipment	\$640	\$0	\$87	\$0	\$727	\$109	\$0	\$125	\$961	\$2
12.4	Other Major Component Control Equipment	\$1,218	\$0	\$830	\$0	\$2,047	\$307	\$102	\$369	\$2,825	\$5
12.5	Signal Processing Equipment	\$945	\$0	\$31	\$0	\$976	\$146	\$0	\$168	\$1,291	\$2
12.6	Control Boards, Panels & Racks	\$274	\$0	\$180	\$0	\$454	\$68	\$23	\$109	\$653	\$1
12.7	Distributed Control System Equipment	\$9,918	\$0	\$324	\$0	\$10,242	\$1,536	\$512	\$1,844	\$14,134	\$27
12.8	Instrument Wiring & Tubing	\$493	\$395	\$1,579	\$0	\$2,467	\$370	\$123	\$740	\$3,701	\$7

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B1B	– Shell IGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		519					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
12.9	Other Instrumentation & Controls Equipment	\$1,107	\$0	\$548	\$0	\$1,655	\$248	\$83	\$298	\$2,284	\$4
	Subtotal	\$15,970	\$395	\$3,924	\$0	\$20,289	\$3,043	\$843	\$3,950	\$28,125	\$54
	13 Improvements to Site										
13.1	Site Preparation	\$0	\$426	\$9,707	\$0	\$10,133	\$1,520	\$0	\$3,496	\$15,149	\$29
13.2	Site Improvements	\$0	\$1,928	\$2,726	\$0	\$4,654	\$698	\$0	\$1,606	\$6,958	\$13
13.3	Site Facilities	\$3,010	\$0	\$3,380	\$0	\$6,390	\$959	\$0	\$2,205	\$9,553	\$18
	Subtotal	\$3,010	\$2,355	\$15,812	\$0	\$21,177	\$3,177	\$0	\$7,306	\$31,660	\$61
	14 Buildings & Structures										
14.1	Combustion Turbine Area	\$0	\$314	\$177	\$0	\$491	\$74	\$0	\$85	\$649	\$1
14.3	Steam Turbine Building	\$0	\$2,739	\$3,900	\$0	\$6,639	\$996	\$0	\$1,145	\$8,780	\$17
14.4	Administration Building	\$0	\$878	\$637	\$0	\$1,514	\$227	\$0	\$261	\$2,003	\$4
14.5	Circulation Water Pumphouse	\$0	\$144	\$76	\$0	\$221	\$33	\$0	\$38	\$292	\$1
14.6	Water Treatment Buildings	\$0	\$348	\$339	\$0	\$687	\$103	\$0	\$118	\$908	\$2
14.7	Machine Shop	\$0	\$486	\$333	\$0	\$818	\$123	\$0	\$141	\$1,082	\$2
14.8	Warehouse	\$0	\$378	\$244	\$0	\$622	\$93	\$0	\$107	\$823	\$2
14.9	Other Buildings & Structures	\$0	\$277	\$216	\$0	\$493	\$74	\$0	\$85	\$652	\$1
14.10	Waste Treating Building & Structures	\$0	\$761	\$1,453	\$0	\$2,214	\$332	\$0	\$382	\$2,928	\$6
	Subtotal	\$0	\$6,325	\$7,375	\$0	\$13,700	\$2,055	\$0	\$2,363	\$18,118	\$35
	Total	\$1,583,726	\$78,870	\$667,668	\$0	\$2,330,264	\$358,737	\$208,271	\$502,190	\$3,399,462	\$6,545

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-52. Case B1B owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$26,967	\$52
1 Month Maintenance Materials	\$6,905	\$13
1 Month Non-fuel Consumables	\$1,186	\$2
1 Month Waste Disposal	\$700	\$1
25% of 1 Months Fuel Cost at 100% CF	\$2,216	\$4
2% of TPC	\$67,989	\$131
Total	\$105,964	\$204
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	\$19,674	\$38
0.5% of TPC (spare parts)	\$16,997	\$33
Total	\$36,671	\$71
Other Costs		
Initial Cost for Catalyst and Chemicals	\$30,371	\$58
Land	\$900	\$2
Other Owner's Costs	\$509,919	\$982
Financing Costs	\$91,785	\$177
Total Overnight Costs (TOC)	\$4,175,072	\$8,039
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	\$4,819,752	\$9,280

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-53. Case B1B initial and annual operating and maintenance costs

Case:	B1B – Shell IGCC w/ CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	519	Heat Rate-net (Btu/kWh):	10,497	Capacity Factor (%):	80
Operating & Maintenance Labor					
Operating Labor			Operating Labor Requirements per Shift		
Operating Labor Rate (base):	38.50	\$/hour	Skilled Operator:	2.0	
Operating Labor Burden:	30.00	% of base	Operator:	11.0	
Labor O-H Charge Rate:	25.00	% of labor	Foreman:	1.0	
			Lab Techs, etc.:	3.0	
			Total:	17.0	
Fixed Operating Costs					
				Annual Cost	
				(\$)	(\$/kW-net)
Annual Operating Labor:				\$7,453,446	\$14.351
Maintenance Labor:				\$35,694,347	\$68.728
Administrative & Support Labor:				\$10,786,948	\$20.770
Property Taxes and Insurance:				\$67,989,233	\$130.910
Total:				\$121,923,974	\$234.758
Variable Operating Costs					
				(\$)	(\$/MWh-net)
Maintenance Material:				\$66,289,502	\$18.21303
Consumables					
	Initial Fill	Per Day	Per Unit	Initial Fill	
Water (/1000 gallons):	0	3,657	\$1.90	\$0	\$2,029,054 \$0.55748
Makeup and Waste Water Treatment Chemicals (ton):	0	10.9	\$550.00	\$0	\$1,749,656 \$0.48072
Sulfur-Impregnated Activated Carbon (ton):	113	0.155	\$12,000.00	\$1,357,251	\$542,901 \$0.14916
Water Gas Shift (WGS) Catalyst (ft³):	17,623	12.1	\$480.00	\$8,458,830	\$1,691,766 \$0.46481
Selexol Solution (gal):	540,913	53.6	\$38.00	\$20,554,696	\$595,168 \$0.16352
Sodium Hydroxide (50 wt%, ton):	0	19.3	\$600.00	\$0	\$3,388,156 \$0.93090
Sulfuric Acid (98 wt%, ton):	0	0.342	\$210.00	\$0	\$20,988 \$0.00577
Claus Catalyst (ft³):	w/equip.	1.94	\$48.00	\$0	\$27,237 \$0.00748
Triethylene Glycol (gal):	w/equip.	675	\$6.80	\$0	\$1,340,675 \$0.36835
Subtotal:				\$30,370,777	\$11,385,601 \$3.12819
Waste Disposal					
Sulfur-Impregnated Activated Carbon (ton):	0	0.155	\$80.00	\$0	\$3,619 \$0.00099
Water Gas Shift Catalyst (ft³):	0	12.1	\$2.50	\$0	\$8,811 \$0.00242
Selexol Solution (gal):	0	53.6	\$0.35	\$0	\$5,482 \$0.00151
Claus Catalyst (ft³):	0	1.94	\$2.50	\$0	\$1,419 \$0.00039
Crystallizer Solids (ton):	0	36.4	\$38.00	\$0	\$404,191 \$0.11105
Slag (ton):	0	562	\$38.00	\$0	\$6,231,962 \$1.71223
Triethylene Glycol (gal):	0	675	\$0.35	\$0	\$69,005 \$0.01896
Subtotal:				\$0	\$6,724,489 \$1.84755
By-Products					
Sulfur (tons):	0	141	\$0.00	\$0	\$0 \$0.00000
Subtotal:				\$0	\$0 \$0.00000
Variable Operating Costs Total:				\$30,370,777	\$84,399,592 \$23.18877
Fuel Cost					
Illinois Number 6 (ton):	0	5,608	\$51.96	\$0	\$85,078,513 \$23.37531
Total:				\$0	\$85,078,513 \$23.37531

Exhibit 3-54. Case B1B LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	93.7	51.4%
Fixed	33.5	18.4%
Variable	23.2	12.7%
Fuel	23.4	12.8%
Total (Excluding T&S)	173.7	95.3%
CO ₂ T&S	8.6	4.7%
Total (Including T&S)	182.3	100.0%

3.3 CB&I E-Gas™ IGCC CASES

This section contains an evaluation of plant designs for cases B4A and B4B, which are based on the CB&I E-Gas™ gasifier. Cases B4A and B4B are very similar in terms of process, equipment, scope and arrangement, except that Case B4B includes SGS reactors, CO₂ absorption/regeneration and compression/transport systems. There are no provisions for CO₂ removal in Case B4A.

The balance of this section is organized in an analogous manner to Section 3.2:

- Gasifier Background
- Process System Description for Case B4A
- Key Assumptions for Cases B4A and B4B
- Sparing Philosophy for Cases B4A and B4B
- Performance Results for Case B4A
- Equipment List for Case B4A
- Cost Estimates for Case B4A
- Process and System Description, Performance Results, Equipment List, and Cost Estimate for Case B4B

3.3.1 Gasifier Background

As mentioned in Section 3.2.1, the “Coal Gasification Guidebook: Status, Application, and Technologies” report published by EPRI provides a detailed history of the development of several types of gasifier technology, including the E-Gas™ gasifier, as well as gasifier capacity, distinguishing characteristics, and important coal characteristics. [104]

In January of 2000, an E-Gas™ demonstration facility was constructed at the Wabash River Generating Station in West Terre Haute, Indiana. [65]

The Wabash River plant was designed for a coal handling capacity of 1,678 tonnes/day (1,850 tpd)—on a moisture and ash-free (MAF) basis – for bituminous coal with a high sulfur content. The unit was designed to produce dry gas at a rate of 189,724 Nm³/hr (6.7 million scf/hr) with an energy content of about 1,950 GJ/hr (1,850 MMBtu/hr) (HHV). This size matches the CT, which is a GEP 7FA. [104]

The E-GasTM gasifier has significant operating experience with bituminous coal at full commercial scale via the Wabash plant. [104] The Wabash plant has also tested and incorporated the use of petcoke as another fuel source. [107]

Compared to a single stage slurry-fed gasifier, the E-GasTM technology demonstrates superior efficiency and lower O₂ requirements. [104]

Notable characteristics of the E-GasTM gasifier are the relatively short refractory life and the high waste heat recovery rate, resulting from the high operating temperature. The E-GasTM gasifier produces a syngas with a higher CH₄ content than other single-stage slurry fed gasifiers, due to the use of quenching in the second stage. However, in CO₂ capture cases the CH₄ passes through the WGS reactors without change, and is also not separated by the AGR, thus limiting the amount of carbon that can be captured. [104]

Bituminous coals with low moisture content are desired for use with the E-GasTM gasifier as it benefits the slurry concentration and lowers the O₂ requirement. As with all slagging gasifiers, low concentrations of ash with low to moderate ash fusion temperatures are preferred. [104]

3.3.2 Key System Assumptions

System assumptions for cases B4A and B4B, E-GasTM IGCC with and without CO₂ capture, are compiled in Exhibit 3-55.

Exhibit 3-55. E-GasTM IGCC plant study configuration matrix

Case	B4A	B4B
Gasifier Pressure, MPa (psia)	4.2 (615)	
O ₂ :Coal Ratio, kg O ₂ /kg As-Received coal	0.683	0.738
Carbon Conversion, %	99.2	
Syngas HHV at Gasifier Outlet, kJ/Nm ³ (Btu/scf) ^A	8,942 (240)	7,675 (206)
Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/566/566 (1,800/1,051/1,051)	12.4/535/535 (1,800/996/996)
Condenser Pressure, mm Hg (in. Hg)	51 (2.0)	
CT	2x State-of-the-Art 2008 F-Class (232 MW output each)	
Gasifier Technology	CB&I E-Gas TM	
Oxidant	95 vol% O ₂	
Coal	Illinois No. 6	
Coal Slurry Solids Content, %	63	

Case	B4A	B4B
COS Hydrolysis	Yes	Occurs in WGS
WGS	No	Yes
H ₂ S Separation	Refrigerated MDEA	Selexol 1 st Stage
Sulfur Removal, %	99.4	~100.0
Sulfur Recovery	Claus Plant with Tail Gas Recycle to Gasifier/Elemental Sulfur	
Particulate Control	Cyclone, Candle Filter, Scrubber, and AGR Absorber	
Chloride Control	Venturi Scrubber, Vacuum Flash, Brine Concentrator, Crystallizer	
Mercury Control	Carbon Bed	
NO _x Control	MNQC (LNB), N ₂ Dilution	
CO ₂ Separation	N/A	Selexol 2 nd Stage
Overall Carbon Capture, %	N/A	89.9
CO ₂ Sequestration	N/A	Off-site Saline Formation

^ASyngas measurement is reflected post-syngas recycle. The gasifier operating condition is different between the capture (B4B) and non-capture (B4A) cases. Due to the higher amount of methane produced by the E-Gas™ gasifier, the capture case (B4B) must operate at a higher O₂:coal ratio to achieve 90 percent overall carbon capture. Three stages of WGS are also required in case B4B to achieve the capture target.

3.3.2.1 Balance of Plant – Case B4A and Case B4B

The balance of plant assumptions are common to both cases and were presented previously in Exhibit 3-22.

3.3.3 Sparing Philosophy

The sparing philosophy for cases B4A and B4B is provided below. Dual trains are used to accommodate the size of commercial CTs. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- Two ASUs (2 x 50 percent)
- Two trains of slurry preparation and slurry pumps (2 x 50 percent)
- Two trains of gasification, including gasifier, SGC, cyclone, and candle filter (2 x 50 percent)
- Two trains of syngas clean-up process (2 x 50 percent)
- Two trains of refrigerated MDEA AGR in Case B4A (2 x 50 percent)
- One train of two-stage Selexol in Case B4B (1 x 100 percent)
- One train of CO₂ compression systems (1 x 100 percent) in Case B4B

- Two trains of process water treatment systems (2 x 50 percent)
- One train of Claus-based sulfur recovery (1 x 100 percent)
- Two CT/HRSG tandems (2 x 50 percent)
- One steam turbine (1 x 100 percent)

3.3.4 Case B4A – E-Gas™ IGCC Power Plant Without CO₂ Capture Process Description

In this section, the E-Gas™ gasification process for Case B4A is described. The system descriptions follow the BFD provided in Exhibit 3-56 with the associated stream tables—providing process data for the numbered streams in the BFD—provided in Exhibit 3-57.

3.3.4.1 Coal Preparation and Feed Systems

Coal receiving and handling is common to all cases and was covered in Section 3.1.1. The receiving and handling subsystem ends at the coal silo. Coal is then fed onto a conveyor by vibratory feeders located below each silo. The conveyor feeds the coal to an inclined conveyor that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. Each hopper outlet discharges onto a weigh feeder, which, in turn, feeds a rod mill. Each rod mill is sized to process 55 percent of the coal feed requirements of the gasifier. The rod mill grinds the coal (stream 8) and wets it with process and slag recovery water (stream 7) transferred from the slurry water tank by the slurry water pumps. The coal slurry is discharged through a trommel screen into the rod mill discharge tank, and then the slurry is pumped to the slurry storage tanks. The dry solids concentration of the final slurry is 63 percent. The Polk Power Station operates at a slurry concentration of 62–68 percent using bituminous coal, and ConocoPhillips presented a paper showing the slurry concentration of Illinois No. 6 coal as 63 percent. [108]

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required depends on local environmental regulations. All of the tanks are equipped with vertical agitators to keep the coal slurry solids suspended.

The equipment in the coal grinding and slurry preparation system is fabricated of materials appropriate for the abrasive environment present in the system. The tanks and agitators are rubber lined. The pumps are either rubber-lined or hardened metal to minimize erosion. Piping is fabricated of high-density polyethylene (HDPE).

3.3.4.2 Gasifier

There are two E-Gas™ slurry fed, pressurized, upflow, entrained, slagging gasifiers, operating at 4.2 MPa (615 psia) and processing a total of 4,968 tonnes/day (5,476 tpd) of as-received coal.

The first (bottom) stage of the gasifier is best described as a horizontal cylinder with two horizontally opposed burners where the highly exothermic gasification/oxidation reactions take place rapidly at temperatures between 1,316 and 1,427°C (2,400 and 2,600°F). The ASU

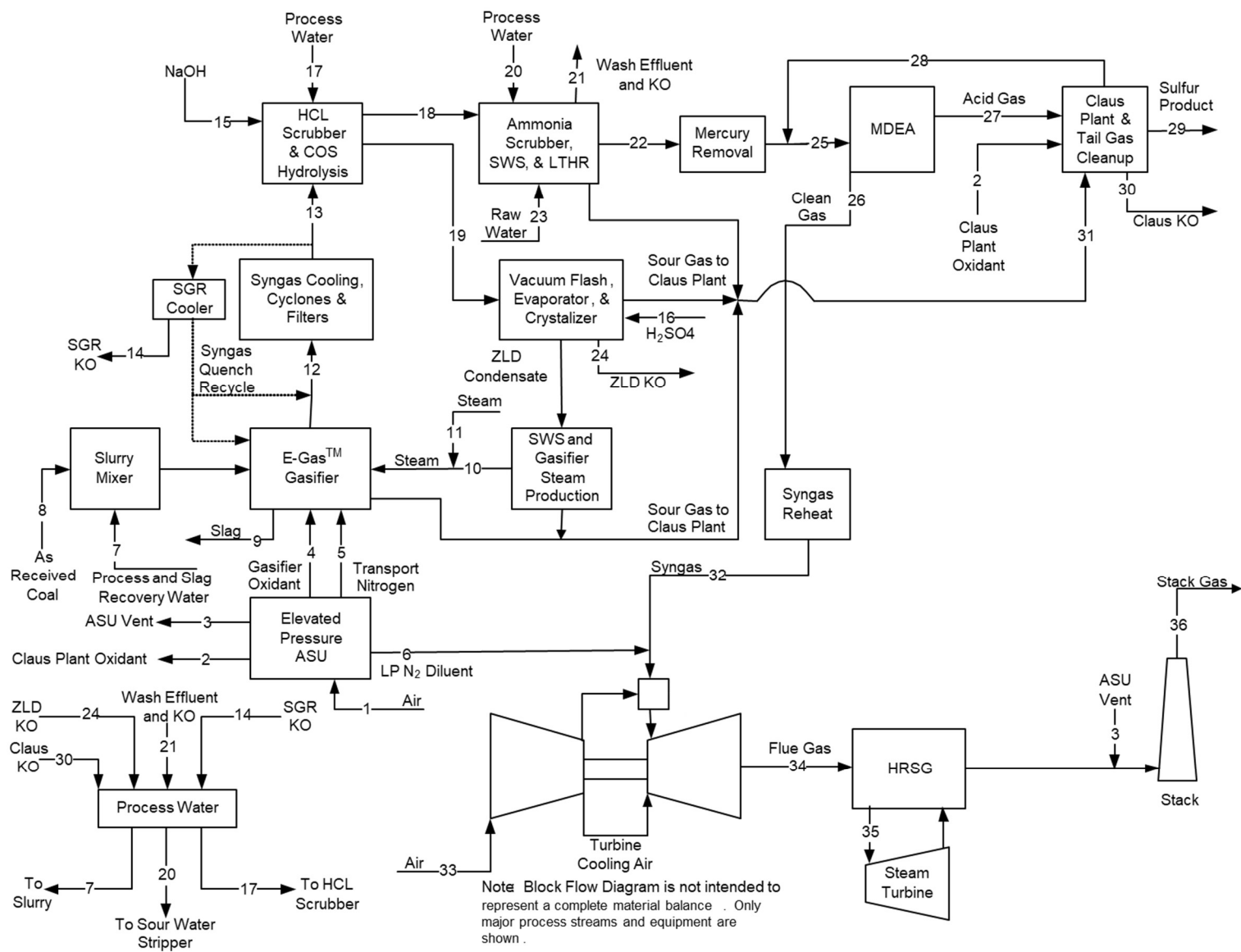
supplies 3,597 tonnes/day (3,965 tpd) of 95 percent O₂ (stream 4) to the first stage of the gasifier, along with about 78 percent of the total slurry feed.

The hot raw gas from the first stage of the gasifier enters the second (top) stage, which is a vertical cylinder, perpendicular to the first stage. The remaining 22 percent of the coal slurry is injected into this hot raw gas. The endothermic gasification/devolatilization reaction in this stage reduces the gasifier exit temperature to 1,038°C (1,900°F).

The coal ash is converted to molten slag, which flows down through a tap hole. The molten slag is quenched in water and removed through a proprietary continuous-pressure letdown/dewatering system (stream 9). Char is produced in the second gasifier stage and is captured and recycled to the hotter first stage to be gasified.

The syngas produced by the E-Gas™ gasifier is higher in methane content than either the GEP or Shell gasifier. The two-stage design allows for improved cold gas efficiency (CGE) and lower O₂ consumption, but the quenched second stage produces CH₄. The syngas CH₄ concentration exiting the gasifier in Case B4A is 4.4 vol% (compared to 0.11 vol% in Case B5A [GEP] and 0.04 vol% in Case B1A [Shell]). The relatively high CH₄ concentration impacts carbon capture efficiency as discussed in Section 3.3.8.

Exhibit 3-56. Case B4A block flow diagram, E-Gas™ IGCC without CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-57. Case B4A stream table, E-Gas™ IGCC without capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0343	0.0132	0.0343	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0070
CH ₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0440
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2852
CO ₂	0.0003	0.0000	0.0023	0.0000	0.0000	0.0000	0.0005	0.0000	0.0000	0.0000	0.0000	0.1479
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0003
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2588
H ₂ O	0.0099	0.0000	0.0480	0.0000	0.0000	0.0000	0.9831	0.0000	0.0000	0.9998	1.0000	0.2297
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004
H ₂ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000	0.0068
N ₂	0.7732	0.0157	0.9331	0.0157	0.9964	0.9964	0.0000	0.0000	0.0000	0.0000	0.0000	0.0156
NH ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0160	0.0000	0.0000	0.0002	0.0000	0.0044
O ₂	0.2074	0.9501	0.0034	0.9501	0.0036	0.0036	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.9998	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	22,012	88	3,098	4,653	209	13,895	4,718	0	0	2,794	930	26,695
V-L Flowrate (kg/hr)	635,191	2,846	85,940	149,864	5,856	389,448	85,030	0	0	50,325	16,759	558,353
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	206,986	21,127	0	0	0
Temperature (°C)	15	27	22	27	129	196	148	15	1,038	343	343	1,001
Pressure (MPa, abs)	0.10	0.86	0.45	5.10	5.41	2.69	5.79	0.10	4.24	5.10	5.10	4.24
Steam Table Enthalpy (kJ/kg) ^A	30.23	21.53	27.71	9.82	127.56	202.61	591.59	---	---	3,083.36	3,093.81	2,257.20
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-0.97	-527.56	-12.68	101.59	176.64	-15,156.08	-2,119.02	1,005.43	-12,884.30	-12,886.48	-5,397.05
Density (kg/m ³)	1.2	11.2	5.3	68.6	44.9	19.2	882.1	---	---	19.9	19.9	8.3
V-L Molecular Weight	28.857	32.209	27.742	32.209	28.028	28.028	18.023	---	---	18.015	18.015	20.916
V-L Flowrate (lb _{mol} /hr)	48,528	195	6,829	10,258	461	30,633	10,401	0	0	6,159	2,051	58,853
V-L Flowrate (lb/hr)	1,400,356	6,275	189,465	330,393	12,909	858,586	187,459	0	0	110,948	36,948	1,230,958
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	456,327	46,576	0	0	0
Temperature (°F)	59	80	71	80	263	385	298	59	1,900	650	650	1,834
Pressure (psia)	14.7	125.0	65.0	740.0	785.0	390.0	840.0	14.7	615.0	740.0	740.0	615.0
Steam Table Enthalpy (Btu/lb) ^A	13.0	9.3	11.9	4.2	54.8	87.1	254.3	---	---	1,325.6	1,330.1	970.4
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-0.4	-226.8	-5.5	43.7	75.9	-6,515.9	-911.0	432.3	-5,539.3	-5,540.2	-2,320.3
Density (lb/ft ³)	0.076	0.700	0.332	4.283	2.802	1.196	55.070	---	---	1.240	1.240	0.518

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-57. Case B4A stream table, E-Gas™ IGCC without capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0070	0.0000	0.0000	0.0000	0.0000	0.0069	0.0000	0.0000	0.0000	0.0091	0.0000	0.0000
CH ₄	0.0440	0.0000	0.0000	0.0000	0.0000	0.0437	0.0000	0.0000	0.0000	0.0575	0.0000	0.0000
CO	0.2852	0.0002	0.0000	0.0000	0.0000	0.2828	0.0001	0.0000	0.0000	0.3723	0.0000	0.0000
CO ₂	0.1479	0.0027	0.0000	0.0000	0.0007	0.1468	0.0009	0.0007	0.0007	0.1924	0.0000	0.0009
COS	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.2588	0.0002	0.0000	0.0000	0.0000	0.2565	0.0001	0.0000	0.0000	0.3378	0.0000	0.0000
H ₂ O	0.2297	0.9793	0.6895	0.1000	0.9828	0.2344	0.9930	0.9828	0.9825	0.0015	0.9999	0.9837
HCl	0.0004	0.0015	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0068	0.0004	0.0000	0.0000	0.0002	0.0070	0.0001	0.0002	0.0002	0.0091	0.0000	0.0002
N ₂	0.0156	0.0000	0.0000	0.0000	0.0000	0.0154	0.0000	0.0000	0.0000	0.0203	0.0000	0.0000
NH ₃	0.0044	0.0156	0.0000	0.0000	0.0160	0.0064	0.0031	0.0160	0.0164	0.0000	0.0000	0.0152
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0026	0.0000	0.0000	0.0000	0.0001	0.0000
NaOH	0.0000	0.0000	0.3105	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	0.1000	0.9998	1.0000	1.0000	0.9998	0.9998	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	22,825	900	29	0	3,573	23,023	3,405	2,171	9,715	17,482	1,169	564
V-L Flowrate (kg/hr)	477,389	16,302	714	13	64,422	480,757	61,768	39,139	175,141	380,595	21,071	10,161
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	232	41	16	15	75	186	173	75	79	29	15	30
Pressure (MPa, abs)	3.93	3.90	4.76	0.13	0.47	3.70	3.83	0.47	0.45	3.37	0.10	0.24
Steam Table Enthalpy (kJ/kg) ^A	843.62	132.07	-338.83	-8,206.86	278.39	777.17	717.27	278.39	292.31	33.20	62.75	92.47
AspenPlus Enthalpy (kJ/kg) ^B	-6,810.64	-15,541.22	-13,665.04	-8,526.27	-15,464.46	-6,921.42	-15,118.98	-15,464.46	-15,445.31	-5,594.89	-15,905.25	-15,665.91
Density (kg/m ³)	19.7	982.7	1,531.7	1,791.5	961.1	20.6	891.5	961.1	958.3	29.7	999.4	986.3
V-L Molecular Weight	20.916	18.104	24.842	90.073	18.028	20.882	18.141	18.028	18.028	21.771	18.019	18.028
V-L Flowrate (lb _{mol} /hr)	50,320	1,985	63	0	7,878	50,756	7,506	4,786	21,417	38,541	2,578	1,243
V-L Flowrate (lb/hr)	1,052,463	35,939	1,574	28	142,026	1,059,888	136,175	86,287	386,120	839,069	46,453	22,401
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	450	105	61	59	167	366	343	167	174	84	59	85
Pressure (psia)	570.2	566.2	690.2	18.2	67.7	537.1	555.3	67.7	65.0	489.0	14.7	35.0
Steam Table Enthalpy (Btu/lb) ^A	362.7	56.8	-145.7	-3,528.3	119.7	334.1	308.4	119.7	125.7	14.3	27.0	39.8
AspenPlus Enthalpy (Btu/lb) ^B	-2,928.0	-6,681.5	-5,874.9	-3,665.6	-6,648.5	-2,975.7	-6,500.0	-6,648.5	-6,640.3	-2,405.4	-6,838.0	-6,735.1
Density (lb/ft ³)	1.231	61.346	95.621	111.841	60.001	1.285	55.657	60.001	59.823	1.853	62.391	61.572

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-57. Case B4A stream table, E-Gas™ IGCC without capture (continued)

	25	26	27	28	29	30	31	32	33	34	35	36
V-L Mole Fraction												
Ar	0.0090	0.0093	0.0000	0.0048	0.0000	0.0000	0.0007	0.0093	0.0092	0.0087	0.0000	0.0088
CH ₄	0.0554	0.0576	0.0010	0.0000	0.0000	0.0000	0.0044	0.0576	0.0000	0.0000	0.0000	0.0000
CO	0.3592	0.3736	0.0049	0.0056	0.0000	0.0000	0.0235	0.3736	0.0000	0.0000	0.0000	0.0000
CO ₂	0.2163	0.1942	0.7597	0.8603	0.0000	0.0000	0.2129	0.1942	0.0003	0.0808	0.0000	0.0790
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.3290	0.3421	0.0042	0.0921	0.0000	0.0000	0.0249	0.3421	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0015	0.0015	0.0014	0.0024	0.0000	0.9999	0.2697	0.0015	0.0099	0.0671	1.0000	0.0667
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0089	0.0000	0.2283	0.0037	0.0000	0.0000	0.0223	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0207	0.0215	0.0002	0.0311	0.0000	0.0000	0.0009	0.0215	0.7732	0.7349	0.0000	0.7394
NH ₃	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.4405	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2074	0.1084	0.0000	0.1061
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	18,130	17,423	707	648	0	186	84	17,423	110,253	135,335	39,206	138,433
V-L Flowrate (kg/hr)	406,157	376,892	29,264	25,561	0	3,353	1,958	376,892	3,181,556	3,947,891	706,309	4,033,830
Solids Flowrate (kg/hr)	0	0	0	0	5,155	0	0	0	0	0	0	0
Temperature (°C)	37	45	45	38	183	50	183	193	15	597	566	128
Pressure (MPa, abs)	3.26	3.23	3.23	3.26	0.29	0.27	0.45	3.04	0.10	0.10	12.51	0.10
Steam Table Enthalpy (kJ/kg) ^A	42.19	56.56	7.85	9.07	---	112.83	803.36	284.56	30.23	756.41	3,517.05	236.12
AspenPlus Enthalpy (kJ/kg) ^B	-5,775.54	-5,639.92	-7,371.67	-8,632.47	146.29	-15,856.50	-7,154.59	-5,411.92	-97.58	-1,019.34	-12,463.25	-1,513.63
Density (kg/m ³)	28.7	26.7	60.4	56.9	5,269.7	967.5	2.8	16.8	1.2	0.4	34.8	0.9
V-L Molecular Weight	22.403	21.632	41.414	39.438	---	18.017	23.328	21.632	28.857	29.171	18.015	29.139
V-L Flowrate (lb _{mol} /hr)	39,970	38,412	1,558	1,429	0	410	185	38,412	243,065	298,364	86,435	305,193
V-L Flowrate (lb/hr)	895,423	830,906	64,517	56,353	0	7,393	4,318	830,906	7,014,130	8,703,609	1,557,144	8,893,074
Solids Flowrate (lb/hr)	0	0	0	0	11,364	0	0	0	0	0	0	0
Temperature (°F)	98	112	112	100	361	123	362	380	59	1,106	1,051	263
Pressure (psia)	472.5	468.1	468.1	472.5	41.7	39.5	65.0	440.6	14.7	15.1	1,814.7	14.8
Steam Table Enthalpy (Btu/lb) ^A	18.1	24.3	3.4	3.9	---	48.5	345.4	122.3	13.0	325.2	1,512.1	101.5
AspenPlus Enthalpy (Btu/lb) ^B	-2,483.0	-2,424.7	-3,169.2	-3,711.3	62.9	-6,817.1	-3,075.9	-2,326.7	-42.0	-438.2	-5,358.2	-650.7
Density (lb/ft ³)	1.794	1.664	3.771	3.552	328.976	60.400	0.174	1.050	0.076	0.026	2.173	0.055

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

3.3.4.3 Raw Gas Cooling and Particulate Removal

The product gas from the gasifier is cooled below 1,038°C (1,900°F) by adding cooled recycled syngas. The mixed gas (stream 12) then goes through the SGC unit, which consists of a fire-tube boiler with convective superheating and economizing sections, which lowers the temperature of the syngas to 357°C (675°F) by producing HP steam at 12.8 MPa (1,852 psia) for use in the steam cycle.

The majority of the fine particulates in the cooled gas from the syngas cooler are removed by passing through a cyclone collector, followed by an array of raw gas metallic candle filter elements in a pressure vessel (recycled syngas is used as the pulse gas to clean the candle filters). The syngas scrubber removes additional PM further downstream (covered in Section 3.3.4.5).

The fines are pneumatically returned to the first stage of the gasifier, which, in combination with the recycling of the char, allows for a carbon conversion of 99.2 percent.

The syngas from the candle filter is further cooled to 232°C (450°F) by producing IP steam at 5.1 MPa (740 psia) for use in the gasifier (stream 10) and preheating the N₂ diluent (stream 6) prior to the CT.

3.3.4.4 Quench Gas Compressor

Eleven percent of the cooled syngas is recycled back to the gasifier, with 38 percent of that being used as quench gas at the gasifier exit (covered in Section 3.3.4.3). A condensing HX is used to dry the recycled syngas from 23.0 vol% water to 0.2 vol% water by cooling it to 41°C (105°F). The dried syngas is compressed to 5.5 MPa (800 psia) in a single-stage compressor prior to distribution in the gasifier.

3.3.4.5 Syngas Scrubber

The ejector-type venturi scrubber is common to all cases and was covered in Section 3.1.12.1.1. The raw syngas exiting the final raw gas cooler at 232°C (450°F) (stream 13) enters the scrubber for removal of HCl and remaining PM. The treated syngas leaves the scrubber saturated at a temperature of 172°C (341°F).

Effluent from the scrubber is recycled to maintain a concentration of chloride in the blowdown (stream 19) of 5,000 ppmw. The recycled effluent is mixed with process water (stream 17) and cooled to 58°C (137°F), by preheating syngas prior to the CT, before being cooled further to 21°C (70°F) with cooling water and injected into the scrubber. The rate of process water addition is controlled to maintain the HCl removal rate at 98 percent. A 50 wt% solution of NaOH (stream 15) is added at a rate of 714 kg/hr (1,574 lb/hr) to the scrubber to maintain pH and form the HSS NaCl.

The blowdown from the syngas scrubber is sent to the process water treatment system for chloride removal and recycle.

3.3.4.6 COS Hydrolysis

The COS hydrolysis unit is common to all non-CO₂ capture cases and was covered in Section 3.1.5.1. Following the syngas scrubber, the gas is reheated to 186°C (366°F) and fed to the COS hydrolysis reactor where 95 percent of the COS is hydrolyzed with steam over a catalyst bed to H₂S and CO₂. Before the raw syngas can be treated in the AGR process, it must be cooled and treated for NH₃.

3.3.4.7 Low Temperature Heat Recovery

The raw syngas from the COS unit is cooled through a series of four shell and tube HXs (covered in Section 3.1.12.1.2). The first stage cools the syngas from 186°C (366°F) to 162°C (323°F) by raising 0.4 MPa (65 psia) process steam. The second stage cools the syngas to 134°C (274°F) by heating the slurry FW, preheating the syngas prior to the CT, and preheating the FW to the HRSG. The third stage cools the syngas to 59°C (138°F) by preheating FW to the HRSG and the fourth stage cools the syngas to 29°C (85°F) with cooling water. During cooling, part of the water vapor condenses, along with significant amounts of NH₃, and is combined with the effluent of the NH₃ wash.

3.3.4.8 Sour Water Stripper and Ammonia Wash

The primary SWS removes NH₃, H₂S, and other dissolved gases from the remaining water from the process water drum (stream 20), as was covered in Section 3.1.12.1.3. Process water flows from the drum to the SWS, which consists of a packed column with a steam-heated reboiler. Sour gas is stripped from the liquid and sent to the SRU. The remaining water is combined with raw water makeup (stream 23) and cooled to 21°C (70°F) with cooling water prior to being used as feed to the NH₃ wash.

The cooled syngas gas from the LTHR is sent to the NH₃ wash (covered in Section 3.1.12.1.4) where it flows upward against a counter-current spray of water from the SWS. The rate of raw water makeup addition to the NH₃ wash is controlled to achieve a concentration of NH₃ in the treated gas (stream 22) of 10 ppm. The effluent from the NH₃ wash contains high concentrations of NH₃ and is combined with the effluent from the LTHR system before being flashed and sent to the process water drum (stream 21). The vapor product of the flash is sent to the SRU.

A secondary SWS is included in this case to reduce the concentration of NH₃ in the condensate from the brine concentrator and crystallizer to 200 ppmw prior to being fed into a steam generator for production of steam injected into the gasifier (stream 10).

3.3.4.9 Process Water Treatment

The process water treatment system—which consists of a vacuum flash, brine concentrator, and crystallizer—is common to all cases and was covered in Section 3.1.12.2. The blowdown (stream 19) from the syngas scrubber is first flashed to 0.5 MPa (70 psia) with the effluent subsequently vacuum flashed to 0.05 MPa (7.5 psia). The vapor products from both the LP and vacuum flash stages are first cooled to 72°C (162°F), by preheating syngas prior to the CT, before being cooled further to 29°C (85°F) using cooling water. The cooled streams are sent to an

overhead flash to 0.2 MPa (35 psia) with the sour gas compressed to 0.4 MPa (65 psia) and sent to the SRU for incineration. The effluent from the overhead flash and condensate from the sour gas compressor are collected and sent to the process water drum for distribution (stream 24).

The effluent from the vacuum flash is sent to the brine concentrator, which evaporates sufficient water to produce an effluent containing approximately 250,000 TDS. The vapor product from the brine concentrator is compressed to 0.14 MPa (21 psia) and cooled to provide heat to the brine concentrator for evaporation. The vapor product is condensed in a HX, which provides preheat to the brine concentrator feed.

The effluent from the brine concentrator then enters the steam-driven crystallizer, where 3,022 kg/hr (6,662 lb/hr) of 0.45 MPa (65 psia) steam is utilized to evaporate sufficient water to produce a super-saturated solution in the effluent. A portion of the effluent is extracted and sent to a centrifuge to separate solids. The centrifuge effluent is returned to the crystallizer.

The vapor product from the brine concentrator is condensed with cooling water and combined with the condensate from the brine concentrator before being further treated in the secondary SWS (covered in sections 3.1.12.1.3 and 3.3.4.8).

3.3.4.10 Mercury Removal and AGR

The cooled syngas (stream 22) passes through a series of two carbon beds to remove approximately 97 percent of the Hg (covered in Section 3.1.4).

Cool, particulate-free syngas (stream 25) enters the absorber unit at approximately 3.3 MPa (473 psia) and 37°C (98°F). In the absorber, H₂S is preferentially removed from the syngas stream by contact with MDEA. The absorber column is operated at 44°C (112°F) by refrigerating the lean MDEA solvent. The lower temperature is required to achieve an outlet H₂S concentration of less than 30 ppmv in the sweet syngas. The stripper acid gas stream (stream 27), consisting of 23 vol% H₂S and 76 vol% CO₂, is sent to the Claus unit.

3.3.4.11 Claus Unit

Acid gas (stream 27) from the MDEA unit is preheated to 219°C (427°F). A portion of the acid gas, along with all of the sour gas (stream 31) and some O₂ from the ASU (stream 2), is fed to the SRU (a Claus bypass type). In the furnace, molten sulfur is produced by catalytically oxidizing approximately one third of the H₂S in the feed to SO₂ at a furnace temperature of 1,316°C (2,400°F), which must be maintained in order to thermally decompose all of the NH₃ present in the sour gas stream. The remaining H₂S is then reacted with SO₂ to produce sulfur and water. Following the thermal stage and condensation of sulfur, three reheaters and three sulfur converters are used to obtain a per-pass H₂S conversion of 99.1 percent. The Claus plant tail gas is hydrogenated and recycled back to the AGR (stream 28).

The total elemental sulfur production from the SRU (stream 28) is approximately 123 tonnes/day (136 tpd).

The waste heat from the Claus unit is used to satisfy all Claus process preheating and reheating requirements, as well as to provide some medium-pressure (1.7 MPa [250 psia]) steam to the ASU.

3.3.4.12 Power Block

The clean syngas exiting the MDEA absorber (stream 26) is reheated (stream 32) to 193°C (380°F) and diluted with LP N₂ from the ASU (stream 6). The diluted syngas enters the state-of-the-art 2008 F-class CT burner. The CT compressor provides combustion air (stream 33) to the burner. The exhaust gas exits the CT at 597°C (1,106°F) (stream 34) and enters the HRSG where additional heat is recovered until the flue gas exits the HRSG at 132°C (270°F) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced, commercially available steam turbine using a 12.4 MPa/566°C/566°C (1,800 psig/1,051°F/1,051°F) steam cycle.

3.3.4.13 Air Separation Unit

The ASU is designed to produce a nominal output of 3,665 tonnes/day (4,040 tpd) of 95 mol% O₂ for use in the gasifier (stream 4) and SRU (stream 2). The plant is designed with two production trains. The air compressor is powered by an electric motor. Approximately 9,489 tonnes/day (10,459 tpd) of N₂ is also recovered, compressed, and used as dilution in the CT combustor and particle filter fines transportation.

3.3.5 Case B4A – Performance Results

The plant produces a net output of 641 MW at a net plant efficiency of 41.1 percent (HHV basis).

Overall performance for the entire plant is summarized in Exhibit 3-58. Exhibit 3-59 provides a detailed breakdown of the auxiliary power requirements. The ASU accounts for approximately 76 percent of the total auxiliary load distributed between the MAC, O₂ compressor, N₂ compressor, and ASU auxiliaries. The cooling water system, including the circulating water pumps and cooling tower fan, accounts for approximately 5 percent of the auxiliary load, and the BFW pumps account for an additional 4 percent. All other systems together constitute the remaining 15 percent of the auxiliary load.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-58. Case B4A plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	464
Sweet Gas Expander Power, MWe	–
Steam Turbine Power, MWe	299
Total Gross Power, MWe	763
Air Separation Unit Main Air Compressor, kWe	61,000
Air Separation Unit Booster Compressor, kWe	4,800
N ₂ Compressors, kWe	25,830
CO ₂ Compression, kWe	–
Acid Gas Removal, kWe	3,200
Balance of Plant, kWe	27,590
Total Auxiliaries, MWe	122
Net Power, MWe	641
HHV Net Plant Efficiency, %	41.1
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,765 (8,308)
HHV Cold Gas Efficiency, %	81.2
HHV Combustion Turbine Efficiency, %	37.6
LHV Net Plant Efficiency, %	42.6
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,454 (8,013)
LHV Cold Gas Efficiency, %	77.5
LHV Combustion Turbine Efficiency, %	40.8
Steam Turbine Cycle Efficiency, %	46.1
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,806 (7,398)
Condenser Duty, GJ/hr (MMBtu/hr)	1,547 (1,467)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	125 (119)
As-Received Coal Feed, kg/hr (lb/hr)	206,986 (456,327)
HHV Thermal Input, kWt	1,560,166
LHV Thermal Input, kWt	1,504,799
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.026 (6.8)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.020 (5.3)
O ₂ :As-Received Coal	0.683

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-59. Case B4A plant power summary

Power Summary	
Combustion Turbine Power, MWe	464
Sweet Gas Expander Power, MWe	–
Steam Turbine Power, MWe	299
Total Gross Power, MWe	763
Auxiliary Load Summary	
Acid Gas Removal, kWe	3,200
Air Separation Unit Auxiliaries, kWe	1,000
Air Separation Unit Main Air Compressor, kWe	61,000
Air Separation Unit Booster Compressor, kWe	4,800
Ammonia Wash Pumps, kWe	70
Circulating Water Pumps, kWe	4,080
Claus Plant TG Recycle Compressor, kWe	1,520
Claus Plant/TGTU Auxiliaries, kWe	250
CO ₂ Compression, kWe	–
Coal Dryer Air Compressor, kWe	–
Coal Handling, kWe	460
Coal Milling, kWe	2,130
Combustion Turbine Auxiliaries, kWe	1,000
Condensate Pumps, kWe	240
Cooling Tower Fans, kWe	2,110
Feedwater Pumps, kWe	4,240
Gasifier Water Pump, kWe	100
Ground Water Pumps, kWe	390
Miscellaneous Balance of Plant ^A , kWe	3,000
N ₂ Compressors, kWe	25,830
N ₂ Humidification Pump, kWe	–
O ₂ Pump, kWe	310
Quench Water Pump, kWe	–
Shift Steam Pump, kWe	–
Slag Handling, kWe	1,090
Slag Reclaim Water Recycle Pump, kWe	–
Slurry Water Pump, kWe	180
Sour Gas Compressors, kWe	90
Sour Water Recycle Pumps, kWe	–
Steam Turbine Auxiliaries, kWe	200
Syngas Recycle Compressor, kWe	970

Power Summary	
Auxiliary Load Summary	
Syngas Scrubber Pumps, kWe	120
Process Water Treatment Auxiliaries, kWe	1,330
Transformer Losses, kWe	2,710
Total Auxiliaries, MWe	122
Net Power, MWe	641

^AIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

3.3.5.1 Environmental Performance

The environmental targets for emissions of Hg, HCl, NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B4A is presented in Exhibit 3-60. All HCl is assumed to be removed and is, therefore, not reported.

Exhibit 3-60. Case B4A air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.012 (0.028)	466 (514)	0.087 (0.192)
NO _x	0.024 (0.056)	954 (1,052)	0.178 (0.393)
Particulate	0.003 (0.007)	120 (132)	0.022 (0.050)
Hg	1.85E-7 (4.30E-7)	0.007 (0.008)	1.36E-6 (3.00E-6)
HCl	0.000 (0.000)	0.00 (0.00)	0.000 (0.000)
CO ₂	86 (199)	3,374,280 (3,719,507)	631 (1,391)
CO ₂ ^C	—	—	751 (1,657)

^ACalculations based on an 80 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

The low level of SO₂ in the plant emissions is achieved by capturing the sulfur in the gas by the refrigerated MDEA AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 30 ppmv. This results in a concentration in the flue gas of less than 4 ppmv. The H₂S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H₂S and then recycled back to the gasifier, thereby eliminating the need for a GTU.

NO_x emissions are limited by the use of N₂ dilution to 15 ppmvd (as NO at 15 percent O₂). NH₃ in the syngas is removed with process condensate prior to the low-temperature AGR process and destroyed in the Claus plant burner. This helps lower NO_x levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Approximately 97 percent of the mercury is captured from the syngas by dual activated carbon beds.

CO₂ emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 3-61. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag and as CO₂ in the stack gas (includes the ASU vent gas).

Exhibit 3-61. Case B4A carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	131,943 (290,884)	Stack Gas	131,406 (289,702)
Air (CO ₂)	519 (1,144)	CO ₂ Product	–
		Slag	1,056 (2,327)
Total	132,462 (292,029)	Total	132,462 (292,029)

Exhibit 3-62 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible.

Exhibit 3-62. Case B4A sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	5,188 (11,437)	Stack Gas	33 (73)
		CO ₂ Product	–
		Elemental Sulfur	5,155 (11,364)
Total	5,188 (11,437)	Total	5,188 (11,437)

Exhibit 3-63 shows the overall water balance for the plant. The water balance was explained in Case B1A (Shell) but is also presented here for completeness.

Exhibit 3-63. Case B4A water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
Slag Handling	0.46 (121)	0.46 (121)	–	–	–
Slurry Water	1.42 (375)	1.42 (375)	–	–	–
Gasifier Water	–	–	–	–	–
Quench	–	–	–	–	–
HCl Scrubber	1.08 (284)	1.08 (284)	–	–	–
NH ₃ Scrubber	0.99 (262)	0.64 (169)	0.35 (93)	–	0.35 (93)
Gasifier Steam	0.84 (222)	0.84 (222)	–	–	–
Condenser Makeup	0.49 (130)	–	0.49 (130)	–	0.49 (130)
BFW Makeup	0.21 (56)	–	0.21 (56)	–	0.21 (56)
Gasifier Steam	0.28 (74)	–	0.28 (74)	–	0.28 (74)
Shift Steam	–	–	–	–	–
N ₂ Humidification	–	–	–	–	–
Cooling Tower	15.88 (4,196)	0.23 (61)	15.65 (4,134)	3.57 (944)	12.08 (3,191)
BFW Blowdown	–	0.21 (56)	-0.21 (-56)	–	-0.21 (-56)
ASU Knockout	–	0.02 (5)	-0.02 (-5)	–	-0.02 (-5)
Total	21.16 (5,589)	4.66 (1,232)	16.49 (4,357)	3.57 (944)	12.92 (3,413)

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and is re-used as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a surface-water source for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from groundwater. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for all purposes, such as cooling tower makeup, BFW makeup, quench system makeup, and slag handling makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

An overall plant energy balance is provided in tabular form in Exhibit 3-64. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a combined generator efficiency of 98.5 percent.

Exhibit 3-64. Case B4A overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, MMBtu/hr (GJ/hr)				
Coal	5,617 (5,324)	4.7 (4.4)	–	5,621 (5,328)
Air	–	115.4 (109.3)	–	115.4 (109.3)
Raw Water Makeup	–	62.0 (58.8)	–	62.0 (58.8)
Auxiliary Power	–	–	440.7 (417.7)	440.7 (417.7)
TOTAL	5,617 (5,324)	182.1 (172.6)	440.7 (417.7)	6,239 (5,914)
Heat Out, MMBtu/hr (GJ/hr)				
Misc. Process Steam	–	4.8 (4.6)	–	4.8 (4.6)
Slag	34.6 (32.8)	23.7 (22.5)	–	58.3 (55.3)
Stack Gas	–	952 (903)	–	952 (903)
Sulfur	47.8 (45.3)	0.6 (0.6)	–	48.4 (45.8)
Motor Losses and Design Allowances	–	–	53.7 (50.9)	53.7 (50.9)
Cooling Tower Load ^A	–	2,074 (1,966)	–	2,074 (1,966)
CO ₂ Product Stream	–	–	–	–
Blowdown Streams	–	34.2 (32.4)	–	34.2 (32.4)
Ambient Losses ^B	–	144.1 (136.6)	–	144.1 (136.6)
Power	–	–	2,748 (2,604)	2,748 (2,604)
TOTAL	82.4 (78.1)	3,234 (3,065)	2,801 (2,655)	6,117 (5,798)
Unaccounted Energy ^C	–	–	–	122.0 (115.6)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers

^CBy difference

3.3.5.2 Energy and Mass Balance Diagrams

Energy and mass balance diagrams are shown for the following subsystems in Exhibit 3-65 through Exhibit 3-67:

- Coal gasification and ASU
- Syngas cleanup, sulfur recovery, and tail gas recycle
- Combined cycle power generation, steam, and FW

This page intentionally left blank

Exhibit 3-65. Case B4A coal gasification and ASU energy and mass balance

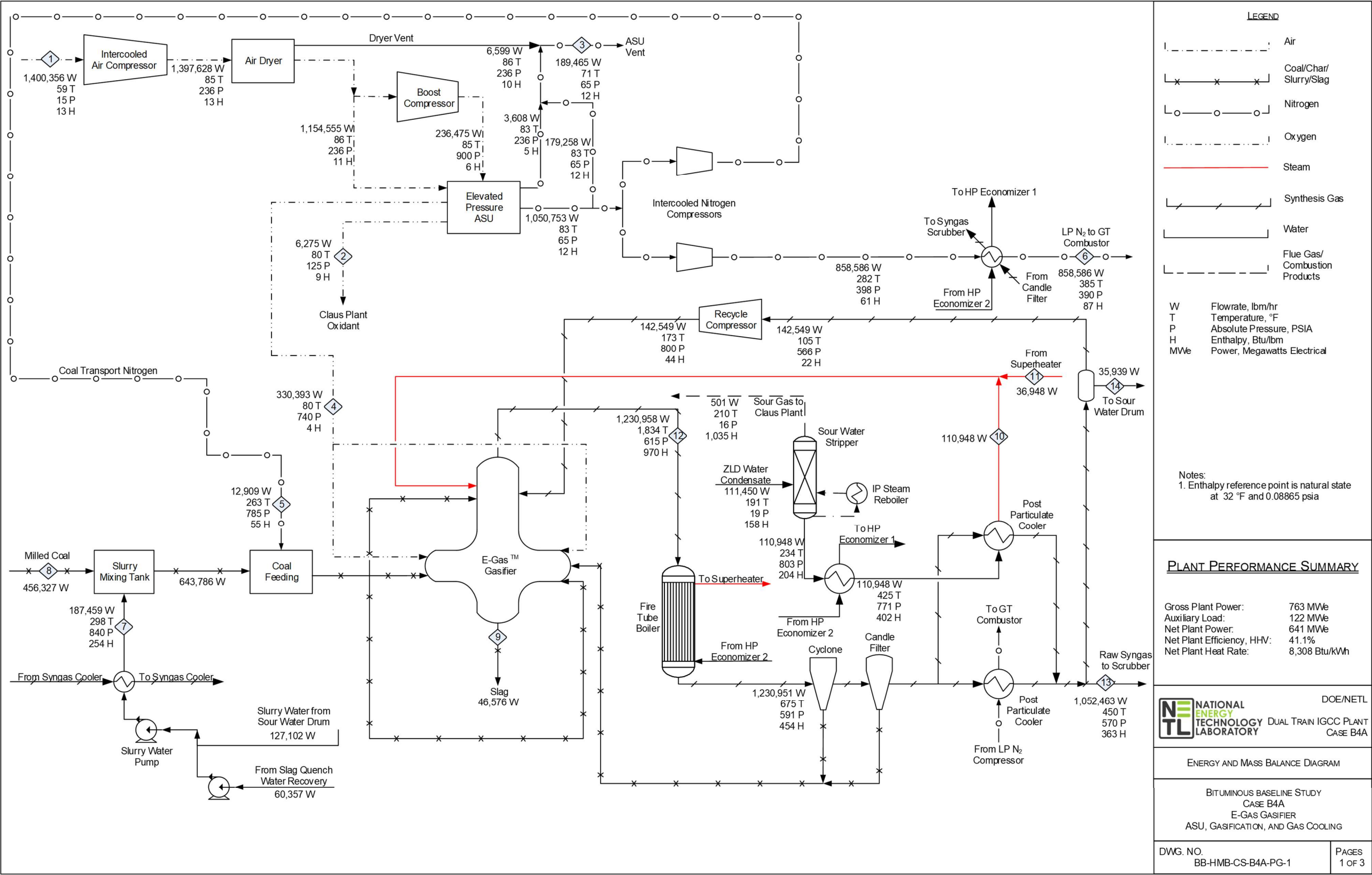


Exhibit 3-66. Case B4A syngas cleanup energy and mass balance

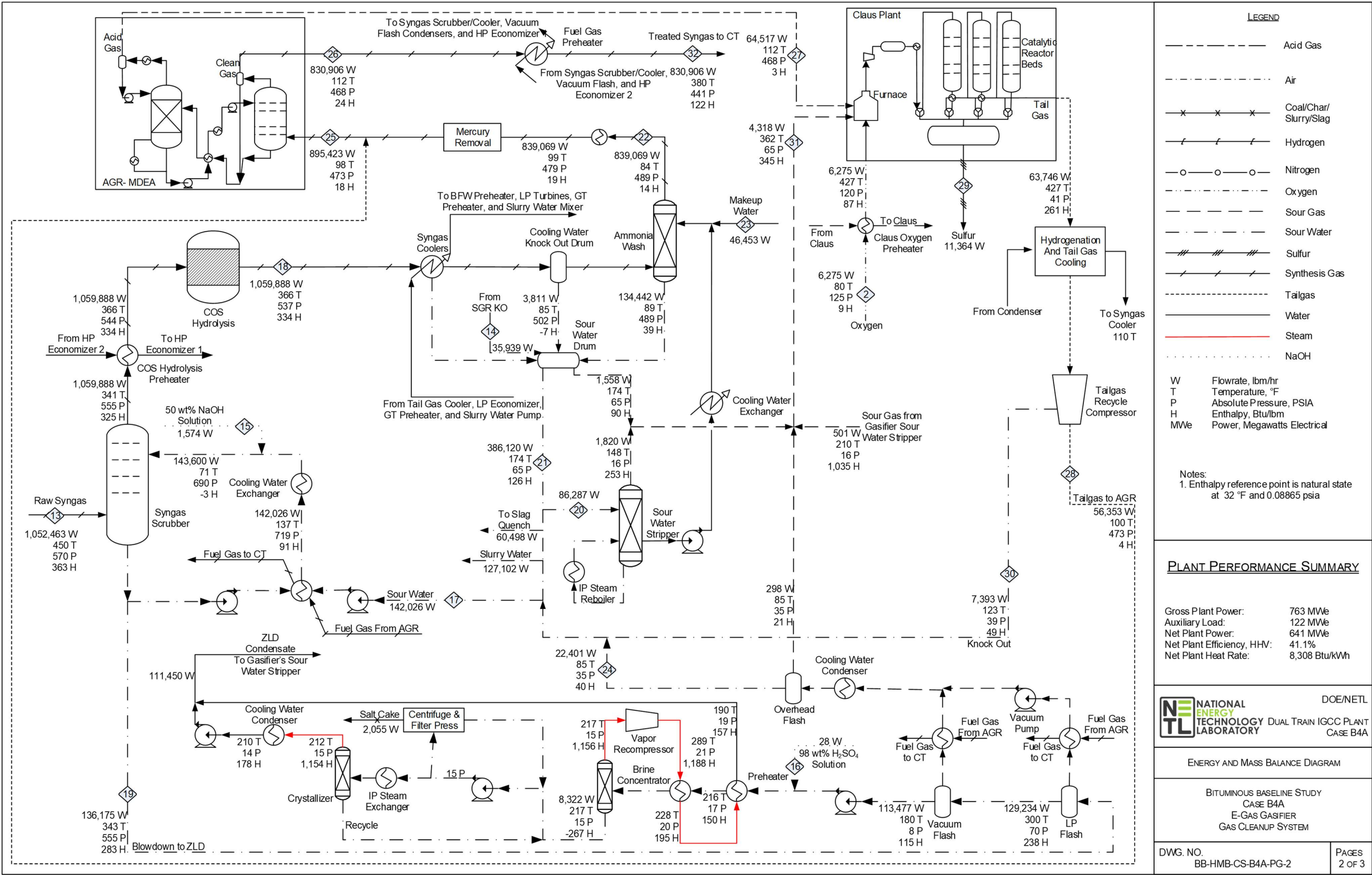
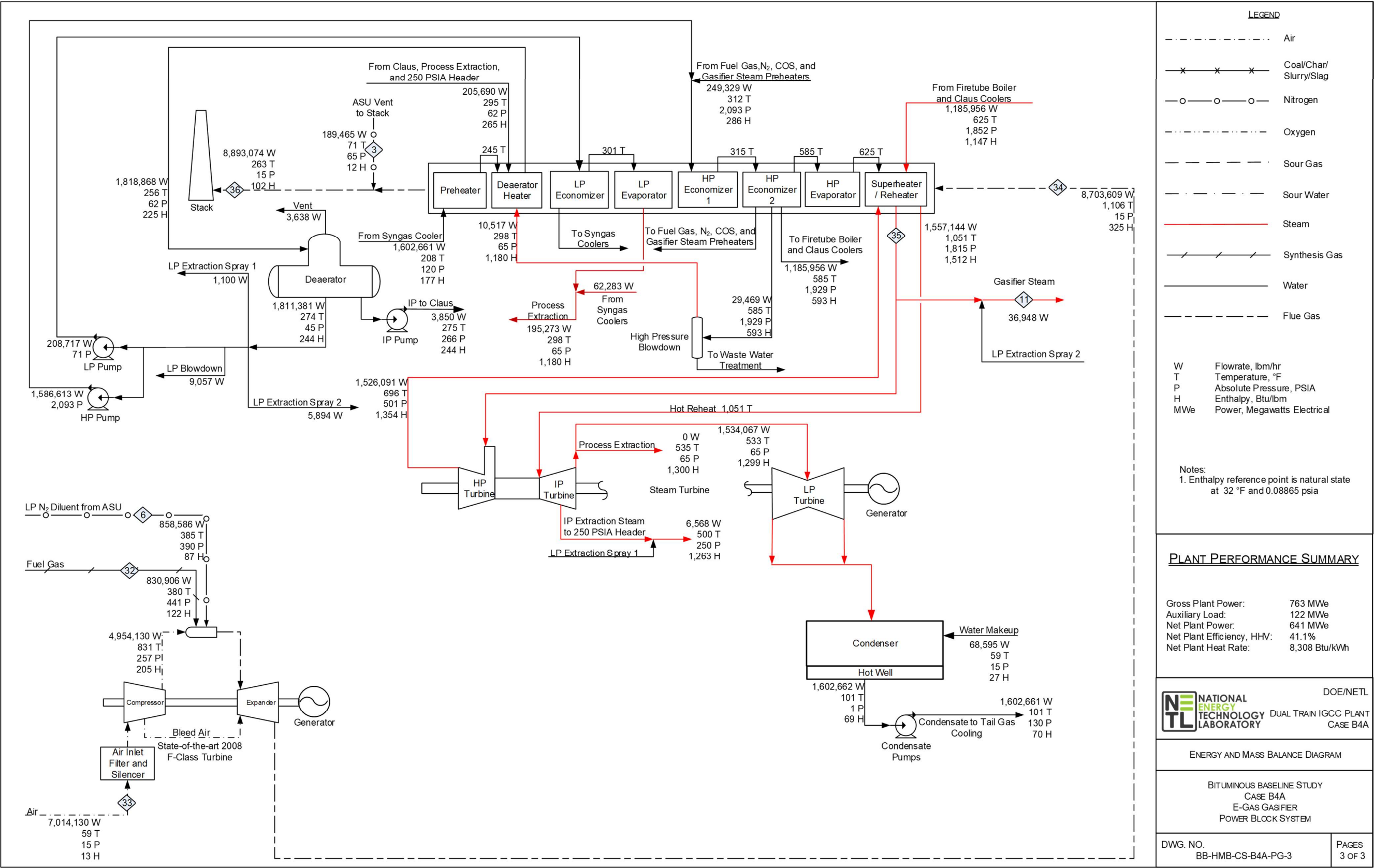


Exhibit 3-67. Case B4A combined cycle power generation energy and mass balance



This page intentionally left blank

3.3.6 Case B4A – Major Equipment List

Major equipment items for the E-Gas™ gasifier with no CO₂ capture are shown in the following tables. In general, the design conditions include a 10 percent design allowance for flows and heat duties, and a 21 percent design allowance for heads on pumps and fans.

Case B4A – Account 1: Coal Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
5	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
6	Reclaim Hopper	N/A	40 tonne (50 ton)	2	1
7	Feeder	Vibratory	170 tonne/hr (190 tph)	2	1
8	Conveyor No. 3	Belt w/ tripper	340 tonne/hr (380 tph)	1	0
9	Coal Surge Bin w/ Vent Filter	Dual outlet	170 tonne (190 ton)	2	0
10	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
11	Conveyor No. 4	Belt w/trippper	340 tonne/hr (380 tph)	1	0
12	Conveyor No. 5	Belt w/ tripper	340 tonne/hr (380 tph)	1	0
13	Coal Silo w/ Vent Filter and Slide Gates	Field erected	760 tonne (840 ton)	3	0

Case B4A – Account 2: Coal Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	80 tonne/hr (80 tph)	3	0
2	Conveyor No. 6	Belt w/trippper	230 tonne/hr (250 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	460 tonne (500 ton)	1	0
4	Weigh Feeder	Belt	110 tonne/hr (130 tph)	2	0
5	Rod Mill	Rotary	110 tonne/hr (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	281,010 liters (74,230 gal)	2	0
7	Slurry Water Pumps	Centrifugal	780 lpm (210 gpm)	2	1
8	Trommel Screen	Coarse	160 tonne/hr (180 tph)	2	0
9	Rod Mill Discharge Tank with Agitator	Field erected	367,600 liters (97,110 gal)	2	0
10	Rod Mill Product Pumps	Centrifugal	3,100 lpm (800 gpm)	2	2
11	Slurry Storage Tank with Agitator	Field erected	1,102,800 liters (291,300 gal)	2	0
12	Slurry Recycle Pumps	Centrifugal	6,100 lpm (1,600 gpm)	2	2
13	Slurry Product Pumps	Positive displacement	3,100 lpm (800 gpm)	2	2

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B4A – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	2,055,000 liters (543,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,710 lpm @ 90 m H ₂ O (1,770 gpm @ 300 ft H ₂ O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	454,000 kg/hr (1,000,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	900 lpm @ 20 m H ₂ O (240 gpm @ 70 ft H ₂ O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,860 lpm @ 1,700 m H ₂ O (1,810 gpm @ 5,700 ft H ₂ O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,080 lpm @ 210 m H ₂ O (280 gpm @ 670 ft H ₂ O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	221 GJ/hr (209 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	79,100 lpm @ 20 m H ₂ O (20,900 gpm @ 70 ft H ₂ O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
14	Municipal Water Pumps	Stainless steel, single suction	3,240 lpm @ 20 m H ₂ O (860 gpm @ 60 ft H ₂ O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	3,240 lpm @ 270 m H ₂ O (860 gpm @ 880 ft H ₂ O)	2	1
16	Filtered Water Pumps	Stainless steel, single suction	480 lpm @ 50 m H ₂ O (130 gpm @ 160 ft H ₂ O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	230,000 liter (61,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	290 lpm (80 gpm)	2	0
19	Liquid Waste Treatment System	N/A	10 years, 24-hour storm	1	0
20	Process Water Treatment	Vacuum flash, brine concentrator, and crystallizer	Vacuum Flash - Inlet: 34,000 kg/hr (75,000 lb/hr) Outlet: 6,000 ppmw Cl- Brine Concentrator Inlet - 28,000 kg/hr (62,000 lb/hr) Crystallizer Inlet - 2,000 kg/hr (5,000 lb/hr)	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B4A – Account 4: Gasifier, ASU, and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized two-stage, slurry-feed entrained bed	2,700 tonne/day, 4.2 MPa (3,000 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Fire-tube boiler	307,000 kg/hr (677,000 lb/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	307,000 kg/hr (677,000 lb/hr) Design efficiency 90%	2	0
4	HCl Scrubber	Ejector Venturi	263,000 kg/hr (579,000 lb/hr)	2	0
5	Ammonia Wash	Counter-flow spray tower	210,000 kg/hr (463,000 lb/hr) @ 3.5 MPa (502 psia)	2	0
6	Primary Sour Water Stripper	Counter-flow with external reboiler	22,000 kg/hr (47,000 lb/hr)	2	0
7	Secondary Sour Water Stripper	Counter-flow with external reboiler	28,000 kg/hr (61,000 lb/hr)	2	0
8	Low Temperature Heat Recovery Coolers	Shell and tube with condensate drain	264,000 kg/hr (583,000 lb/hr)	6	0
9	Low Temperature Heat Recovery Knockout Drum	Vertical with mist eliminator	211,000 kg/hr, 59°C, 3.5 MPa (466,000 lb/hr, 138°F, 506 psia)	2	0
10	Saturation Water Economizers	Shell and tube	N/A	4	0
11	HP Nitrogen Gas Saturator	Direct Injection	N/A	2	0
12	LP Nitrogen Gas Saturator	Direct Injection	214,000 kg/hr, 196°C, 2.7 MPa (472,000 lb/hr, 385°F, 390 psia)	2	0
13	Saturator Water Pump	Centrifugal	N/A	2	2
14	Saturated Nitrogen Reheaters	Shell and tube	N/A	4	0
15	Synthesis Gas Reheaters	Shell and tube	Reheater 1: N/A Reheater 2: 35,000 kg/hr (76,000 lb/hr) Reheater 3: 98,000 kg/hr (216,000 lb/hr) Reheater 4: 75,000 kg/hr (165,000 lb/hr) Reheater 5: 207,000 kg/hr (457,000 lb/hr) Reheater 6: 207,000 kg/hr (457,000 lb/hr)	2	0
16	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	264,000 kg/hr (583,000 lb/hr) syngas	2	0
17	ASU Main Air Compressor	Centrifugal, multi-stage	5,000 m ³ /min @ 1.6 MPa (169,000 scfm @ 236 psia)	2	0
18	Cold Box	Vendor design	2,000 tonne/day (2,200 tpd) of 95% purity O ₂	2	0
19	Gasifier O ₂ Pump	Centrifugal, multi-stage	1,000 m ³ /min (36,000 scfm) Suction - 1.0 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	2	0
20	AGR Nitrogen Boost Compressor	Centrifugal, multi-stage	N/A	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
21	High Pressure Nitrogen Diluent Compressor	Centrifugal, multi-stage	N/A	2	0
22	Low Pressure Nitrogen Diluent Compressor	Centrifugal, single-stage	3,020 m ³ /min (107,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - 2.7 MPa (400 psia)	2	0
23	Gasifier Nitrogen Boost Compressor	Centrifugal, single-stage	50 m ³ /min (2,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - 5.4 MPa (790 psia)	2	0

Case B4A – Account 5: Syngas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber 1	Sulfated carbon bed	209,000 kg/hr (461,000 lb/hr) 29°C (84°F), 3.4 MPa (489 psia)	2	0
2	Mercury Adsorber 2	Sulfated carbon bed	209,000 kg/hr (461,000 lb/hr) 37°C (99°F), 3.3 MPa (476 psia)	2	0
3	Sulfur Plant	Claus type	136 tonne/day (150 tpd)	1	0
4	COS Hydrolysis Reactor	Fixed bed, catalytic	264,000 kg/hr (583,000 lb/hr) 188°C (370°F), 3.7 MPa (540 psia)	2	0
5	COS Hydrolysis Heat Exchanger	Shell and Tube	6 GJ/hr (5 MMBtu/hr)	2	0
6	Acid Gas Removal Plant	MDEA	223,000 kg/hr (492,000 lb/hr) 37°C (98°F), 3.3 MPa (473 psia)	2	0
7	Hydrogenation Reactor	Fixed bed, catalytic	32,000 kg/hr (70,000 lb/hr), 219°C (427°F), 0.3 MPa (40.8425733 psia)	1	0
8	Tail Gas Recycle Compressor	Centrifugal	28,000 kg/hr (62,000 lb/hr) each	1	0
9	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0

Case B4A – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	State-of-the-art 2008 F-Class	232 MW	2	0
2	Combustion Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

Case B4A – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.5 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 388,470 kg/hr, 12.4 MPa/566°C (856,429 lb/hr, 1,800 psig/1,051°F)	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
			Reheat steam - 380,723 kg/hr, 3.3 MPa/566°C (839,350 lb/hr, 477 psig/1,051°F)		

Case B4A – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	315 MW 12.4 MPa/566°C/566°C (1,800 psig/1,051°F/1,051°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	350 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,700GJ/hr (1,610 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

Case B4A – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	409,000 lpm @ 30 m (108,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 2,280 GJ/hr (2,160 MMBtu/hr) heat duty	1	0

Case B4A – Account 10: Slag Recovery and Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	222,000 liters (59,000 gal)	2	0
2	Slag Crusher	Roll	12 tonne/hr (13 tph)	2	0
3	Slag Depressurizer	Proprietary	12 tonne/hr (13 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	133,000 liters (35,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	60,000 liters (16,000 gal)	2	0
6	Slag Conveyor	Drag chain	12 tonne/hr (13 tph)	2	0
7	Slag Separation Screen	Vibrating	12 tonne/hr (13 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	12 tonne/hr (13 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	190,000 liters (50,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	50 lpm @ 14 m H ₂ O (10 gpm @ 46 ft H ₂ O)	2	2
11	Grey Water Storage Tank	Field erected	60,000 liters (16,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	210 lpm @ 430 m H ₂ O (60 gpm @ 1,420 ft H ₂ O)	2	2
13	Slag Storage Bin	Vertical, field erected	800 tonne (900 tons)	2	0
14	Unloading Equipment	Telescoping chute	100 tonne/hr (110 tph)	1	0

Case B4A – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 320 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 51 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 31 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 5 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B4A – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.3.7 Case B4A – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 3-68 shows a detailed breakdown of the capital costs; Exhibit 3-69 shows the owner's costs, TOC, and TASC; Exhibit 3-70 shows the initial and annual O&M costs; and Exhibit 3-71 shows the LCOE breakdown.

The estimated TPC of the E-Gas™ gasifier with no CO₂ capture is \$3,656/kW. Process contingency represents 4.9 percent of the TPC, and project contingency is 14.6 percent. The LCOE is \$103.2/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-68. Case B4A total plant cost details

Case:		B4A	– E-Gas™ IGCC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		641					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
	1					Coal Handling					
1.1	Coal Receive & Unload	\$957	\$0	\$461	\$0	\$1,418	\$213	\$0	\$326	\$1,956	\$3
1.2	Coal Stackout & Reclaim	\$3,127	\$0	\$748	\$0	\$3,875	\$581	\$0	\$891	\$5,347	\$8
1.3	Coal Conveyors & Yard Crush	\$29,830	\$0	\$7,589	\$0	\$37,418	\$5,613	\$0	\$8,606	\$51,637	\$81
1.4	Other Coal Handling	\$4,645	\$0	\$1,046	\$0	\$5,691	\$854	\$0	\$1,309	\$7,854	\$12
1.9	Coal & Sorbent Handling Foundations	\$0	\$84	\$219	\$0	\$302	\$45	\$0	\$70	\$417	\$1
	Subtotal	\$38,558	\$84	\$10,062	\$0	\$48,704	\$7,306	\$0	\$11,202	\$67,212	\$105
	2					Coal Preparation & Feed					
2.1	Coal Crushing & Drying	\$2,313	\$139	\$332	\$0	\$2,785	\$418	\$0	\$640	\$3,843	\$6
2.2	Prepared Coal Storage & Feed	\$7,104	\$1,708	\$1,101	\$0	\$9,912	\$1,487	\$0	\$2,280	\$13,679	\$21
2.3	Slurry Coal Injection System	\$6,953	\$0	\$3,050	\$0	\$10,003	\$1,500	\$0	\$2,301	\$13,804	\$22
2.4	Miscellaneous Coal Preparation & Feed	\$702	\$513	\$1,510	\$0	\$2,725	\$409	\$0	\$627	\$3,760	\$6
2.9	Coal & Sorbent Feed Foundation	\$0	\$1,707	\$1,465	\$0	\$3,172	\$476	\$0	\$730	\$4,377	\$7
	Subtotal	\$17,072	\$4,067	\$7,458	\$0	\$28,596	\$4,289	\$0	\$6,577	\$39,463	\$62
	3					Feedwater & Miscellaneous BOP Systems					
3.1	Feedwater System	\$2,203	\$3,777	\$1,888	\$0	\$7,869	\$1,180	\$0	\$1,810	\$10,859	\$17
3.2	Water Makeup & Pretreating	\$4,666	\$467	\$2,644	\$0	\$7,776	\$1,166	\$0	\$2,683	\$11,625	\$18
3.3	Other Feedwater Subsystems	\$1,139	\$373	\$355	\$0	\$1,867	\$280	\$0	\$429	\$2,576	\$4
3.4	Service Water Systems	\$1,394	\$2,662	\$8,619	\$0	\$12,675	\$1,901	\$0	\$4,373	\$18,949	\$30
3.5	Other Boiler Plant Systems	\$296	\$108	\$269	\$0	\$672	\$101	\$0	\$155	\$928	\$1
3.6	Natural Gas Pipeline and Start-Up System	\$7,156	\$308	\$231	\$0	\$7,695	\$1,154	\$0	\$1,770	\$10,618	\$17
3.7	Waste Water Treatment Equipment	\$6,687	\$0	\$4,098	\$0	\$10,785	\$1,618	\$0	\$3,721	\$16,124	\$25
3.8	Vacuum Flash, Brine Concentrator, & Crystallizer	\$24,262	\$0	\$15,029	\$0	\$39,291	\$5,894	\$0	\$13,555	\$58,740	\$92
3.9	Miscellaneous Plant Equipment	\$15,238	\$1,998	\$7,744	\$0	\$24,981	\$3,747	\$0	\$8,618	\$37,346	\$58
	Subtotal	\$63,040	\$9,692	\$40,877	\$0	\$113,610	\$17,041	\$0	\$37,114	\$167,765	\$262
	4					Gasifier, ASU, & Accessories					
4.1	Gasifier & Auxiliaries (E-GAS)	\$371,379	\$0	\$207,402	\$0	\$578,781	\$86,817	\$81,029	\$111,994	\$858,622	\$1,340
4.2	Syngas Cooler	\$50,342	\$0	\$28,114	\$0	\$78,456	\$11,768	\$10,984	\$15,181	\$116,389	\$182
4.3	Air Separation Unit/Oxidant Compression	\$119,827	\$27,425	\$28,519	\$0	\$175,770	\$35,154	\$17,577	\$34,275	\$262,776	\$410
4.5	Miscellaneous Gasification Equipment	\$3,787	\$0	\$2,115	\$0	\$5,901	\$885	\$0	\$1,018	\$7,805	\$12
4.6	Low Temperature Heat Recovery & Flue Gas Saturation	\$44,443	\$0	\$16,885	\$0	\$61,328	\$9,199	\$0	\$14,105	\$84,632	\$132
4.7	Flare Stack System	\$1,878	\$0	\$331	\$0	\$2,210	\$331	\$0	\$508	\$3,049	\$5
4.15	Major Component Rigging	\$211	\$0	\$118	\$0	\$328	\$49	\$0	\$57	\$434	\$1
4.16	Gasification Foundations	\$0	\$465	\$277	\$0	\$742	\$111	\$0	\$213	\$1,066	\$2
	Subtotal	\$591,866	\$27,889	\$283,761	\$0	\$903,516	\$144,316	\$109,590	\$177,352	\$1,334,774	\$2,083

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B4A	– E-Gas™ IGCC w/o CO ₂ Capture				Estimate Type:		Conceptual		
Plant Size (MW, net):		641					Cost Base:		Dec 2018		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
5											
Syngas Cleanup											
5.2	Methyldiethanolamine (MDEA) - Low Temperature Acid Gas Removal	\$5,162	\$0	\$4,350	\$0	\$9,512	\$1,427	\$0	\$2,188	\$13,127	\$20
5.3	Elemental Sulfur Plant	\$46,692	\$9,101	\$59,831	\$0	\$115,623	\$17,344	\$0	\$26,593	\$159,560	\$249
5.6	Mercury Removal (Carbon Bed)	\$211	\$0	\$159	\$0	\$370	\$55	\$18	\$89	\$532	\$1
5.8	Carbonyl Sulfide (COS) Hydrolysis	\$9,651	\$0	\$12,517	\$0	\$22,168	\$3,325	\$0	\$5,099	\$30,592	\$48
5.9	Particulate Removal	\$1,378	\$0	\$591	\$0	\$1,969	\$295	\$0	\$340	\$2,604	\$4
5.10	Blowback Gas Systems	\$751	\$422	\$235	\$0	\$1,407	\$211	\$0	\$324	\$1,942	\$3
5.11	Fuel Gas Piping	\$0	\$2,858	\$1,870	\$0	\$4,728	\$709	\$0	\$1,087	\$6,524	\$10
5.12	Gas Cleanup Foundations	\$0	\$216	\$146	\$0	\$362	\$54	\$0	\$125	\$541	\$1
	Subtotal	\$63,844	\$12,596	\$79,700	\$0	\$156,140	\$23,421	\$18	\$35,844	\$215,424	\$336
6											
Combustion Turbine & Accessories											
6.1	Combustion Turbine Generator	\$74,944	\$0	\$5,399	\$0	\$80,343	\$12,051	\$4,017	\$14,462	\$110,873	\$173
6.3	Combustion Turbine Accessories	\$2,687	\$0	\$164	\$0	\$2,851	\$428	\$0	\$492	\$3,770	\$6
6.4	Compressed Air Piping	\$0	\$509	\$333	\$0	\$843	\$126	\$0	\$194	\$1,163	\$2
6.5	Combustion Turbine Foundations	\$0	\$216	\$250	\$0	\$466	\$70	\$0	\$161	\$697	\$1
	Subtotal	\$77,632	\$726	\$6,146	\$0	\$84,503	\$12,675	\$4,017	\$15,308	\$116,504	\$182
7											
HRSG, Ductwork, & Stack											
7.1	Heat Recovery Steam Generator	\$35,914	\$0	\$6,955	\$0	\$42,869	\$6,430	\$0	\$7,395	\$56,695	\$88
7.2	Heat Recovery Steam Generator Accessories	\$12,824	\$0	\$2,483	\$0	\$15,307	\$2,296	\$0	\$2,640	\$20,243	\$32
7.3	Ductwork	\$0	\$1,085	\$761	\$0	\$1,846	\$277	\$0	\$425	\$2,547	\$4
7.4	Stack	\$9,225	\$0	\$3,441	\$0	\$12,667	\$1,900	\$0	\$2,185	\$16,752	\$26
7.5	Heat Recovery Steam Generator, Ductwork & Stack Foundations	\$0	\$230	\$230	\$0	\$460	\$69	\$0	\$159	\$688	\$1
	Subtotal	\$57,963	\$1,315	\$13,870	\$0	\$73,149	\$10,972	\$0	\$12,804	\$96,924	\$151
8											
Steam Turbine & Accessories											
8.1	Steam Turbine Generator & Accessories	\$39,518	\$0	\$6,029	\$0	\$45,547	\$6,832	\$0	\$7,857	\$60,236	\$94
8.2	Steam Turbine Plant Auxiliaries	\$1,922	\$0	\$4,375	\$0	\$6,297	\$945	\$0	\$1,086	\$8,328	\$13
8.3	Condenser & Auxiliaries	\$7,195	\$0	\$4,065	\$0	\$11,260	\$1,689	\$0	\$1,942	\$14,892	\$23
8.4	Steam Piping	\$7,418	\$0	\$3,217	\$0	\$10,635	\$1,595	\$0	\$3,057	\$15,287	\$24
8.5	Turbine Generator Foundations	\$0	\$299	\$528	\$0	\$828	\$124	\$0	\$286	\$1,237	\$2
	Subtotal	\$56,053	\$299	\$18,214	\$0	\$74,567	\$11,185	\$0	\$14,229	\$99,981	\$156
9											
Cooling Water System											
9.1	Cooling Towers	\$10,618	\$0	\$3,228	\$0	\$13,846	\$2,077	\$0	\$2,388	\$18,312	\$29
9.2	Circulating Water Pumps	\$1,386	\$0	\$99	\$0	\$1,485	\$223	\$0	\$256	\$1,964	\$3
9.3	Circulating Water System Auxiliaries	\$9,618	\$0	\$1,358	\$0	\$10,976	\$1,646	\$0	\$1,893	\$14,515	\$23
9.4	Circulating Water Piping	\$0	\$5,432	\$4,919	\$0	\$10,352	\$1,553	\$0	\$2,381	\$14,285	\$22
9.5	Make-up Water System	\$566	\$0	\$777	\$0	\$1,342	\$201	\$0	\$309	\$1,852	\$3
9.6	Component Cooling Water System	\$196	\$235	\$161	\$0	\$592	\$89	\$0	\$136	\$816	\$1
9.7	Circulating Water System Foundations	\$0	\$450	\$799	\$0	\$1,249	\$187	\$0	\$431	\$1,867	\$3

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B4A	– E-Gas™ IGCC w/o CO ₂ Capture			Estimate Type:		Conceptual			
Plant Size (MW, net):		641				Cost Base:		Dec 2018			
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
	Subtotal	\$22,384	\$6,116	\$11,341	\$0	\$39,841	\$5,976	\$0	\$7,794	\$53,612	\$84
	10	Slag Recovery & Handling									
10.1	Slag Dewatering & Cooling	\$1,928	\$0	\$944	\$0	\$2,872	\$431	\$0	\$495	\$3,798	\$6
10.2	Gasifier Ash Depressurization	\$1,092	\$0	\$535	\$0	\$1,627	\$244	\$0	\$281	\$2,152	\$3
10.3	Cleanup Ash Depressurization	\$491	\$0	\$240	\$0	\$731	\$110	\$0	\$126	\$967	\$2
10.6	Ash Storage Silos	\$1,100	\$0	\$1,190	\$0	\$2,289	\$343	\$0	\$395	\$3,027	\$5
10.7	Ash Transport & Feed Equipment	\$424	\$0	\$99	\$0	\$523	\$78	\$0	\$90	\$692	\$1
10.8	Miscellaneous Ash Handling Equipment	\$61	\$74	\$22	\$0	\$157	\$24	\$0	\$27	\$208	\$0
10.9	Ash/Spent Sorbent Foundation	\$0	\$430	\$571	\$0	\$1,001	\$150	\$0	\$346	\$1,497	\$2
	Subtotal	\$5,096	\$505	\$3,601	\$0	\$9,202	\$1,380	\$0	\$1,760	\$12,342	\$19
	11	Accessory Electric Plant									
11.1	Generator Equipment	\$2,833	\$0	\$2,137	\$0	\$4,969	\$745	\$0	\$857	\$6,572	\$10
11.2	Station Service Equipment	\$3,526	\$0	\$303	\$0	\$3,829	\$574	\$0	\$660	\$5,064	\$8
11.3	Switchgear & Motor Control	\$21,279	\$0	\$3,692	\$0	\$24,970	\$3,746	\$0	\$4,307	\$33,023	\$52
11.4	Conduit & Cable Tray	\$0	\$94	\$272	\$0	\$366	\$55	\$0	\$105	\$526	\$1
11.5	Wire & Cable	\$0	\$1,291	\$2,308	\$0	\$3,599	\$540	\$0	\$1,035	\$5,173	\$8
11.6	Protective Equipment	\$241	\$0	\$837	\$0	\$1,078	\$162	\$0	\$186	\$1,426	\$2
11.7	Standby Equipment	\$864	\$0	\$797	\$0	\$1,661	\$249	\$0	\$287	\$2,197	\$3
11.8	Main Power Transformers	\$6,557	\$0	\$134	\$0	\$6,691	\$1,004	\$0	\$1,154	\$8,849	\$14
11.9	Electrical Foundations	\$0	\$76	\$192	\$0	\$268	\$40	\$0	\$92	\$400	\$1
	Subtotal	\$35,299	\$1,461	\$10,671	\$0	\$47,431	\$7,115	\$0	\$8,684	\$63,230	\$99
	12	Instrumentation & Control									
12.1	Integrated Gasification and Combined Cycle Control Equipment	\$605	\$0	\$338	\$0	\$943	\$141	\$0	\$163	\$1,247	\$2
12.2	Combustion Turbine Control Equipment	\$650	\$0	\$47	\$0	\$697	\$105	\$0	\$120	\$921	\$1
12.3	Steam Turbine Control Equipment	\$601	\$0	\$92	\$0	\$693	\$104	\$0	\$119	\$916	\$1
12.4	Other Major Component Control Equipment	\$1,161	\$0	\$791	\$0	\$1,953	\$293	\$98	\$351	\$2,695	\$4
12.5	Signal Processing Equipment	\$901	\$0	\$29	\$0	\$930	\$140	\$0	\$160	\$1,230	\$2
12.6	Control Boards, Panels & Racks	\$261	\$0	\$170	\$0	\$431	\$65	\$22	\$104	\$621	\$1
12.7	Distributed Control System Equipment	\$9,454	\$0	\$309	\$0	\$9,764	\$1,465	\$488	\$1,757	\$13,474	\$21
12.8	Instrument Wiring & Tubing	\$470	\$376	\$1,505	\$0	\$2,352	\$353	\$118	\$706	\$3,528	\$6
12.9	Other Instrumentation & Controls Equipment	\$1,055	\$0	\$523	\$0	\$1,578	\$237	\$79	\$284	\$2,178	\$3
	Subtotal	\$15,160	\$376	\$3,805	\$0	\$19,342	\$2,901	\$804	\$3,765	\$26,812	\$42
	13	Improvements to Site									
13.1	Site Preparation	\$0	\$416	\$9,412	\$0	\$9,827	\$1,474	\$0	\$3,390	\$14,692	\$23
13.2	Site Improvements	\$0	\$1,870	\$2,644	\$0	\$4,514	\$677	\$0	\$1,557	\$6,748	\$11
13.3	Site Facilities	\$2,920	\$0	\$3,278	\$0	\$6,197	\$930	\$0	\$2,138	\$9,265	\$14
	Subtotal	\$2,920	\$2,286	\$15,333	\$0	\$20,538	\$3,081	\$0	\$7,086	\$30,705	\$48

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B4A	– E-Gas™ IGCC w/o CO ₂ Capture				Estimate Type:		Conceptual		
Plant Size (MW, net):		641					Cost Base:		Dec 2018		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
14		Buildings & Structures									
14.1	Combustion Turbine Area	\$0	\$314	\$177	\$0	\$491	\$74	\$0	\$85	\$649	\$1
14.3	Steam Turbine Building	\$0	\$2,783	\$3,962	\$0	\$6,746	\$1,012	\$0	\$1,164	\$8,921	\$14
14.4	Administration Building	\$0	\$885	\$642	\$0	\$1,527	\$229	\$0	\$263	\$2,020	\$3
14.5	Circulation Water Pumphouse	\$0	\$136	\$72	\$0	\$208	\$31	\$0	\$36	\$275	\$0
14.6	Water Treatment Buildings	\$0	\$311	\$303	\$0	\$614	\$92	\$0	\$106	\$811	\$1
14.7	Machine Shop	\$0	\$490	\$335	\$0	\$825	\$124	\$0	\$142	\$1,091	\$2
14.8	Warehouse	\$0	\$382	\$247	\$0	\$628	\$94	\$0	\$108	\$831	\$1
14.9	Other Buildings & Structures	\$0	\$280	\$217	\$0	\$497	\$75	\$0	\$86	\$657	\$1
14.10	Waste Treating Building & Structures	\$0	\$751	\$1,434	\$0	\$2,185	\$328	\$0	\$377	\$2,890	\$5
	Subtotal	\$0	\$6,331	\$7,390	\$0	\$13,721	\$2,058	\$0	\$2,367	\$18,146	\$28
	Total	\$1,046,888	\$73,743	\$512,228	\$0	\$1,632,860	\$253,717	\$114,430	\$341,886	\$2,342,893	\$3,656

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-69. Case B4A owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$19,760	\$31
1 Month Maintenance Materials	\$4,759	\$7
1 Month Non-fuel Consumables	\$770	\$1
1 Month Waste Disposal	\$688	\$1
25% of 1 Months Fuel Cost at 100% CF	\$2,164	\$3
2% of TPC	\$46,858	\$73
Total	\$74,998	\$117
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	\$18,485	\$29
0.5% of TPC (spare parts)	\$11,714	\$18
Total	\$30,200	\$47
Other Costs		
Initial Cost for Catalyst and Chemicals	\$3,115	\$5
Land	\$900	\$1
Other Owner's Costs	\$351,434	\$548
Financing Costs	\$63,258	\$99
Total Overnight Costs (TOC)	\$2,866,797	\$4,474
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	\$3,309,464	\$5,165

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-70. Case B4A initial and annual operating and maintenance costs

Case:	B4A – E-Gas™ IGCC w/o CO ₂ Capture			Cost Base:	Dec 2018	
Plant Size (MW, net):	641	Heat Rate-net (Btu/kWh):	8,308	Capacity Factor (%):	80	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	% of base	Operator:	10.0	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	3.0	
				Total:	16.0	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$7,015,008	\$10.948
Maintenance Labor:					\$24,600,373	\$38.391
Administrative & Support Labor:					\$7,903,845	\$12.335
Property Taxes and Insurance:					\$46,857,854	\$73.126
Total:					\$86,377,081	\$134.800
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$45,686,408	\$10.17382
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (gal/1000):	0	3,137	\$1.90	\$0	\$1,740,388	\$0.38756
Makeup and Waste Water Treatment Chemicals (ton):	0	9.34	\$550.00	\$0	\$1,500,739	\$0.33420
Sulfur-Impregnated Activated Carbon (ton):	64.7	0.089	\$12,000.00	\$775,814	\$310,326	\$0.06911
COS Hydrolysis Catalyst (ft³):	1,733	1.19	\$1,300.00	\$2,253,455	\$450,691	\$0.10036
Methyldiethanolamine Solution (gal):	30,614	38.3	\$2.80	\$85,720	\$31,341	\$0.00698
Sodium Hydroxide (50 wt%, ton):	0	18.9	\$600.00	\$0	\$3,308,882	\$0.73685
Sulfuric Acid (98 wt%, ton):	0	0.335	\$210.00	\$0	\$20,560	\$0.00458
Claus Catalyst (ft³):	w/equip.	1.89	\$48.00	\$0	\$26,496	\$0.00590
Subtotal:				\$3,114,989	\$7,389,422	\$1.64554
Waste Disposal						
Sulfur-Impregnated Activated Carbon (ton):	0	0.089	\$80.00	\$0	\$2,069	\$0.00046
COS Hydrolysis Catalyst (ft³):	0	1.19	\$2.50	\$0	\$867	\$0.00019
MDEA Solution (gal):	0	38.3	\$0.35	\$0	\$3,918	\$0.00087
Claus Catalyst (ft³):	0	1.89	\$2.50	\$0	\$1,380	\$0.00031
Crystallizer Solids (ton):	0	35.7	\$38.00	\$0	\$395,907	\$0.08816
Slag (ton):	0	559	\$38.00	\$0	\$6,201,712	\$1.38105
Subtotal:				\$0	\$6,605,853	\$1.47104
By-Products						
Sulfur (tons):	0	136	\$0.00	\$0	\$0	\$0.00000
Subtotal:				\$0	\$0	\$0.00000
Variable Operating Costs Total:				\$3,114,989	\$59,681,683	\$13.29040
Fuel Cost						
Illinois Number 6 (ton):	0	5,476	\$51.96	\$0	\$83,079,249	\$18.50076
Total:				\$0	\$83,079,249	\$18.50076

Exhibit 3-71. Case B4A LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	52.1	50.5%
Fixed	19.2	18.6%
Variable	13.3	12.9%
Fuel	18.5	17.9%
Total (Excluding T&S)	103.2	100.0%
CO ₂ T&S	—	—
Total (Including T&S)	103.2	100.0%

3.3.8 Case B4B – E-Gas™ IGCC Power Plant with CO₂ Capture Process Description

In this section, the E-Gas™ gasification process for Case B4B is described. The plant configuration is nearly identical to that of Case B4A, with the exception that this case is configured to produce electric power with CO₂ capture.

The gross power output is constrained by the capacity of the two CTs, and since the CO₂ capture and compression process increases the auxiliary load on the plant, the net output is significantly reduced relative to Case B4A (557 MW versus 641 MW).

The process descriptions for Case B4B are similar to Case B4A with several notable exceptions to accommodate CO₂ capture. The system descriptions follow the BFD provided in Exhibit 3-72 with the associated stream tables—providing process data for the numbered streams in the BFD—provided in Exhibit 3-73. Rather than repeating the entire process description, only differences from Case B4A are reported here.

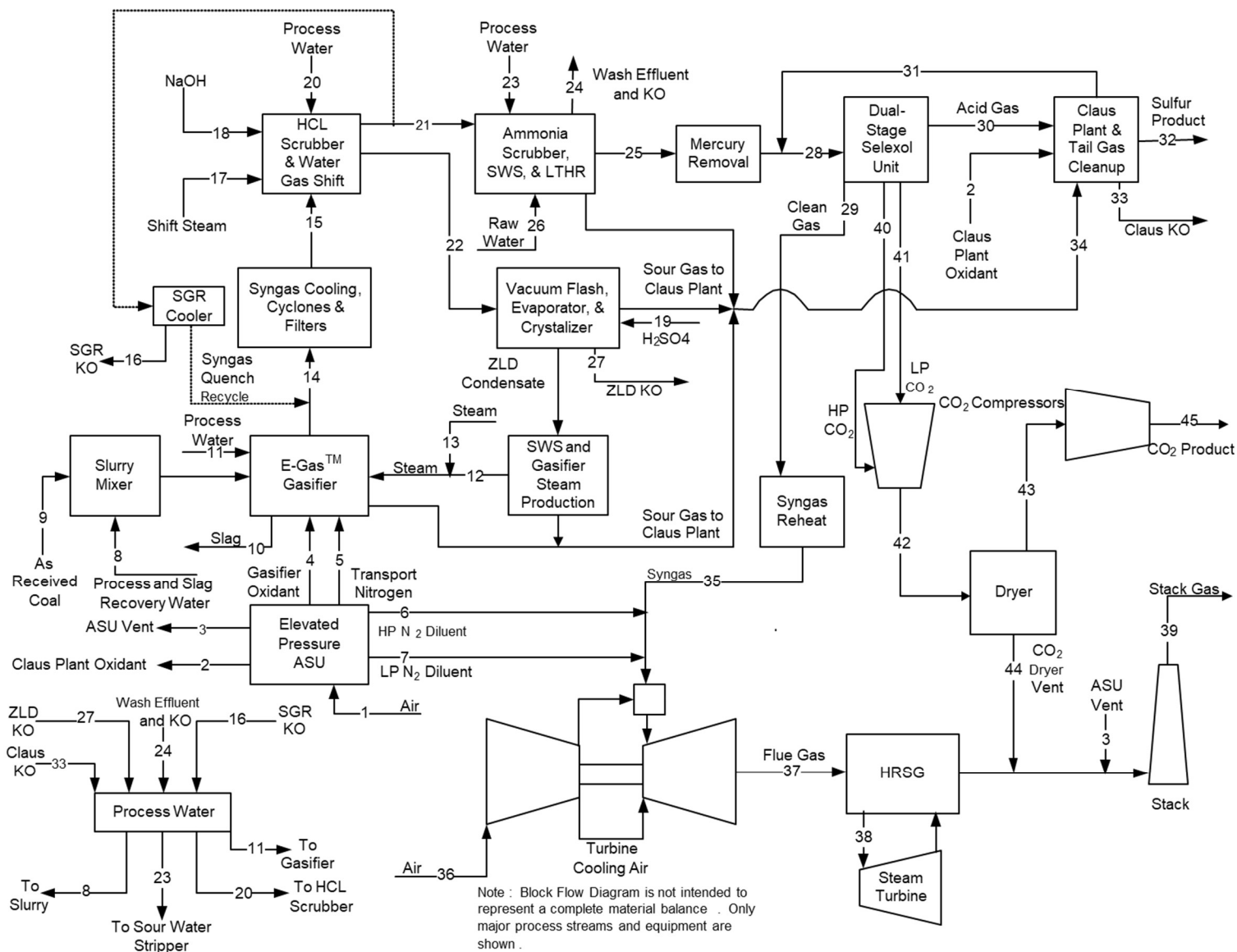
3.3.8.1 Coal Preparation and Feed Systems

No differences from Case B4A.

3.3.8.2 Gasifier

There are no differences from the gasifier design presented in Case B4A. However, since the E-Gas™ gasifier produces higher amounts of methane, Case B4B is operated at a higher O₂:coal ratio than B4A (0.738 in B4B versus 0.683 in B4A), which facilitates achieving a carbon capture rate of 90 percent.

Exhibit 3-72. Case B4B block flow diagram, E-Gas™ IGCC with CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-73. Case B4B stream table, E-Gas™ IGCC with capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0343	0.1077	0.0343	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0000	0.0189	0.0000	0.0000	0.0000	0.0000	0.0008	0.0000	0.0000	0.0010	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0000	0.3906	0.0000	0.0000	0.0000	0.0000	0.9809	0.0000	0.0000	0.9806	0.9998
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0001	0.0000
N ₂	0.7732	0.0157	0.4811	0.0157	0.9964	0.9964	0.9964	0.0000	0.0000	0.0000	0.0000	0.0000
NH ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0182	0.0000	0.0000	0.0182	0.0002
O ₂	0.2074	0.9501	0.0017	0.9501	0.0036	0.0036	0.0036	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	25,139	104	434	5,311	228	8,009	10,974	4,986	0	0	1,281	2,904
V-L Flowrate (kg/hr)	725,437	3,339	11,166	171,067	6,396	224,465	307,590	89,846	0	0	23,096	52,315
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	218,710	22,323	0	0
Temperature (°C)	15	27	26	27	130	196	196	148	15	1,038	148	343
Pressure (MPa, abs)	0.10	0.86	0.45	5.10	5.62	3.24	2.69	5.79	0.10	4.24	5.79	5.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	21.53	23.80	9.82	129.22	202.25	202.61	590.25	---	---	589.80	3,083.36
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-0.97	-4,654.65	-12.68	103.25	176.29	176.64	-15,134.95	-2,119.02	1,005.43	-15,129.93	-12,884.30
Density (kg/m ³)	1.2	11.2	7.6	68.6	46.4	23.1	19.2	876.5	---	---	875.4	19.9
V-L Molecular Weight	28.857	32.209	25.703	32.209	28.028	28.028	28.028	18.020	---	---	18.028	18.015
V-L Flowrate (lb _{mol} /hr)	55,422	229	958	11,709	503	17,656	24,195	10,992	0	0	2,824	6,402
V-L Flowrate (lb/hr)	1,599,314	7,362	24,617	377,139	14,100	494,860	678,120	198,077	0	0	50,918	115,334
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	482,173	49,214	0	0
Temperature (°F)	59	80	78	80	267	385	385	298	59	1,900	298	650
Pressure (psia)	14.7	125.0	65.0	740.0	815.0	470.0	390.0	840.0	14.7	615.0	840.0	740.0
Steam Table Enthalpy (Btu/lb) ^A	13.0	9.3	10.2	4.2	55.6	87.0	87.1	253.8	---	---	253.6	1,325.6
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-0.4	-2,001.1	-5.5	44.4	75.8	75.9	-6,506.9	-911.0	432.3	-6,504.7	-5,539.3
Density (lb/ft ³)	0.076	0.700	0.472	4.283	2.894	1.439	1.196	54.721	---	---	54.651	1.240

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-73. Case B4B stream table, E-Gas™ IGCC with capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0064	0.0064	0.0000	0.0000	0.0000	0.0000	0.0000	0.0054	0.0000	0.0000	0.0000
CH ₄	0.0000	0.0158	0.0158	0.0000	0.0000	0.0000	0.0000	0.0000	0.0133	0.0000	0.0000	0.0000
CO	0.0000	0.2342	0.2342	0.0000	0.0000	0.0000	0.0000	0.0000	0.0055	0.0001	0.0000	0.0000
CO ₂	0.0000	0.1544	0.1544	0.0054	0.0000	0.0000	0.0000	0.0010	0.3216	0.0010	0.0010	0.0010
COS	0.0000	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.2846	0.2846	0.0003	0.0000	0.0000	0.0000	0.0000	0.4309	0.0002	0.0000	0.0000
H ₂ O	1.0000	0.2788	0.2788	0.9676	1.0000	0.6895	0.1000	0.9806	0.2005	0.9925	0.9806	0.9801
HCl	0.0000	0.0003	0.0003	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0000	0.0058	0.0058	0.0003	0.0000	0.0000	0.0000	0.0001	0.0051	0.0001	0.0001	0.0001
N ₂	0.0000	0.0130	0.0130	0.0000	0.0000	0.0000	0.0000	0.0000	0.0110	0.0000	0.0000	0.0000
NH ₃	0.0000	0.0063	0.0063	0.0264	0.0000	0.0000	0.0000	0.0182	0.0068	0.0036	0.0182	0.0187
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0026	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.3105	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.1000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	2,031	30,347	30,347	459	5,634	30	0	3,669	33,842	3,601	3,901	12,958
V-L Flowrate (kg/hr)	36,594	611,703	611,698	8,314	101,491	754	13	66,140	670,445	65,323	70,320	233,605
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	343	984	232	41	288	16	15	65	228	180	65	68
Pressure (MPa, abs)	5.10	4.24	3.93	3.42	3.83	4.76	0.13	0.47	3.44	3.83	0.47	0.45
Steam Table Enthalpy (kJ/kg) ^A	3,093.81	2,398.07	982.99	114.41	2,972.92	-338.83	-8,206.86	233.68	835.84	750.05	233.68	243.68
AspenPlus Enthalpy (kJ/kg) ^B	-12,886.48	-5,990.05	-7,405.13	-15,427.11	-13,007.37	-13,665.04	-8,526.27	-15,486.05	-8,597.55	-15,080.76	-15,486.05	-15,470.28
Density (kg/m ³)	19.9	8.1	19.1	973.4	16.6	1,531.7	1,791.5	966.2	16.5	882.4	966.2	964.1
V-L Molecular Weight	18.015	20.157	20.157	18.131	18.015	24.842	90.073	18.028	19.811	18.142	18.028	18.028
V-L Flowrate (lb _{mol} /hr)	4,478	66,903	66,903	1,011	12,420	67	0	8,088	74,609	7,938	8,600	28,568
V-L Flowrate (lb/hr)	80,676	1,348,575	1,348,563	18,329	223,748	1,663	30	145,813	1,478,078	144,012	155,030	515,011
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	650	1,804	450	105	550	61	59	149	442	356	149	154
Pressure (psia)	740.0	615.0	570.2	496.0	555.3	690.2	18.2	67.7	499.5	555.3	67.7	65.0
Steam Table Enthalpy (Btu/lb) ^A	1,330.1	1,031.0	422.6	49.2	1,278.1	-145.7	-3,528.3	100.5	359.3	322.5	100.5	104.8
AspenPlus Enthalpy (Btu/lb) ^B	-5,540.2	-2,575.3	-3,183.6	-6,632.5	-5,592.2	-5,874.9	-3,665.6	-6,657.8	-3,696.3	-6,483.6	-6,657.8	-6,651.0
Density (lb/ft ³)	1.240	0.507	1.191	60.765	1.039	95.621	111.841	60.318	1.030	55.088	60.318	60.189

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-73. Case B4B stream table, E-Gas™ IGCC with capture (continued)

	25	26	27	28	29	30	31	32	33	34	35	36
V-L Mole Fraction												
Ar	0.0068	0.0000	0.0000	0.0068	0.0114	0.0000	0.0094	0.0000	0.0000	0.0004	0.0114	0.0092
CH ₄	0.0168	0.0000	0.0000	0.0165	0.0258	0.0018	0.0000	0.0000	0.0000	0.0009	0.0258	0.0000
CO	0.0069	0.0000	0.0000	0.0069	0.0113	0.0003	0.0052	0.0000	0.0000	0.0022	0.0113	0.0000
CO ₂	0.4040	0.0000	0.0009	0.4072	0.0318	0.5124	0.6314	0.0000	0.0000	0.3100	0.0318	0.0003
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0009	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.5438	0.0000	0.0000	0.5396	0.8945	0.0109	0.2460	0.0000	0.0000	0.0238	0.8945	0.0000
H ₂ O	0.0016	0.9999	0.9825	0.0016	0.0001	0.0211	0.0024	0.0000	1.0000	0.1913	0.0001	0.0099
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0063	0.0000	0.0002	0.0063	0.0000	0.4518	0.0049	0.0000	0.0000	0.0126	0.0000	0.0000
N ₂	0.0138	0.0000	0.0000	0.0151	0.0251	0.0001	0.1007	0.0000	0.0000	0.0004	0.0251	0.7732
NH ₃	0.0000	0.0000	0.0164	0.0000	0.0000	0.0006	0.0000	0.0000	0.0000	0.4584	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2074
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	26,808	1,707	646	27,193	16,315	377	385	0	234	161	16,315	110,253
V-L Flowrate (kg/hr)	542,592	30,759	11,654	554,834	83,064	14,508	12,243	0	4,222	4,099	83,064	3,181,556
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	5,481	0	0	0	0
Temperature (°C)	29	15	30	37	18	27	38	184	50	166	193	15
Pressure (MPa, abs)	3.14	0.10	0.24	3.03	2.85	0.18	3.03	0.12	0.11	0.45	2.68	0.10
Steam Table Enthalpy (kJ/kg) ^A	37.28	62.75	90.09	48.52	104.06	40.92	24.17	---	110.26	574.81	1,129.86	30.23
AspenPlus Enthalpy (kJ/kg) ^B	-7,984.48	-15,905.25	-15,654.29	-7,969.95	-3,125.68	-5,633.14	-7,848.90	147.53	-15,859.68	-7,250.11	-2,099.87	-97.58
Density (kg/m ³)	25.8	999.4	985.6	24.4	5.9	2.9	39.9	5,266.5	968.6	3.2	3.5	1.2
V-L Molecular Weight	20.240	18.019	18.027	20.404	5.091	38.457	31.836	---	18.016	25.476	5.091	28.857
V-L Flowrate (lb _{mol} /hr)	59,103	3,763	1,425	59,950	35,968	832	848	0	517	355	35,968	243,065
V-L Flowrate (lb/hr)	1,196,210	67,811	25,692	1,223,200	183,125	31,985	26,990	0	9,309	9,036	183,125	7,014,130
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	12,084	0	0	0	0
Temperature (°F)	84	59	85	99	65	80	100	364	122	330	380	59
Pressure (psia)	454.7	14.7	35.0	439.4	413.2	26.7	439.4	16.8	15.9	65.0	388.9	14.7
Steam Table Enthalpy (Btu/lb) ^A	16.0	27.0	38.7	20.9	44.7	17.6	10.4	---	47.4	247.1	485.8	13.0
AspenPlus Enthalpy (Btu/lb) ^B	-3,432.7	-6,838.0	-6,730.1	-3,426.5	-1,343.8	-2,421.8	-3,374.4	63.4	-6,818.4	-3,117.0	-902.8	-42.0
Density (lb/ft ³)	1.609	62.391	61.529	1.526	0.369	0.180	2.488	328.777	60.467	0.198	0.218	0.076

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-73. Case B4B stream table, E-Gas™ IGCC with capture (continued)

	37	38	39	40	41	42	43	44	45
V-L Mole Fraction									
Ar	0.0087	0.0000	0.0090	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.0000	0.0000	0.0031	0.0011	0.0026	0.0026	0.0000	0.0026
CO	0.0000	0.0000	0.0000	0.0003	0.0000	0.0002	0.0002	0.0000	0.0002
CO ₂	0.0084	0.0000	0.0084	0.9826	0.9974	0.9866	0.9893	0.0500	0.9893
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0097	0.0007	0.0072	0.0073	0.0000	0.0073
H ₂ O	0.1196	1.0000	0.1206	0.0041	0.0007	0.0032	0.0005	0.9500	0.0005
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7568	0.0000	0.7558	0.0001	0.0000	0.0001	0.0001	0.0000	0.0001
NH ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.1064	0.0000	0.1061	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	138,161	38,970	138,625	7,660	2,841	10,501	10,471	30	10,471
V-L Flowrate (kg/hr)	3,796,668	702,056	3,808,407	332,441	124,821	457,262	456,690	572	456,690
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0
Temperature (°C)	566	535	130	-3	-11	29	29	29	30
Pressure (MPa, abs)	0.10	12.51	0.10	0.55	0.12	2.50	2.39	2.50	15.27
Steam Table Enthalpy (kJ/kg) ^A	834.10	3,436.78	338.25	-8.35	-9.65	2.13	0.56	138.13	-226.92
AspenPlus Enthalpy (kJ/kg) ^B	-562.02	-12,543.52	-1,069.57	-8,971.51	-8,971.34	-8,960.80	-8,954.35	-15,225.03	-9,181.83
Density (kg/m ³)	0.4	36.6	0.8	11.2	2.3	49.7	47.2	319.0	836.6
V-L Molecular Weight	27.480	18.015	27.473	43.402	43.930	43.545	43.614	19.315	43.614
V-L Flowrate (lb _{mol} /hr)	304,593	85,914	305,616	16,886	6,264	23,150	23,085	65	23,085
V-L Flowrate (lb/hr)	8,370,221	1,547,767	8,396,099	732,907	275,184	1,008,091	1,006,830	1,261	1,006,830
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0
Temperature (°F)	1,051	996	265	26	12	85	85	85	86
Pressure (psia)	15.1	1,814.7	14.8	80.0	16.7	363.0	346.5	363.0	2,214.7
Steam Table Enthalpy (Btu/lb) ^A	358.6	1,477.5	145.4	-3.6	-4.1	0.9	0.2	59.4	-97.6
AspenPlus Enthalpy (Btu/lb) ^B	-241.6	-5,392.7	-459.8	-3,857.1	-3,857.0	-3,852.4	-3,849.7	-6,545.6	-3,947.5
Density (lb/ft ³)	0.026	2.287	0.052	0.697	0.146	3.105	2.945	19.917	52.229

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

3.3.8.3 Raw Gas Cooling and Particulate Removal

No differences from Case B4A.

3.3.8.4 Syngas Scrubber

Case B4B differs from Case B4A only in the degree of cooling completed prior to the cooling water HX. In Case B4A, both the process water and scrubber effluent recycle are cooled to 58°C (137°F) by preheating syngas prior to the CT. However, in this case, the recycled effluent is cooled from 181°C (357°F) to 44°C (112°F) by preheating FW to the WGS steam generator, and the process water (stream 20) is cooled to 32°C (90°F) by preheating syngas prior to the CT and mixed with the cooled effluent before being cooled further to 21°C (70°F) with cooling water and injected into the scrubber.

3.3.8.5 Water Gas Shift

The WGS process was described in Section 3.1.3. After the scrubber, the syngas is combined with steam (stream 17) to adjust the steam to dry gas ratio prior to the first WGS reactor. The rate of steam injection is controlled to maintain an exit steam to dry gas ratio of approximately 0.25. Three stages total are used to convert 97.3 percent of the CO in the syngas to CO₂. The heat generated from the first two reactors is used to produce most (an additional 12,565 kg/hr [27,700 lb/hr] is extracted from the steam cycle) of the steam required to maintain the desired steam to dry gas ratio while cooling the syngas to 253°C (487°F) prior to entering the second and third stages. Prior to the syngas being sent to the LTHR system (stream 21), the warm syngas from the third stage of WGS is cooled to 228°C (442°F) by preheating the FW of the WGS steam generator.

The WGS catalyst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor.

3.3.8.6 Quench Gas Compressor

The recycle to the gasifier in Case B4B is taken after the WGS, rather than before the syngas scrubber, as was done in Case B4A. Approximately six percent of the syngas exiting the WGS is recycled to the gasifier exit. All other aspects of the syngas recycle are identical to those of Case B4A.

3.3.8.7 Low Temperature Heat Recovery

Case B4B only differs from Case B4A in that the second stage of the LTHR system cools the syngas by heating water fed to the gasifier and preheating the FW of the WGS steam generator, in addition to the other uses described for Case B4A.

3.3.8.8 Sour Water Stripper and Ammonia Wash

No differences from Case B4A.

3.3.8.9 Process Water Treatment

The process water treatment system is identical to that used in Case B4A, with the exception that the vapor products from both the LP and vacuum flash stages are cooled to 46°C (115°F) prior to the cooling water condensing HX. The lower temperature reached in this case (46°C [115°F] versus 72°C [162°F]) is due to the lower exit temperature of the Selexol system, compared to the MDEA system.

3.3.8.10 Mercury Removal and AGR

Mercury removal is the same as in Case B4A.

The AGR process in Case B4B is a two-stage Selexol process (covered in Section 3.1.5.4) where H₂S is removed in the first stage and CO₂ in the second stage of absorption. The process results in four product streams, the clean syngas (stream 29), two CO₂-rich streams (streams 40 and 41) and an acid gas feed to the Claus plant (stream 30). The acid gas contains 45 vol% H₂S and 51 vol% CO₂ with the balance primarily water and H₂. The raw CO₂ stream from the Selexol process contains over 99 vol% CO₂.

3.3.8.11 Claus Unit

No differences from Case B4A.

3.3.8.12 Power Block

In Case B4B, HP N₂ (stream 6) at 3.2 MPa (470 psia), in addition to the LP N₂ (stream 7) at 2.7 MPa (390 psia), is used as a syngas diluent. The exhaust gas (stream 37) exits the CT at a lower temperature (566°C [1,051°F]) than Case B4A due to the higher moisture content.

3.3.8.13 Air Separation Unit

No differences from Case B4A.

3.3.9 Case B4B – Performance Results

The Case B4B modeling assumptions were presented previously in Section 3.3.2.

The plant produces a net output of 557 MW at a net plant efficiency of 33.8 percent (HHV basis). Overall performance for the entire plant is summarized in Exhibit 3-74. Exhibit 3-75 provides a detailed breakdown of the auxiliary power requirements. The ASU accounts for nearly 62 percent of the auxiliary load between the MAC, N₂ compressor, O₂ compressor, and ASU auxiliaries. The two-stage Selexol process and CO₂ compression account for an additional 24 percent of the auxiliary power load. The BFW pumps and cooling water system (circulating water pumps and cooling tower fan) compose nearly 6 percent of the load, with all other systems together constituting the remaining 8 percent of the auxiliary load.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-74. Case B4B plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	464
Sweet Gas Expander Power, MWe	–
Steam Turbine Power, MWe	278
Total Gross Power, MWe	742
Air Separation Unit Main Air Compressor, kWe	69,670
Air Separation Unit Booster Compressor, kWe	5,480
N ₂ Compressors, kWe	36,930
CO ₂ Compression, kWe	31,930
Acid Gas Removal, kWe	11,650
Balance of Plant, kWe	29,160
Total Auxiliaries, MWe	185
Net Power, MWe	557
HHV Net Plant Efficiency, %	33.8
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,657 (10,101)
HHV Cold Gas Efficiency, %	80.4
HHV Combustion Turbine Efficiency, %	36.3
LHV Net Plant Efficiency, %	35.0
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,279 (9,743)
LHV Cold Gas Efficiency, %	76.4
LHV Combustion Turbine Efficiency, %	42.6
Steam Turbine Cycle Efficiency, %	44.7
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	8,052 (7,632)
Condenser Duty, GJ/hr (MMBtu/hr)	1,492 (1,414)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	148 (141)
As-Received Coal Feed, kg/hr (lb/hr)	218,710 (482,173)
HHV Thermal Input, kWt	1,648,535
LHV Thermal Input, kWt	1,590,032
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.035 (9.3)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.028 (7.4)
O ₂ :As-Received Coal	0.738

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-75. Case B4B plant power summary

Power Summary	
Combustion Turbine Power, MWe	464
Sweet Gas Expander Power, MWe	–
Steam Turbine Power, MWe	278
Total Gross Power, MWe	742
Auxiliary Load Summary	
Acid Gas Removal, kWe	11,650
Air Separation Unit Auxiliaries, kWe	1,000
Air Separation Unit Main Air Compressor, kWe	69,670
Air Separation Unit Booster Compressor, kWe	5,480
Ammonia Wash Pumps, kWe	120
Circulating Water Pumps, kWe	4,770
Claus Plant TG Recycle Compressor, kWe	1,300
Claus Plant/TGTU Auxiliaries, kWe	250
CO ₂ Compression, kWe	31,930
Coal Dryer Air Compressor, kWe	–
Coal Handling, kWe	470
Coal Milling, kWe	2,250
Combustion Turbine Auxiliaries, kWe	1,000
Condensate Pumps, kWe	270
Cooling Tower Fans, kWe	2,470
Feedwater Pumps, kWe	4,240
Gasifier Water Pump, kWe	160
Ground Water Pumps, kWe	470
Miscellaneous Balance of Plant ^A , kWe	3,000
N ₂ Compressors, kWe	36,930
N ₂ Humidification Pump, kWe	–
O ₂ Pump, kWe	350
Quench Water Pump, kWe	–
Shift Steam Pump, kWe	150
Slag Handling, kWe	1,160
Slag Reclaim Water Recycle Pump, kWe	–
Slurry Water Pump, kWe	190

Power Summary	
Auxiliary Load Summary	
Sour Gas Compressors, kWe	170
Sour Water Recycle Pumps, kWe	–
Steam Turbine Auxiliaries, kWe	200
Syngas Recycle Compressor, kWe	810
Syngas Scrubber Pumps, kWe	120
Process Water Treatment Auxiliaries, kWe	1,370
Transformer Losses, kWe	2,870
Total Auxiliaries, MWe	185
Net Power, MWe	557

^AIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

3.3.9.1 Environmental Performance

The environmental targets for emissions of Hg, HCl, NO_x, SO₂, CO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B4B is presented in Exhibit 3-76.

Exhibit 3-76. Case B4B air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.021 (0.049)	874 (963)	0.168 (0.371)
Particulate	0.003 (0.007)	127 (140)	0.024 (0.054)
Hg	1.70E-7 (3.96E-7)	0.007 (0.008)	1.36E-6 (3.00E-6)
HCl	0.000 (0.000)	0.00 (0.00)	0.000 (0.000)
CO ₂	9 (20)	360,945 (397,873)	69 (153)
CO ₂ ^C	–	–	92 (204)

^ACalculations based on an 80 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

The low level of SO₂ emissions is achieved by capturing the sulfur in the gas by the two-stage Selexol AGR process. The CO₂ capture target results in the sulfur compounds being removed to a greater extent than required in the environmental targets of Section 2.4. The clean syngas exiting the AGR process has a sulfur concentration of approximately 5 ppmv. This results in a concentration in the flue gas of less than 1 ppmv. The H₂S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H₂S, and then recycled back to the Selexol, thereby eliminating the need for a TGTU.

NO_x emissions are limited by the use of N₂ dilution to 15 ppmvd (NO at 15 percent O₂). NH₃ in the syngas is removed with process condensate prior to the low-temperature AGR process and ultimately destroyed in the Claus plant burner. This helps lower NO_x levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Approximately 97 percent of the mercury is captured from the syngas by dual activated carbon beds.

Ninety five percent of the CO₂ from the syngas is captured in the AGR system and compressed for sequestration. Because not all CO is converted to CO₂ in the shift reactors, the overall carbon removal is 90 percent.

The carbon balance for the plant is shown in Exhibit 3-77. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon leaves the plant as unburned carbon in the slag and, the captured CO₂ product, and as CO₂ in the stack gas (includes the ASU vent gas). The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in less carbon contained in the slag, represented by the following fraction:

$$\left(1 - \left(\frac{\text{Carbon in Stack}}{(\text{Total Carbon In}) - (\text{Carbon in Slag})}\right)\right) * 100 = \left(1 - \left(\frac{30,989}{308,532 - 2,459}\right)\right) * 100 = 90\%$$

The high methane content of the syngas, relative to the GEP and Shell cases, prevented reaching the nominal 90 percent carbon capture. In order to achieve an overall 90 percent capture, a third stage of WGS was added.

Exhibit 3-77. Case B4B carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	139,416 (307,360)	Stack Gas	14,056 (30,989)
Air (CO ₂)	531 (1,171)	CO ₂ Product	124,776 (275,084)
		Slag	1,115 (2,459)
Total	139,948 (308,532)	Total	139,948 (308,532)

Exhibit 3-78 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant and sulfur in the CO₂ product. Sulfur in the slag is considered to be negligible.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-78. Case B4B sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	5,482 (12,085)	Stack Gas	–
		CO ₂ Product	1 (2)
		Elemental Sulfur	5,481 (12,084)
Total	5,482 (12,085)	Total	5,482 (12,085)

Exhibit 3-79 shows the overall water balance for the plant. The exhibit is presented in an identical manner as cases B1A through B4A.

Exhibit 3-79. Case B4B water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
Slag Handling	0.48 (128)	0.48 (128)	–	–	–
Slurry Water	1.50 (396)	1.50 (396)	–	–	–
Gasifier Water	0.39 (102)	0.39 (102)	–	–	–
Quench	–	–	–	–	–
HCl Scrubbers	1.30 (342)	1.30 (342)	–	–	–
NH ₃ Scrubber	1.66 (438)	1.15 (303)	0.51 (136)	–	0.51 (136)
Gasifier Steam	0.87 (231)	0.87 (231)	–	–	–
Condenser Makeup	0.82 (216)	–	0.82 (216)	–	0.82 (216)
BFW Makeup	0.21 (55)	–	0.21 (55)	–	0.21 (55)
Gasifier Steam	0.61 (161)	–	0.61 (161)	–	0.61 (161)
Shift Steam	–	–	–	–	–
N ₂ Humidification	–	–	–	–	–
Cooling Tower	18.57 (4,906)	0.23 (61)	18.34 (4,845)	4.18 (1,103)	14.16 (3,741)
BFW Blowdown	–	0.21 (55)	-0.21 (-55)	–	-0.21 (-55)
ASU Knockout	–	0.02 (6)	-0.02 (-6)	–	-0.02 (-6)
Total	25.59 (6,760)	5.92 (1,563)	19.67 (5,197)	4.18 (1,103)	15.50 (4,093)

An overall plant energy balance is provided in tabular form in Exhibit 3-80. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a combined generator efficiency of 98.5 percent.

Exhibit 3-80. Case B4B overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, MMBtu/hr (GJ/hr)				
Coal	5,935 (5,625)	5.0 (4.7)	–	5,940 (5,630)
Air	–	118.1 (111.9)	–	118.1 (111.9)
Raw Water Makeup	–	74.0 (70.1)	–	74.0 (70.1)
Auxiliary Power	–	–	665.4 (630.6)	665.4 (630.6)
TOTAL	5,935 (5,625)	197.0 (186.7)	665.4 (630.6)	6,797 (6,442)
Heat Out, MMBtu/hr (GJ/hr)				
Misc. Process Steam	–	4.8 (4.6)	–	4.8 (4.6)
Slag	36.6 (34.7)	25.1 (23.8)	–	61.6 (58.4)
Stack Gas	–	1,288 (1,221)	–	1,288 (1,221)
Sulfur	50.8 (48.1)	0.7 (0.6)	–	51.4 (48.8)
Motor Losses and Design Allowances	–	–	58.2 (55.2)	58.2 (55.2)
Cooling Tower Load ^A	–	2,425 (2,298)	–	2,425 (2,298)
CO ₂ Product Stream	–	-103.6 (-98.2)	–	-103.6 (-98.2)
Blowdown Streams	–	38.5 (36.5)	–	38.5 (36.5)
Ambient Losses ^B	–	144.0 (136.5)	–	144.0 (136.5)
Power	–	–	2,670 (2,531)	2,670 (2,531)
TOTAL	87.4 (82.8)	3,822 (3,623)	2,728 (2,586)	6,638 (6,292)
Unaccounted Energy ^C	–	–	–	159.2 (150.9)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers

^CBy difference

3.3.9.2 Energy and Mass Balance Diagrams

Energy and mass balance diagrams are shown for the following subsystems in Exhibit 3-81 through Exhibit 3-83:

- Coal gasification and ASU
- Syngas cleanup including sulfur recovery and tail gas recycle
- Combined cycle power generation, steam, and FW

Exhibit 3-81. Case B4B coal gasification and ASU energy and mass balance

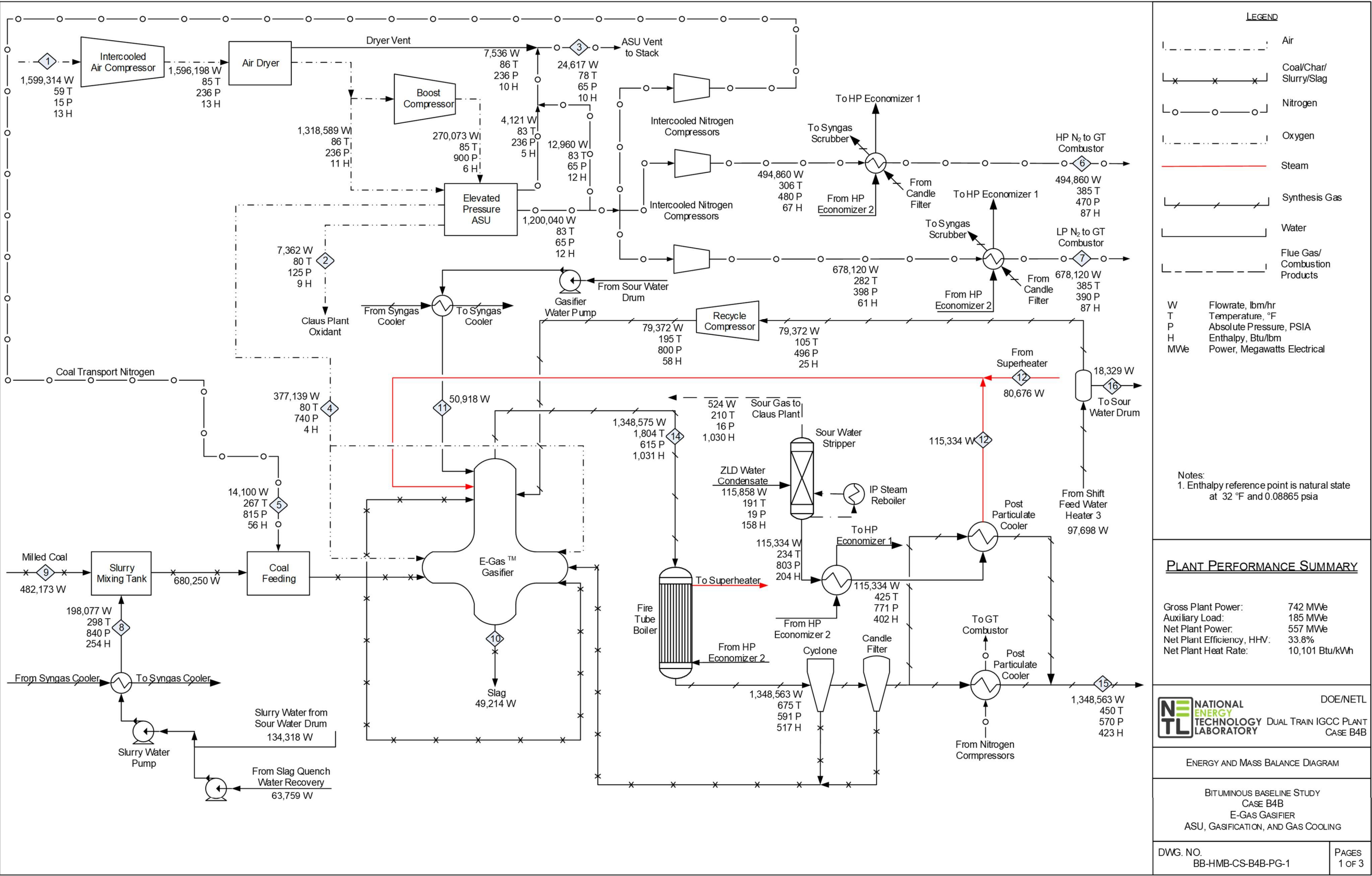


Exhibit 3-82. Case B4B syngas cleanup energy and mass balance

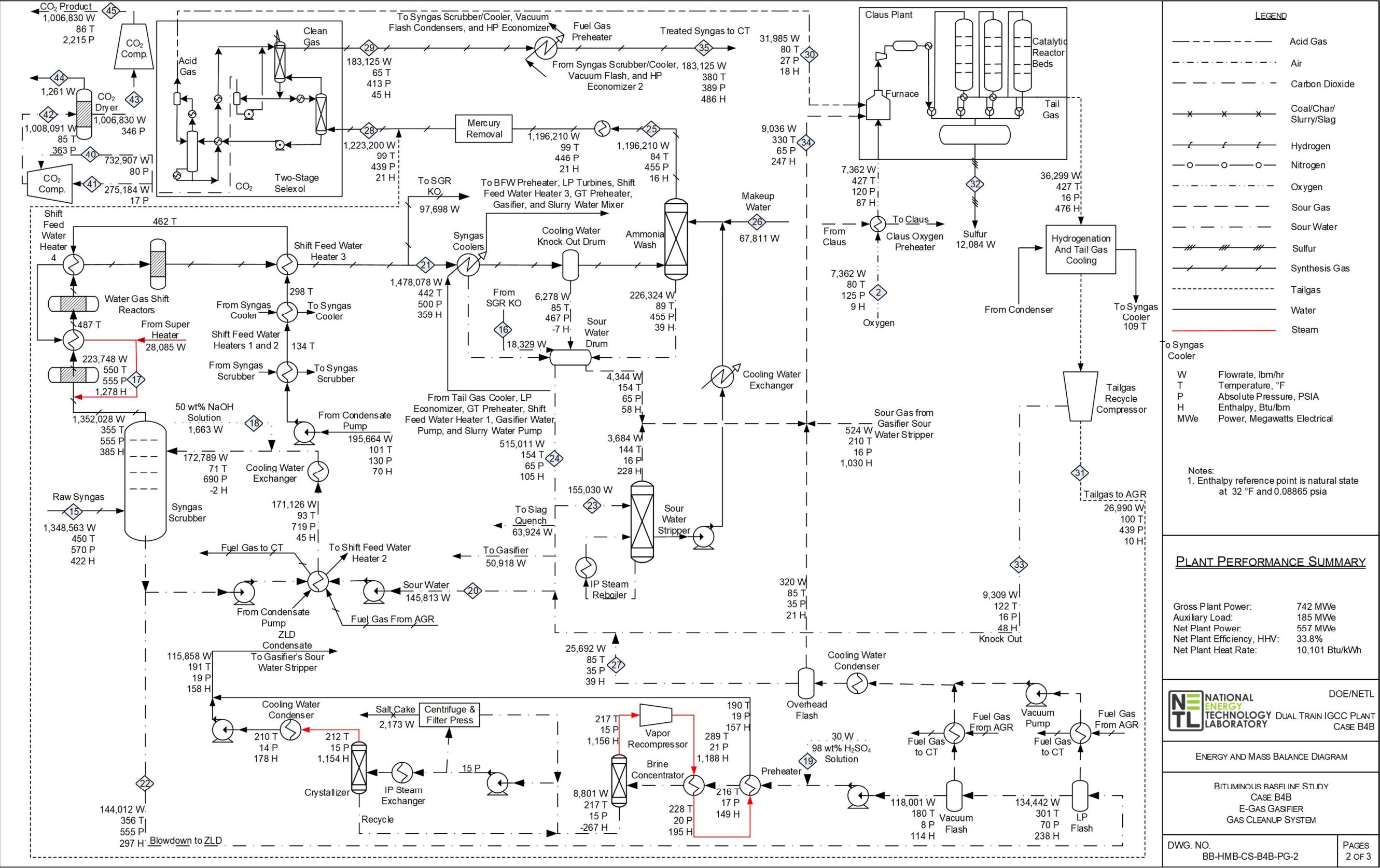
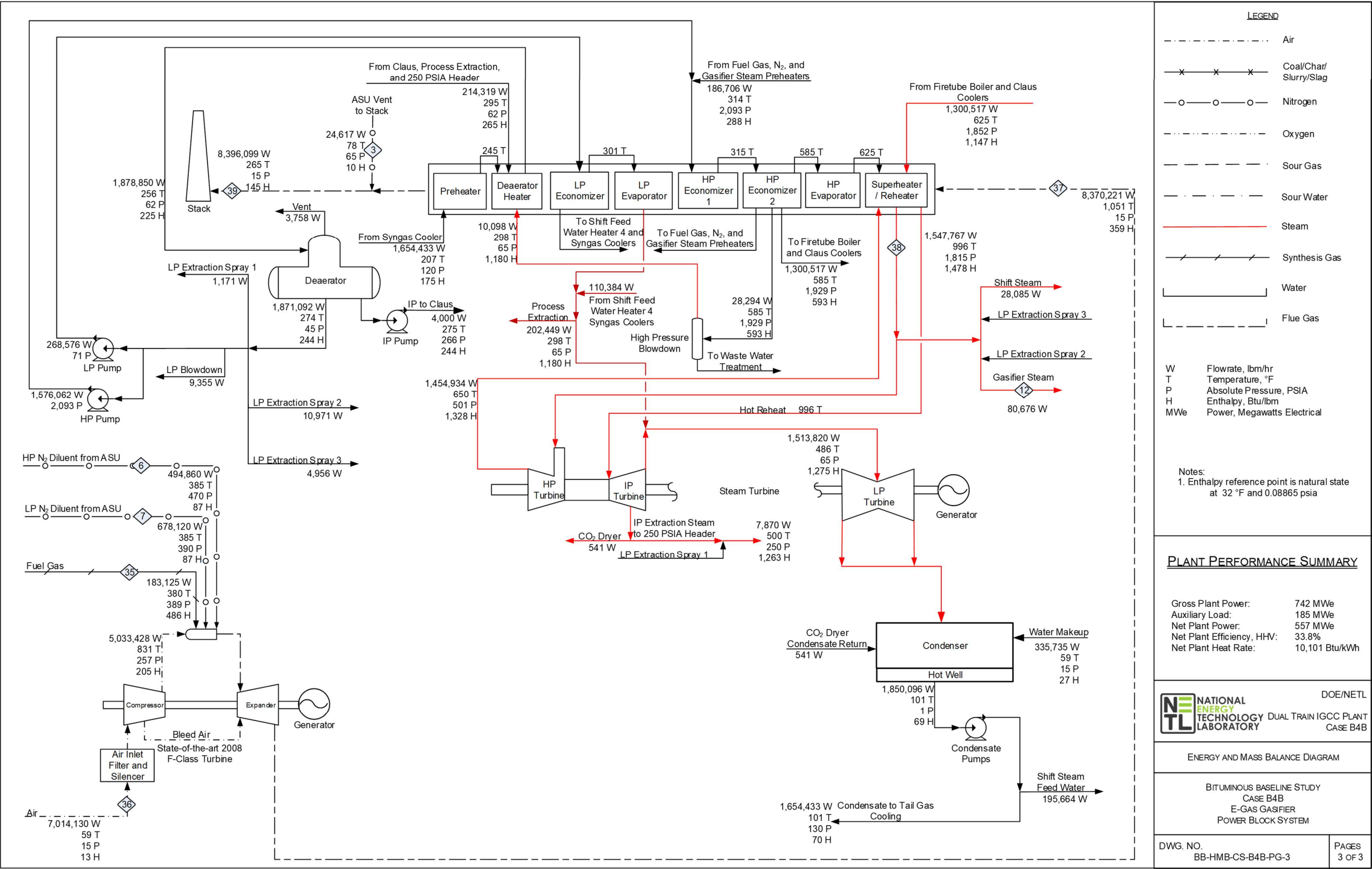


Exhibit 3-83. Case B4B combined cycle power generation energy and mass balance



This page intentionally left blank

3.3.10 Case B4B – Major Equipment List

Major equipment items for the E-Gas™ gasifier with CO₂ capture are shown in the following tables. In general, the design conditions include a 10 percent design allowance for flows and heat duties and a 21 percent design allowance for heads on pumps and fans.

Case B4B – Account 1: Coal Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
5	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
6	Reclaim Hopper	N/A	50 tonne (50 ton)	2	1
7	Feeder	Vibratory	180 tonne/hr (200 tph)	2	1
8	Conveyor No. 3	Belt w/ tripper	360 tonne/hr (400 tph)	1	0
9	Coal Surge Bin w/ Vent Filter	Dual outlet	180 tonne (200 ton)	2	0
10	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
11	Conveyor No. 4	Belt w/trippper	360 tonne/hr (400 tph)	1	0
12	Conveyor No. 5	Belt w/ tripper	360 tonne/hr (400 tph)	1	0
13	Coal Silo w/ Vent Filter and Slide Gates	Field erected	800 tonne (880 ton)	3	0

Case B4B – Account 2: Coal Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	80 tonne/hr (90 tph)	3	0
2	Conveyor No. 6	Belt w/trippper	240 tonne/hr (270 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	480 tonne (530 ton)	1	0
4	Weigh Feeder	Belt	120 tonne/hr (130 tph)	2	0
5	Rod Mill	Rotary	120 tonne/hr (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	296,930 liters (78,440 gal)	2	0
7	Slurry Water Pumps	Centrifugal	820 lpm (220 gpm)	2	1
8	Trommel Screen	Coarse	170 tonne/hr (190 tph)	2	0
9	Rod Mill Discharge Tank with Agitator	Field erected	388,420 liters (102,610 gal)	2	0
10	Rod Mill Product Pumps	Centrifugal	3,200 lpm (900 gpm)	2	2
11	Slurry Storage Tank with Agitator	Field erected	1,165,300 liters (307,800 gal)	2	0
12	Slurry Recycle Pumps	Centrifugal	6,500 lpm (1,700 gpm)	2	2
13	Slurry Product Pumps	Positive displacement	3,200 lpm (900 gpm)	2	2

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B4B – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	10,057,000 liters (2,657,000 gal)	2	0
2	Condensate Pumps	Vertical canned	7,750 lpm @ 90 m H ₂ O (2,050 gpm @ 300 ft H ₂ O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	469,000 kg/hr (1,033,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	1,160 lpm @ 20 m H ₂ O (310 gpm @ 70 ft H ₂ O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,820 lpm @ 1,700 m H ₂ O (1,800 gpm @ 5,700 ft H ₂ O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 810 lpm @ 210 m H ₂ O (210 gpm @ 670 ft H ₂ O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	431 GJ/hr (409 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	154,700 lpm @ 20 m H ₂ O (40,900 gpm @ 70 ft H ₂ O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
14	Municipal Water Pumps	Stainless steel, single suction	3,680 lpm @ 20 m H ₂ O (970 gpm @ 60 ft H ₂ O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,450 lpm @ 270 m H ₂ O (650 gpm @ 880 ft H ₂ O)	3	1
16	Filtered Water Pumps	Stainless steel, single suction	1,680 lpm @ 50 m H ₂ O (440 gpm @ 160 ft H ₂ O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	806,000 liter (213,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	1,400 lpm (370 gpm)	2	0
19	Liquid Waste Treatment System	N/A	10 years, 24-hour storm	1	0
20	Process Water Treatment	Vacuum flash, brine concentrator, and crystallizer	Vacuum Flash - Inlet: 36,000 kg/hr (79,000 lb/hr) Outlet: 6,102 ppmw Cl- Brine Concentrator Inlet - 29,000 kg/hr (65,000 lb/hr) Crystallizer Inlet - 2,000 kg/hr (5,000 lb/hr)	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B4B – Account 4: Gasifier, ASU, and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized two-stage, slurry-feed entrained bed	2,900 tonne/day, 4.2 MPa (3,200 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Fire-tube boiler	336,000 kg/hr (742,000 lb/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	336,000 kg/hr (742,000 lb/hr) Design efficiency 90%	2	0
4	HCl Scrubber	Ejector Venturi	336,000 kg/hr (742,000 lb/hr)	2	0
5	Ammonia Wash	Counter-flow spray tower	300,000 kg/hr (662,000 lb/hr) @ 3.2 MPa (467 psia)	2	0
6	Primary Sour Water Stripper	Counter-flow with external reboiler	39,000 kg/hr (85,000 lb/hr)	2	0
7	Secondary Sour Water Stripper	Counter-flow with external reboiler	29,000 kg/hr (64,000 lb/hr)	2	0
8	Low Temperature Heat Recovery Coolers	Shell and tube with condensate drain	369,000 kg/hr (813,000 lb/hr)	6	0
9	Low Temperature Heat Recovery Knockout Drum	Vertical with mist eliminator	302,000 kg/hr, 59°C, 3.2 MPa (665,000 lb/hr, 138°F, 470 psia)	2	0
10	Saturation Water Economizers	Shell and tube	N/A	4	0
11	HP Nitrogen Gas Saturator	Direct Injection	123,000 kg/hr, 196°C, 3.2 MPa (272,000 lb/hr, 385°F, 470 psia)	2	0
12	LP Nitrogen Gas Saturator	Direct Injection	169,000 kg/hr, 196°C, 2.7 MPa (373,000 lb/hr, 385°F, 390 psia)	2	0
13	Saturator Water Pump	Centrifugal	N/A	2	2
14	Saturated Nitrogen Reheaters	Shell and tube	N/A	4	0
15	Synthesis Gas Reheaters	Shell and tube	Reheater 1: N/A Reheater 2: 10,000 kg/hr (22,000 lb/hr) Reheater 3: 26,000 kg/hr (57,000 lb/hr) Reheater 4: 10,000 kg/hr (22,000 lb/hr) Reheater 5: 46,000 kg/hr (101,000 lb/hr) Reheater 6: 46,000 kg/hr (101,000 lb/hr)	2	0
16	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	337,000 kg/hr (744,000 lb/hr) syngas	2	0
17	ASU Main Air Compressor	Centrifugal, multi-stage	5,000 m ³ /min @ 1.6 MPa (193,000 scfm @ 236 psia)	2	0
18	Cold Box	Vendor design	2,300 tonne/day (2,500 tpd) of 95% purity O ₂	2	0
19	Gasifier O ₂ Pump	Centrifugal, multi-stage	1,000 m ³ /min (41,000 scfm) Suction - 1.0 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	2	0
20	AGR Nitrogen Boost Compressor	Centrifugal, multi-stage	N/A	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
21	High Pressure Nitrogen Diluent Compressor	Centrifugal, multi-stage	2,000 m ³ /min (61,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - 3.3 MPa (480 psia)	2	0
22	Low Pressure Nitrogen Diluent Compressor	Centrifugal, single-stage	2,380 m ³ /min (84,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - 2.7 MPa (400 psia)	2	0
23	Gasifier Nitrogen Boost Compressor	Centrifugal, single-stage	50 m ³ /min (2,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - 5.6 MPa (820 psia)	2	0

Case B4B – Account 5: Syngas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber 1	Sulfated carbon bed	298,000 kg/hr (658,000 lb/hr) 29°C (84°F) 3.1 MPa (455 psia)	2	0
2	Mercury Adsorber 2	Sulfated carbon bed	298,000 kg/hr (658,000 lb/hr) 37°C (99°F) 3.1 MPa (442 psia)	2	0
3	Sulfur Plant	Claus type	145 tonne/day (160 tpd)	1	0
4	Water Gas Shift Reactors	Fixed bed, catalytic	131,000 kg/hr (289,000 lb/hr) 199°C (390°F) 3.9 MPa (560 psia)	6	0
5	Shift Reactor Heat Recovery Exchangers	Shell and Tube	Exchanger 1: 88 GJ/hr (84 MMBtu/hr) Exchanger 2: 93 GJ/hr (88 MMBtu/hr) Exchanger 3: 29 GJ/hr (28 MMBtu/hr) Exchanger 4: 40 GJ/hr (38 MMBtu/hr)	8	0
6	Acid Gas Removal Plant	Two-stage Selexol	610,000 kg/hr (1,346,000 lb/hr) 37°C (99°F) 3.0 MPa (439 psia)	1	0
7	Hydrogenation Reactor	Fixed bed, catalytic	18,000 kg/hr (40,000 lb/hr) 219°C (427°F) 0.1 MPa (16.4388411 psia)	1	0
8	Tail Gas Recycle Compressor	Centrifugal	13,000 kg/hr (30,000 lb/hr) each	1	0
9	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0
10	CO ₂ Dryer	Triethylene glycol	Inlet: 153 m ³ /min @ 2.5 MPa (5,411 acfm @ 363 psia) Outlet: 2.4 MPa (346 psia) Water Recovered: 572 kg/hr (1,261 lb/hr)	1	0
11	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	10 m ³ /min @ 15.3 MPa (353 acfm @ 2,217 psia)	1	0
12	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 78 GJ/hr (74 MMBtu/hr)	1	0

Case B4B – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	State-of-the-art 2008 F-Class	232 MW	2	0
2	Combustion Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

Case B4B – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.5 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 386,131 kg/hr, 12.4 MPa/535°C (851,272 lb/hr, 1,800 psig/996°F) Reheat steam - 362,971 kg/hr, 3.3 MPa/535°C (800,214 lb/hr, 477 psig/996°F)	2	0

Case B4B – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	292 MW 12.4 MPa/535°C/535°C (1,800 psig/996°F/996°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	320 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,640GJ/hr (1,560 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

Case B4B – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	479,000 lpm @ 30 m (126,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 2,670 GJ/hr (2,530 MMBtu/hr) heat duty	1	0

Case B4B – Account 10: Slag Recovery and Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	234,000 liters (62,000 gal)	2	0
2	Slag Crusher	Roll	12 tonne/hr (14 tph)	2	0
3	Slag Depressurizer	Proprietary	12 tonne/hr (14 tph)	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
4	Slag Receiving Tank	Horizontal, weir	141,000 liters (37,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	64,000 liters (17,000 gal)	2	0
6	Slag Conveyor	Drag chain	12 tonne/hr (14 tph)	2	0
7	Slag Separation Screen	Vibrating	12 tonne/hr (14 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	12 tonne/hr (14 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	200,000 liters (53,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	50 lpm @ 14 m H ₂ O (10 gpm @ 46 ft H ₂ O)	2	2
11	Grey Water Storage Tank	Field erected	64,000 liters (17,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	230 lpm @ 430 m H ₂ O (60 gpm @ 1,420 ft H ₂ O)	2	2
13	Slag Storage Bin	Vertical, field erected	900 tonne (1,000 tons)	2	0
14	Unloading Equipment	Telescoping chute	100 tonne/hr (110 tph)	1	0

Case B4B – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 280 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 80 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 42 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 6 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B4B – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.3.11 Case B4B – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 3-84 shows a detailed breakdown of the capital costs; Exhibit 3-85 shows the owner's costs, TOC, and TASC; Exhibit 3-86 shows the initial and annual O&M costs; and Exhibit 3-87 shows the LCOE breakdown.

The estimated TPC of the E-GasTM gasifier with CO₂ capture is \$5,501/kW. Process contingency represents 5.5 percent of the TPC, and project contingency represents 15.1 percent. The LCOE, including CO₂ T&S costs of \$8.2/MWh, is \$158.3/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-84. Case B4B total plant cost details

Case:		B4B	– E-Gas™ IGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		557					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1 Coal Handling											
1.1	Coal Receive & Unload	\$990	\$0	\$477	\$0	\$1,467	\$220	\$0	\$337	\$2,024	\$4
1.2	Coal Stackout & Reclaim	\$3,235	\$0	\$774	\$0	\$4,009	\$601	\$0	\$922	\$5,533	\$10
1.3	Coal Conveyors & Yard Crush	\$30,868	\$0	\$7,856	\$0	\$38,724	\$5,809	\$0	\$8,907	\$53,440	\$96
1.4	Other Coal Handling	\$4,807	\$0	\$1,082	\$0	\$5,889	\$883	\$0	\$1,354	\$8,127	\$15
1.9	Coal & Sorbent Handling Foundations	\$0	\$87	\$226	\$0	\$313	\$47	\$0	\$72	\$432	\$1
	Subtotal	\$39,900	\$87	\$10,415	\$0	\$50,402	\$7,560	\$0	\$11,592	\$69,555	\$125
2 Coal Preparation & Feed											
2.1	Coal Crushing & Drying	\$2,399	\$145	\$345	\$0	\$2,888	\$433	\$0	\$664	\$3,985	\$7
2.2	Prepared Coal Storage & Feed	\$7,369	\$1,769	\$1,141	\$0	\$10,279	\$1,542	\$0	\$2,364	\$14,185	\$25
2.3	Slurry Coal Injection System	\$7,211	\$0	\$3,163	\$0	\$10,374	\$1,556	\$0	\$2,386	\$14,316	\$26
2.4	Miscellaneous Coal Preparation & Feed	\$728	\$532	\$1,566	\$0	\$2,825	\$424	\$0	\$650	\$3,898	\$7
2.9	Coal & Sorbent Feed Foundation	\$0	\$1,770	\$1,519	\$0	\$3,289	\$493	\$0	\$756	\$4,539	\$8
	Subtotal	\$17,706	\$4,215	\$7,733	\$0	\$29,655	\$4,448	\$0	\$6,821	\$40,924	\$73
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$2,193	\$3,759	\$1,880	\$0	\$7,831	\$1,175	\$0	\$1,801	\$10,807	\$19
3.2	Water Makeup & Pretreating	\$5,288	\$529	\$2,996	\$0	\$8,813	\$1,322	\$0	\$3,040	\$13,175	\$24
3.3	Other Feedwater Subsystems	\$1,133	\$372	\$353	\$0	\$1,858	\$279	\$0	\$427	\$2,564	\$5
3.4	Service Water Systems	\$1,580	\$3,017	\$9,768	\$0	\$14,365	\$2,155	\$0	\$4,956	\$21,476	\$39
3.5	Other Boiler Plant Systems	\$294	\$107	\$268	\$0	\$669	\$100	\$0	\$154	\$923	\$2
3.6	Natural Gas Pipeline and Start-Up System	\$7,251	\$312	\$234	\$0	\$7,797	\$1,170	\$0	\$1,793	\$10,760	\$19
3.7	Waste Water Treatment Equipment	\$7,468	\$0	\$4,577	\$0	\$12,045	\$1,807	\$0	\$4,156	\$18,008	\$32
3.8	Vacuum Flash, Brine Concentrator, & Crystallizer	\$25,507	\$0	\$15,795	\$0	\$41,303	\$6,195	\$0	\$14,250	\$61,748	\$111
3.9	Miscellaneous Plant Equipment	\$15,441	\$2,025	\$7,847	\$0	\$25,313	\$3,797	\$0	\$8,733	\$37,843	\$68
	Subtotal	\$66,156	\$10,120	\$43,718	\$0	\$119,995	\$17,999	\$0	\$39,310	\$177,304	\$318
4 Gasifier, ASU, & Accessories											
4.1	Gasifier & Auxiliaries (E-GAS)	\$375,564	\$0	\$209,329	\$0	\$584,893	\$87,734	\$81,885	\$113,177	\$867,689	\$1,558
4.2	Syngas Cooler	\$50,059	\$0	\$27,901	\$0	\$77,960	\$11,694	\$10,914	\$15,085	\$115,654	\$208
4.3	Air Separation Unit/Oxidant Compression	\$129,771	\$29,700	\$30,885	\$0	\$190,357	\$38,071	\$19,036	\$37,120	\$284,583	\$511
4.5	Miscellaneous Gasification Equipment	\$3,895	\$0	\$2,171	\$0	\$6,066	\$910	\$0	\$1,046	\$8,023	\$14

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B4B	– E-Gas™ IGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		557					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
4.6	Low Temperature Heat Recovery & Flue Gas Saturation	\$45,010	\$0	\$17,100	\$0	\$62,110	\$9,316	\$0	\$14,285	\$85,711	\$154
4.7	Flare Stack System	\$1,931	\$0	\$341	\$0	\$2,271	\$341	\$0	\$522	\$3,135	\$6
4.15	Major Component Rigging	\$217	\$0	\$121	\$0	\$338	\$51	\$0	\$58	\$446	\$1
4.16	Gasification Foundations	\$0	\$478	\$285	\$0	\$762	\$114	\$0	\$219	\$1,096	\$2
	Subtotal	\$606,446	\$30,178	\$288,133	\$0	\$924,758	\$148,231	\$111,835	\$181,513	\$1,366,337	\$2,454
5		Syngas Cleanup									
5.1	Double Stage Selexol	\$163,403	\$0	\$66,742	\$0	\$230,146	\$34,522	\$46,029	\$62,139	\$372,836	\$670
5.2	Sulfur Removal	w/5.1	w/5.1	w/5.1	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5.3	Elemental Sulfur Plant	\$48,542	\$9,461	\$62,201	\$0	\$120,204	\$18,031	\$0	\$27,647	\$165,881	\$298
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$32,478	\$4,872	\$14,073	\$0	\$51,423	\$7,713	\$0	\$11,827	\$70,963	\$127
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$485	\$77	\$208	\$0	\$769	\$115	\$0	\$177	\$1,061	\$2
5.6	Mercury Removal (Carbon Bed)	\$485	\$0	\$367	\$0	\$852	\$128	\$43	\$204	\$1,227	\$2
5.7	Water Gas Shift (WGS) Reactors	\$132,230	\$0	\$52,861	\$0	\$185,091	\$27,764	\$0	\$42,571	\$255,425	\$459
5.9	Particulate Removal	\$1,522	\$0	\$652	\$0	\$2,174	\$326	\$0	\$375	\$2,875	\$5
5.10	Blowback Gas Systems	\$779	\$438	\$244	\$0	\$1,462	\$219	\$0	\$336	\$2,017	\$4
5.11	Fuel Gas Piping	\$0	\$962	\$629	\$0	\$1,591	\$239	\$0	\$366	\$2,196	\$4
5.12	Gas Cleanup Foundations	\$0	\$227	\$153	\$0	\$380	\$57	\$0	\$131	\$568	\$1
	Subtotal	\$379,923	\$16,036	\$198,131	\$0	\$594,091	\$89,114	\$46,072	\$145,774	\$875,050	\$1,571
6		Combustion Turbine & Accessories									
6.1	Combustion Turbine Generator	\$76,557	\$0	\$5,425	\$0	\$81,983	\$12,297	\$8,198	\$15,372	\$117,850	\$212
6.3	Combustion Turbine Accessories	\$2,687	\$0	\$164	\$0	\$2,851	\$428	\$0	\$492	\$3,770	\$7
6.4	Compressed Air Piping	\$0	\$509	\$333	\$0	\$843	\$126	\$0	\$194	\$1,163	\$2
6.5	Combustion Turbine Foundations	\$0	\$216	\$250	\$0	\$466	\$70	\$0	\$161	\$697	\$1
	Subtotal	\$79,245	\$726	\$6,172	\$0	\$86,143	\$12,921	\$8,198	\$16,218	\$123,480	\$222
7		HRSO, Ductwork, & Stack									
7.1	Heat Recovery Steam Generator	\$33,951	\$0	\$6,573	\$0	\$40,524	\$6,079	\$0	\$6,990	\$53,592	\$96
7.2	Heat Recovery Steam Generator Accessories	\$12,122	\$0	\$2,347	\$0	\$14,469	\$2,170	\$0	\$2,496	\$19,136	\$34
7.3	Ductwork	\$0	\$1,088	\$763	\$0	\$1,851	\$278	\$0	\$426	\$2,555	\$5
7.4	Stack	\$9,256	\$0	\$3,454	\$0	\$12,709	\$1,906	\$0	\$2,192	\$16,808	\$30
7.5	Heat Recovery Steam Generator, Ductwork & Stack Foundations	\$0	\$230	\$231	\$0	\$461	\$69	\$0	\$159	\$690	\$1
	Subtotal	\$55,328	\$1,318	\$13,368	\$0	\$70,014	\$10,502	\$0	\$12,264	\$92,780	\$167
8		Steam Turbine & Accessories									
8.1	Steam Turbine Generator & Accessories	\$37,697	\$0	\$5,533	\$0	\$43,230	\$6,484	\$0	\$7,457	\$57,171	\$103
8.2	Steam Turbine Plant Auxiliaries	\$1,818	\$0	\$4,150	\$0	\$5,968	\$895	\$0	\$1,029	\$7,892	\$14

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B4B	– E-Gas™ IGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		557					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
8.3	Condenser & Auxiliaries	\$7,017	\$0	\$3,955	\$0	\$10,971	\$1,646	\$0	\$1,893	\$14,510	\$26
8.4	Steam Piping	\$7,382	\$0	\$3,201	\$0	\$10,583	\$1,587	\$0	\$3,043	\$15,213	\$27
8.5	Turbine Generator Foundations	\$0	\$283	\$501	\$0	\$784	\$118	\$0	\$271	\$1,173	\$2
	Subtotal	\$53,914	\$283	\$17,339	\$0	\$71,537	\$10,730	\$0	\$13,692	\$95,960	\$172
9		Cooling Water System									
9.1	Cooling Towers	\$11,714	\$0	\$3,783	\$0	\$15,497	\$2,325	\$0	\$2,673	\$20,495	\$37
9.2	Circulating Water Pumps	\$1,546	\$0	\$116	\$0	\$1,662	\$249	\$0	\$287	\$2,198	\$4
9.3	Circulating Water System Auxiliaries	\$10,622	\$0	\$1,509	\$0	\$12,131	\$1,820	\$0	\$2,093	\$16,044	\$29
9.4	Circulating Water Piping	\$0	\$5,975	\$5,411	\$0	\$11,385	\$1,708	\$0	\$2,619	\$15,712	\$28
9.5	Make-up Water System	\$630	\$0	\$867	\$0	\$1,497	\$225	\$0	\$344	\$2,066	\$4
9.6	Component Cooling Water System	\$217	\$259	\$178	\$0	\$654	\$98	\$0	\$150	\$902	\$2
9.7	Circulating Water System Foundations	\$0	\$493	\$876	\$0	\$1,369	\$205	\$0	\$472	\$2,047	\$4
	Subtotal	\$24,730	\$6,727	\$12,740	\$0	\$44,196	\$6,629	\$0	\$8,638	\$59,464	\$107
10		Slag Recovery & Handling									
10.1	Slag Dewatering & Cooling	\$1,997	\$0	\$978	\$0	\$2,975	\$446	\$0	\$513	\$3,935	\$7
10.2	Gasifier Ash Depressurization	\$1,131	\$0	\$554	\$0	\$1,685	\$253	\$0	\$291	\$2,229	\$4
10.3	Cleanup Ash Depressurization	\$508	\$0	\$249	\$0	\$758	\$114	\$0	\$131	\$1,002	\$2
10.6	Ash Storage Silos	\$1,135	\$0	\$1,225	\$0	\$2,359	\$354	\$0	\$407	\$3,120	\$6
10.7	Ash Transport & Feed Equipment	\$437	\$0	\$102	\$0	\$539	\$81	\$0	\$93	\$713	\$1
10.8	Miscellaneous Ash Handling Equipment	\$63	\$77	\$23	\$0	\$162	\$24	\$0	\$28	\$215	\$0
10.9	Ash/Spent Sorbent Foundation	\$0	\$446	\$587	\$0	\$1,032	\$155	\$0	\$356	\$1,543	\$3
	Subtotal	\$5,271	\$523	\$3,717	\$0	\$9,511	\$1,427	\$0	\$1,819	\$12,756	\$23
11		Accessory Electric Plant									
11.1	Generator Equipment	\$2,721	\$0	\$2,053	\$0	\$4,773	\$716	\$0	\$823	\$6,313	\$11
11.2	Station Service Equipment	\$4,244	\$0	\$364	\$0	\$4,609	\$691	\$0	\$795	\$6,095	\$11
11.3	Switchgear & Motor Control	\$25,612	\$0	\$4,444	\$0	\$30,056	\$4,508	\$0	\$5,185	\$39,749	\$71
11.4	Conduit & Cable Tray	\$0	\$113	\$327	\$0	\$440	\$66	\$0	\$127	\$633	\$1
11.5	Wire & Cable	\$0	\$1,554	\$2,778	\$0	\$4,332	\$650	\$0	\$1,245	\$6,227	\$11
11.6	Protective Equipment	\$241	\$0	\$837	\$0	\$1,078	\$162	\$0	\$186	\$1,426	\$3
11.7	Standby Equipment	\$852	\$0	\$786	\$0	\$1,638	\$246	\$0	\$283	\$2,167	\$4
11.8	Main Power Transformers	\$6,425	\$0	\$131	\$0	\$6,557	\$983	\$0	\$1,131	\$8,671	\$16
11.9	Electrical Foundations	\$0	\$74	\$188	\$0	\$263	\$39	\$0	\$91	\$393	\$1
	Subtotal	\$40,096	\$1,742	\$11,908	\$0	\$53,745	\$8,062	\$0	\$9,865	\$71,672	\$129
12		Instrumentation & Control									
12.1	Integrated Gasification and Combined Cycle Control Equipment	\$639	\$0	\$356	\$0	\$995	\$149	\$0	\$172	\$1,316	\$2
12.2	Combustion Turbine Control Equipment	\$686	\$0	\$49	\$0	\$735	\$110	\$0	\$127	\$972	\$2

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B4B	– E-Gas™ IGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		557					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
12.3	Steam Turbine Control Equipment	\$637	\$0	\$94	\$0	\$731	\$110	\$0	\$126	\$966	\$2
12.4	Other Major Component Control Equipment	\$1,225	\$0	\$834	\$0	\$2,059	\$309	\$103	\$371	\$2,842	\$5
12.5	Signal Processing Equipment	\$950	\$0	\$31	\$0	\$981	\$147	\$0	\$169	\$1,298	\$2
12.6	Control Boards, Panels & Racks	\$275	\$0	\$180	\$0	\$455	\$68	\$23	\$109	\$656	\$1
12.7	Distributed Control System Equipment	\$9,974	\$0	\$326	\$0	\$10,300	\$1,545	\$515	\$1,854	\$14,213	\$26
12.8	Instrument Wiring & Tubing	\$496	\$397	\$1,588	\$0	\$2,482	\$372	\$124	\$744	\$3,722	\$7
12.9	Other Instrumentation & Controls Equipment	\$1,113	\$0	\$552	\$0	\$1,665	\$250	\$83	\$300	\$2,298	\$4
	Subtotal	\$15,997	\$397	\$4,009	\$0	\$20,403	\$3,060	\$848	\$3,972	\$28,283	\$51
13		Improvements to Site									
13.1	Site Preparation	\$0	\$424	\$9,621	\$0	\$10,046	\$1,507	\$0	\$3,466	\$15,019	\$27
13.2	Site Improvements	\$0	\$1,912	\$2,703	\$0	\$4,615	\$692	\$0	\$1,592	\$6,899	\$12
13.3	Site Facilities	\$2,985	\$0	\$3,350	\$0	\$6,335	\$950	\$0	\$2,186	\$9,471	\$17
	Subtotal	\$2,985	\$2,337	\$15,675	\$0	\$20,996	\$3,149	\$0	\$7,244	\$31,389	\$56
14		Buildings & Structures									
14.1	Combustion Turbine Area	\$0	\$314	\$177	\$0	\$491	\$74	\$0	\$85	\$649	\$1
14.3	Steam Turbine Building	\$0	\$2,770	\$3,944	\$0	\$6,714	\$1,007	\$0	\$1,158	\$8,879	\$16
14.4	Administration Building	\$0	\$883	\$641	\$0	\$1,524	\$229	\$0	\$263	\$2,016	\$4
14.5	Circulation Water Pumphouse	\$0	\$146	\$78	\$0	\$224	\$34	\$0	\$39	\$296	\$1
14.6	Water Treatment Buildings	\$0	\$353	\$345	\$0	\$698	\$105	\$0	\$120	\$923	\$2
14.7	Machine Shop	\$0	\$488	\$334	\$0	\$823	\$123	\$0	\$142	\$1,088	\$2
14.8	Warehouse	\$0	\$381	\$246	\$0	\$626	\$94	\$0	\$108	\$829	\$1
14.9	Other Buildings & Structures	\$0	\$279	\$217	\$0	\$496	\$74	\$0	\$86	\$656	\$1
14.10	Waste Treating Building & Structures	\$0	\$762	\$1,455	\$0	\$2,217	\$333	\$0	\$382	\$2,932	\$5
	Subtotal	\$0	\$6,377	\$7,436	\$0	\$13,813	\$2,072	\$0	\$2,383	\$18,267	\$33
	Total	\$1,387,698	\$81,065	\$640,495	\$0	\$2,109,258	\$325,907	\$166,953	\$461,105	\$3,063,223	\$5,501

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-85. Case B4B owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$24,761	\$44
1 Month Maintenance Materials	\$6,222	\$11
1 Month Non-fuel Consumables	\$1,280	\$2
1 Month Waste Disposal	\$735	\$1
25% of 1 Months Fuel Cost at 100% CF	\$2,286	\$4
2% of TPC	\$61,264	\$110
Total	\$96,548	\$173
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	\$20,415	\$37
0.5% of TPC (spare parts)	\$15,316	\$28
Total	\$35,731	\$64
Other Costs		
Initial Cost for Catalyst and Chemicals	\$34,798	\$62
Land	\$900	\$2
Other Owner's Costs	\$459,483	\$825
Financing Costs	\$82,707	\$149
Total Overnight Costs (TOC)	\$3,773,390	\$6,776
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	\$4,356,046	\$7,822

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-86. Case B4B initial and annual operating and maintenance costs

Case:	B4B	– E-Gas™ IGCC w/ CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	557	Heat Rate-net (Btu/kWh):	10,101	Capacity Factor (%):	80	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	% of base	Operator:	11.0	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	3.0	
				Total:	17.0	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$7,453,446	\$13.384
Maintenance Labor:					\$32,163,837	\$57.757
Administrative & Support Labor:					\$9,904,321	\$17.785
Property Taxes and Insurance:					\$61,264,452	\$110.014
Total:					\$110,786,057	\$198.941
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$59,732,841	\$15.30585
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (gal/1000):	0	3,742	\$1.90	\$0	\$2,075,881	\$0.53192
Makeup and Waste Water Treatment Chemicals (ton):	0	11.1	\$550.00	\$0	\$1,790,035	\$0.45868
Sulfur-Impregnated Activated Carbon (ton):	107	0.147	\$12,000.00	\$1,288,576	\$515,431	\$0.13207
Water Gas Shift (WGS) Catalyst (ft³):	25,790	17.7	\$480.00	\$12,379,238	\$2,475,848	\$0.63441
Selexol Solution (gal):	556,047	55.1	\$38.00	\$21,129,771	\$611,819	\$0.15677
Sodium Hydroxide (50 wt%, ton):	0	20.0	\$600.00	\$0	\$3,496,413	\$0.89592
Sulfuric Acid (98 wt%, ton):	0	0.355	\$210.00	\$0	\$21,743	\$0.00557
Claus Catalyst (ft³):	w/equip.	2.00	\$48.00	\$0	\$28,031	\$0.00718
Triethylene Glycol (gal):	w/equip.	639	\$6.80	\$0	\$1,268,343	\$0.32500
Subtotal:				\$34,797,585	\$12,283,543	\$3.14752
Waste Disposal						
Sulfur-Impregnated Activated Carbon (ton):	0	0.147	\$80.00	\$0	\$3,436	\$0.00088
Water Gas Shift Catalyst (ft³):	0	17.7	\$2.50	\$0	\$12,895	\$0.00330
Selexol Solution (gal):	0	55.1	\$0.35	\$0	\$5,635	\$0.00144
Claus Catalyst (ft³):	0	2.00	\$2.50	\$0	\$1,460	\$0.00037
Crystallizer Solids (ton):	0	37.7	\$38.00	\$0	\$418,690	\$0.10728
Slag (ton):	0	591	\$38.00	\$0	\$6,552,985	\$1.67913
Triethylene Glycol (gal):	0	639	\$0.35	\$0	\$65,282	\$0.01673
Subtotal:				\$0	\$7,060,384	\$1.80914
By-Products						
Sulfur (tons):	0	145	\$0.00	\$0	\$0	\$0.00000
Subtotal:				\$0	\$0	\$0.00000
Variable Operating Costs Total:				\$34,797,585	\$79,076,768	\$20.26251
Fuel Cost						
Illinois Number 6 (ton):	0	5,786	\$51.96	\$0	\$87,784,958	\$22.49388
Total:				\$0	\$87,784,958	\$22.49388

Exhibit 3-87. Case B4B LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	79.0	49.9%
Fixed	28.4	17.9%
Variable	20.3	12.8%
Fuel	22.5	14.2%
Total (Excluding T&S)	150.1	94.8%
CO ₂ T&S	8.2	5.2%
Total (Including T&S)	158.3	100.0%

3.4 GENERAL ELECTRIC POWER IGCC CASES

This section contains an evaluation of three GEP plant designs (radiant-only [with and without CO₂ capture] and quench-only [with CO₂ capture]). Cases B5A and B5B are based on the GEP gasifier in the “radiant-only” configuration and Case B5B-Q is based on the GEP gasifier in the “quench-only” configuration. GEP offers three design configurations [109]:

- **Quench:** In this configuration, the hot syngas exiting the gasifier passes through a pool of water to quench the temperature to 288°C (550°F) before entering the syngas scrubber. It is the simplest design, but also the least efficient.
- **Radiant:** In this configuration, the hot syngas exiting the gasifier passes through a radiant syngas cooler where it is cooled from about 1,316°C (2,400°F) to 677°C (1,250°F), and then passes through a water quench where the syngas is further cooled to about 232°C (450°F) prior to entering the syngas scrubber. Relative to the quench configuration, the radiant design offers increased output, higher efficiency, a reduction in wastewater emissions, and improved reliability/availability. This configuration was chosen by GEP and Bechtel for the design of their reference plant.
- **Radiant-Convective:** In this configuration, the hot syngas exiting the gasifier passes through a radiant syngas cooler where it is cooled from about 1,316°C (2,400°F) to 760°C (1,400°F), and then through a convective syngas cooler where the syngas is further cooled to about 371°C (700°F) prior to entering additional HXs or the scrubber. This configuration has the highest overall efficiency, but at the expense of the lowest availability. This was the original design configuration of Tampa Electric’s Polk Power Station. However, due to extensive downtime, the convective HX was subsequently removed from service.

GEP also offers an extended slurry technology that can improve the slurry concentrations for higher moisture content coals. This technology is not considered in this report. Note that the radiant configuration includes a water quench and, based on functionality, would be more appropriately named radiant-quench. The term radiant is used to distinguish it from the radiant-convective configuration. Since radiant is the terminology used by GEP, it is used throughout this report.

The balance of this section is organized in an analogous manner to Section 3.2 and Section 3.3:

- Gasifier Background
- Process System Description for Case B5A
- Key Assumptions for Cases B5A, B5B, and B5B-Q
- Sparing Philosophy for Cases B5A, B5B, and B5B-Q
- Performance Results for Case B5A
- Equipment List for Case B5A
- Cost Estimates for Case B5A
- Process and System Description, Performance Results, Equipment Lists, and Cost Estimates for Cases B5B and B5B-Q

3.4.1 Gasifier Background

As mentioned in Section 3.2.1 and Section 3.3.1, the “Coal Gasification Guidebook: Status, Application, and Technologies” report published by the EPRI provides a detailed history of the development of several types of gasifier technology, including the GEP gasifier, as well as gasifier capacity, distinguishing characteristics, and important coal characteristics. [104]

The Tampa Electric Polk plant was designed to use the radiant-convective GEP gasifier configuration. As stated previously, due to extensive downtime, the convective HX was removed from service, and the unit now operates in the radiant configuration. The daily coal-handling design capacity of this unit was 2,268 tonnes (2,500 tons) of bituminous coal. The dry gas design production rate was 0.19 million Nm³/hr (6.7 million scfh) with an energy content of about 1,897 million kJ/hr (HHV) (1,800 million Btu/hr). This size matches the F-Class CTs that are used at Tampa. The largest GE gasifier is the unit at Duke Edwardsport, which is also a radiant configuration, and has a daily capacity (dry basis) of approximately 2,268 tonnes (2,500 tons) of coal per gasifier. The Duke Edwardsport gasifier operates at a pressure of 4.1 MPa (600 psia). [110]

The GEP gasifier operates at the highest pressure of the three gasifiers in this report, 5.6 MPa (815 psia) compared to 4.2 MPa (615 psia) for E-GasTM and Shell. The GEP gasifier can operate at pressures as high as 8.7 MPa (1,260 psia), as demonstrated by the quench gasifier operating at the Pucheng project in China. [111]

The relatively high H₂/CO ratio and CO₂ content of the GEP gasification fuel gas helps achieve low NO_x and CO emissions in even the higher-temperature advanced CTs. [104]

Coals with low concentrations of ash and soluble salts are preferred for use with the GEP gasifiers, as high levels of ash increase the O₂ requirement and soluble salts may build-up in concentration when high levels of process condensate recycle are used. [104]

The slurry feeding also favors the use of high-rank coals, such as bituminous coal, since their low inherent moisture content increases the moisture-free solids content of the slurry and thereby reduces O₂ requirements. [104]

3.4.2 Key System Assumptions

System assumptions for cases B5A, B5B, and B5B-Q, GEP IGCC with and without CO₂ capture, are presented in Exhibit 3-88.

Exhibit 3-88. GEP IGCC plant study configuration matrix

Case	B5A	B5B	B5B-Q
Gasifier Pressure, MPa (psia)	5.6 (815)		
O ₂ :Coal Ratio, kg O ₂ /kg As-Received coal	0.760		
Carbon Conversion, %	98		
Syngas HHV at Gasifier Outlet, kJ/Nm ³ (Btu/scf) ^A	8,956 (240)	8,960 (240)	8,958 (240)
Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/566/566 (1,800/1,051/1,051)	12.4/535/535 (1,800/996/996)	12.4/535/535 (1,800/996/996)
Condenser Pressure, mm Hg (in. Hg)	51 (2.0)		
Combustion Turbine	2x State-of-the-Art 2008 F-Class (232 MW output each)		
Gasifier Technology	GEP Radiant	GEP Radiant	GEP Quench
Oxidant	95 vol% O ₂		
Coal	Illinois No. 6		
Coal Slurry Solids Content, %	63		
COS Hydrolysis	Yes	Occurs in WGS	Occurs in WGS
WGS	No	Yes	Yes
H ₂ S Separation	Selexol	Selexol 1 st Stage	Selexol 1 st Stage
Sulfur Removal, %	99.9	~100.0	~100.0
Sulfur Recovery	Claus Plant with Tail Gas Recycle to Selexol/Elemental Sulfur		
Particulate Control	Water Quench, Scrubber, and AGR Absorber		
Chloride Control	Venturi Scrubber, Vacuum Flash, Brine Concentrator, Crystallizer		
Mercury Control	Carbon Bed		
NO _x Control	MNQC (LNB) and N ₂ Dilution		
CO ₂ Separation	N/A	Selexol 2 nd Stage	Selexol 2 nd Stage
Overall Carbon Capture, %	N/A	90.0	90.0
CO ₂ Sequestration	N/A	Off-site Saline Formation	Off-site Saline Formation

^ASyngas measurement is reflected before syngas quench

3.4.2.1 Balance of Plant – Cases B5A, B5B, and B5B-Q

The balance of plant assumptions are common to all three cases and are presented in Exhibit 3-22.

3.4.3 Sparing Philosophy

The sparing philosophy for cases B5A, B5B, and B5B-Q is provided below. Dual trains are used to accommodate the size of commercial CTs. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- Two ASUs (2 x 50 percent)
- Two trains of slurry preparation and slurry pumps (2 x 50 percent)
- Two trains of gasification, including gasifier, SGC, quench and scrubber (2 x 50 percent)
- Two trains of syngas clean-up process (2 x 50 percent)
- Two trains of Selexol AGR, single-stage in Case B5A (2 x 50 percent)
- One train of two-stage Selexol AGR in Cases B5B and B5B-Q, (1 x 100 percent)
- One Claus-based SRU (1 x 100 percent)
- One train of CO₂ compression systems (1 x 100 percent) in cases B5B and B5B-Q
- Two trains of process water treatment systems (2 x 50 percent)
- Two CT/HRSG tandems (2 x 50 percent)
- One steam turbine (1 x 100 percent)

3.4.4 Case B5A – GEP Radiant IGCC Without CO₂ Capture Process Description

In this section, the GEP gasification process for Case B5A is described. The system descriptions follow the BFD provided in Exhibit 3-89 with the associated stream tables—providing process data for the numbered streams in the BFD—provided in Exhibit 3-90.

3.4.4.1 Coal Preparation and Feed Systems

Coal receiving and handling is common to all cases and was covered in Section 3.1.1. The receiving and handling subsystem ends at the coal silo. Coal is then fed onto a conveyor by vibratory feeders located below each silo. The conveyor feeds the coal to an inclined conveyor that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. Each hopper outlet discharges onto a weigh feeder, which, in turn, feeds a rod mill. Each rod mill is sized to process 55 percent of the coal feed requirements of the gasifier. The rod mill grinds the coal (stream 8) and wets it with process and slag recovery water (stream 7) transferred from the slurry water tank by the slurry water pumps. The coal slurry is discharged through a trommel screen into the rod mill discharge tank, and then the slurry is pumped to the slurry storage tanks. The dry solids concentration of the final slurry is 63 percent. The Polk Power Station operates at a slurry concentration of 62–68 percent using bituminous coal, and ConocoPhillips presented a paper showing the slurry concentration of Illinois No. 6 coal as 63 percent. [108]

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required depends on local environmental regulations. All tanks are equipped with vertical agitators to keep the coal slurry solids suspended.

The equipment in the coal grinding and slurry preparation system is fabricated of materials appropriate for the abrasive environment present in the system. The tanks and agitators are rubber lined. The pumps are either rubber-lined or hardened metal to minimize erosion. Piping is fabricated of HDPE.

3.4.4.2 Gasifier

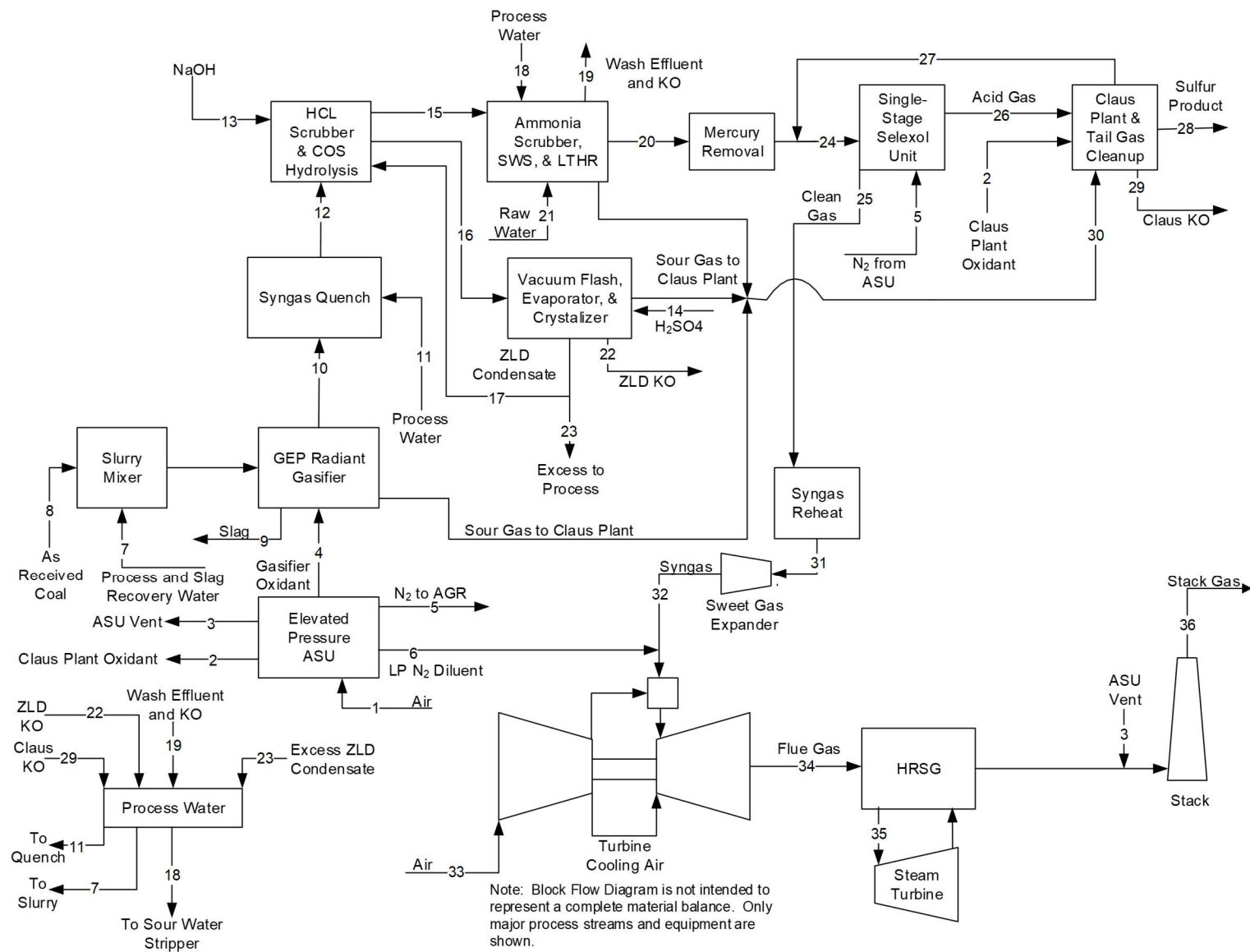
There are two GEP slurry feed, pressurized, downflow, entrained, slagging gasifiers, operating at 5.6 MPa (815 psia) and processing a total of 5,059 tonnes/day (5,577 tpd) of as-received coal.

The air separation plant supplies 4,073 tonnes/day (4,489 tpd) of 95 percent O₂ to the gasifiers (stream 4), which is fed through a fuel injector at the top of the gasifier vessel, along with the coal slurry feedstock. The coal slurry and the O₂ react in the gasifier at 1,316°C (2,400°F) to produce principally H₂ and CO with little CO₂ formed.

The heat in the gasifier liquefies coal ash. Hot syngas and molten solids from the reactor flow downward into a radiant HX where the syngas is cooled.

The largest operating GEP gasifier is the 2,268 tonne/day (2,500 tpd) unit at Polk Power Station. However, that unit operates at about 2.8 MPa (400 psia). The gasifier in this report will be able to process more coal and maintain the same gas residence time.

Exhibit 3-89. Case B5A block flow diagram, GEP IGCC without CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-90. Case B5A stream table, GEP IGCC without capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0343	0.0084	0.0343	0.0000	0.0000	0.0000	0.0000	0.0000	0.0082	0.0000	0.0058
CH ₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0011	0.0000	0.0008
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3569	0.0000	0.2513
CO ₂	0.0003	0.0000	0.0015	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.1384	0.0003	0.0975
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0001
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3410	0.0000	0.2401
H ₂ O	0.0099	0.0000	0.0305	0.0000	0.0000	0.0000	0.9925	0.0000	0.0000	0.1366	0.9917	0.3898
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000	0.0003
H ₂ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0073	0.0001	0.0052
N ₂	0.7732	0.0157	0.9561	0.0157	0.9964	0.9964	0.0000	0.0000	0.0000	0.0078	0.0000	0.0055
NH ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0073	0.0000	0.0000	0.0020	0.0079	0.0038
O ₂	0.2074	0.9501	0.0034	0.9501	0.0036	0.0036	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	24,843	83	5,492	5,268	402	13,520	4,807	0	0	22,077	9,285	31,362
V-L Flowrate (kg/hr)	716,900	2,661	152,943	169,693	11,271	378,935	86,596	0	0	443,960	167,286	611,238
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	210,799	23,128	0	0	0
Temperature (°C)	15	27	21	27	87	196	148	15	1,316	677	188	232
Pressure (MPa, abs)	0.10	0.86	0.45	6.48	5.41	2.69	5.79	0.10	5.62	5.51	6.33	5.47
Steam Table Enthalpy (kJ/kg) ^A	30.23	21.53	27.89	6.21	82.12	202.61	610.94	---	---	1,428.66	787.77	1,253.07
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-0.97	-333.75	-16.30	56.16	176.64	-15,262.49	-2,119.02	-727.24	-5,247.86	-15,075.57	-7,938.02
Density (kg/m ³)	1.2	11.2	5.2	87.9	50.3	19.2	903.8	---	---	13.8	862.8	26.2
V-L Molecular Weight	28.857	32.209	27.846	32.209	28.028	28.028	18.015	---	---	20.110	18.017	19.490
V-L Flowrate (lb _{mol} /hr)	54,770	182	12,109	11,615	887	29,806	10,598	0	0	48,671	20,470	69,140
V-L Flowrate (lb/hr)	1,580,493	5,867	337,183	374,109	24,848	835,408	190,912	0	0	978,764	368,803	1,347,550
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	464,732	50,989	0	0	0
Temperature (°F)	59	80	71	80	189	385	298	59	2,400	1,250	371	450
Pressure (psia)	14.7	125.0	65.0	940.0	785.0	390.0	840.0	14.7	815.0	798.7	918.7	793.1
Steam Table Enthalpy (Btu/lb) ^A	13.0	9.3	12.0	2.7	35.3	87.1	262.7	---	---	614.2	338.7	538.7
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-0.4	-143.5	-7.0	24.1	75.9	-6,561.7	-911.0	-312.7	-2,256.2	-6,481.3	-3,412.7
Density (lb/ft ³)	0.076	0.700	0.327	5.487	3.143	1.196	56.421	---	---	0.864	53.865	1.636

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-90. Case B5A stream table, GEP IGCC without capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0063	0.0000	0.0000	0.0000	0.0000	0.0095	0.0000	0.0000	0.0000	0.0093
CH ₄	0.0000	0.0000	0.0009	0.0000	0.0000	0.0000	0.0000	0.0013	0.0000	0.0000	0.0000	0.0013
CO	0.0000	0.0000	0.2734	0.0001	0.0000	0.0000	0.0000	0.4145	0.0000	0.0000	0.0000	0.3974
CO ₂	0.0000	0.0000	0.1062	0.0008	0.0000	0.0003	0.0003	0.1600	0.0000	0.0008	0.0000	0.1840
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.2612	0.0002	0.0000	0.0000	0.0000	0.3960	0.0000	0.0000	0.0000	0.3809
H ₂ O	0.6895	0.1000	0.3364	0.9942	0.9997	0.9917	0.9904	0.0012	0.9999	0.9918	0.9997	0.0012
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0000	0.0000	0.0057	0.0001	0.0000	0.0001	0.0001	0.0085	0.0000	0.0002	0.0000	0.0083
N ₂	0.0000	0.0000	0.0060	0.0000	0.0000	0.0000	0.0000	0.0090	0.0000	0.0000	0.0000	0.0178
NH ₃	0.0000	0.0000	0.0039	0.0018	0.0003	0.0079	0.0092	0.0000	0.0000	0.0072	0.0003	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0026	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000
NaOH	0.3105	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	0.1000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	29	0	28,818	3,452	879	544	11,910	19,004	1,607	757	1,781	19,826
V-L Flowrate (kg/hr)	727	13	565,173	62,621	15,829	9,805	214,578	387,966	28,952	13,653	32,082	420,076
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	16	15	216	202	89	111	121	29	15	29	89	37
Pressure (MPa, abs)	6.30	0.13	5.15	5.33	0.13	0.47	0.45	4.69	0.10	0.24	0.13	4.53
Steam Table Enthalpy (kJ/kg) ^A	-337.57	-8,206.86	1,098.98	851.40	369.32	447.06	486.70	34.25	62.75	107.94	369.32	42.36
AspenPlus Enthalpy (kJ/kg) ^B	-13,663.78	-8,526.27	-7,551.74	-15,001.58	-15,597.14	-15,416.29	-15,359.35	-5,360.22	-15,905.25	-15,752.92	-15,597.14	-5,511.93
Density (kg/m ³)	1,532.5	1,791.5	25.5	863.3	965.9	940.9	929.3	38.4	999.4	991.3	965.9	37.6
V-L Molecular Weight	24.842	90.073	19.612	18.140	18.015	18.017	18.016	20.415	18.019	18.032	18.015	21.188
V-L Flowrate (lb _{mol} /hr)	65	0	63,532	7,610	1,937	1,200	26,258	41,897	3,542	1,669	3,926	43,709
V-L Flowrate (lb/hr)	1,603	28	1,245,994	138,055	34,897	21,617	473,063	855,318	63,827	30,099	70,728	926,109
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	61	59	420	396	191	231	249	84	59	85	191	99
Pressure (psia)	913.1	18.2	747.2	772.5	19.4	67.7	65.0	680.2	14.7	35.0	19.4	657.3
Steam Table Enthalpy (Btu/lb) ^A	-145.1	-3,528.3	472.5	366.0	158.8	192.2	209.2	14.7	27.0	46.4	158.8	18.2
AspenPlus Enthalpy (Btu/lb) ^B	-5,874.4	-3,665.6	-3,246.7	-6,449.5	-6,705.6	-6,627.8	-6,603.3	-2,304.5	-6,838.0	-6,772.5	-6,705.6	-2,369.7
Density (lb/ft ³)	95.670	111.841	1.591	53.893	60.299	58.740	58.013	2.396	62.391	61.884	60.299	2.345

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-90. Case B5A stream table, GEP IGCC without capture (continued)

	25	26	27	28	29	30	31	32	33	34	35	36
V-L Mole Fraction												
Ar	0.0095	0.0000	0.0035	0.0000	0.0000	0.0008	0.0095	0.0095	0.0092	0.0089	0.0000	0.0089
CH ₄	0.0013	0.0000	0.0000	0.0000	0.0000	0.0001	0.0013	0.0013	0.0000	0.0000	0.0000	0.0000
CO	0.4084	0.0002	0.0017	0.0000	0.0000	0.0312	0.4084	0.4084	0.0000	0.0000	0.0000	0.0000
CO ₂	0.1587	0.6244	0.7385	0.0000	0.0000	0.1862	0.1587	0.1587	0.0003	0.0813	0.0000	0.0782
COS	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.3915	0.0000	0.0315	0.0000	0.0000	0.0392	0.3915	0.3915	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0006	0.0127	0.0020	0.0000	1.0000	0.6194	0.0006	0.0006	0.0099	0.0643	1.0000	0.0630
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0000	0.1754	0.0032	0.0000	0.0000	0.0231	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0300	0.1854	0.2196	0.0000	0.0000	0.0005	0.0300	0.0300	0.7732	0.7336	0.0000	0.7423
NH ₃	0.0000	0.0002	0.0000	0.0000	0.0000	0.0994	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0015	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2074	0.1119	0.0000	0.1077
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	19,289	940	822	0	230	100	19,289	19,289	110,253	135,347	36,165	140,839
V-L Flowrate (kg/hr)	394,754	36,593	32,110	0	4,144	2,281	394,754	394,754	3,181,556	3,955,244	651,521	4,108,187
Solids Flowrate (kg/hr)	0	0	0	5,281	0	0	0	0	0	0	0	0
Temperature (°C)	45	45	38	182	50	195	241	207	15	597	566	126
Pressure (MPa, abs)	4.49	4.49	4.53	0.29	0.27	0.45	4.31	3.17	0.10	0.10	12.51	0.10
Steam Table Enthalpy (kJ/kg) ^A	55.89	5.19	0.71	---	112.50	1,517.11	364.92	311.96	30.23	750.36	3,516.60	227.99
AspenPlus Enthalpy (kJ/kg) ^B	-5,251.15	-6,513.58	-7,484.51	145.99	-15,856.93	-9,881.76	-4,942.12	-4,995.07	-97.58	-1,000.75	-12,463.69	-1,471.40
Density (kg/m ³)	34.9	80.3	80.6	5,270.5	968.6	2.7	20.4	16.1	1.2	0.4	34.8	0.9
V-L Molecular Weight	20.465	38.948	39.051	---	18.016	22.837	20.465	20.465	28.857	29.223	18.015	29.169
V-L Flowrate (lb _{mol} /hr)	42,525	2,071	1,813	0	507	220	42,525	42,525	243,065	298,389	79,730	310,498
V-L Flowrate (lb/hr)	870,283	80,674	70,791	0	9,136	5,029	870,283	870,283	7,014,130	8,719,820	1,436,358	9,057,003
Solids Flowrate (lb/hr)	0	0	0	11,642	0	0	0	0	0	0	0	0
Temperature (°F)	112	112	100	360	122	384	465	404	59	1,106	1,051	260
Pressure (psia)	651.1	651.1	657.3	41.7	39.5	65.0	625.3	460.0	14.7	15.1	1,814.7	14.8
Steam Table Enthalpy (Btu/lb) ^A	24.0	2.2	0.3	---	48.4	652.2	156.9	134.1	13.0	322.6	1,511.9	98.0
AspenPlus Enthalpy (Btu/lb) ^B	-2,257.6	-2,800.3	-3,217.8	62.8	-6,817.3	-4,248.4	-2,124.7	-2,147.5	-42.0	-430.2	-5,358.4	-632.6
Density (lb/ft ³)	2.176	5.016	5.031	329.024	60.469	0.166	1.272	1.006	0.076	0.026	2.173	0.056

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

3.4.4.3 Raw Gas Cooling and Particulate Removal

The product gas from the gasifier is cooled from 1,316°C (2,400°F) to 677°C (1,250°F) in the radiant SGC (stream 10), and the molten slag solidifies in the process. The solids collect in the water sump at the bottom of the gasifier and are removed periodically using a lock hopper system (stream 9). The waste heat from this cooling is used to generate HP steam at 12.8 MPa (1,852 psia) for use in the steam cycle.

The syngas exiting the SGC is directed downwards by a dip tube into a water sump. Most of the entrained solids are separated from the syngas at the bottom of the dip tube as the syngas goes upwards through the water. The syngas exits the quench chamber saturated at a temperature of 232°C (450°F).

The slag handling system removes solids from the gasification process equipment. These solids consist of a small amount of unconverted carbon and essentially all the ash contained in the feed coal. These solids are in the form of glass, which fully encapsulates any metals. Solids collected in the water sump below the radiant SGC are removed by gravity and forced circulation of water from the lock hopper circulating pump. The fine solids not removed from the bottom of the quench water sump remain entrained in the water circulating through the quench chamber. In order to limit the amount of solids recycled to the quench chamber, a continuous blowdown stream is removed from the bottom of the syngas quench. The blowdown is sent to the vacuum flash drum in the black water flash section. The circulating quench water is pumped by circulating pumps to the quench gasifier. Carbon conversion in the gasifier is assumed to be 98 percent, including the fines recycle stream.

The syngas scrubber removes additional PM further downstream (covered in Section 3.4.4.4).

3.4.4.4 Syngas Scrubber

The ejector-type venturi scrubber is common to all cases and was covered in Section 3.1.12.1.1. The raw syngas exits the quench at 232°C (450°F) (stream 12) and enters the scrubber for removal of HCl and remaining PM. The treated syngas leaves the scrubber saturated at a temperature of 202°C (396°F).

Effluent from the scrubber is recycled to maintain a concentration of chloride in the blowdown (stream 16) of 5,000 ppmw. The recycled effluent is mixed with ZLD condensate (stream 17) and cooled to 58°C (137°F), by preheating syngas prior to the CT, before being cooled further to 21°C (70°F) with cooling water and injected into the scrubber. The rate of ZLD condensate addition is controlled to maintain the HCl removal rate at 96 percent. A 50 wt% solution of NaOH (stream 13) is added at a rate of 727 kg/hr (1,603 lb/hr) to the scrubber to maintain pH and form the HSS NaCl.

The blowdown from the syngas scrubber is sent to the process water treatment system for chloride removal and recycle.

3.4.4.5 COS Hydrolysis

The COS hydrolysis unit is common to all non-CO₂ capture cases and was covered in Section 3.1.5.1. Following the syngas scrubber, the gas is reheated to 216°C (421°F) and fed to the COS hydrolysis reactor where 95 percent of the COS is hydrolyzed with steam over a catalyst bed to H₂S and CO₂. Before the raw syngas can be treated in the AGR process, it must be cooled and treated for NH₃.

3.4.4.6 Low Temperature Heat Recovery

The raw syngas from the COS unit is cooled through a series of four shell and tube HXs (covered in Section 3.1.12.1.2). The first stage cools the syngas from 216°C (420°F) to 162°C (323°F) by raising 0.4 MPa (65 psia) process steam. The second stage cools the syngas to 134°C (274°F) by heating the slurry and quench FW, preheating the syngas prior to the CT, and preheating the FW to the HRSG. The third stage cools the syngas to 59°C (138°F) by preheating FW to the HRSG and the fourth stage cools the syngas to 29°C (85°F) with cooling water. During cooling, part of the water vapor condenses, along with significant amounts of NH₃, and is combined with the effluent of the NH₃ wash.

3.4.4.7 Sour Water Stripper and Ammonia Wash

The primary SWS removes NH₃, H₂S, and other dissolved gases from the remaining water from the process water drum (stream 18), as was covered in Section 3.1.12.1.3. Process water flows from the drum to the SWS, which consists of a packed column with a steam-heated reboiler. Sour gas is stripped from the liquid and sent to the SRU. The remaining water is combined with raw water makeup (stream 21) and cooled to 21°C (70°F) with cooling water prior to being used as feed to the NH₃ wash.

The cooled syngas gas from the LTHR is sent to the NH₃ wash (covered in Section 3.1.12.1.4) where it flows upward against a counter-current spray of water from the SWS. The rate of raw water makeup addition to the NH₃ wash is controlled to achieve a concentration of NH₃ in the treated gas (stream 20) of 10 ppm. The effluent from the NH₃ wash contains high concentrations of NH₃ and is combined with the effluent from the LTHR system before being flashed and sent to the process water drum (stream 19). The vapor product of the flash is sent to the SRU.

3.4.4.8 Process Water Treatment

The process water treatment system—which consists of a vacuum flash, brine concentrator, and crystallizer—is common to all cases and was covered in Section 3.1.12.2. The blowdown (stream 16) from the syngas scrubber is first flashed to 0.5 MPa (70 psia) with the effluent subsequently vacuum flashed to 0.05 MPa (7.5 psia). The vapor products from both the LP and vacuum flash stages are first cooled to 72°C (162°F), by preheating syngas prior to the CT, before being cooled further to 29°C (85°F) using cooling water. The cooled streams are sent to an overhead flash to 0.2 MPa (35 psia) with the sour gas compressed to 0.4 MPa (65 psia) and sent to the SRU for incineration. The effluent from the overhead flash and condensate from the sour gas compressor are collected and sent to the process water drum for distribution (stream 22).

The effluent from the vacuum flash is sent to the brine concentrator, which evaporates sufficient water to produce an effluent containing approximately 250,000 TDS. The vapor product from the brine concentrator is compressed to 0.14 MPa (20 psia) and cooled to provide heat to the brine concentrator for evaporation. The vapor product is condensed in a HX, which provides preheat to the brine concentrator feed.

The effluent from the brine concentrator then enters the steam-driven crystallizer, where 3,063 kg/hr (6,753 lb/hr) of 0.45 MPa (65 psia) steam is utilized to evaporate sufficient water to produce a super-saturated solution in the effluent. A portion of the effluent is extracted and sent to a centrifuge to separate solids. The centrifuge effluent is returned to the crystallizer.

The vapor product from the brine concentrator is condensed with cooling water and combined with the condensate from the brine concentrator before either being recycled to the syngas scrubber (stream 17) or sent to the process water drum (stream 23) for distribution.

3.4.4.9 Mercury Removal and AGR

The cooled syngas (stream 20) passes through a series of two carbon beds to remove approximately 97 percent of the Hg (covered in Section 3.1.4).

Cool, particulate-free syngas (stream 24) enters the Selexol absorber unit at approximately 4.5 MPa (657 psia) and 37°C (99°F). In this absorber, H₂S is preferentially removed from the fuel gas stream along with smaller amounts of CO₂, COS, and other gases, such as H₂.

The rich solution leaving the bottom of the absorber is heated against the lean solvent returning from the regenerator before entering the H₂S concentrator. A portion of the non-sulfur bearing absorbed gases is driven from the solvent in the H₂S concentrator using N₂ from the ASU as the stripping medium. The temperature of the H₂S concentrator overhead stream is reduced prior to entering the reabsorber where a second stage of H₂S absorption occurs. The rich solvent from the reabsorber is combined with the rich solvent from the absorber and sent to the stripper where it is regenerated through the indirect application of thermal energy via condensation of LP steam in a reboiler. The stripper acid gas stream (stream 26), consisting of 18 vol% H₂S and 62 vol% CO₂ (with the balance mostly N₂), is then sent to the Claus unit.

3.4.4.10 Claus Unit

Acid gas (stream 26) from the Selexol unit is preheated to 219°C (427°F). A portion of the acid gas, along with all of the sour gas (stream 30) and some O₂ from the ASU (stream 2), is fed to the SRU (a Claus bypass type). In the furnace, molten sulfur is produced by catalytically oxidizing approximately one third of the H₂S in the feed to SO₂ at a furnace temperature of 1,316°C (2,400°F), which must be maintained in order to thermally decompose all of the NH₃ present in the sour gas stream. The remaining H₂S is then reacted with SO₂ to produce sulfur and water. Following the thermal stage and condensation of sulfur, three reheaters and three sulfur converters are used to obtain a per-pass H₂S conversion of 99.1 percent. The Claus plant tail gas is hydrogenated and recycled back to the AGR (stream 27).

The total elemental sulfur production from the SRU (stream 28) is approximately 127 tonnes/day (140 tpd).

The waste heat from the Claus unit is used to satisfy all Claus process preheating and reheating requirements, as well as to provide some medium-pressure (1.7 MPa [250 psia]) steam to the ASU.

3.4.4.11 Power Block

The clean syngas exiting the Selexol absorber (stream 25) is reheated (stream 31) to 241°C (465°F) and expanded (stream 32) to 3.2 MPa (460 psia), which produces 6 MWe, before being diluted with LP N₂ from the ASU (stream 6). The diluted syngas enters the state-of-the-art 2008 F-class CT burner. The CT compressor provides combustion air (stream 33) to the burner. The exhaust gas exits the CT at 597°C (1,106°F) (stream 34) and enters the HRSG where additional heat is recovered until the flue gas exits the HRSG at 132°C (270°F) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced, commercially available steam turbine using a 12.4 MPa/566°C/566°C (1,800 psig/1,051°F/1,051°F) steam cycle.

3.4.4.12 Air Separation Unit

The ASU is designed to produce a nominal output of 4,137 tonnes/day (4,559 tpd) of 95 mol% O₂ for use in the gasifier (stream 4) and SRU (stream 2). The plant is designed with two production trains. The air compressor is powered by an electric motor. Approximately 9,365 tonnes/day (10,323 tpd) of N₂ is also recovered, compressed, and used as dilution in the CT combustor and AGR.

3.4.5 Case B5A – Performance Results

The plant produces a net output of 634 MW at a net plant efficiency of 39.9 percent (HHV basis). GEP has reported a net plant efficiency of 38.5 percent for their reference plant, and they also presented a range of efficiencies of 38.5–40 percent depending on fuel type. [30], [112] Typically the higher efficiencies result from fuel blends that include petroleum coke.

Overall performance for the plant is summarized in Exhibit 3-91. Exhibit 3-92 provides a detailed breakdown of the auxiliary power requirements. The ASU accounts for approximately 77 percent of the auxiliary load between the MAC, N₂ compressor, O₂ compressor, and ASU auxiliaries. The cooling water system, including the circulating water pumps and the cooling tower fan, accounts for approximately 5 percent of the auxiliary load, and the BFW pumps account for an additional 3 percent. All other systems together constitute the remaining 15 percent of the auxiliary load.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-91. Case B5A plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	464
Sweet Gas Expander Power, MWe	6
Steam Turbine Power, MWe	295
Total Gross Power, MWe	765
Air Separation Unit Main Air Compressor, kWe	68,850
Air Separation Unit Booster Compressor, kWe	5,420
N ₂ Compressors, kWe	25,640
CO ₂ Compression, kWe	–
Acid Gas Removal, kWe	2,950
Balance of Plant, kWe	28,240
Total Auxiliaries, MWe	131
Net Power, MWe	634
HHV Net Plant Efficiency, %	39.9
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,025 (8,554)
HHV Cold Gas Efficiency, %	78.9
HHV Combustion Turbine Efficiency, %	37.9
LHV Net Plant Efficiency, %	41.4
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,705 (8,250)
LHV Cold Gas Efficiency, %	75.6
LHV Combustion Turbine Efficiency, %	41.0
Steam Turbine Cycle Efficiency, %	43.4
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	8,287 (7,855)
Condenser Duty, GJ/hr (MMBtu/hr)	1,654 (1,568)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	172 (163)
As-Received Coal Feed, kg/hr (lb/hr)	210,799 (464,732)
HHV Thermal Input, kWt	1,588,902
LHV Thermal Input, kWt	1,532,516
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.029 (7.6)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.022 (5.9)
O ₂ :As-Received Coal	0.760

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-92. Case B5A plant power summary

Power Summary	
Combustion Turbine Power, MWe	464
Sweet Gas Expander Power, MWe	6
Steam Turbine Power, MWe	295
Total Gross Power, MWe	765
Auxiliary Load Summary	
Acid Gas Removal, kWe	2,950
Air Separation Unit Auxiliaries, kWe	1,000
Air Separation Unit Main Air Compressor, kWe	68,850
Air Separation Unit Booster Compressor, kWe	5,420
Ammonia Wash Pumps, kWe	70
Circulating Water Pumps, kWe	4,460
Claus Plant TG Recycle Compressor, kWe	2,210
Claus Plant/TGTU Auxiliaries, kWe	250
CO ₂ Compression, kWe	–
Coal Dryer Air Compressor, kWe	–
Coal Handling, kWe	460
Coal Milling, kWe	2,170
Combustion Turbine Auxiliaries, kWe	1,000
Condensate Pumps, kWe	250
Cooling Tower Fans, kWe	2,310
Feedwater Pumps, kWe	4,010
Gasifier Water Pump, kWe	–
Ground Water Pumps, kWe	430
Miscellaneous Balance of Plant ^A , kWe	3,000
N ₂ Compressors, kWe	25,640
N ₂ Humidification Pump, kWe	–
O ₂ Pump, kWe	460
Quench Water Pump, kWe	400
Shift Steam Pump, kWe	–
Slag Handling, kWe	1,110
Slag Reclaim Water Recycle Pump, kWe	–
Slurry Water Pump, kWe	190

Power Summary	
Auxiliary Load Summary	
Sour Gas Compressors, kWe	90
Sour Water Recycle Pumps, kWe	10
Steam Turbine Auxiliaries, kWe	200
Syngas Recycle Compressor, kWe	–
Syngas Scrubber Pumps, kWe	130
Process Water Treatment Auxiliaries, kWe	1,280
Transformer Losses, kWe	2,750
Total Auxiliaries, MWe	131
Net Power, MWe	634

^AIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

3.4.5.1 Environmental Performance

The environmental targets for emissions of Hg, HCl, NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B5A is presented in Exhibit 3-93.

Exhibit 3-93. Case B5A air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.001 (0.002)	37 (40)	0.007 (0.015)
NO _x	0.023 (0.054)	922 (1,017)	0.172 (0.379)
Particulate	0.003 (0.007)	122 (135)	0.023 (0.050)
Hg	1.82E-7 (4.23E-7)	0.007 (0.008)	1.36E-6 (3.00E-6)
HCl	0.000 (0.000)	0.00 (0.00)	0.000 (0.000)
CO ₂	85 (197)	3,395,061 (3,742,415)	633 (1,396)
CO ₂ ^C	–	–	764 (1,685)

^ACalculations based on an 80 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

The low level of SO₂ emissions is achieved by capturing the sulfur in the gas by the Selexol AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 30 ppmv. This results in a concentration in the flue gas of less than 4 ppmv. The H₂S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H₂S and then recycled back to the Selexol process, thereby eliminating the need for a TGTU.

NO_x emissions are limited by N₂ dilution of the syngas to 15 ppmvd (as NO at 15 percent O₂). NH₃ in the syngas is removed with process condensate prior to the low-temperature AGR process and ultimately destroyed in the Claus plant burner. This helps lower NO_x levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the syngas quench in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Approximately 97 percent of the mercury is captured from the syngas by dual activated carbon beds.

CO₂ emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 3-94. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag and as CO₂ in the stack gas (includes the ASU vent gas).

Exhibit 3-94. Case B5A carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	134,373 (296,242)	Stack Gas	132,216 (291,486)
Air (CO ₂)	530 (1,169)	CO ₂ Product	–
		Slag	2,687 (5,925)
Total	134,903 (297,411)	Total	134,903 (297,411)

Exhibit 3-95 shows the sulfur balances for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible.

Exhibit 3-95. Case B5A sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	5,283 (11,648)	Stack Gas	3 (6)
		CO ₂ Product	–
		Elemental Sulfur	5,281 (11,642)
Total	5,283 (11,648)	Total	5,283 (11,648)

Exhibit 3-96 shows the overall water balance for the plant. The water balance was explained in cases B1A (Shell) and B4A (E-GasTM), but is also presented here for completeness

Exhibit 3-96. Case B5A water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
Slag Handling	0.50 (132)	0.50 (132)	–	–	–
Slurry Water	1.45 (382)	1.45 (382)	–	–	–
Gasifier Water	–	–	–	–	–
Quench	2.79 (738)	2.47 (652)	0.32 (86)	–	0.32 (86)
HCl Scrubber	2.60 (686)	2.60 (686)	–	–	–
NH ₃ Scrubber	0.64 (170)	0.16 (43)	0.48 (128)	–	0.48 (128)
Gasifier Steam	–	–	–	–	–
Condenser Makeup	0.22 (57)	–	0.22 (57)	–	0.22 (57)
BFW Makeup	0.22 (57)	–	0.22 (57)	–	0.22 (57)
Gasifier Steam	–	–	–	–	–
Shift Steam	–	–	–	–	–
N ₂ Humidification	–	–	–	–	–
Cooling Tower	17.38 (4,591)	0.24 (64)	17.14 (4,528)	3.91 (1,033)	13.23 (3,495)
BFW Blowdown	–	0.22 (57)	-0.22 (-57)	–	-0.22 (-57)
ASU Knockout	–	0.02 (6)	-0.02 (-6)	–	-0.02 (-6)
Total	25.58 (6,757)	7.41 (1,958)	18.17 (4,799)	3.91 (1,033)	14.26 (3,766)

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and is re-used as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a surface-water source for use in the plant. For this report, it was assumed to be provided 50 percent by a POTW and 50 percent from groundwater. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for all purposes, such as cooling tower makeup, BFW makeup, quench system makeup, and slag handling makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products, or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

An overall plant energy balance is provided in tabular form in Exhibit 3-97. The power out is the combined CT, steam turbine, and sweet gas expander power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a combined generator efficiency of 98.5 percent.

Exhibit 3-97. Case B5A overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, MMBtu/hr (GJ/hr)				
Coal	5,720 (5,422)	4.8 (4.5)	–	5,725 (5,426)
Air	–	117.8 (111.7)	–	117.8 (111.7)
Raw Water Makeup	–	68.3 (64.7)	–	68.3 (64.7)
Auxiliary Power	–	–	472.0 (447.3)	472.0 (447.3)
TOTAL	5,720 (5,422)	190.9 (181.0)	472.0 (447.3)	6,383 (6,050)
Heat Out, MMBtu/hr (GJ/hr)				
Misc. Process Steam	–	4.8 (4.6)	–	4.8 (4.6)
Slag	88.1 (83.5)	36.1 (34.2)	–	124.2 (117.7)
Stack Gas	–	937 (888)	–	937 (888)
Sulfur	48.9 (46.4)	0.6 (0.6)	–	49.6 (47.0)
Motor Losses and Design Allowances	–	–	54.6 (51.8)	54.6 (51.8)
Cooling Tower Load ^A	–	2,270 (2,151)	–	2,270 (2,151)
CO ₂ Product Stream	–	–	–	–
Blowdown Streams	–	36.9 (34.9)	–	36.9 (34.9)
Ambient Losses ^B	–	142.7 (135.2)	–	142.7 (135.2)
Power	–	–	2,754 (2,610)	2,754 (2,610)
TOTAL	137.0 (129.9)	3,427 (3,249)	2,808 (2,662)	6,373 (6,040)
Unaccounted Energy ^C	–	–	–	10.3 (9.7)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers

^CBy difference

3.4.5.2 Energy and Mass Balance Diagrams

Energy and mass balance diagrams are shown for the following subsystems in Exhibit 3-98 through Exhibit 3-100:

- Coal gasification and ASU
- Syngas cleanup, sulfur recovery, and tail gas recycle
- Combined cycle power generation, steam, and FW

Exhibit 3-98. Case B5A coal gasification and ASU energy and mass balance

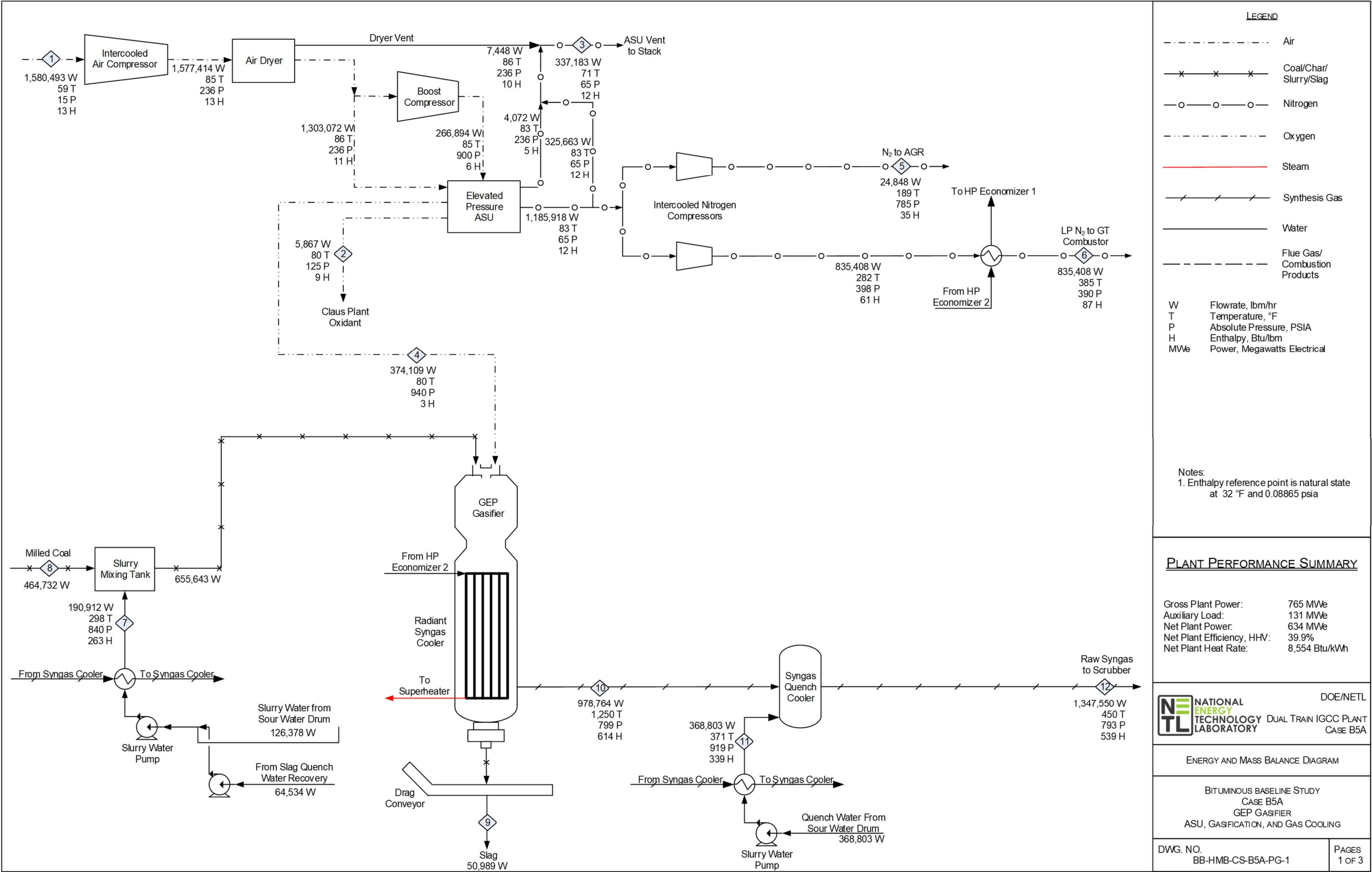


Exhibit 3-99. Case B5A syngas cleanup energy and mass balance

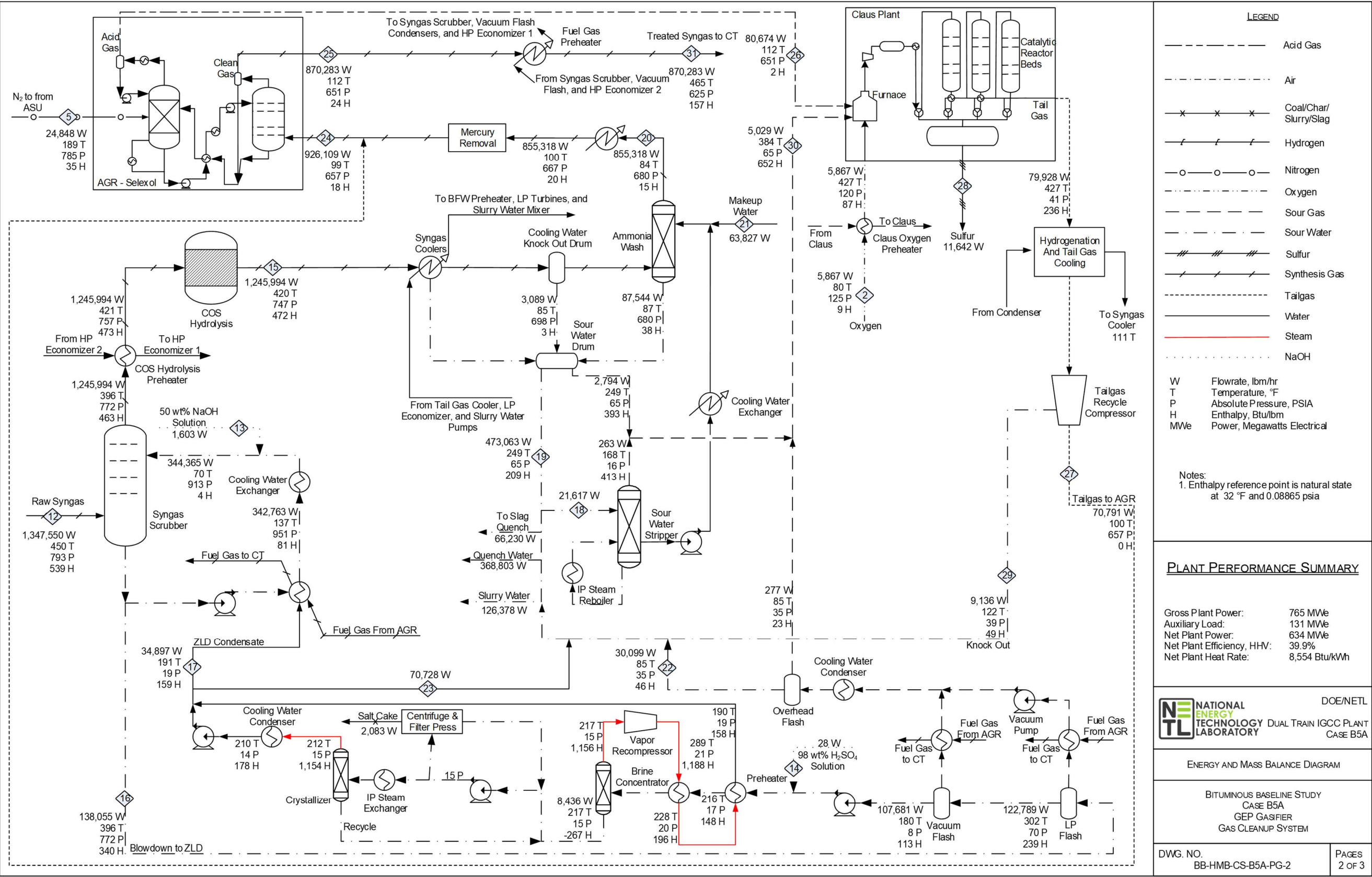
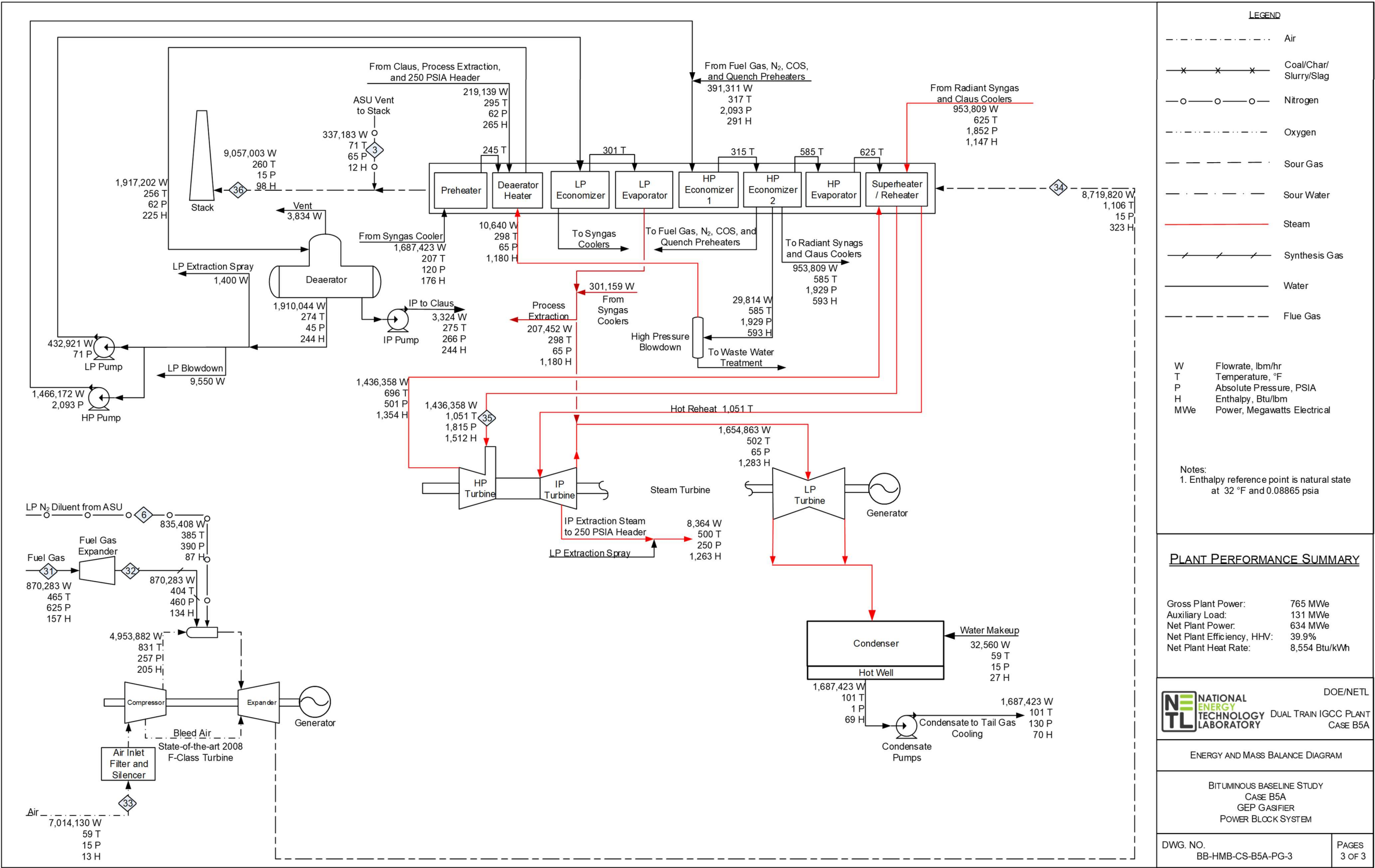


Exhibit 3-100. Case B5A combined cycle power generation energy and mass balance



This page intentionally left blank

3.4.6 Case B5A – Major Equipment List

Major equipment items for the GEP gasifier with no CO₂ capture are shown in the following tables. In general, the design conditions include a 10 percent design allowance for flows and heat duties and a 21 percent design allowance for heads on pumps and fans.

Case B5A – Account 1: Coal Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
5	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
6	Reclaim Hopper	N/A	40 tonne (50 ton)	2	1
7	Feeder	Vibratory	170 tonne/hr (190 tph)	2	1
8	Conveyor No. 3	Belt w/ tripper	350 tonne/hr (380 tph)	1	0
9	Coal Surge Bin w/ Vent Filter	Dual outlet	170 tonne (190 ton)	2	0
10	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
11	Conveyor No. 4	Belt w/trippper	350 tonne/hr (380 tph)	1	0
12	Conveyor No. 5	Belt w/ tripper	350 tonne/hr (380 tph)	1	0
13	Coal Silo w/ Vent Filter and Slide Gates	Field erected	770 tonne (850 ton)	3	0

Case B5A – Account 2: Coal Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	80 tonne/hr (90 tph)	3	0
2	Conveyor No. 6	Belt w/trippper	230 tonne/hr (260 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	460 tonne (510 ton)	1	0
4	Weigh Feeder	Belt	120 tonne/hr (130 tph)	2	0
5	Rod Mill	Rotary	120 tonne/hr (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	286,180 liters (75,600 gal)	2	0
7	Slurry Water Pumps	Centrifugal	790 lpm (210 gpm)	2	1
8	Trommel Screen	Coarse	160 tonne/hr (180 tph)	2	0
9	Rod Mill Discharge Tank with Agitator	Field erected	374,370 liters (98,900 gal)	2	0
10	Rod Mill Product Pumps	Centrifugal	3,100 lpm (800 gpm)	2	2
11	Slurry Storage Tank with Agitator	Field erected	1,123,100 liters (296,700 gal)	2	0
12	Slurry Recycle Pumps	Centrifugal	6,200 lpm (1,600 gpm)	2	2
13	Slurry Product Pumps	Positive displacement	3,100 lpm (800 gpm)	2	2

Case B5A – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	975,000 liters (258,000 gal)	2	0
2	Condensate Pumps	Vertical canned	7,060 lpm @ 90 m H ₂ O (1,870 gpm @ 300 ft H ₂ O)	2	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	Deaerator (integral w/ HRSG)	Horizontal spray type	478,000 kg/hr (1,054,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	1,870 lpm @ 20 m H ₂ O (490 gpm @ 70 ft H ₂ O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,340 lpm @ 1,700 m H ₂ O (1,680 gpm @ 5,700 ft H ₂ O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,690 lpm @ 210 m H ₂ O (450 gpm @ 670 ft H ₂ O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	244 GJ/hr (231 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	87,400 lpm @ 20 m H ₂ O (23,100 gpm @ 70 ft H ₂ O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
14	Municipal Water Pumps	Stainless steel, single suction	2,950 lpm @ 20 m H ₂ O (780 gpm @ 60 ft H ₂ O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,950 lpm @ 270 m H ₂ O (780 gpm @ 880 ft H ₂ O)	2	1
16	Filtered Water Pumps	Stainless steel, single suction	430 lpm @ 50 m H ₂ O (110 gpm @ 160 ft H ₂ O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	207,000 liter (55,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	170 lpm (40 gpm)	2	0
19	Liquid Waste Treatment System	N/A	10 years, 24-hour storm	1	0
20	Process Water Treatment	Vacuum flash, brine concentrator, and crystallizer	Vacuum Flash - Inlet: 34,000 kg/hr (76,000 lb/hr) Outlet: 6,410 ppmw Cl- Brine Concentrator Inlet - 27,000 kg/hr (59,000 lb/hr) Crystallizer Inlet - 2,000 kg/hr (5,000 lb/hr)	2	0

Case B5A – Account 4: Gasifier, ASU, and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized slurry-feed, entrained bed	2,800 tonne/day, 5.6 MPa (3,100 tpd, 815 psia)	2	0
2	Synthesis Gas Cooler	Vertical downflow radiant heat exchanger with outlet quench chamber	244,000 kg/hr (538,000 lb/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	N/A	2	0
4	HCl Scrubber	Ejector Venturi	336,000 kg/hr (741,000 lb/hr)	2	0
5	Ammonia Wash	Counter-flow spray tower	214,000 kg/hr (472,000 lb/hr) @ 4.8 MPa (698 psia)	2	0
6	Primary Sour Water Stripper	Counter-flow with external reboiler	5,000 kg/hr (12,000 lb/hr)	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
7	Secondary Sour Water Stripper	Counter-flow with external reboiler	N/A	2	0
8	Low Temperature Heat Recovery Coolers	Shell and tube with condensate drain	311,000 kg/hr (685,000 lb/hr)	6	0
9	Low Temperature Heat Recovery Knockout Drum	Vertical with mist eliminator	215,000 kg/hr, 59°C, 4.8 MPa (473,000 lb/hr, 138°F, 703 psia)	2	0
10	Saturation Water Economizers	Shell and tube	N/A	4	0
11	HP Nitrogen Gas Saturator	Direct Injection	N/A	2	0
12	LP Nitrogen Gas Saturator	Direct Injection	208,000 kg/hr, 196°C, 2.7 MPa (459,000 lb/hr, 385°F, 390 psia)	2	0
13	Saturator Water Pump	Centrifugal	N/A	2	2
14	Saturated Nitrogen Reheaters	Shell and tube	N/A	4	0
15	Synthesis Gas Reheaters	Shell and tube	Reheater 1: 207,000 kg/hr (456,000 lb/hr) Reheater 2: 10,000 kg/hr (23,000 lb/hr) Reheater 3: N/A Reheater 4: N/A Reheater 5: 217,000 kg/hr (479,000 lb/hr) Reheater 6: 217,000 kg/hr (479,000 lb/hr)	2	0
16	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	311,000 kg/hr (685,000 lb/hr) syngas	2	0
17	ASU Main Air Compressor	Centrifugal, multi-stage	5,000 m ³ /min @ 1.6 MPa (191,000 scfm @ 236 psia)	2	0
18	Cold Box	Vendor design	2,300 tonne/day (2,500 tpd) of 95% purity O ₂	2	0
19	Gasifier O ₂ Pump	Centrifugal, multi-stage	1,000 m ³ /min (40,000 scfm) Suction - 1.0 MPa (130 psia) Discharge - 6.5 MPa (940 psia)	2	0
20	AGR Nitrogen Boost Compressor	Centrifugal, multi-stage	100 m ³ /min (3,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - N/A MPa (N/A psia)	2	0
21	High Pressure Nitrogen Diluent Compressor	Centrifugal, multi-stage	N/A	2	0
22	Low Pressure Nitrogen Diluent Compressor	Centrifugal, single-stage	2,940 m ³ /min (104,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - 2.7 MPa (400 psia)	2	0
23	Gasifier Nitrogen Boost Compressor	Centrifugal, single-stage	N/A	2	0

Case B5A – Account 5: Syngas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber 1	Sulfated carbon bed	213,000 kg/hr (470,000 lb/hr) 29°C (84°F) 4.7 MPa (680 psia)	2	0
2	Mercury Adsorber 2	Sulfated carbon bed	213,000 kg/hr (470,000 lb/hr) 38°C (100°F) 4.6 MPa (662 psia)	2	0
3	Sulfur Plant	Claus type	139 tonne/day (154 tpd)	1	0
4	COS Hydrolysis Reactor	Fixed bed, catalytic	311,000 kg/hr (685,000 lb/hr) 216°C (420°F) 5.2 MPa (760 psia)	2	0
5	COS Hydrolysis Heat Exchanger	Shell and Tube	7 GJ/hr (6 MMBtu/hr)	2	0
6	Acid Gas Removal Plant	Selexol	231,000 kg/hr (509,000 lb/hr) 37°C (99°F) 4.5 MPa (657 psia)	2	0
7	Hydrogenation Reactor	Fixed bed, catalytic	40,000 kg/hr (88,000 lb/hr) 219°C (427°F) 0.3 MPa (40.8425733 psia)	1	0
8	Tail Gas Recycle Compressor	Centrifugal	35,000 kg/hr (78,000 lb/hr) each	1	0
9	Candle Filter	Pressurized filter with pulse-jet cleaning	N/A	2	0

Case B5A – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	State-of-the-art 2008 F-Class	232 MW	2	0
2	Combustion Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

Case B5A – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.6 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 358,337 kg/hr, 12.4 MPa/566°C (789,997 lb/hr, 1,800 psig/1,051°F) Reheat steam - 358,337 kg/hr, 3.3 MPa/566°C (789,997 lb/hr, 477 psig/1,051°F)	2	0

Case B5A – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	311 MW 12.4 MPa/566°C/566°C (1,800 psig/1,051°F/1,051°F)	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
2	Steam Turbine Generator	Hydrogen cooled, static excitation	350 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,820GJ/hr (1,720 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0
4	Steam Bypass	One per HRS	50% steam flow @ design steam conditions	2	0

Case B5A – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	448,000 lpm @ 30 m (118,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/ 16°C (60°F) CWT/ 27°C (80°F) HWT/ 2,500 GJ/hr (2,370 MMBtu/hr) heat duty	1	0

Case B5A – Account 10: Slag Recovery and Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	243,000 liters (64,000 gal)	2	0
2	Slag Crusher	Roll	13 tonne/hr (14 tph)	2	0
3	Slag Depressurizer	Lock Hopper	13 tonne/hr (14 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	146,000 liters (39,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	66,000 liters (17,000 gal)	2	0
6	Slag Conveyor	Drag chain	13 tonne/hr (14 tph)	2	0
7	Slag Separation Screen	Vibrating	13 tonne/hr (14 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	13 tonne/hr (14 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	207,000 liters (55,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	50 lpm @ 14 m H ₂ O (10 gpm @ 46 ft H ₂ O)	2	2
11	Grey Water Storage Tank	Field erected	66,000 liters (17,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	230 lpm @ 560 m H ₂ O (60 gpm @ 1,850 ft H ₂ O)	2	2
13	Slag Storage Bin	Vertical, field erected	900 tonne (1,000 tons)	2	0
14	Unloading Equipment	Telescoping chute	110 tonne/hr (120 tph)	1	0

Case B5A – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 310 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 56 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 32 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 5 MVA, 3-ph, 60 Hz	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B5A – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.4.7 Case B5A – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 3-101 shows a detailed breakdown of the capital costs; Exhibit 3-102 shows the owner's costs, TOC, and TASC; Exhibit 3-103 shows the initial and annual O&M costs; and Exhibit 3-104 shows the LCOE breakdown.

The estimated TPC of the GEP gasifier with no CO₂ capture is \$4,105/kW. Process contingency represents 5.2 percent of the TPC, and project contingency represents 14.5 percent. The LCOE is \$114.0/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-101. Case B5A total plant cost details

Case:		B5A	– GEP Radiant IGCC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		634					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
	1					Coal Handling					
1.1	Coal Receive & Unload	\$967	\$0	\$466	\$0	\$1,433	\$215	\$0	\$330	\$1,978	\$3
1.2	Coal Stackout & Reclaim	\$3,162	\$0	\$756	\$0	\$3,918	\$588	\$0	\$901	\$5,407	\$9
1.3	Coal Conveyors & Yard Crush	\$30,167	\$0	\$7,678	\$0	\$37,844	\$5,677	\$0	\$8,704	\$52,225	\$82
1.4	Other Coal Handling	\$4,698	\$0	\$1,058	\$0	\$5,756	\$863	\$0	\$1,324	\$7,943	\$13
1.9	Coal & Sorbent Handling Foundations	\$0	\$85	\$221	\$0	\$306	\$46	\$0	\$70	\$422	\$1
	Subtotal	\$38,994	\$85	\$10,179	\$0	\$49,258	\$7,389	\$0	\$11,329	\$67,976	\$107
	2					Coal Preparation & Feed					
2.1	Coal Crushing & Drying	\$2,341	\$141	\$336	\$0	\$2,819	\$423	\$0	\$648	\$3,890	\$6
2.2	Prepared Coal Storage & Feed	\$7,191	\$1,727	\$1,110	\$0	\$10,028	\$1,504	\$0	\$2,307	\$13,839	\$22
2.3	Slurry Coal Injection System	\$7,051	\$0	\$3,074	\$0	\$10,125	\$1,519	\$0	\$2,329	\$13,972	\$22
2.4	Miscellaneous Coal Preparation & Feed	\$710	\$519	\$1,528	\$0	\$2,758	\$414	\$0	\$634	\$3,806	\$6
2.9	Coal & Sorbent Feed Foundation	\$0	\$1,727	\$1,482	\$0	\$3,210	\$481	\$0	\$738	\$4,429	\$7
	Subtotal	\$17,293	\$4,114	\$7,531	\$0	\$28,939	\$4,341	\$0	\$6,656	\$39,936	\$63
	3					Feedwater & Miscellaneous BOP Systems					
3.1	Feedwater System	\$2,083	\$3,571	\$1,786	\$0	\$7,440	\$1,116	\$0	\$1,711	\$10,267	\$16
3.2	Water Makeup & Pretreating	\$4,997	\$500	\$2,832	\$0	\$8,328	\$1,249	\$0	\$2,873	\$12,451	\$20
3.3	Other Feedwater Subsystems	\$1,077	\$353	\$335	\$0	\$1,765	\$265	\$0	\$406	\$2,435	\$4
3.4	Service Water Systems	\$1,493	\$2,851	\$9,231	\$0	\$13,575	\$2,036	\$0	\$4,683	\$20,295	\$32
3.5	Other Boiler Plant Systems	\$279	\$102	\$254	\$0	\$635	\$95	\$0	\$146	\$876	\$1
3.6	Natural Gas Pipeline and Start-Up System	\$7,187	\$309	\$232	\$0	\$7,728	\$1,159	\$0	\$1,778	\$10,665	\$17
3.7	Waste Water Treatment Equipment	\$7,128	\$0	\$4,369	\$0	\$11,498	\$1,725	\$0	\$3,967	\$17,189	\$27
3.8	Vacuum Flash, Brine Concentrator, & Crystallizer	\$25,091	\$0	\$15,544	\$0	\$40,636	\$6,095	\$0	\$14,019	\$60,751	\$96
3.9	Miscellaneous Plant Equipment	\$15,305	\$2,007	\$7,778	\$0	\$25,090	\$3,764	\$0	\$8,656	\$37,510	\$59
	Subtotal	\$64,641	\$9,692	\$42,361	\$0	\$116,694	\$17,504	\$0	\$38,239	\$172,438	\$272
	4					Gasifier, ASU, & Accessories					
4.1	Gasifier & Auxiliaries (GEP)	\$515,494	\$0	\$283,918	\$0	\$799,411	\$119,912	\$111,918	\$154,686	\$1,185,927	\$1,871
4.2	Syngas Cooler	w/4.1	w/4.1	w/4.1	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.3	Air Separation Unit/Oxidant Compression	\$128,853	\$29,490	\$30,667	\$0	\$189,009	\$37,802	\$18,901	\$36,857	\$282,569	\$446

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B5A	– GEP Radiant IGCC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		634					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
4.5	Miscellaneous Gasification Equipment	\$3,840	\$0	\$2,115	\$0	\$5,956	\$893	\$0	\$1,027	\$7,876	\$12
4.6	Low Temperature Heat Recovery & Flue Gas Saturation	\$44,630	\$0	\$16,956	\$0	\$61,586	\$9,238	\$0	\$14,165	\$84,988	\$134
4.7	Flare Stack System	\$1,895	\$0	\$334	\$0	\$2,230	\$334	\$0	\$385	\$2,949	\$5
4.8	Black Water & Sour Gas Section	w/4.1	w/4.1	w/4.1	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.15	Major Component Rigging	\$214	\$0	\$118	\$0	\$331	\$50	\$0	\$57	\$438	\$1
4.16	Gasification Foundations	\$0	\$400	\$349	\$0	\$748	\$112	\$0	\$215	\$1,076	\$2
	Subtotal	\$694,926	\$29,890	\$334,456	\$0	\$1,059,272	\$168,341	\$130,819	\$207,392	\$1,565,823	\$2,471
5		Syngas Cleanup									
5.2	Single Stage Selexol	\$4,291	\$0	\$3,616	\$0	\$7,907	\$1,186	\$0	\$1,819	\$10,911	\$17
5.3	Elemental Sulfur Plant	\$47,457	\$9,252	\$60,812	\$0	\$117,521	\$17,628	\$0	\$27,030	\$162,179	\$256
5.6	Mercury Removal (Carbon Bed)	\$143	\$0	\$108	\$0	\$251	\$38	\$13	\$60	\$362	\$1
5.8	Carbonyl Sulfide (COS) Hydrolysis	\$11,550	\$0	\$14,980	\$0	\$26,530	\$3,980	\$0	\$6,102	\$36,611	\$58
5.10	Blowback Gas Systems	\$668	\$375	\$209	\$0	\$1,252	\$188	\$0	\$216	\$1,656	\$3
5.11	Fuel Gas Piping	\$0	\$2,955	\$1,933	\$0	\$4,888	\$733	\$0	\$1,124	\$6,746	\$11
5.12	Gas Cleanup Foundations	\$0	\$220	\$149	\$0	\$369	\$55	\$0	\$127	\$552	\$1
	Subtotal	\$64,108	\$12,802	\$81,808	\$0	\$158,718	\$23,808	\$13	\$36,478	\$219,017	\$346
6		Combustion Turbine & Accessories									
6.1	Combustion Turbine Generator	\$74,944	\$0	\$5,399	\$0	\$80,343	\$12,051	\$4,017	\$14,462	\$110,873	\$175
6.2	Syngas Expander	\$8,466	\$0	\$1,162	\$0	\$9,628	\$1,444	\$0	\$1,661	\$12,734	\$20
6.3	Combustion Turbine Accessories	\$2,687	\$0	\$164	\$0	\$2,851	\$428	\$0	\$492	\$3,770	\$6
6.4	Compressed Air Piping	\$0	\$510	\$333	\$0	\$843	\$126	\$0	\$194	\$1,163	\$2
6.5	Combustion Turbine Foundations	\$0	\$216	\$250	\$0	\$467	\$70	\$0	\$161	\$697	\$1
	Subtotal	\$86,098	\$726	\$7,308	\$0	\$94,131	\$14,120	\$4,017	\$16,969	\$129,238	\$204
7		HRSg, Ductwork, & Stack									
7.1	Heat Recovery Steam Generator	\$35,906	\$0	\$6,954	\$0	\$42,860	\$6,429	\$0	\$7,393	\$56,682	\$89
7.2	Heat Recovery Steam Generator Accessories	\$12,821	\$0	\$2,483	\$0	\$15,304	\$2,296	\$0	\$2,640	\$20,239	\$32
7.3	Ductwork	\$0	\$1,094	\$767	\$0	\$1,861	\$279	\$0	\$428	\$2,569	\$4
7.4	Stack	\$9,308	\$0	\$3,474	\$0	\$12,782	\$1,917	\$0	\$2,205	\$16,905	\$27
7.5	Heat Recovery Steam Generator, Ductwork & Stack Foundations	\$0	\$232	\$232	\$0	\$464	\$70	\$0	\$160	\$694	\$1
	Subtotal	\$58,035	\$1,326	\$13,910	\$0	\$73,271	\$10,991	\$0	\$12,826	\$97,088	\$153

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B5A	– GEP Radiant IGCC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		634					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
	8	Steam Turbine & Accessories									
8.1	Steam Turbine Generator & Accessories	\$39,116	\$0	\$6,004	\$0	\$45,120	\$6,768	\$0	\$7,783	\$59,672	\$94
8.2	Steam Turbine Plant Auxiliaries	\$1,899	\$0	\$4,329	\$0	\$6,228	\$934	\$0	\$1,074	\$8,237	\$13
8.3	Condenser & Auxiliaries	\$7,525	\$0	\$4,282	\$0	\$11,807	\$1,771	\$0	\$2,037	\$15,615	\$25
8.4	Steam Piping	\$7,008	\$0	\$3,039	\$0	\$10,048	\$1,507	\$0	\$2,889	\$14,443	\$23
8.5	Turbine Generator Foundations	\$0	\$296	\$523	\$0	\$820	\$123	\$0	\$283	\$1,225	\$2
	Subtotal	\$55,549	\$296	\$18,178	\$0	\$74,023	\$11,103	\$0	\$14,066	\$99,192	\$157
	9	Cooling Water System									
9.1	Cooling Towers	\$11,332	\$0	\$3,443	\$0	\$14,775	\$2,216	\$0	\$2,549	\$19,540	\$31
9.2	Circulating Water Pumps	\$1,478	\$0	\$107	\$0	\$1,585	\$238	\$0	\$273	\$2,096	\$3
9.3	Circulating Water System Auxiliaries	\$10,189	\$0	\$1,439	\$0	\$11,628	\$1,744	\$0	\$2,006	\$15,378	\$24
9.4	Circulating Water Piping	\$0	\$5,739	\$5,197	\$0	\$10,935	\$1,640	\$0	\$2,515	\$15,091	\$24
9.5	Make-up Water System	\$599	\$0	\$825	\$0	\$1,424	\$214	\$0	\$328	\$1,965	\$3
9.6	Component Cooling Water System	\$208	\$248	\$171	\$0	\$627	\$94	\$0	\$144	\$865	\$1
9.7	Circulating Water System Foundations	\$0	\$474	\$843	\$0	\$1,317	\$198	\$0	\$454	\$1,969	\$3
	Subtotal	\$23,805	\$6,461	\$12,024	\$0	\$42,290	\$6,344	\$0	\$8,269	\$56,903	\$90
	10	Slag Recovery & Handling									
10.1	Slag Dewatering & Cooling	\$2,043	\$0	\$1,001	\$0	\$3,044	\$457	\$0	\$525	\$4,025	\$6
10.2	Gasifier Ash Depressurization	\$1,157	\$0	\$567	\$0	\$1,724	\$259	\$0	\$297	\$2,280	\$4
10.3	Cleanup Ash Depressurization	\$520	\$0	\$255	\$0	\$775	\$116	\$0	\$134	\$1,025	\$2
10.6	Ash Storage Silos	\$1,156	\$0	\$1,250	\$0	\$2,406	\$361	\$0	\$415	\$3,182	\$5
10.7	Ash Transport & Feed Equipment	\$446	\$0	\$104	\$0	\$550	\$82	\$0	\$95	\$727	\$1
10.8	Miscellaneous Ash Handling Equipment	\$64	\$78	\$23	\$0	\$165	\$25	\$0	\$29	\$219	\$0
10.9	Ash/Spent Sorbent Foundation	\$0	\$452	\$593	\$0	\$1,045	\$157	\$0	\$360	\$1,562	\$2
	Subtotal	\$5,386	\$531	\$3,792	\$0	\$9,708	\$1,456	\$0	\$1,855	\$13,020	\$21
	11	Accessory Electric Plant									
11.1	Generator Equipment	\$2,812	\$0	\$2,121	\$0	\$4,933	\$740	\$0	\$851	\$6,524	\$10
11.2	Station Service Equipment	\$3,637	\$0	\$312	\$0	\$3,949	\$592	\$0	\$681	\$5,222	\$8
11.3	Switchgear & Motor Control	\$21,945	\$0	\$3,807	\$0	\$25,752	\$3,863	\$0	\$4,442	\$34,057	\$54
11.4	Conduit & Cable Tray	\$0	\$97	\$280	\$0	\$377	\$57	\$0	\$108	\$542	\$1
11.5	Wire & Cable	\$0	\$1,331	\$2,380	\$0	\$3,711	\$557	\$0	\$1,067	\$5,335	\$8
11.6	Protective Equipment	\$241	\$0	\$837	\$0	\$1,078	\$162	\$0	\$186	\$1,426	\$2
11.7	Standby Equipment	\$865	\$0	\$798	\$0	\$1,663	\$249	\$0	\$287	\$2,199	\$3
11.8	Main Power Transformers	\$6,567	\$0	\$134	\$0	\$6,701	\$1,005	\$0	\$1,156	\$8,863	\$14

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B5A	– GEP Radiant IGCC w/o CO ₂ Capture				Estimate Type:		Conceptual		
Plant Size (MW, net):		634					Cost Base:		Dec 2018		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
11.9	Electrical Foundations	\$0	\$76	\$193	\$0	\$268	\$40	\$0	\$93	\$401	\$1
	Subtotal	\$36,066	\$1,504	\$10,863	\$0	\$48,433	\$7,265	\$0	\$8,871	\$64,570	\$102
12 Instrumentation & Control											
12.1	Integrated Gasification and Combined Cycle Control Equipment	\$614	\$0	\$338	\$0	\$951	\$143	\$0	\$164	\$1,258	\$2
12.2	Combustion Turbine Control Equipment	\$656	\$0	\$47	\$0	\$703	\$105	\$0	\$121	\$930	\$1
12.3	Steam Turbine Control Equipment	\$606	\$0	\$93	\$0	\$699	\$105	\$0	\$121	\$924	\$1
12.4	Other Major Component Control Equipment	\$1,172	\$0	\$799	\$0	\$1,970	\$296	\$99	\$355	\$2,719	\$4
12.5	Signal Processing Equipment	\$909	\$0	\$30	\$0	\$939	\$141	\$0	\$162	\$1,241	\$2
12.6	Control Boards, Panels & Racks	\$264	\$0	\$172	\$0	\$435	\$65	\$22	\$104	\$627	\$1
12.7	Distributed Control System Equipment	\$9,539	\$0	\$312	\$0	\$9,851	\$1,478	\$493	\$1,773	\$13,595	\$21
12.8	Instrument Wiring & Tubing	\$475	\$380	\$1,519	\$0	\$2,373	\$356	\$119	\$712	\$3,560	\$6
12.9	Other Instrumentation & Controls Equipment	\$1,065	\$0	\$528	\$0	\$1,592	\$239	\$80	\$287	\$2,198	\$3
	Subtotal	\$15,298	\$380	\$3,837	\$0	\$19,515	\$2,927	\$811	\$3,799	\$27,052	\$43
13 Improvements to Site											
13.1	Site Preparation	\$0	\$417	\$9,494	\$0	\$9,911	\$1,487	\$0	\$3,419	\$14,817	\$23
13.3	Site Facilities	\$2,945	\$0	\$3,306	\$0	\$6,250	\$938	\$0	\$2,156	\$9,344	\$15
	Subtotal	\$2,945	\$2,303	\$15,466	\$0	\$20,713	\$3,107	\$0	\$7,146	\$30,966	\$49
14 Buildings & Structures											
14.1	Combustion Turbine Area	\$0	\$314	\$177	\$0	\$491	\$74	\$0	\$85	\$649	\$1
14.3	Steam Turbine Building	\$0	\$2,784	\$3,964	\$0	\$6,748	\$1,012	\$0	\$1,164	\$8,924	\$14
14.4	Administration Building	\$0	\$886	\$642	\$0	\$1,529	\$229	\$0	\$264	\$2,022	\$3
14.5	Circulation Water Pumphouse	\$0	\$142	\$75	\$0	\$217	\$33	\$0	\$37	\$287	\$0
14.6	Water Treatment Buildings	\$0	\$333	\$325	\$0	\$658	\$99	\$0	\$113	\$870	\$1
14.7	Machine Shop	\$0	\$490	\$335	\$0	\$824	\$124	\$0	\$142	\$1,090	\$2
14.8	Warehouse	\$0	\$382	\$246	\$0	\$628	\$94	\$0	\$108	\$831	\$1
14.9	Other Buildings & Structures	\$0	\$280	\$218	\$0	\$498	\$75	\$0	\$86	\$658	\$1
14.10	Waste Treating Building & Structures	\$0	\$757	\$1,445	\$0	\$2,203	\$330	\$0	\$380	\$2,913	\$5
	Subtotal	\$0	\$6,368	\$7,428	\$0	\$13,795	\$2,069	\$0	\$2,380	\$18,244	\$29
	Total	\$1,163,145	\$76,478	\$569,139	\$0	\$1,808,762	\$280,765	\$135,659	\$376,276	\$2,601,462	\$4,105

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-102. Case B5A owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$21,456	\$34
1 Month Maintenance Materials	\$5,284	\$8
1 Month Non-fuel Consumables	\$860	\$1
1 Month Waste Disposal	\$750	\$1
25% of 1 Months Fuel Cost at 100% CF	\$2,203	\$3
2% of TPC	\$52,029	\$82
Total	\$82,583	\$130
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	\$18,947	\$30
0.5% of TPC (spare parts)	\$13,007	\$21
Total	\$31,954	\$50
Other Costs		
Initial Cost for Catalyst and Chemicals	\$11,824	\$19
Land	\$900	\$1
Other Owner's Costs	\$390,219	\$616
Financing Costs	\$70,239	\$111
Total Overnight Costs (TOC)	\$3,189,182	\$5,032
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	\$3,681,629	\$5,809

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-103. Case B5A initial and annual operating and maintenance costs

Case:	B5A	– GEP Radiant IGCC w/o CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	634	Heat Rate-net (Btu/kWh):	8,554		Capacity Factor (%):	80
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	% of base	Operator:	10.0	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	3.0	
				Total:	16.0	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$7,015,008	\$11.068
Maintenance Labor:					\$27,315,352	\$43.098
Administrative & Support Labor:					\$8,582,590	\$13.541
Property Taxes and Insurance:					\$52,029,242	\$82.091
Total:					\$94,942,192	\$149.798
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$50,728,511	\$11.42104
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (gal/1000):	0	3,455	\$1.90	\$0	\$1,916,875	\$0.43157
Makeup and Waste Water Treatment Chemicals (ton):	0	10.3	\$550.00	\$0	\$1,652,924	\$0.37214
Sulfur-Impregnated Activated Carbon (ton):	51.1	0.070	\$12,000.00	\$612,994	\$245,198	\$0.05520
COS Hydrolysis Catalyst (ft³):	2,170	1.49	\$1,300.00	\$2,820,669	\$564,134	\$0.12701
Selexol Solution (gal):	220,807	41.0	\$38.00	\$8,390,684	\$454,782	\$0.10239
Sodium Hydroxide (50 wt%, ton):	0	19.2	\$600.00	\$0	\$3,369,391	\$0.75859
Sulfuric Acid (98 wt%, ton):	0	0.340	\$210.00	\$0	\$20,844	\$0.00469
Claus Catalyst (ft³):	w/equip.	1.93	\$48.00	\$0	\$27,090	\$0.00610
Subtotal:				\$11,824,347	\$8,251,238	\$1.85769
Waste Disposal						
Sulfur-Impregnated Activated Carbon (ton):	0	0.070	\$80.00	\$0	\$1,635	\$0.00037
COS Hydrolysis Catalyst (ft³):	0	1.49	\$2.50	\$0	\$1,085	\$0.00024
Selexol Solution (gal):	0	41.0	\$0.35	\$0	\$4,189	\$0.00094
Claus Catalyst (ft³):	0	1.93	\$2.50	\$0	\$1,411	\$0.00032
Crystallizer Solids (ton):	0	36.2	\$38.00	\$0	\$401,337	\$0.09036
Slag (ton):	0	612	\$38.00	\$0	\$6,789,283	\$1.52854
Subtotal:				\$0	\$7,198,940	\$1.62077
By-Products						
Sulfur (tons):	0	140	\$0.00	\$0	\$0	\$0.00000
Subtotal:				\$0	\$0	\$0.00000
Variable Operating Costs Total:				\$11,824,347	\$66,178,689	\$14.89950
Fuel Cost						
Illinois Number 6 (ton):	0	5,577	\$51.96	\$0	\$84,609,474	\$19.04902
Total:				\$0	\$84,609,474	\$19.04902

Exhibit 3-104. Case B5A LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	58.6	51.5%
Fixed	21.4	18.8%
Variable	14.9	13.1%
Fuel	19.0	16.7%
Total (Excluding T&S)	114.0	100.0%
CO ₂ T&S	—	—
Total (Including T&S)	114.0	100.0%

3.4.8 Case B5B – GEP Radiant IGCC with CO₂ Capture Process Description

In this section, the GEP gasification process for Case B5B is described. The plant configuration is nearly identical to that of Case B5A, with the exception that this case is configured to produce electric power with CO₂ capture.

The gross power output is constrained by the capacity of the two CTs, and since the CO₂ capture and compression process increases the auxiliary load on the plant, the net output is significantly reduced relative to Case B5A (556 MW versus 634 MW).

The process descriptions for Case B5B are similar to Case B5A with several notable exceptions to accommodate CO₂ capture. The system descriptions follow the BFD provided in Exhibit 3-105 with the associated stream tables—providing process data for the numbered streams in the BFD—provided in Exhibit 3-106. Rather than repeating the entire process description, only differences from Case B5A are reported here.

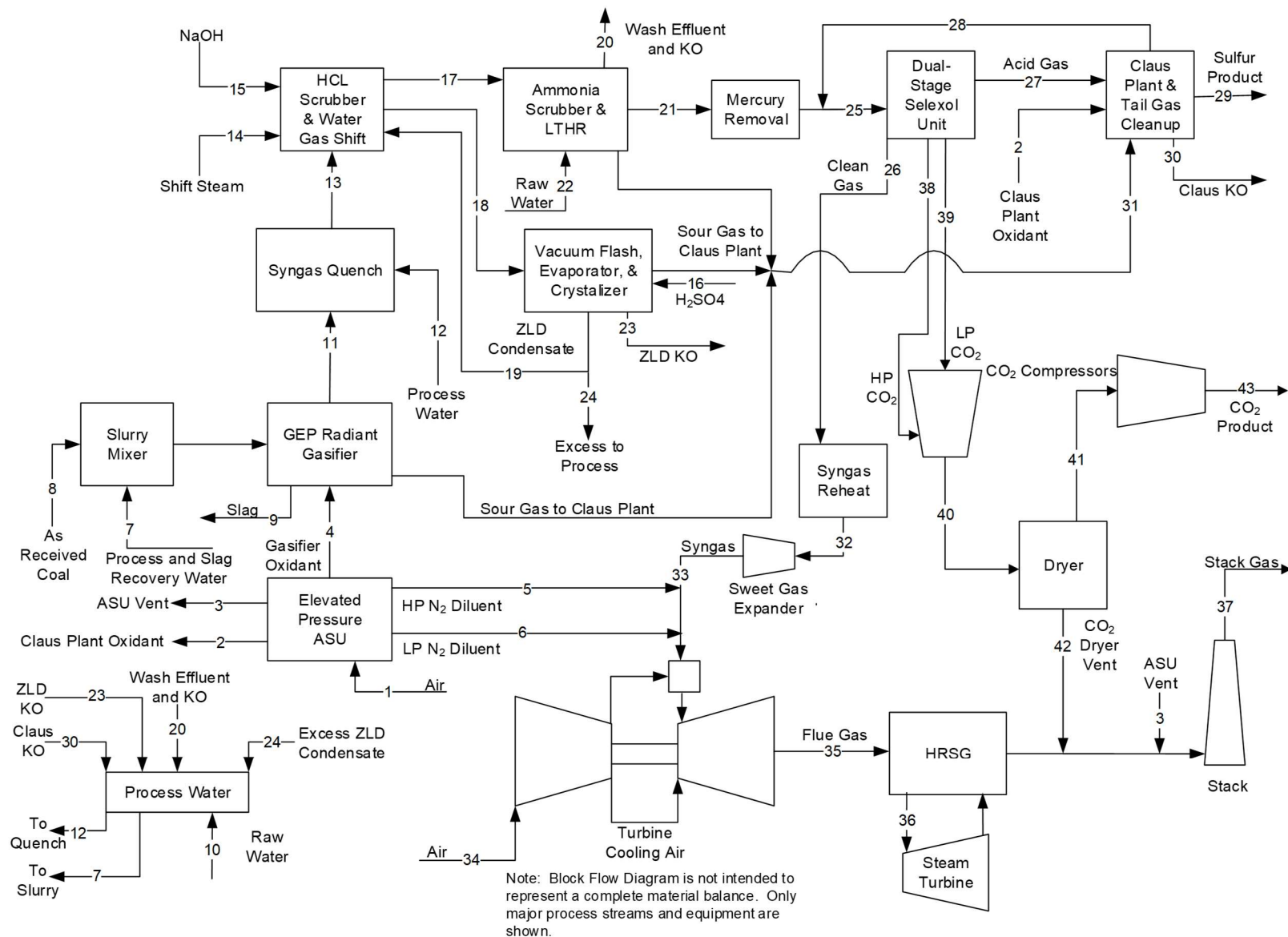
3.4.8.1 Coal Preparation and Feed Systems

No differences from Case B5A.

3.4.8.2 Gasifier

No differences from Case B5A.

Exhibit 3-105. Case B5B block flow diagram, GEP IGCC with CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-106. Case B5B stream table, GEP IGCC with capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0343	0.0443	0.0343	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0082	0.0000
CH ₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0011	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3571	0.0000
CO ₂	0.0003	0.0000	0.0078	0.0000	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000	0.1381	0.0005
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3412	0.0000
H ₂ O	0.0099	0.0000	0.1606	0.0000	0.0000	0.0000	0.9904	0.0000	0.0000	0.9999	0.1363	0.9902
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000
H ₂ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0073	0.0001
N ₂	0.7732	0.0157	0.7846	0.0157	0.9964	0.9964	0.0000	0.0000	0.0000	0.0000	0.0080	0.0000
NH ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0091	0.0000	0.0000	0.0000	0.0021	0.0091
O ₂	0.2074	0.9501	0.0028	0.9501	0.0036	0.0036	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	25,720	69	1,081	5,471	8,786	10,232	4,990	0	0	1,777	22,932	9,650
V-L Flowrate (kg/hr)	742,208	2,229	29,273	176,210	246,260	286,790	89,922	0	0	32,021	461,011	173,917
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	218,895	24,016	0	0	0
Temperature (°C)	15	27	23	27	196	196	148	15	1,316	15	677	188
Pressure (MPa, abs)	0.10	0.86	0.45	6.48	3.24	2.69	5.79	0.10	5.62	0.10	5.51	6.33
Steam Table Enthalpy (kJ/kg) ^A	30.23	21.53	26.49	6.21	202.25	202.61	607.31	---	---	62.75	1,428.33	785.40
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-0.97	-1,815.18	-16.30	176.29	176.64	-15,239.17	-2,119.02	-727.24	-15,905.25	-5,242.22	-15,058.15
Density (kg/m ³)	1.2	11.2	5.8	87.9	23.1	19.2	898.7	---	---	999.4	13.8	859.7
V-L Molecular Weight	28.857	32.209	27.072	32.209	28.028	28.028	18.019	---	---	18.019	20.104	18.023
V-L Flowrate (lb _{mol} /hr)	56,703	153	2,384	12,061	19,370	22,559	11,002	0	0	3,918	50,555	21,274
V-L Flowrate (lb/hr)	1,636,288	4,913	64,537	388,477	542,910	632,264	198,245	0	0	70,593	1,016,355	383,422
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	482,580	52,947	0	0	0
Temperature (°F)	59	80	74	80	385	385	298	59	2,400	59	1,250	371
Pressure (psia)	14.7	125.0	65.0	940.0	470.0	390.0	840.0	14.7	815.0	14.7	798.7	918.7
Steam Table Enthalpy (Btu/lb) ^A	13.0	9.3	11.4	2.7	87.0	87.1	261.1	---	---	27.0	614.1	337.7
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-0.4	-780.4	-7.0	75.8	75.9	-6,551.7	-911.0	-312.7	-6,838.0	-2,253.7	-6,473.8
Density (lb/ft ³)	0.076	0.700	0.365	5.487	1.439	1.196	56.102	---	---	62.391	0.864	53.671

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-106. Case B5B stream table, GEP IGCC with capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0058	0.0000	0.0000	0.0000	0.0055	0.0000	0.0000	0.0000	0.0069	0.0000	0.0000	0.0000
CH ₄	0.0008	0.0000	0.0000	0.0000	0.0008	0.0000	0.0000	0.0000	0.0010	0.0000	0.0000	0.0000
CO	0.2513	0.0000	0.0000	0.0000	0.0167	0.0001	0.0000	0.0000	0.0210	0.0000	0.0000	0.0000
CO ₂	0.0974	0.0000	0.0000	0.0000	0.3139	0.0008	0.0000	0.0007	0.3928	0.0000	0.0008	0.0000
COS	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.2402	0.0000	0.0000	0.0000	0.4492	0.0002	0.0000	0.0000	0.5644	0.0000	0.0000	0.0000
H ₂ O	0.3892	1.0000	0.6895	0.1000	0.2000	0.9941	0.9997	0.9866	0.0012	0.9999	0.9911	0.9997
HCl	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0052	0.0000	0.0000	0.0000	0.0050	0.0001	0.0000	0.0001	0.0062	0.0000	0.0002	0.0000
N ₂	0.0056	0.0000	0.0000	0.0000	0.0053	0.0000	0.0000	0.0000	0.0067	0.0000	0.0000	0.0000
NH ₃	0.0041	0.0000	0.0000	0.0000	0.0037	0.0020	0.0003	0.0125	0.0000	0.0000	0.0079	0.0003
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0026	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000
NaOH	0.0000	0.0000	0.3105	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	0.1000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	32,581	4,428	30	0	34,370	3,584	915	10,086	27,347	3,118	786	1,847
V-L Flowrate (kg/hr)	634,905	79,778	755	13	666,900	65,022	16,485	181,793	539,289	56,178	14,174	33,266
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	232	288	16	15	225	202	88	89	28	15	29	88
Pressure (MPa, abs)	5.47	5.33	6.30	0.13	4.79	5.33	0.13	0.45	4.36	0.10	0.24	0.13
Steam Table Enthalpy (kJ/kg) ^A	1,252.06	2,932.37	-337.57	-8,206.86	840.10	850.86	369.16	344.46	32.19	62.75	106.51	369.16
AspenPlus Enthalpy (kJ/kg) ^B	-7,931.49	-13,047.92	-13,663.78	-8,526.27	-8,636.20	-14,999.84	-15,596.91	-15,452.29	-7,990.65	-15,905.25	-15,745.25	-15,596.91
Density (kg/m ³)	26.2	24.5	1,532.5	1,791.5	22.6	862.9	965.9	954.2	35.1	999.4	990.8	965.9
V-L Molecular Weight	19.487	18.015	24.842	90.073	19.403	18.140	18.015	18.025	19.720	18.019	18.032	18.015
V-L Flowrate (lb _{mol} /hr)	71,828	9,763	67	0	75,774	7,902	2,017	22,235	60,290	6,874	1,733	4,071
V-L Flowrate (lb/hr)	1,399,727	175,879	1,664	29	1,470,263	143,350	36,342	400,785	1,188,929	123,852	31,249	73,338
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	450	550	61	59	437	396	191	192	82	59	85	191
Pressure (psia)	793.1	772.5	913.1	18.2	694.8	772.5	19.4	65.0	632.5	14.7	35.0	19.4
Steam Table Enthalpy (Btu/lb) ^A	538.3	1,260.7	-145.1	-3,528.3	361.2	365.8	158.7	148.1	13.8	27.0	45.8	158.7
AspenPlus Enthalpy (Btu/lb) ^B	-3,409.9	-5,609.6	-5,874.4	-3,665.6	-3,712.9	-6,448.8	-6,705.5	-6,643.3	-3,435.4	-6,838.0	-6,769.2	-6,705.5
Density (lb/ft ³)	1.636	1.530	95.670	111.841	1.413	53.872	60.298	59.566	2.194	62.391	61.856	60.298

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-106. Case B5B stream table, GEP IGCC with capture (continued)

	25	26	27	28	29	30	31	32	33	34	35	36
V-L Mole Fraction												
Ar	0.0069	0.0112	0.0001	0.0083	0.0000	0.0000	0.0010	0.0112	0.0112	0.0092	0.0088	0.0000
CH ₄	0.0009	0.0014	0.0001	0.0000	0.0000	0.0000	0.0001	0.0014	0.0014	0.0000	0.0000	0.0000
CO	0.0208	0.0336	0.0008	0.0056	0.0000	0.0000	0.0103	0.0336	0.0336	0.0000	0.0000	0.0000
CO ₂	0.3971	0.0304	0.5121	0.7967	0.0000	0.0000	0.7110	0.0304	0.0304	0.0003	0.0083	0.0000
COS	0.0000	0.0000	0.0010	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.5602	0.9123	0.0116	0.1726	0.0000	0.0000	0.0726	0.9123	0.9123	0.0000	0.0000	0.0000
H ₂ O	0.0012	0.0001	0.0160	0.0020	0.0000	1.0000	0.1473	0.0001	0.0001	0.0099	0.1197	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0062	0.0000	0.4576	0.0076	0.0000	0.0000	0.0285	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0067	0.0109	0.0000	0.0072	0.0000	0.0000	0.0006	0.0109	0.0109	0.7732	0.7554	0.0000
NH ₃	0.0000	0.0000	0.0006	0.0000	0.0000	0.0000	0.0285	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2074	0.1079	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	27,641	16,882	374	294	0	146	60	16,882	16,882	110,253	138,169	34,077
V-L Flowrate (kg/hr)	549,993	82,706	14,421	10,704	0	2,631	2,171	82,706	82,706	3,181,556	3,797,304	613,905
Solids Flowrate (kg/hr)	0	0	0	0	5,486	0	0	0	0	0	0	0
Temperature (°C)	36	18	27	38	184	49	90	241	219	15	566	535
Pressure (MPa, abs)	4.21	3.96	0.18	4.21	0.12	0.11	0.45	3.81	3.17	0.10	0.10	12.51
Steam Table Enthalpy (kJ/kg) ^A	42.85	108.20	41.01	5.09	---	107.98	271.72	1,453.85	1,320.53	30.23	834.08	3,436.63
AspenPlus Enthalpy (kJ/kg) ^B	-7,992.68	-3,270.09	-5,581.34	-8,669.69	146.92	-15,861.78	-8,809.63	-1,924.43	-2,057.75	-97.58	-560.76	-12,543.66
Density (kg/m ³)	33.4	7.9	2.9	68.7	5,268.0	963.4	5.4	4.3	3.8	1.2	0.4	36.6
V-L Molecular Weight	19.898	4.899	38.543	36.396	---	18.016	35.895	4.899	4.899	28.857	27.483	18.015
V-L Flowrate (lb _{mol} /hr)	60,938	37,218	825	648	0	322	133	37,218	37,218	243,065	304,610	75,127
V-L Flowrate (lb/hr)	1,212,527	182,336	31,793	23,598	0	5,801	4,787	182,336	182,336	7,014,130	8,371,623	1,353,430
Solids Flowrate (lb/hr)	0	0	0	0	12,094	0	0	0	0	0	0	0
Temperature (°F)	97	65	80	100	362	121	194	465	426	59	1,051	996
Pressure (psia)	611.2	574.8	26.7	611.2	17.1	16.2	65.0	552.0	460.0	14.7	15.1	1,814.7
Steam Table Enthalpy (Btu/lb) ^A	18.4	46.5	17.6	2.2	---	46.4	116.8	625.0	567.7	13.0	358.6	1,477.5
AspenPlus Enthalpy (Btu/lb) ^B	-3,436.2	-1,405.9	-2,399.5	-3,727.3	63.2	-6,819.3	-3,787.5	-827.4	-884.7	-42.0	-241.1	-5,392.8
Density (lb/ft ³)	2.084	0.491	0.180	4.288	328.873	60.145	0.338	0.269	0.235	0.076	0.026	2.288

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit 3-106. Case B5B stream table, GEP IGCC with capture (continued)

	37	38	39	40	41	42	43
V-L Mole Fraction							
Ar	0.0090	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.0002	0.0001	0.0002	0.0002	0.0000	0.0002
CO	0.0000	0.0009	0.0001	0.0007	0.0007	0.0000	0.0007
CO ₂	0.0083	0.9853	0.9985	0.9889	0.9908	0.0500	0.9908
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0103	0.0008	0.0077	0.0077	0.0000	0.0077
H ₂ O	0.1201	0.0031	0.0005	0.0024	0.0005	0.9500	0.0005
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7555	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
NH ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.1070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	139,271	7,572	2,814	10,385	10,364	21	10,364
V-L Flowrate (kg/hr)	3,826,982	329,179	123,687	452,866	452,461	404	452,461
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0
Temperature (°C)	129	-3	-11	29	29	29	30
Pressure (MPa, abs)	0.10	0.55	0.12	2.50	2.39	2.50	15.27
Steam Table Enthalpy (kJ/kg) ^A	336.80	-5.70	-9.81	1.28	0.53	138.13	-226.97
AspenPlus Enthalpy (kJ/kg) ^B	-1,062.91	-8,968.75	-8,972.37	-8,961.74	-8,956.76	-15,225.03	-9,184.27
Density (kg/m ³)	0.8	11.1	2.3	49.8	47.2	319.0	838.2
V-L Molecular Weight	27.479	43.474	43.960	43.606	43.655	19.315	43.655
V-L Flowrate (lb _{mol} /hr)	307,040	16,693	6,203	22,896	22,850	46	22,850
V-L Flowrate (lb/hr)	8,437,051	725,715	272,683	998,398	997,507	891	997,507
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0
Temperature (°F)	265	26	12	85	85	85	86
Pressure (psia)	14.8	80.0	16.7	363.0	346.5	363.0	2,214.7
Steam Table Enthalpy (Btu/lb) ^A	144.8	-2.4	-4.2	0.5	0.2	59.4	-97.6
AspenPlus Enthalpy (Btu/lb) ^B	-457.0	-3,855.9	-3,857.4	-3,852.9	-3,850.7	-6,545.6	-3,948.5
Density (lb/ft ³)	0.052	0.696	0.146	3.109	2.948	19.917	52.328

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

3.4.8.3 Raw Gas Cooling and Particulate Removal

No differences from Case B5A.

3.4.8.4 Syngas Scrubber

Case B5B differs from Case B5A only in the degree of cooling completed prior to the cooling water HX. In Case B5A, both the process water and scrubber effluent recycle are cooled to 58°C (137°F) by preheating syngas prior to the CT. However, in this case, the recycled effluent is cooled from 203°C (397°F) to 44°C (112°F) by preheating FW to the WGS steam generator, and the ZLD condensate (stream 19) is cooled to 32°C (90°F) by preheating syngas prior to the CT and mixed with the cooled effluent before being cooled further to 21°C (70°F) with cooling water and injected into the scrubber.

3.4.8.5 Water Gas Shift

The WGS process was described in Section 3.1.3. After the scrubber, the syngas is combined with steam (stream 14) to adjust the steam to dry gas ratio prior to the first WGS reactor. The rate of steam injection is controlled to maintain an exit steam to dry gas ratio of approximately 0.25. Two stages total are used to convert 93.0 percent of the CO in the syngas to CO₂. The heat generated from the first reactor is used to produce more steam than is required (26,677 kg/hr [58,813 lb/hr] of 5.3MPa [773 psia] steam is exported for use in the steam cycle) to maintain the desired steam to dry gas ratio while cooling the syngas to 253°C (487°F) prior to entering the second stage. Prior to the syngas being sent to the LTHR system (stream 17), the warm syngas from the second stage of WGS is cooled to 225°C (437°F) by preheating the FW of the WGS steam generator.

The WGS catalyst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor.

3.4.8.6 Low Temperature Heat Recovery

Case B5B only differs from Case B5A in that the second stage of the LTHR system cools the syngas by preheating the FW to the WGS steam generator, in addition to the other uses described for Case B5A.

3.4.8.7 Ammonia Wash

As Case B5B has no SWS; raw water is utilized as the sole source of NH₃ wash water. All other aspects of this section are identical to those described for Case B5A.

3.4.8.8 Process Water Treatment

The process water treatment system is identical to that used in Case B5A, with the exception that the vapor products from both the LP and vacuum flash stages are cooled to 46°C (115°F) prior to the cooling water condensing HX. The lower temperature reached in this case (46°C [115°F] versus 72°C [162°F]) is due to the lower exit temperature of the two-stage Selexol system, compared to the one-stage Selexol system.

3.4.8.9 Mercury Removal and AGR

Mercury removal is the same as in Case B5A.

The AGR process in Case B5B is a two-stage Selexol process (covered in Section 3.1.5) where H₂S is removed in the first stage and CO₂ in the second stage of absorption. The process results in four product streams, the clean syngas (stream 26), two CO₂-rich streams (streams 38 and 39) and an acid gas feed to the Claus plant (stream 27). The acid gas contains 46 vol% H₂S and 51 vol% CO₂ with the balance primarily water and H₂. The raw CO₂ stream from the Selexol process contains over 99 vol% CO₂.

3.4.8.10 Claus Unit

No differences from Case B5A.

3.4.8.11 Power Block

In Case B5B, HP N₂ (stream 5) at 3.2 MPa (470 psia), in addition to the LP N₂ (stream 6) at 2.7 MPa (390 psia), is used as a syngas diluent. The exhaust gas (stream 35) exits the CT at a lower temperature (566°C [1,051°F]) than Case B5A due to the higher moisture content.

3.4.8.12 Air Separation Unit

No differences from Case B5A.

3.4.9 Case B5B – Performance Results

The Case B5B modeling assumptions were presented previously in Section 3.4.2.

The plant produces a net output of 556 MW at a net plant efficiency of 33.7 percent (HHV basis). Overall performance for the entire plant is summarized in Exhibit 3-107.

Exhibit 3-107. Case B5B plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	464
Sweet Gas Expander Power, MWe	3
Steam Turbine Power, MWe	274
Total Gross Power, MWe	741
Air Separation Unit Main Air Compressor, kWe	71,280
Air Separation Unit Booster Compressor, kWe	5,610
N ₂ Compressors, kWe	36,580
CO ₂ Compression, kWe	31,670
Acid Gas Removal, kWe	11,550
Balance of Plant, kWe	28,080
Total Auxiliaries, MWe	185
Net Power, MWe	556
HHV Net Plant Efficiency, %	33.7
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,675 (10,118)
HHV Cold Gas Efficiency, %	79.0
HHV Combustion Turbine Efficiency, %	36.4
LHV Net Plant Efficiency, %	35.0
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,296 (9,759)
LHV Cold Gas Efficiency, %	75.7
LHV Combustion Turbine Efficiency, %	42.8
Steam Turbine Cycle Efficiency, %	43.1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Performance Summary	
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	8,356 (7,920)
Condenser Duty, GJ/hr (MMBtu/hr)	1,555 (1,474)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	147 (140)
As-Received Coal Feed, kg/hr (lb/hr)	218,895 (482,580)
HHV Thermal Input, kWt	1,649,926
LHV Thermal Input, kWt	1,591,374
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.037 (9.9)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.030 (7.9)
O ₂ :As-Received Coal	0.760

Exhibit 3-108 provides a detailed breakdown of the auxiliary power requirements. The ASU accounts for nearly 62 percent of the auxiliary load between the MAC, N₂ compressor, O₂ compressor, and ASU auxiliaries. The two-stage Selexol process and CO₂ compression account for an additional 23 percent of the auxiliary power load. The BFW pumps and cooling water system (circulating water pumps and cooling tower fan) compose over 6 percent of the load, with all other systems together constituting the remaining 9 percent of the auxiliary load.

Exhibit 3-108. Case B5B plant power summary

Power Summary	
Combustion Turbine Power, MWe	464
Sweet Gas Expander Power, MWe	3
Steam Turbine Power, MWe	274
Total Gross Power, MWe	741
Auxiliary Load Summary	
Acid Gas Removal, kWe	11,550
Air Separation Unit Auxiliaries, kWe	1,000
Air Separation Unit Main Air Compressor, kWe	71,280
Air Separation Unit Booster Compressor, kWe	5,610
Ammonia Wash Pumps, kWe	90
Circulating Water Pumps, kWe	4,850
Claus Plant TG Recycle Compressor, kWe	1,080
Claus Plant/TGTU Auxiliaries, kWe	250
CO ₂ Compression, kWe	31,670
Coal Dryer Air Compressor, kWe	—

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Power Summary	
Auxiliary Load Summary	
Coal Handling, kWe	470
Coal Milling, kWe	2,250
Combustion Turbine Auxiliaries, kWe	1,000
Condensate Pumps, kWe	270
Cooling Tower Fans, kWe	2,510
Feedwater Pumps, kWe	3,840
Gasifier Water Pump, kWe	–
Ground Water Pumps, kWe	500
Miscellaneous Balance of Plant ^A , kWe	3,000
N ₂ Compressors, kWe	36,580
N ₂ Humidification Pump, kWe	–
O ₂ Pump, kWe	480
Quench Water Pump, kWe	400
Shift Steam Pump, kWe	210
Slag Handling, kWe	1,150
Slag Reclaim Water Recycle Pump, kWe	–
Slurry Water Pump, kWe	190
Sour Gas Compressors, kWe	–
Sour Water Recycle Pumps, kWe	10
Steam Turbine Auxiliaries, kWe	200
Syngas Recycle Compressor, kWe	–
Syngas Scrubber Pumps, kWe	140
Process Water Treatment Auxiliaries, kWe	1,320
Transformer Losses, kWe	2,870
Total Auxiliaries, MWe	185
Net Power, MWe	556

^AIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

3.4.9.1 Environmental Performance

The environmental targets for emissions of Hg, HCl, NO_x, SO₂, and PM were presented in Section 2.42.3. A summary of the plant air emissions for Case B5B is presented in Exhibit 3-109.

Exhibit 3-109. Case B5B air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.021 (0.048)	858 (945)	0.165 (0.364)
Particulate	0.003 (0.007)	127 (140)	0.024 (0.054)
Hg	1.70E-7 (3.95E-7)	0.007 (0.008)	1.36E-6 (3.00E-6)
HCl	0.000 (0.000)	0.00 (0.00)	0.000 (0.000)
CO ₂	9 (20)	355,046 (391,372)	68 (151)
CO ₂ ^C	–	–	91 (201)

^ACalculations based on an 80 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

The low level of SO₂ emissions is achieved by capturing the sulfur in the gas by the two-stage Selexol AGR process. As a result of achieving the 90 percent CO₂ removal target, the sulfur compounds are removed to an extent that exceeds the environmental target in Section 2.4. The clean syngas exiting the AGR process has a sulfur concentration of approximately 5 ppmv. This results in a concentration in the flue gas of less than 1 ppmv. The H₂S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H₂S and then recycled back to the Selexol process, thereby eliminating the need for a TGTU.

NO_x emissions are limited by N₂ dilution to 15 ppmvd (as NO at 15 percent O₂). NH₃ in the syngas is removed with process condensate prior to the low-temperature AGR process. This helps lower NO_x levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the syngas quench in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Approximately 97 percent of the mercury is captured from the syngas by dual activated carbon beds.

Ninety two percent of the CO₂ from the syngas is captured in the AGR system and compressed for sequestration. Because not all CO is converted to CO₂ in the shift reactors, the overall carbon removal is 90 percent.

The carbon balance for the plant is shown in Exhibit 3-110. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon leaves the plant as unburned carbon in the slag and the captured CO₂ product, and as CO₂ in the stack gas (includes the ASU vent gas). The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in less carbon contained in the slag, represented by the following fraction:

$$\left(1 - \left(\frac{\text{Carbon in Stack}}{(\text{Total Carbon In}) - (\text{Carbon in Slag})}\right)\right) * 100 = \left(1 - \left(\frac{30,483}{308,796 - 6,152}\right)\right) * 100 = 90\%$$

Exhibit 3-110. Case B5B carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	139,534 (307,620)	Stack Gas	13,827 (30,483)
Air (CO ₂)	534 (1,176)	CO ₂ Product	123,450 (272,161)
		Slag	2,791 (6,152)
Total	140,067 (308,796)	Total	140,067 (308,796)

Exhibit 3-111 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant and sulfur in the CO₂ product. Sulfur in the slag is considered to be negligible.

Exhibit 3-111. Case B5B sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	5,486 (12,095)	Stack Gas	—
		CO ₂ Product	1 (2)
		Elemental Sulfur	5,486 (12,094)
Total	5,486 (12,095)	Total	5,486 (12,095)

Exhibit 3-112 shows the overall water balance for the plant. The exhibit is presented in an identical manner as for cases B1A through B5A.

Exhibit 3-112. Case B5B water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
Slag Handling	0.52 (138)	0.52 (138)	—	—	—
Slurry Water	1.50 (396)	1.50 (396)	—	—	—
Gasifier Water	—	—	—	—	—
Quench	2.90 (767)	1.85 (488)	1.05 (279)	—	1.05 (279)
HCl Scrubber	2.69 (712)	2.69 (712)	—	—	—
NH ₃ Scrubber	0.94 (248)	0.00 (0)	0.94 (248)	—	0.94 (248)
Gasifier Steam	—	—	—	—	—
Condenser Makeup	0.21 (55)	—	0.21 (55)	—	0.21 (55)

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
BFW Makeup	0.21 (55)	–	0.21 (55)	–	0.21 (55)
Gasifier Steam	–	–	–	–	–
Shift Steam	–	–	–	–	–
N ₂ Humidification	–	–	–	–	–
Cooling Tower	18.90 (4,992)	0.23 (62)	18.66 (4,930)	4.25 (1,123)	14.41 (3,808)
BFW Blowdown	–	0.21 (55)	-0.21 (-55)	–	-0.21 (-55)
ASU Knockout	–	0.02 (6)	-0.02 (-6)	–	-0.02 (-6)
Total	27.66 (7,308)	6.80 (1,796)	20.86 (5,512)	4.25 (1,123)	16.61 (4,389)

An overall plant energy balance is presented in tabular form in Exhibit 3-113. The power out is the combined CT, steam turbine, and sweet gas expander power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a combined generator efficiency of 98.5 percent.

Exhibit 3-113. Case B5B overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, MMBtu/hr (GJ/hr)				
Coal	5,940 (5,630)	5.0 (4.7)	–	5,945 (5,634)
Air	–	118.6 (112.4)	–	118.6 (112.4)
Raw Water Makeup	–	78.5 (74.4)	–	78.5 (74.4)
Auxiliary Power	–	–	665.2 (630.5)	665.2 (630.5)
TOTAL	5,940 (5,630)	202.0 (191.5)	665.2 (630.5)	6,807 (6,452)
Heat Out, MMBtu/hr (GJ/hr)				
Misc. Process Steam	–	4.8 (4.6)	–	4.8 (4.6)
Slag	91.5 (86.7)	37.5 (35.5)	–	129.0 (122.3)
Stack Gas	–	1,289 (1,222)	–	1,289 (1,222)
Sulfur	50.8 (48.2)	0.6 (0.6)	–	51.5 (48.8)
Motor Losses and Design Allowances	–	–	58.1 (55.1)	58.1 (55.1)
Cooling Tower Load ^A	–	2,467 (2,339)	–	2,467 (2,339)
CO ₂ Product Stream	–	-102.7 (-97.3)	–	-102.7 (-97.3)
Blowdown Streams	–	39.1 (37.1)	–	39.1 (37.1)
<i>Ambient Losses^B</i>	–	144.7 (137.1)	–	144.7 (137.1)

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

	HHV	Sensible + Latent	Power	Total
Power	–	–	2,668 (2,529)	2,668 (2,529)
TOTAL	142.3 (134.9)	3,880 (3,678)	2,726 (2,584)	6,749 (6,397)
Unaccounted Energy ^C	–	57.9 (54.9)	–	57.9 (54.9)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers

^CBy difference

3.4.9.2 Energy and Mass Balance Diagrams

Energy and mass balance diagrams are shown for the following subsystems in Exhibit 3-114 through Exhibit 3-116:

- Coal gasification and ASU
- Syngas cleanup, sulfur recovery, and tail gas recycle
- Combined cycle power generation, steam, and FW

Exhibit 3-114. Case B5B coal gasification and ASU energy and mass balance

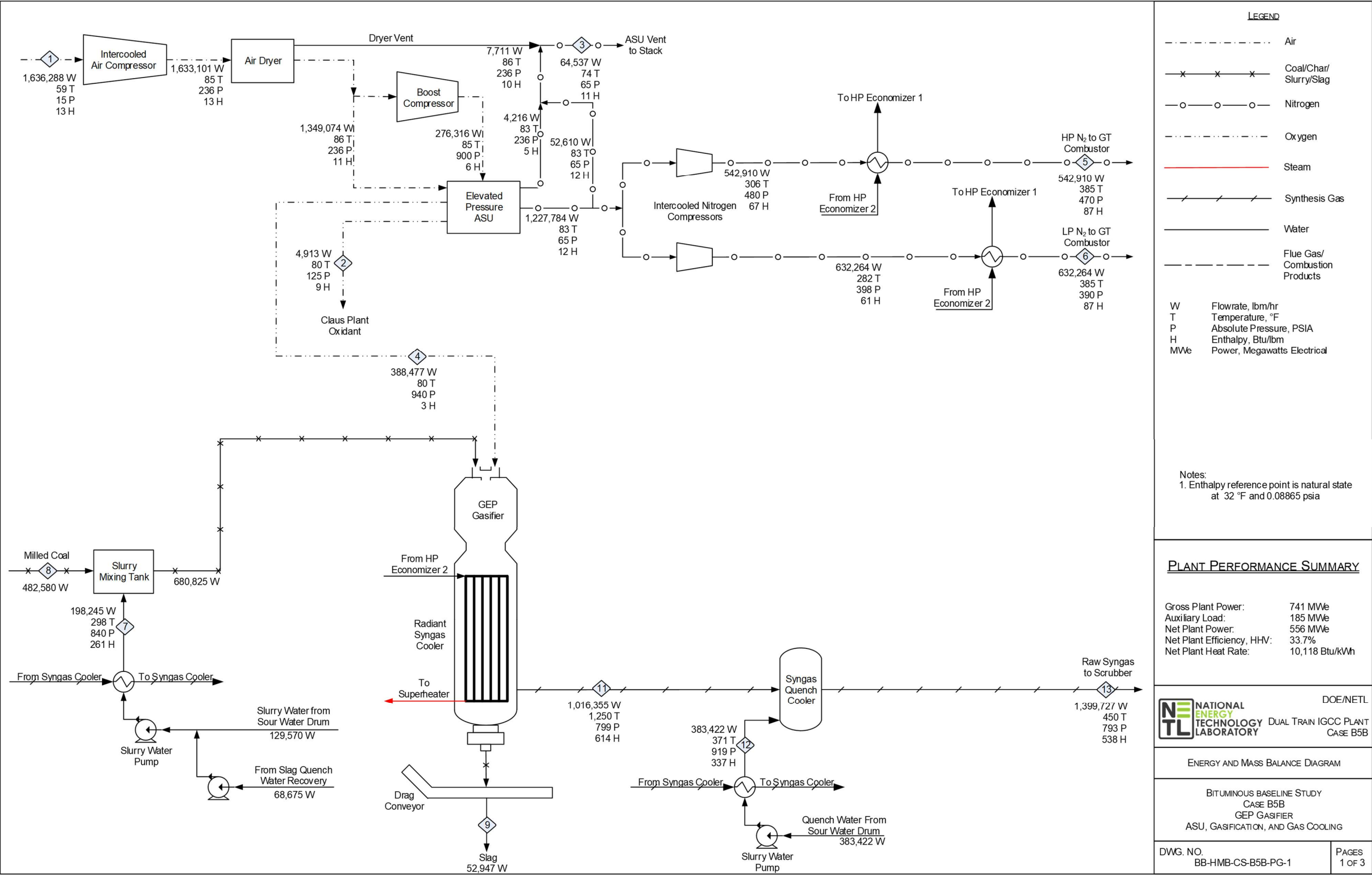


Exhibit 3-115. Case B5B syngas cleanup energy and mass balance

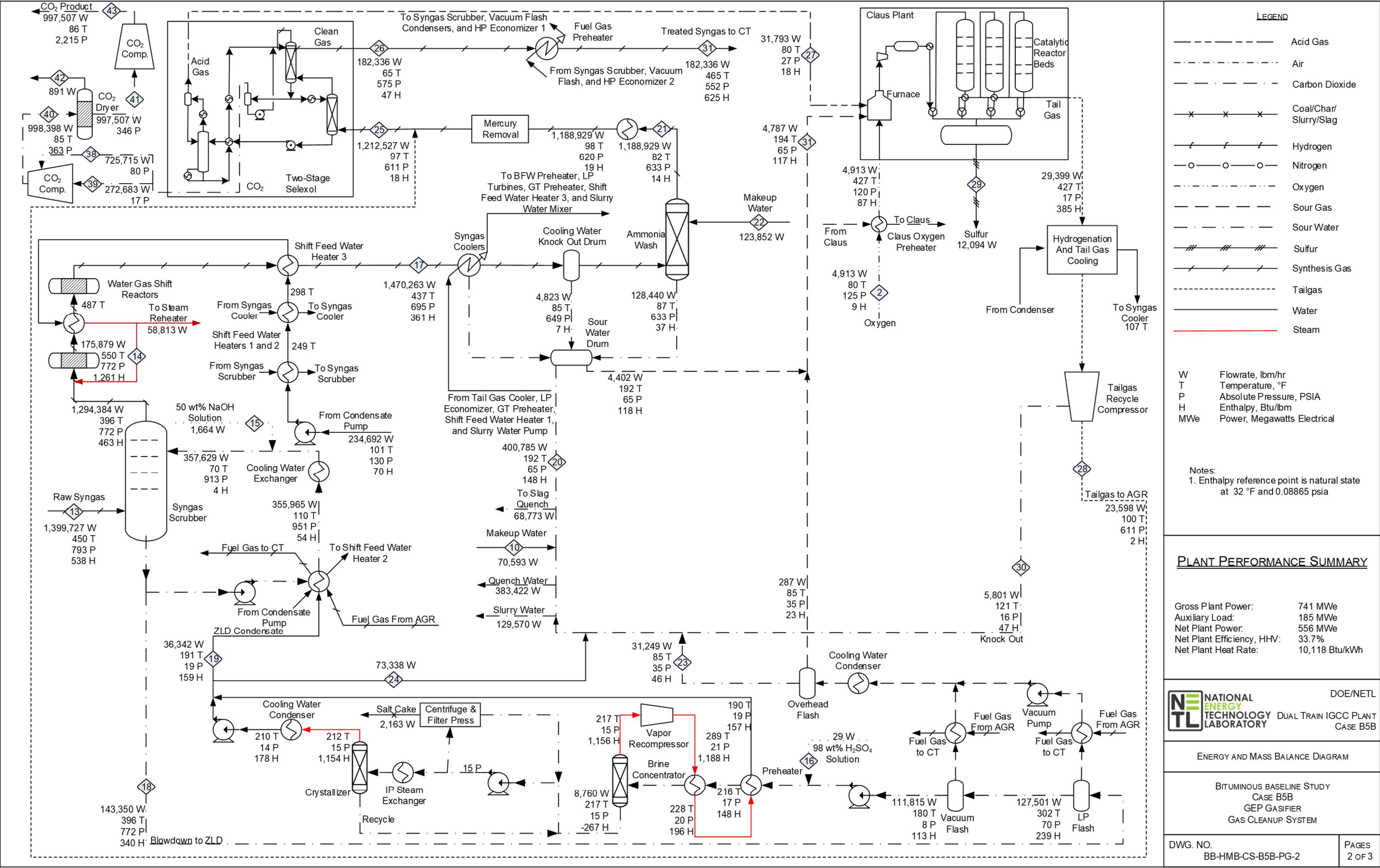
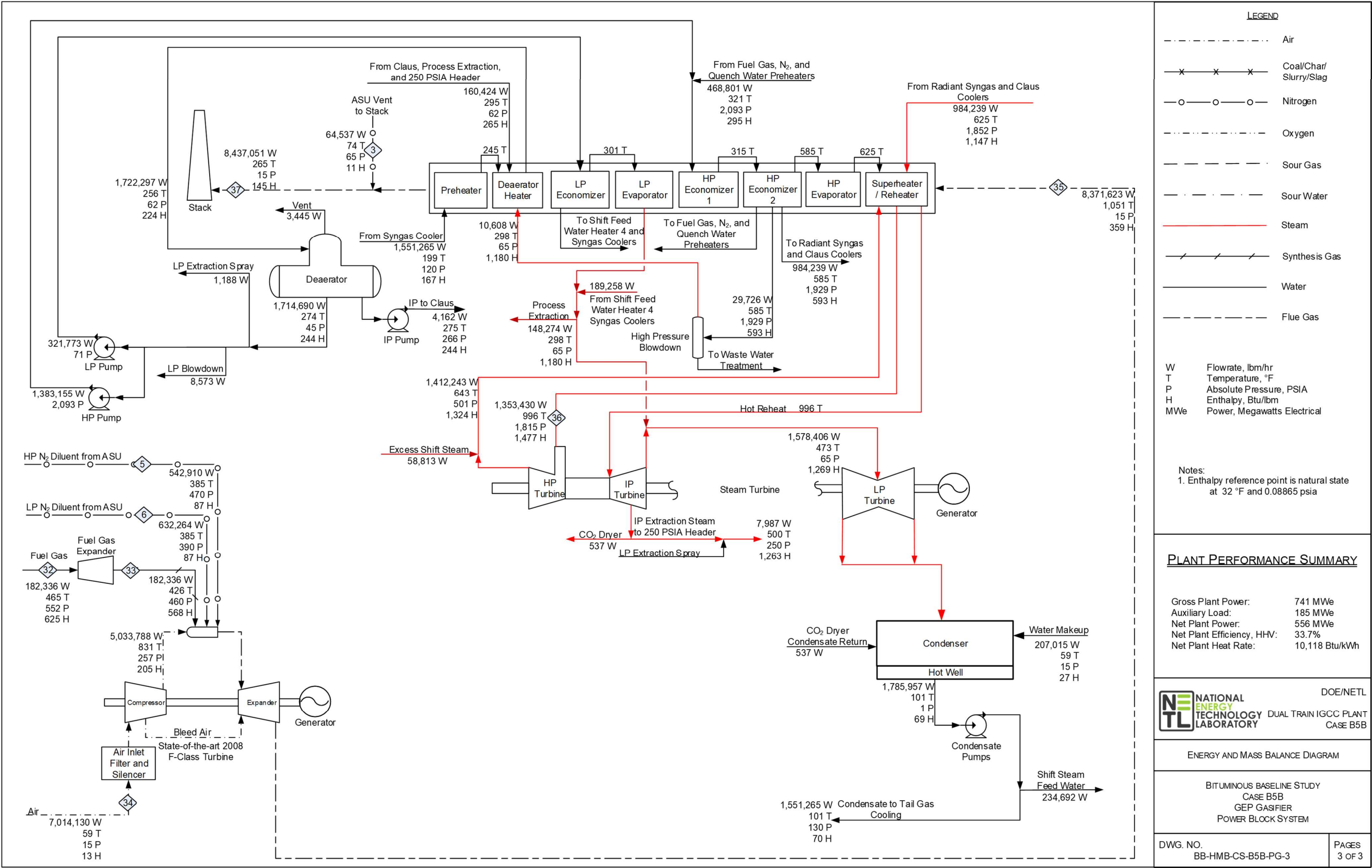


Exhibit 3-116. Case B5B combined cycle power generation energy and mass balance



This page intentionally left blank

3.4.10 Case B5B – Major Equipment List

Major equipment items for the GEP gasifier with CO₂ capture are shown in the following tables. In general, the design conditions include a 10 percent design allowance for flows and heat duties and a 21 percent design allowance for heads on pumps and fans.

Case B5B – Account 1: Coal Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
5	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
6	Reclaim Hopper	N/A	50 tonne (50 ton)	2	1
7	Feeder	Vibratory	180 tonne/hr (200 tph)	2	1
8	Conveyor No. 3	Belt w/ tripper	360 tonne/hr (400 tph)	1	0
9	Coal Surge Bin w/ Vent Filter	Dual outlet	180 tonne (200 ton)	2	0
10	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
11	Conveyor No. 4	Belt w/tripper	360 tonne/hr (400 tph)	1	0
12	Conveyor No. 5	Belt w/ tripper	360 tonne/hr (400 tph)	1	0
13	Coal Silo w/ Vent Filter and Slide Gates	Field erected	800 tonne (880 ton)	3	0

Case B5B – Account 2: Coal Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	80 tonne/hr (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	240 tonne/hr (270 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	480 tonne (530 ton)	1	0
4	Weigh Feeder	Belt	120 tonne/hr (130 tph)	2	0
5	Rod Mill	Rotary	120 tonne/hr (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	297,180 liters (78,510 gal)	2	0
7	Slurry Water Pumps	Centrifugal	830 lpm (220 gpm)	2	1
8	Trommel Screen	Coarse	170 tonne/hr (190 tph)	2	0
9	Rod Mill Discharge Tank with Agitator	Field erected	388,750 liters (102,700 gal)	2	0
10	Rod Mill Product Pumps	Centrifugal	3,200 lpm (900 gpm)	2	2
11	Slurry Storage Tank with Agitator	Field erected	1,166,300 liters (308,100 gal)	2	0
12	Slurry Recycle Pumps	Centrifugal	6,500 lpm (1,700 gpm)	2	2
13	Slurry Product Pumps	Positive displacement	3,200 lpm (900 gpm)	2	2

Case B5B – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	6,201,000 liters (1,638,000 gal)	2	0
2	Condensate Pumps	Vertical canned	7,480 lpm @ 90 m H ₂ O (1,980 gpm @ 300 ft H ₂ O)	2	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	Deaerator (integral w/ HRSG)	Horizontal spray type	430,000 kg/hr (947,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	1,390 lpm @ 20 m H ₂ O (370 gpm @ 70 ft H ₂ O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 5,980 lpm @ 1,700 m H ₂ O (1,580 gpm @ 5,700 ft H ₂ O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 2,030 lpm @ 210 m H ₂ O (540 gpm @ 670 ft H ₂ O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	421 GJ/hr (399 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	151,000 lpm @ 20 m H ₂ O (39,900 gpm @ 70 ft H ₂ O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
14	Municipal Water Pumps	Stainless steel, single suction	3,790 lpm @ 20 m H ₂ O (1,000 gpm @ 60 ft H ₂ O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,530 lpm @ 270 m H ₂ O (670 gpm @ 880 ft H ₂ O)	3	1
16	Filtered Water Pumps	Stainless steel, single suction	1,670 lpm @ 50 m H ₂ O (440 gpm @ 160 ft H ₂ O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	802,000 liter (212,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	860 lpm (230 gpm)	2	0
19	Liquid Waste Treatment System	N/A	10 years, 24-hour storm	1	0
20	Process Water Treatment	Vacuum flash, brine concentrator, and crystallizer	Vacuum Flash - Inlet: 36,000 kg/hr (79,000 lb/hr) Outlet: 6,410 ppmw Cl- Brine Concentrator Inlet - 28,000 kg/hr (61,000 lb/hr) Crystallizer Inlet - 2,000 kg/hr (5,000 lb/hr)	2	0

Case B5B – Account 4: Gasifier, ASU, and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized slurry-feed, entrained bed	2,900 tonne/day, 5.6 MPa (3,200 tpd, 815 psia)	2	0
2	Synthesis Gas Cooler	Vertical downflow radiant heat exchanger with outlet quench chamber	254,000 kg/hr (559,000 lb/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	N/A	2	0
4	HCl Scrubber	Ejector Venturi	349,000 kg/hr (770,000 lb/hr)	2	0
5	Ammonia Wash	Counter-flow spray tower	298,000 kg/hr (656,000 lb/hr) @ 4.5 MPa (649 psia)	2	0
6	Primary Sour Water Stripper	Counter-flow with external reboiler	N/A	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
7	Secondary Sour Water Stripper	Counter-flow with external reboiler	N/A	2	0
8	Low Temperature Heat Recovery Coolers	Shell and tube with condensate drain	367,000 kg/hr (809,000 lb/hr)	6	0
9	Low Temperature Heat Recovery Knockout Drum	Vertical with mist eliminator	299,000 kg/hr, 59°C, 4.5 MPa (659,000 lb/hr, 138°F, 654 psia)	2	0
10	Saturation Water Economizers	Shell and tube	N/A	4	0
11	HP Nitrogen Gas Saturator	Direct Injection	135,000 kg/hr, 196°C, 3.2 MPa (299,000 lb/hr, 385°F, 470 psia)	2	0
12	LP Nitrogen Gas Saturator	Direct Injection	158,000 kg/hr, 196°C, 2.7 MPa (348,000 lb/hr, 385°F, 390 psia)	2	0
13	Saturator Water Pump	Centrifugal	N/A	2	2
14	Saturated Nitrogen Reheaters	Shell and tube	N/A	4	0
15	Synthesis Gas Reheaters	Shell and tube	Reheater 1: 32,000 kg/hr (71,000 lb/hr) Reheater 2: 13,000 kg/hr (29,000 lb/hr) Reheater 3: N/A Reheater 4: N/A Reheater 5: 45,000 kg/hr (100,000 lb/hr) Reheater 6: 45,000 kg/hr (100,000 lb/hr)	2	0
16	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	323,000 kg/hr (712,000 lb/hr) syngas	2	0
17	ASU Main Air Compressor	Centrifugal, multi-stage	6,000 m ³ /min @ 1.6 MPa (197,000 scfm @ 236 psia)	2	0
18	Cold Box	Vendor design	2,400 tonne/day (2,600 tpd) of 95% purity O ₂	2	0
19	Gasifier O ₂ Pump	Centrifugal, multi-stage	1,000 m ³ /min (42,000 scfm) Suction - 1.0 MPa (130 psia) Discharge - 6.5 MPa (940 psia)	2	0
20	AGR Nitrogen Boost Compressor	Centrifugal, multi-stage	N/A	2	0
21	High Pressure Nitrogen Diluent Compressor	Centrifugal, multi-stage	2,000 m ³ /min (67,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - 3.3 MPa (480 psia)	2	0
22	Low Pressure Nitrogen Diluent Compressor	Centrifugal, single-stage	2,220 m ³ /min (78,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - 2.7 MPa (400 psia)	2	0
23	Gasifier Nitrogen Boost Compressor	Centrifugal, single-stage	N/A	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B5B – Account 5: Syngas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber 1	Sulfated carbon bed	297,000 kg/hr (654,000 lb/hr) 28°C (82°F) 4.4 MPa (633 psia)	2	0
2	Mercury Adsorber 2	Sulfated carbon bed	297,000 kg/hr (654,000 lb/hr) 36°C (98°F) 4.2 MPa (616 psia)	2	0
3	Sulfur Plant	Claus type	145 tonne/day (160 tpd)	1	0
4	WGS Reactors	Fixed bed, catalytic	183,000 kg/hr (404,000 lb/hr) 216°C (420°F) 5.3 MPa (770 psia)	4	0
5	Shift Reactor Heat Recovery Exchangers	Shell and Tube	Exchanger 1: 121 GJ/hr (114 MMBtu/hr) Exchanger 2: 88 GJ/hr (83 MMBtu/hr) Exchanger 3: 47 GJ/hr (45 MMBtu/hr) Exchanger 4: 48 GJ/hr (45 MMBtu/hr)	8	0
6	Acid Gas Removal Plant	Two-stage Selexol	605,000 kg/hr (1,334,000 lb/hr) 36°C (97°F) 4.2 MPa (611 psia)	1	0
7	Hydrogenation Reactor	Fixed bed, catalytic	15,000 kg/hr (32,000 lb/hr) 219°C (427°F) 0.1 MPa (16.7743276 psia)	1	0
8	Tail Gas Recycle Compressor	Centrifugal	12,000 kg/hr (26,000 lb/hr) each	1	0
9	Candle Filter	Pressurized filter with pulse-jet cleaning	N/A	2	0
10	CO ₂ Dryer	Triethylene glycol	Inlet: 152 m ³ /min @ 2.5 MPa (5,352 acfm @ 363 psia) Outlet: 2.4 MPa (346 psia) Water Recovered: 404 kg/hr (891 lb/hr)	1	0
11	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	10 m ³ /min @ 15.3 MPa (349 acfm @ 2,217 psia)	1	0
12	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 78 GJ/hr (74 MMBtu/hr)	1	0

Case B5B – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	State-of-the-art 2008 F-Class	232 MW	2	0
2	Combustion Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

Case B5B – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.5 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer	Main steam - 337,648 kg/hr, 12.4 MPa/535°C (744,386 lb/hr, 1,800 psig/996°F)	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
		section and integral deaerator	Reheat steam - 352,321 kg/hr, 3.3 MPa/535°C (776,734 lb/hr, 477 psig/996°F)		

Case B5B – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	289 MW 12.4 MPa/535°C/535°C (1,800 psig/996°F/996°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	320 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,710GJ/hr (1,620 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

Case B5B – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	487,000 lpm @ 30 m (129,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/ 16°C (60°F) CWT/ 27°C (80°F) HWT/ 2,710 GJ/hr (2,570 MMBtu/hr) heat duty	1	0

Case B5B – Account 10: Slag Recovery and Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	252,000 liters (67,000 gal)	2	0
2	Slag Crusher	Roll	13 tonne/hr (15 tph)	2	0
3	Slag Depressurizer	Lock Hopper	13 tonne/hr (15 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	152,000 liters (40,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	68,000 liters (18,000 gal)	2	0
6	Slag Conveyor	Drag chain	13 tonne/hr (15 tph)	2	0
7	Slag Separation Screen	Vibrating	13 tonne/hr (15 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	13 tonne/hr (15 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	215,000 liters (57,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	60 lpm @ 14 m H ₂ O (10 gpm @ 46 ft H ₂ O)	2	2
11	Grey Water Storage Tank	Field erected	69,000 liters (18,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	240 lpm @ 560 m H ₂ O (60 gpm @ 1,850 ft H ₂ O)	2	2
13	Slag Storage Bin	Vertical, field erected	1,000 tonne (1,000 tons)	2	0
14	Unloading Equipment	Telescoping chute	110 tonne/hr (120 tph)	1	0

Case B5B – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 280 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 81 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 41 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 6 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B5B – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.4.11 Case B5B – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 3-117 shows a detailed breakdown of the capital costs; Exhibit 3-118 shows the owner's costs, TOC, and TASC; Exhibit 3-119 shows the initial and annual O&M costs; and Exhibit 3-120 shows the LCOE breakdown.

The estimated TPC of the GEP gasifier with CO₂ capture is \$5,568/kW. Process contingency represents 5.7 percent of the TPC, and project contingency represents 14.8 percent. The LCOE, including CO₂ T&S costs of \$8.1/MWh, is \$159.4/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-117. Case B5B total plant cost details

Case:		B5B	– GEP Radiant IGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		556					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1		Coal Handling									
1.1	Coal Receive & Unload	\$990	\$0	\$477	\$0	\$1,467	\$220	\$0	\$337	\$2,025	\$4
1.2	Coal Stackout & Reclaim	\$3,237	\$0	\$774	\$0	\$4,011	\$602	\$0	\$922	\$5,535	\$10
1.3	Coal Conveyors & Yard Crush	\$30,879	\$0	\$7,860	\$0	\$38,739	\$5,811	\$0	\$8,910	\$53,460	\$96
1.4	Other Coal Handling	\$4,810	\$0	\$1,082	\$0	\$5,892	\$884	\$0	\$1,355	\$8,131	\$15
1.9	Coal & Sorbent Handling Foundations	\$0	\$87	\$226	\$0	\$313	\$47	\$0	\$72	\$432	\$1
	Subtotal	\$39,916	\$87	\$10,420	\$0	\$50,422	\$7,563	\$0	\$11,597	\$69,583	\$125
2		Coal Preparation & Feed									
2.1	Coal Crushing & Drying	\$2,400	\$145	\$345	\$0	\$2,890	\$433	\$0	\$665	\$3,988	\$7
2.2	Prepared Coal Storage & Feed	\$7,372	\$1,771	\$1,142	\$0	\$10,285	\$1,543	\$0	\$2,366	\$14,193	\$26
2.3	Slurry Coal Injection System	\$7,228	\$0	\$3,151	\$0	\$10,380	\$1,557	\$0	\$2,387	\$14,324	\$26
2.4	Miscellaneous Coal Preparation & Feed	\$728	\$532	\$1,567	\$0	\$2,826	\$424	\$0	\$650	\$3,901	\$7
2.9	Coal & Sorbent Feed Foundation	\$0	\$1,771	\$1,520	\$0	\$3,291	\$494	\$0	\$757	\$4,541	\$8
	Subtotal	\$17,729	\$4,219	\$7,724	\$0	\$29,671	\$4,451	\$0	\$6,824	\$40,946	\$74
3		Feedwater & Miscellaneous BOP Systems									
3.1	Feedwater System	\$1,999	\$3,426	\$1,713	\$0	\$7,138	\$1,071	\$0	\$1,642	\$9,851	\$18
3.2	Water Makeup & Pretreating	\$5,513	\$551	\$3,124	\$0	\$9,189	\$1,378	\$0	\$3,170	\$13,738	\$25
3.3	Other Feedwater Subsystems	\$1,033	\$339	\$322	\$0	\$1,693	\$254	\$0	\$389	\$2,337	\$4
3.4	Service Water Systems	\$1,648	\$3,145	\$10,185	\$0	\$14,978	\$2,247	\$0	\$5,167	\$22,392	\$40
3.5	Other Boiler Plant Systems	\$268	\$97	\$243	\$0	\$608	\$91	\$0	\$140	\$839	\$2
3.6	Natural Gas Pipeline and Start-Up System	\$7,253	\$312	\$234	\$0	\$7,799	\$1,170	\$0	\$1,794	\$10,762	\$19
3.7	Waste Water Treatment Equipment	\$7,564	\$0	\$4,636	\$0	\$12,200	\$1,830	\$0	\$4,209	\$18,239	\$33
3.8	Vacuum Flash, Brine Concentrator, & Crystallizer	\$25,856	\$0	\$16,016	\$0	\$41,872	\$6,281	\$0	\$14,446	\$62,598	\$112
3.9	Miscellaneous Plant Equipment	\$15,444	\$2,025	\$7,849	\$0	\$25,318	\$3,798	\$0	\$8,735	\$37,851	\$68
	Subtotal	\$66,577	\$9,896	\$44,322	\$0	\$120,795	\$18,119	\$0	\$39,692	\$178,606	\$321
4		Gasifier, ASU, & Accessories									
4.1	Gasifier & Auxiliaries (GEP)	\$513,580	\$0	\$282,918	\$0	\$796,498	\$119,475	\$111,510	\$154,122	\$1,181,605	\$2,124
4.2	Syngas Cooler	w/4.1	w/4.1	w/4.1	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.3	Air Separation Unit/Oxidant Compression	\$131,563	\$30,110	\$31,312	\$0	\$192,985	\$38,597	\$19,298	\$37,632	\$288,512	\$519
4.5	Miscellaneous Gasification Equipment	\$3,913	\$0	\$2,156	\$0	\$6,069	\$910	\$0	\$1,047	\$8,026	\$14

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B5B	– GEP Radiant IGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		556					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
4.6	Low Temperature Heat Recovery & Flue Gas Saturation	\$45,018	\$0	\$17,103	\$0	\$62,122	\$9,318	\$0	\$14,288	\$85,728	\$154
4.7	Flare Stack System	\$1,932	\$0	\$341	\$0	\$2,272	\$341	\$0	\$392	\$3,005	\$5
4.8	Black Water & Sour Gas Section	w/4.1	w/4.1	w/4.1	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.15	Major Component Rigging	\$218	\$0	\$120	\$0	\$338	\$51	\$0	\$58	\$447	\$1
4.16	Gasification Foundations	\$0	\$407	\$355	\$0	\$763	\$114	\$0	\$219	\$1,096	\$2
	Subtotal	\$696,223	\$30,518	\$334,305	\$0	\$1,061,046	\$168,806	\$130,808	\$207,759	\$1,568,419	\$2,819
5 Syngas Cleanup											
5.1	Double Stage Selexol	\$126,860	\$0	\$51,816	\$0	\$178,677	\$26,802	\$35,735	\$48,243	\$289,456	\$520
5.2	Sulfur Removal	w/5.1	w/5.1	w/5.1	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5.3	Elemental Sulfur Plant	\$48,681	\$9,489	\$62,377	\$0	\$120,546	\$18,082	\$0	\$27,726	\$166,354	\$299
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$32,248	\$4,838	\$13,969	\$0	\$51,054	\$7,658	\$0	\$11,743	\$70,455	\$127
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$481	\$76	\$206	\$0	\$764	\$115	\$0	\$176	\$1,054	\$2
5.6	Mercury Removal (Carbon Bed)	\$283	\$0	\$214	\$0	\$497	\$75	\$25	\$119	\$715	\$1
5.7	Water Gas Shift (WGS) Reactors	\$88,465	\$0	\$35,368	\$0	\$123,833	\$18,575	\$0	\$28,482	\$170,889	\$307
5.10	Blowback Gas Systems	\$675	\$379	\$212	\$0	\$1,267	\$190	\$0	\$218	\$1,675	\$3
5.11	Fuel Gas Piping	\$0	\$958	\$627	\$0	\$1,585	\$238	\$0	\$365	\$2,188	\$4
5.12	Gas Cleanup Foundations	\$0	\$227	\$153	\$0	\$380	\$57	\$0	\$131	\$568	\$1
	Subtotal	\$297,693	\$15,968	\$164,941	\$0	\$478,603	\$71,790	\$35,760	\$117,202	\$703,355	\$1,264
6 Combustion Turbine & Accessories											
6.1	Combustion Turbine Generator	\$76,557	\$0	\$5,425	\$0	\$81,983	\$12,297	\$8,198	\$15,372	\$117,850	\$212
6.2	Syngas Expander	\$2,132	\$0	\$293	\$0	\$2,425	\$364	\$0	\$418	\$3,207	\$6
6.3	Combustion Turbine Accessories	\$2,687	\$0	\$164	\$0	\$2,851	\$428	\$0	\$492	\$3,770	\$7
6.4	Compressed Air Piping	\$0	\$509	\$333	\$0	\$842	\$126	\$0	\$194	\$1,162	\$2
6.5	Combustion Turbine Foundations	\$0	\$216	\$250	\$0	\$467	\$70	\$0	\$161	\$697	\$1
	Subtotal	\$81,377	\$726	\$6,465	\$0	\$88,567	\$13,285	\$8,198	\$16,636	\$126,687	\$228
7 HRSG, Ductwork, & Stack											
7.1	Heat Recovery Steam Generator	\$33,953	\$0	\$6,574	\$0	\$40,527	\$6,079	\$0	\$6,991	\$53,597	\$96
7.2	Heat Recovery Steam Generator Accessories	\$12,123	\$0	\$2,347	\$0	\$14,470	\$2,171	\$0	\$2,496	\$19,137	\$34
7.3	Ductwork	\$0	\$1,091	\$765	\$0	\$1,856	\$278	\$0	\$427	\$2,561	\$5
7.4	Stack	\$9,277	\$0	\$3,462	\$0	\$12,740	\$1,911	\$0	\$2,198	\$16,848	\$30
7.5	Heat Recovery Steam Generator, Ductwork & Stack Foundations	\$0	\$231	\$232	\$0	\$462	\$69	\$0	\$160	\$691	\$1
	Subtotal	\$55,354	\$1,322	\$13,379	\$0	\$70,055	\$10,508	\$0	\$12,271	\$92,834	\$167

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B5B	– GEP Radiant IGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		556					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
8 Steam Turbine & Accessories											
8.1	Steam Turbine Generator & Accessories	\$37,092	\$0	\$5,757	\$0	\$42,849	\$6,427	\$0	\$7,391	\$56,667	\$102
8.2	Steam Turbine Plant Auxiliaries	\$1,802	\$0	\$4,103	\$0	\$5,906	\$886	\$0	\$1,019	\$7,811	\$14
8.3	Condenser & Auxiliaries	\$7,207	\$0	\$4,092	\$0	\$11,299	\$1,695	\$0	\$1,949	\$14,943	\$27
8.4	Steam Piping	\$6,720	\$0	\$2,914	\$0	\$9,634	\$1,445	\$0	\$2,770	\$13,849	\$25
8.5	Turbine Generator Foundations	\$0	\$281	\$496	\$0	\$777	\$117	\$0	\$268	\$1,162	\$2
	Subtotal	\$52,821	\$281	\$17,362	\$0	\$70,465	\$10,570	\$0	\$13,397	\$94,431	\$170
9 Cooling Water System											
9.1	Cooling Towers	\$12,044	\$0	\$3,648	\$0	\$15,692	\$2,354	\$0	\$2,707	\$20,753	\$37
9.2	Circulating Water Pumps	\$1,566	\$0	\$117	\$0	\$1,683	\$252	\$0	\$290	\$2,226	\$4
9.3	Circulating Water System Auxiliaries	\$10,734	\$0	\$1,533	\$0	\$12,267	\$1,840	\$0	\$2,116	\$16,223	\$29
9.4	Circulating Water Piping	\$0	\$6,038	\$5,468	\$0	\$11,507	\$1,726	\$0	\$2,646	\$15,879	\$29
9.5	Make-up Water System	\$657	\$0	\$903	\$0	\$1,560	\$234	\$0	\$359	\$2,152	\$4
9.6	Component Cooling Water System	\$219	\$262	\$180	\$0	\$661	\$99	\$0	\$152	\$913	\$2
9.7	Circulating Water System Foundations	\$0	\$498	\$885	\$0	\$1,383	\$208	\$0	\$477	\$2,068	\$4
	Subtotal	\$25,220	\$6,799	\$12,735	\$0	\$44,753	\$6,713	\$0	\$8,748	\$60,214	\$108
10 Slag Recovery & Handling											
10.1	Slag Dewatering & Cooling	\$2,093	\$0	\$1,025	\$0	\$3,118	\$468	\$0	\$538	\$4,123	\$7
10.2	Gasifier Ash Depressurization	\$1,186	\$0	\$581	\$0	\$1,766	\$265	\$0	\$305	\$2,336	\$4
10.3	Cleanup Ash Depressurization	\$533	\$0	\$261	\$0	\$794	\$119	\$0	\$137	\$1,050	\$2
10.6	Ash Storage Silos	\$1,182	\$0	\$1,276	\$0	\$2,458	\$369	\$0	\$424	\$3,251	\$6
10.7	Ash Transport & Feed Equipment	\$455	\$0	\$106	\$0	\$561	\$84	\$0	\$97	\$742	\$1
10.8	Miscellaneous Ash Handling Equipment	\$65	\$80	\$24	\$0	\$169	\$25	\$0	\$29	\$223	\$0
10.9	Ash/Spent Sorbent Foundation	\$0	\$467	\$607	\$0	\$1,075	\$161	\$0	\$371	\$1,607	\$3
	Subtotal	\$5,513	\$547	\$3,880	\$0	\$9,941	\$1,491	\$0	\$1,900	\$13,332	\$24
11 Accessory Electric Plant											
11.1	Generator Equipment	\$2,702	\$0	\$2,038	\$0	\$4,741	\$711	\$0	\$818	\$6,270	\$11
11.2	Station Service Equipment	\$4,244	\$0	\$364	\$0	\$4,608	\$691	\$0	\$795	\$6,094	\$11
11.3	Switchgear & Motor Control	\$25,609	\$0	\$4,443	\$0	\$30,052	\$4,508	\$0	\$5,184	\$39,744	\$71
11.4	Conduit & Cable Tray	\$0	\$113	\$327	\$0	\$440	\$66	\$0	\$127	\$633	\$1
11.5	Wire & Cable	\$0	\$1,554	\$2,777	\$0	\$4,331	\$650	\$0	\$1,245	\$6,226	\$11
11.6	Protective Equipment	\$241	\$0	\$837	\$0	\$1,078	\$162	\$0	\$186	\$1,426	\$3
11.7	Standby Equipment	\$852	\$0	\$786	\$0	\$1,638	\$246	\$0	\$283	\$2,166	\$4
11.8	Main Power Transformers	\$6,422	\$0	\$131	\$0	\$6,553	\$983	\$0	\$1,130	\$8,667	\$16
11.9	Electrical Foundations	\$0	\$74	\$188	\$0	\$262	\$39	\$0	\$91	\$392	\$1
	Subtotal	\$40,070	\$1,741	\$11,893	\$0	\$53,704	\$8,056	\$0	\$9,858	\$71,618	\$129
12 Instrumentation & Control											

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B5B	– GEP Radiant IGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		556					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
12.1	Integrated Gasification and Combined Cycle Control Equipment	\$642	\$0	\$353	\$0	\$995	\$149	\$0	\$172	\$1,316	\$2
12.2	Combustion Turbine Control Equipment	\$686	\$0	\$49	\$0	\$735	\$110	\$0	\$127	\$972	\$2
12.3	Steam Turbine Control Equipment	\$633	\$0	\$98	\$0	\$731	\$110	\$0	\$126	\$966	\$2
12.4	Other Major Component Control Equipment	\$1,225	\$0	\$835	\$0	\$2,060	\$309	\$103	\$371	\$2,843	\$5
12.5	Signal Processing Equipment	\$950	\$0	\$31	\$0	\$981	\$147	\$0	\$169	\$1,298	\$2
12.6	Control Boards, Panels & Racks	\$276	\$0	\$180	\$0	\$456	\$68	\$23	\$109	\$657	\$1
12.7	Distributed Control System Equipment	\$9,974	\$0	\$326	\$0	\$10,299	\$1,545	\$515	\$1,854	\$14,213	\$26
12.8	Instrument Wiring & Tubing	\$496	\$397	\$1,588	\$0	\$2,482	\$372	\$124	\$744	\$3,722	\$7
12.9	Other Instrumentation & Controls Equipment	\$1,113	\$0	\$552	\$0	\$1,665	\$250	\$83	\$300	\$2,298	\$4
	Subtotal	\$15,995	\$397	\$4,012	\$0	\$20,404	\$3,061	\$848	\$3,972	\$28,285	\$51
13		Improvements to Site									
13.1	Site Preparation	\$0	\$423	\$9,633	\$0	\$10,056	\$1,508	\$0	\$3,469	\$15,034	\$27
13.2	Site Improvements	\$0	\$1,914	\$2,706	\$0	\$4,620	\$693	\$0	\$1,594	\$6,906	\$12
13.3	Site Facilities	\$2,988	\$0	\$3,354	\$0	\$6,342	\$951	\$0	\$2,188	\$9,481	\$17
	Subtotal	\$2,988	\$2,337	\$15,693	\$0	\$21,017	\$3,153	\$0	\$7,251	\$31,421	\$56
14		Buildings & Structures									
14.1	Combustion Turbine Area	\$0	\$314	\$177	\$0	\$491	\$74	\$0	\$85	\$649	\$1
14.3	Steam Turbine Building	\$0	\$2,769	\$3,943	\$0	\$6,712	\$1,007	\$0	\$1,158	\$8,877	\$16
14.4	Administration Building	\$0	\$884	\$640	\$0	\$1,524	\$229	\$0	\$263	\$2,015	\$4
14.5	Circulation Water Pumphouse	\$0	\$147	\$78	\$0	\$225	\$34	\$0	\$39	\$298	\$1
14.6	Water Treatment Buildings	\$0	\$371	\$362	\$0	\$734	\$110	\$0	\$127	\$970	\$2
14.7	Machine Shop	\$0	\$488	\$334	\$0	\$823	\$123	\$0	\$142	\$1,088	\$2
14.8	Warehouse	\$0	\$381	\$245	\$0	\$626	\$94	\$0	\$108	\$828	\$1
14.9	Other Buildings & Structures	\$0	\$279	\$217	\$0	\$496	\$74	\$0	\$86	\$656	\$1
14.10	Waste Treating Building & Structures	\$0	\$766	\$1,463	\$0	\$2,229	\$334	\$0	\$385	\$2,948	\$5
	Subtotal	\$0	\$6,399	\$7,460	\$0	\$13,859	\$2,079	\$0	\$2,391	\$18,329	\$33
	Total	\$1,397,476	\$81,236	\$654,590	\$0	\$2,133,302	\$329,645	\$175,615	\$459,498	\$3,098,059	\$5,568

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-118. Case B5B owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$24,989	\$45
1 Month Maintenance Materials	\$6,293	\$11
1 Month Non-fuel Consumables	\$1,149	\$2
1 Month Waste Disposal	\$784	\$1
25% of 1 Months Fuel Cost at 100% CF	\$2,288	\$4
2% of TPC	\$61,961	\$111
Total	\$97,464	\$175
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	\$20,142	\$36
0.5% of TPC (spare parts)	\$15,490	\$28
Total	\$35,633	\$64
Other Costs		
Initial Cost for Catalyst and Chemicals	\$29,381	\$53
Land	\$900	\$2
Other Owner's Costs	\$464,709	\$835
Financing Costs	\$83,648	\$150
Total Overnight Costs (TOC)	\$3,809,794	\$6,847
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	\$4,398,071	\$7,904

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-119. Case B5B initial and annual operating and maintenance costs

Case:	B5B	– GEP Radiant IGCC w/ CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	556	Heat Rate-net (Btu/kWh):		10,118	Capacity Factor (%):	80
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	% of base	Operator:	11.0	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	3.0	
				Total:	17.0	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$7,453,446	\$13.395
Maintenance Labor:					\$32,529,623	\$58.461
Administrative & Support Labor:					\$9,995,767	\$17.964
Property Taxes and Insurance:					\$61,961,187	\$111.355
Total:					\$111,940,024	\$201.175
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$60,412,158	\$15.49244
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (gal/1000):	0	3,969	\$1.90	\$0	\$2,201,757	\$0.56463
Makeup and Waste Water Treatment Chemicals (ton):	0	11.8	\$550.00	\$0	\$1,898,578	\$0.48688
Sulfur-Impregnated Activated Carbon (ton):	78	0.107	\$12,000.00	\$939,432	\$375,773	\$0.09637
Water Gas Shift (WGS) Catalyst (ft³):	15,607	10.7	\$480.00	\$7,491,563	\$1,498,313	\$0.38424
Selexol Solution (gal):	551,323	54.7	\$38.00	\$20,950,275	\$606,622	\$0.15557
Sodium Hydroxide (50 wt%, ton):	0.00	20.0	\$600.00	\$0	\$3,498,833	\$0.89726
Sulfuric Acid (98 wt%, ton):	0.00	0.353	\$210.00	\$0	\$21,643	\$0.00555
Claus Catalyst (ft³):	w/equip.	2.00	\$48.00	\$0	\$28,053	\$0.00719
Triethylene Glycol (gal):	w/equip.	452	\$6.80	\$0	\$896,534	\$0.22991
Subtotal:				\$29,381,269	\$11,026,105	\$2.82760
Waste Disposal						
Sulfur-Impregnated Activated Carbon (ton):	0	0.107	\$80.00	\$0	\$2,505	\$0.00064
WGS Catalyst (ft³):	0	10.7	\$2.50	\$0	\$7,804	\$0.00200
Selexol Solution (gal):	0	54.7	\$0.35	\$0	\$5,587	\$0.00143
Claus Catalyst (ft³):	0	2.00	\$2.50	\$0	\$1,461	\$0.00037
Crystallizer Solids (ton):	0	37.6	\$38.00	\$0	\$416,756	\$0.10688
Slag (ton):	0	635	\$38.00	\$0	\$7,050,036	\$1.80795
Triethylene Glycol (gal):	0	452	\$0.35	\$0	\$46,145	\$0.01183
Subtotal:				\$0	\$7,530,294	\$1.93111
By-Products						
Sulfur (tons):	0	145	\$0.00	\$0	\$0	\$0.00000
Subtotal:				\$0	\$0	\$0.00000
Variable Operating Costs Total:				\$29,381,269	\$78,968,556	\$20.25114
Fuel Cost						
Illinois Number 6 (ton):	0	5,791	\$51.96	\$0	\$87,859,022	\$22.53107
Total:				\$0	\$87,859,022	\$22.53107

Exhibit 3-120. Case B5B LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	79.8	50.1%
Fixed	28.7	18.0%
Variable	20.3	12.7%
Fuel	22.5	14.1%
Total (Excluding T&S)	151.3	94.9%
CO ₂ T&S	8.1	5.1%
Total (Including T&S)	159.4	100.0%

3.4.12 Case B5B-Q – GEP Quench IGCC with CO₂ Capture Process Description

In this section, the GEP gasification process for Case B5B-Q is described. The plant configuration is nearly identical to that of Case B5B, with the exception that this case is configured as a quench-only gasifier, compared to Case B5B, which was a radiant-only gasifier.

As was the case in Case B5B, the gross power output is constrained by the capacity of the two CTs, and since the CO₂ capture and compression process increases the auxiliary load on the plant, the net output is significantly reduced relative to Case B5A (499 MW versus 634 MW).

The process descriptions for Case B5B-Q are similar to Case B5B with several notable exceptions. The system descriptions follow the BFD provided in Exhibit 3-121 with the associated stream tables—providing process data for the numbered streams in the BFD—provided in Exhibit 3-122. Rather than repeating the entire process description, only differences from Case B5B are reported here.

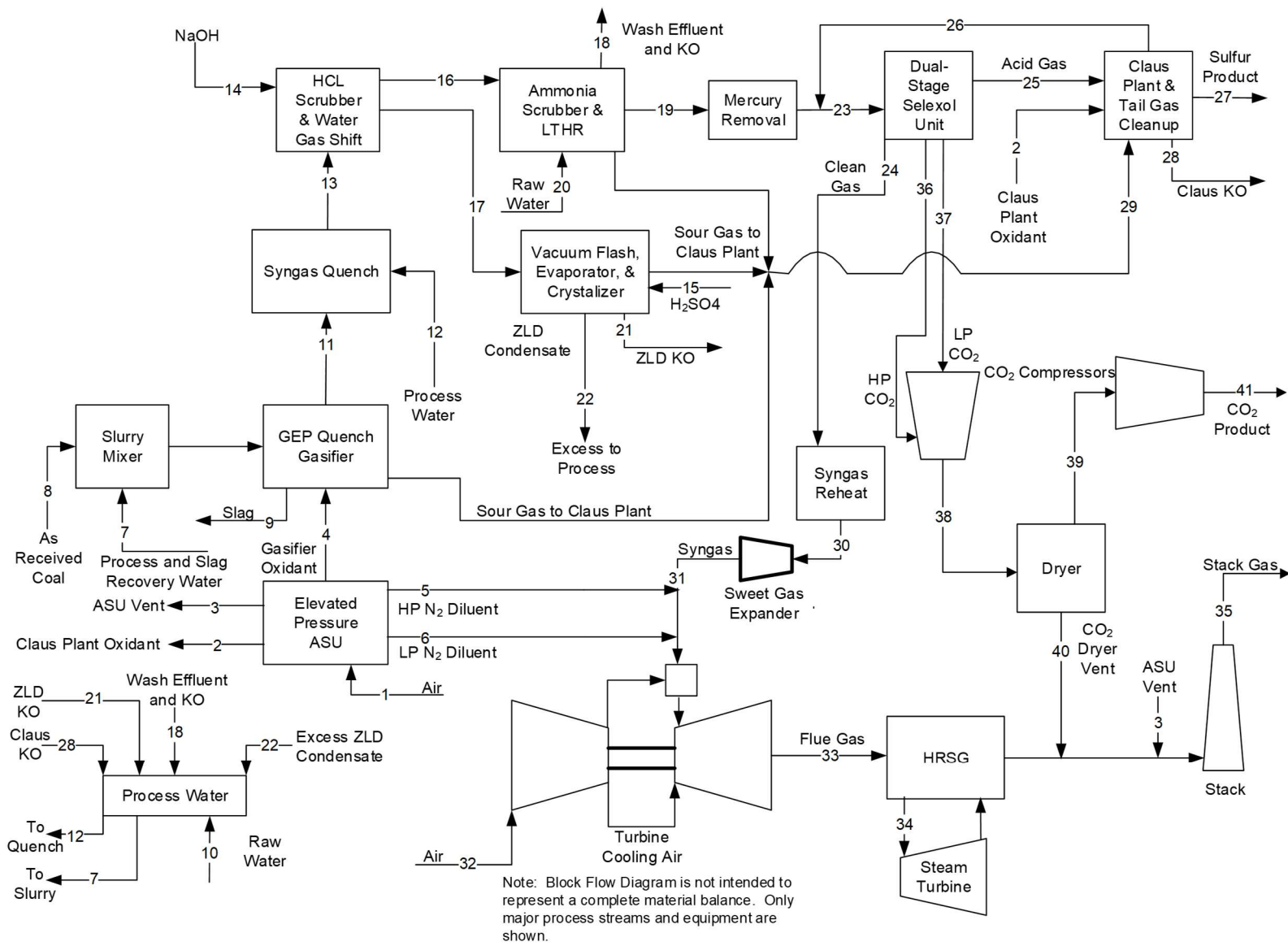
3.4.12.1 Coal Preparation and Feed Systems

No differences from Case B5B.

3.4.12.2 Gasifier

The gasification process is the same as Case B5B with the exception that the syngas exiting the gasifier passes through a water quench where the temperature is reduced from 1,316°C (2,400°F) to 288°C (550°F).

Exhibit 3-121. Case B5B-Q block flow diagram, GEP quench-only IGCC with CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-122. Case B5B-Q stream table, GEP quench-only IGCC with capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0343	0.0431	0.0343	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0082	0.0000
CH ₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0011	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3570	0.0000
CO ₂	0.0003	0.0000	0.0076	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.1383	0.0003
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3411	0.0000
H ₂ O	0.0099	0.0000	0.1565	0.0000	0.0000	0.0000	0.9914	0.0000	0.0000	0.9999	0.1365	0.9913
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000
H ₂ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0073	0.0000
N ₂	0.7732	0.0157	0.7900	0.0157	0.9964	0.9964	0.0000	0.0000	0.0000	0.0000	0.0079	0.0000
NH ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0083	0.0000	0.0000	0.0000	0.0021	0.0083
O ₂	0.2074	0.9501	0.0028	0.9501	0.0036	0.0036	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	25,755	73	1,111	5,475	8,787	10,229	4,995	0	0	5,737	22,945	22,429
V-L Flowrate (kg/hr)	743,202	2,344	30,104	176,334	246,273	286,699	89,985	0	0	103,364	461,334	404,116
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	219,048	24,033	0	0	0
Temperature (°C)	15	27	23	27	196	196	148	15	1,316	15	1,316	188
Pressure (MPa, abs)	0.10	0.86	0.45	6.48	3.24	2.69	5.79	0.10	5.62	0.10	5.62	6.45
Steam Table Enthalpy (kJ/kg) ^A	30.23	21.53	26.53	6.21	202.25	202.61	609.23	---	---	62.75	2,637.00	787.32
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-0.97	-1,767.37	-16.30	176.29	176.64	-15,251.12	-2,119.02	-727.24	-15,905.25	-4,036.55	-15,071.53
Density (kg/m ³)	1.2	11.2	5.8	87.9	23.1	19.2	901.3	---	---	999.4	8.5	862.1
V-L Molecular Weight	28.857	32.209	27.096	32.209	28.028	28.028	18.016	---	---	18.019	20.106	18.017
V-L Flowrate (lb _{mol} /hr)	56,779	160	2,449	12,070	19,371	22,551	11,012	0	0	12,647	50,585	49,448
V-L Flowrate (lb/hr)	1,638,480	5,168	66,369	388,749	542,939	632,063	198,383	0	0	227,879	1,017,067	890,923
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	482,918	52,984	0	0	0
Temperature (°F)	59	80	74	80	385	385	298	59	2,400	59	2,400	371
Pressure (psia)	14.7	125.0	65.0	940.0	470.0	390.0	840.0	14.7	815.0	14.7	815.0	935.0
Steam Table Enthalpy (Btu/lb) ^A	13.0	9.3	11.4	2.7	87.0	87.1	261.9	---	---	27.0	1,133.7	338.5
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-0.4	-759.8	-7.0	75.8	75.9	-6,556.8	-911.0	-312.7	-6,838.0	-1,735.4	-6,479.6
Density (lb/ft ³)	0.076	0.700	0.363	5.487	1.439	1.196	56.264	---	---	62.391	0.529	53.818

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-122. Case B5B-Q stream table, GEP quench-only IGCC with capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0041	0.0000	0.0000	0.0048	0.0000	0.0000	0.0069	0.0000	0.0000	0.0000	0.0069	0.0112
CH ₄	0.0006	0.0000	0.0000	0.0007	0.0000	0.0000	0.0010	0.0000	0.0000	0.0000	0.0009	0.0014
CO	0.1805	0.0000	0.0000	0.0148	0.0001	0.0000	0.0210	0.0000	0.0000	0.0000	0.0208	0.0337
CO ₂	0.0701	0.0000	0.0000	0.2787	0.0007	0.0005	0.3926	0.0000	0.0008	0.0000	0.3972	0.0305
COS	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.1725	0.0000	0.0000	0.3987	0.0002	0.0000	0.5646	0.0000	0.0000	0.0000	0.5601	0.9122
H ₂ O	0.5590	0.6895	0.1000	0.2876	0.9952	0.9852	0.0012	0.9999	0.9911	0.9997	0.0012	0.0001
HCl	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0037	0.0000	0.0000	0.0044	0.0001	0.0001	0.0062	0.0000	0.0002	0.0000	0.0062	0.0000
N ₂	0.0040	0.0000	0.0000	0.0047	0.0000	0.0000	0.0066	0.0000	0.0000	0.0000	0.0067	0.0109
NH ₃	0.0051	0.0000	0.0000	0.0056	0.0023	0.0142	0.0000	0.0000	0.0079	0.0003	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0014	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.3105	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	0.1000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	45,373	31	0	38,734	6,670	14,884	27,339	3,586	1,717	4,914	27,653	16,887
V-L Flowrate (kg/hr)	865,406	774	25	745,529	120,651	268,152	538,876	64,611	30,959	88,533	550,336	82,775
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	287	16	15	225	222	108	28	15	29	88	37	18
Pressure (MPa, abs)	5.58	6.41	0.13	4.89	5.43	0.45	4.45	0.10	0.24	0.13	4.30	4.04
Steam Table Enthalpy (kJ/kg) ^A	1,773.16	-337.48	-8,206.86	1,045.47	945.35	422.74	32.40	62.75	106.49	367.84	42.95	108.14
AspenPlus Enthalpy (kJ/kg) ^B	-9,190.08	-13,663.69	-8,526.27	-9,086.51	-14,939.42	-15,357.96	-7,990.44	-15,905.25	-15,746.95	-15,598.25	-7,992.79	-3,270.47
Density (kg/m ³)	24.0	1,532.5	1,791.5	23.2	836.1	936.3	35.8	999.4	990.9	966.1	34.0	8.0
V-L Molecular Weight	19.073	24.842	90.073	19.247	18.088	18.016	19.711	18.019	18.030	18.015	19.902	4.902
V-L Flowrate (lb _{mol} /hr)	100,031	69	1	85,395	14,706	32,813	60,272	7,905	3,785	10,834	60,964	37,230
V-L Flowrate (lb/hr)	1,907,893	1,706	55	1,643,610	265,989	591,173	1,188,017	142,443	68,252	195,183	1,213,284	182,487
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	549	61	59	437	432	226	83	59	85	191	98	65
Pressure (psia)	809.3	929.3	18.2	709.0	788.3	65.0	645.4	14.7	35.0	19.1	623.7	586.5
Steam Table Enthalpy (Btu/lb) ^A	762.3	-145.1	-3,528.3	449.5	406.4	181.7	13.9	27.0	45.8	158.1	18.5	46.5
AspenPlus Enthalpy (Btu/lb) ^B	-3,951.0	-5,874.3	-3,665.6	-3,906.5	-6,422.8	-6,602.7	-3,435.3	-6,838.0	-6,770.0	-6,706.0	-3,436.3	-1,406.0
Density (lb/ft ³)	1.496	95.673	111.841	1.447	52.194	58.453	2.236	62.391	61.858	60.312	2.125	0.502

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-122. Case B5B-Q stream table, GEP quench-only IGCC with capture (continued)

	25	26	27	28	29	30	31	32	33	34	35	36
V-L Mole Fraction												
Ar	0.0001	0.0083	0.0000	0.0000	0.0008	0.0112	0.0112	0.0092	0.0088	0.0000	0.0090	0.0001
CH ₄	0.0001	0.0000	0.0000	0.0000	0.0001	0.0014	0.0014	0.0000	0.0000	0.0000	0.0000	0.0002
CO	0.0008	0.0049	0.0000	0.0000	0.0090	0.0337	0.0337	0.0000	0.0000	0.0000	0.0000	0.0009
CO ₂	0.5129	0.7967	0.0000	0.0000	0.5636	0.0305	0.0305	0.0003	0.0083	0.0000	0.0083	0.9853
COS	0.0006	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0117	0.1676	0.0000	0.0000	0.0650	0.9122	0.9122	0.0000	0.0000	0.0000	0.0000	0.0103
H ₂ O	0.0161	0.0020	0.0000	1.0000	0.2841	0.0001	0.0001	0.0099	0.1197	1.0000	0.1201	0.0031
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.4571	0.0074	0.0000	0.0000	0.0231	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0131	0.0000	0.0000	0.0005	0.0109	0.0109	0.7732	0.7554	0.0000	0.7556	0.0001
NH ₃	0.0006	0.0000	0.0000	0.0000	0.0538	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2074	0.1078	0.0000	0.1070	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	374	314	0	173	103	16,887	16,887	110,253	138,169	20,504	139,301	7,577
V-L Flowrate (kg/hr)	14,408	11,461	0	3,117	3,316	82,775	82,775	3,181,556	3,797,300	369,377	3,827,810	329,389
Solids Flowrate (kg/hr)	0	0	5,489	0	0	0	0	0	0	0	0	0
Temperature (°C)	27	38	183	50	108	241	217	15	566	535	129	-3
Pressure (MPa, abs)	0.18	4.30	0.12	0.11	0.45	3.88	3.17	0.10	0.10	12.51	0.10	0.55
Steam Table Enthalpy (kJ/kg) ^A	41.02	4.15	---	109.31	513.76	1,453.30	1,305.68	30.23	834.13	3,436.62	336.95	-5.69
AspenPlus Enthalpy (kJ/kg) ^B	-5,588.29	-8,638.11	146.72	-15,860.47	-9,097.64	-1,925.31	-2,072.93	-97.58	-561.13	-12,543.67	-1,062.90	-8,968.76
Density (kg/m ³)	2.9	70.6	5,268.5	964.1	4.6	4.4	3.8	1.2	0.4	36.6	0.8	11.1
V-L Molecular Weight	38.540	36.526	---	18.016	32.057	4.902	4.902	28.857	27.483	18.015	27.479	43.474
V-L Flowrate (lb _{mol} /hr)	824	692	0	381	228	37,230	37,230	243,065	304,611	45,203	307,106	16,704
V-L Flowrate (lb/hr)	31,763	25,266	0	6,873	7,310	182,487	182,487	7,014,130	8,371,613	814,337	8,438,876	726,177
Solids Flowrate (lb/hr)	0	0	12,102	0	0	0	0	0	0	0	0	0
Temperature (°F)	80	100	362	121	226	465	422	59	1,051	996	265	26
Pressure (psia)	26.7	623.7	17.1	16.2	65.0	563.3	460.0	14.7	15.1	1,814.7	14.8	80.0
Steam Table Enthalpy (Btu/lb) ^A	17.6	1.8	---	47.0	220.9	624.8	561.3	13.0	358.6	1,477.5	144.9	-2.4
AspenPlus Enthalpy (Btu/lb) ^B	-2,402.5	-3,713.7	63.1	-6,818.8	-3,911.3	-827.7	-891.2	-42.0	-241.2	-5,392.8	-457.0	-3,855.9
Density (lb/ft ³)	0.180	4.409	328.904	60.186	0.288	0.275	0.236	0.076	0.026	2.288	0.052	0.696

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit 3-122. Case B5B-Q stream table, GEP quench-only IGCC with capture (continued)

	37	38	39	40	41
V-L Mole Fraction					
Ar	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0001	0.0002	0.0002	0.0000	0.0002
CO	0.0001	0.0007	0.0007	0.0000	0.0007
CO ₂	0.9985	0.9889	0.9908	0.0500	0.9908
COS	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0008	0.0077	0.0077	0.0000	0.0077
H ₂ O	0.0005	0.0024	0.0005	0.9500	0.0005
HCl	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ S	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000
NH ₃	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000
NaOH	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	2,815	10,392	10,371	21	10,371
V-L Flowrate (kg/hr)	123,765	453,154	452,749	405	452,749
Solids Flowrate (kg/hr)	0	0	0	0	0
Temperature (°C)	-11	29	29	29	30
Pressure (MPa, abs)	0.12	2.50	2.39	2.50	15.27
Steam Table Enthalpy (kJ/kg) ^A	-9.81	1.28	0.53	138.13	-226.97
AspenPlus Enthalpy (kJ/kg) ^B	-8,972.37	-8,961.74	-8,956.76	-15,225.03	-9,184.27
Density (kg/m ³)	2.3	49.8	47.2	319.0	838.2
V-L Molecular Weight	43.960	43.606	43.655	19.315	43.655
V-L Flowrate (lb _{mol} /hr)	6,207	22,910	22,864	46	22,864
V-L Flowrate (lb/hr)	272,856	999,034	998,140	893	998,140
Solids Flowrate (lb/hr)	0	0	0	0	0
Temperature (°F)	12	85	85	85	86
Pressure (psia)	16.7	363.0	346.5	363.0	2,214.7
Steam Table Enthalpy (Btu/lb) ^A	-4.2	0.6	0.2	59.4	-97.6
AspenPlus Enthalpy (Btu/lb) ^B	-3,857.4	-3,852.9	-3,850.7	-6,545.6	-3,948.5
Density (lb/ft ³)	0.146	3.109	2.948	19.917	52.328

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

3.4.12.3 Syngas Scrubber

Due to the extremely high moisture content of the syngas entering the syngas scrubber (56 vol% versus 39 vol% in Case B5B), no additional process water or ZLD condensate is required beyond the scrubber effluent recycle. Rather, the scrubber effluent recycle rate is controlled to maintain the HCl removal rate at 96 percent. The resulting chloride concentration of the blowdown (stream 17) is 2,770 ppmw.

The recycled scrubber effluent is first cooled to 44°C (112°F) by preheating IP steam generator FW and syngas prior to the CT, before being further cooled to 21°C (70°F) by cooling water and injected into the scrubber.

All other aspects of the syngas scrubber are identical to those described for Case B5B.

3.4.12.4 Water Gas Shift

The WGS process was described in Section 3.1.3. Due to the extremely high moisture content of the syngas entering the WGS (48 vol% versus 34 vol% in Case B5B), no additional moisture is required and the steam to dry gas ratio goal of 0.25 is exceeded (actual ratio is 0.43).

As with Case B5B, two stages total are used to convert 93.0 percent of the CO in the syngas to CO₂. The heat generated from the first reactor is used to produce 113,615 kg/hr (250,477 lb/hr) IP steam at 5.4 MPa (788 psia), which is sent to the steam cycle for use while cooling the syngas to 253°C (487°F) prior to entering the second stage. Prior to the syngas being sent to the LTHR system (stream 16), the warm syngas from the second stage of WGS is cooled to 225°C (437°F) by preheating the FW to the IP steam generator.

The WGS catalyst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor.

3.4.12.5 Low Temperature Heat Recovery

Case B5B-Q only differs from Case B5B in that the second stage of the LTHR system does not provide any heat to the WGS steam generator, as this case does not require any additional steam for WGS operation.

3.4.12.6 Ammonia Wash

No differences from Case B5B.

3.4.12.7 Process Water Treatment

No differences from Case B5B.

3.4.12.8 Mercury Removal and AGR

No differences from Case B5B.

3.4.12.9 Claus Unit

No differences from Case B5B.

3.4.12.10 Power Block

No differences from Case B5B.

3.4.12.11 Air Separation Unit

No differences from Case B5B.

3.4.13 Case B5B-Q – Performance Results

The plant produces a net output of 499 MW at a net plant efficiency of 30.2 percent (HHV basis). Overall performance for the entire plant is summarized in Exhibit 3-123 and Exhibit 3-124, which includes auxiliary power requirements. The ASU accounts for 62 percent of

the auxiliary load between the MAC, N₂ compressor, O₂ compressor, and ASU auxiliaries. The two-stage Selexol process and CO₂ compression account for an additional 23 percent of the auxiliary power load. The BFW pumps and cooling water system (circulating water pumps and cooling tower fan) compose about 6 percent of the load, with all other systems together constituting the remaining 9 percent of the auxiliary load.

Exhibit 3-123. Case B5B-Q plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	464
Sweet Gas Expander Power, MWe	3
Steam Turbine Power, MWe	217
Total Gross Power, MWe	685
Air Separation Unit Main Air Compressor, kWe	71,370
Air Separation Unit Booster Compressor, kWe	5,610
N ₂ Compressors, kWe	36,570
CO ₂ Compression, kWe	31,690
Acid Gas Removal, kWe	11,550
Balance of Plant, kWe	28,790
Total Auxiliaries, MWe	186
Net Power, MWe	499
HHV Net Plant Efficiency, %	30.2
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,909 (11,287)
HHV Cold Gas Efficiency, %	79.0
HHV Combustion Turbine Efficiency, %	36.4
LHV Net Plant Efficiency, %	31.3
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,486 (10,887)
LHV Cold Gas Efficiency, %	75.6
LHV Combustion Turbine Efficiency, %	42.8
Steam Turbine Cycle Efficiency, %	38.5
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	9,343 (8,855)
Condenser Duty, GJ/hr (MMBtu/hr)	1,453 (1,377)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	147 (140)
As-Received Coal Feed, kg/hr (lb/hr)	219,048 (482,918)
HHV Thermal Input, kWt	1,651,082
LHV Thermal Input, kWt	1,592,489
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.048 (12.6)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.038 (10.2)
O ₂ :As-Received Coal	0.760

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-124. Case B5B-Q plant power summary

Power Summary	
Combustion Turbine Power, MWe	464
Sweet Gas Expander Power, MWe	3
Steam Turbine Power, MWe	217
Total Gross Power, MWe	685
Auxiliary Load Summary	
Acid Gas Removal, kWe	11,550
Air Separation Unit Auxiliaries, kWe	1,000
Air Separation Unit Main Air Compressor, kWe	71,370
Air Separation Unit Booster Compressor, kWe	5,610
Ammonia Wash Pumps, kWe	100
Circulating Water Pumps, kWe	5,260
Claus Plant TG Recycle Compressor, kWe	1,160
Claus Plant/TGTU Auxiliaries, kWe	250
CO ₂ Compression, kWe	31,690
Coal Dryer Air Compressor, kWe	–
Coal Handling, kWe	470
Coal Milling, kWe	2,250
Combustion Turbine Auxiliaries, kWe	1,000
Condensate Pumps, kWe	220
Cooling Tower Fans, kWe	2,720
Feedwater Pumps, kWe	2,540
Gasifier Water Pump, kWe	–
Ground Water Pumps, kWe	570
Miscellaneous Balance of Plant ^A , kWe	3,000
N ₂ Compressors, kWe	36,570
N ₂ Humidification Pump, kWe	–
O ₂ Pump, kWe	480
Quench Water Pump, kWe	960
Shift Steam Pump, kWe	220
Slag Handling, kWe	1,150
Slag Reclaim Water Recycle Pump, kWe	–
Slurry Water Pump, kWe	190

Power Summary	
Auxiliary Load Summary	
Sour Gas Compressors, kWe	–
Sour Water Recycle Pumps, kWe	30
Steam Turbine Auxiliaries, kWe	200
Syngas Recycle Compressor, kWe	–
Syngas Scrubber Pumps, kWe	250
Process Water Treatment Auxiliaries, kWe	2,070
Transformer Losses, kWe	2,700
Total Auxiliaries, MWe	186
Net Power, MWe	499

^AIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

3.4.13.1 Environmental Performance

The environmental targets for emissions of Hg, HCl, NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B5B-Q is presented in Exhibit 3-125.

Exhibit 3-125. Case B5B-Q air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.021 (0.048)	858 (946)	0.179 (0.394)
Particulate	0.003 (0.007)	127 (140)	0.026 (0.058)
Hg	1.57E-7 (3.65E-7)	0.007 (0.007)	1.36E-6 (3.00E-6)
HCl	0.000 (0.000)	0.00 (0.00)	0.000 (0.000)
CO ₂	9 (20)	355,497 (391,868)	74 (163)
CO ₂ ^C	–	–	102 (224)

^ACalculations based on an 80 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

The low level of SO₂ emissions is achieved by capturing the sulfur in the gas by the two-stage Selexol AGR process. As a result of achieving the 90 percent CO₂ removal target, the sulfur compounds are removed to an extent that exceeds the environmental target in Section 2.4. The clean syngas exiting the AGR process has a sulfur concentration of approximately 5 ppmv. This results in a concentration in the flue gas of less than less than 1 ppmv. The H₂S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H₂S and then recycled back to the Selexol process, thereby eliminating the need for a TGTU.

NO_x emissions are limited by N₂ dilution to 15 ppmvd (as NO at 15 percent O₂). NH₃ in the syngas is removed with process condensate prior to the low-temperature AGR process. This helps lower NO_x levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the syngas quench in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Approximately 97 percent of the mercury is captured from the syngas by dual activated carbon beds.

Ninety-two percent of the CO₂ from the syngas is captured in the AGR system and compressed for sequestration. Because not all CO is converted to CO₂ in the shift reactors, the overall carbon removal is 90 percent.

The carbon balance for the plant is shown in Exhibit 3-126. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon leaves the plant as unburned carbon in the slag and the captured CO₂ product, and as CO₂ in the stack gas (includes the ASU vent gas). The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in less carbon contained in the slag, represented by the following fraction:

$$\left(1 - \left(\frac{\text{Carbon in Stack}}{(\text{Total Carbon In}) - (\text{Carbon in Slag})}\right)\right) * 100 = \left(1 - \left(\frac{30,521}{309,012 - 6,157}\right)\right) * 100 = 90\%$$

Exhibit 3-126. Case B5B-Q carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	139,632 (307,835)	Stack Gas	13,844 (30,521)
Air (CO ₂)	534 (1,177)	CO ₂ Product	123,528 (272,334)
		Slag	2,793 (6,157)
Total	140,165 (309,012)	Total	140,165 (309,012)

Exhibit 3-127 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant and sulfur in the CO₂ product. Sulfur in the slag is considered to be negligible.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-127. Case B5B-Q sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	5,490 (12,104)	Stack Gas	–
		CO ₂ Product	1 (2)
		Elemental Sulfur	5,489 (12,102)
Total	5,490 (12,104)	Total	5,490 (12,104)

Exhibit 3-128 shows the overall water balance for the plant. The exhibit is presented in an identical manner as for cases B1A through B5B.

Exhibit 3-128. Case B5B-Q water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
Slag Handling	0.52 (138)	0.52 (138)	–	–	–
Slurry Water	1.50 (397)	1.50 (397)	–	–	–
Gasifier Water	–	–	–	–	–
Quench	6.75 (1,782)	4.50 (1,189)	2.25 (593)	–	2.25 (593)
HCl Scrubber	6.34 (1,674)	6.34 (1,674)	–	–	–
NH ₃ Scrubber	1.08 (285)	0.00 (0)	1.08 (285)	–	1.08 (285)
Gasifier Steam	–	–	–	–	–
Condenser Makeup	0.18 (47)	–	0.18 (47)	–	0.18 (47)
BFW Makeup	0.18 (47)	–	0.18 (47)	–	0.18 (47)
Gasifier Steam	–	–	–	–	–
Shift Steam	–	–	–	–	–
N ₂ Humidification	–	–	–	–	–
Cooling Tower	20.49 (5,414)	0.20 (53)	20.29 (5,361)	4.61 (1,218)	15.68 (4,143)
BFW Blowdown	–	0.18 (47)	-0.18 (-47)	–	-0.18 (-47)
ASU Knockout	–	0.02 (6)	-0.02 (-6)	–	-0.02 (-6)
Total	36.85 (9,736)	13.06 (3,450)	23.79 (6,286)	4.61 (1,218)	19.19 (5,068)

An overall plant energy balance is provided in tabular form in Exhibit 3-129. The power out is the combined CT, steam turbine, and sweet gas expander power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a combined generator efficiency of 98.5 percent.

Exhibit 3-129. Case B5B-Q overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, MMBtu/hr (GJ/hr)				
Coal	5,944 (5,634)	5.0 (4.7)	–	5,949 (5,638)
Air	–	118.6 (112.4)	–	118.6 (112.4)
Raw Water Makeup	–	89.5 (84.8)	–	89.5 (84.8)
Auxiliary Power	–	–	668.1 (633.2)	668.1 (633.2)
TOTAL	5,944 (5,634)	213.1 (201.9)	668.1 (633.2)	6,825 (6,469)
Heat Out, MMBtu/hr (GJ/hr)				
Misc. Process Steam	–	4.8 (4.6)	–	4.8 (4.6)
Slag	91.6 (86.8)	37.5 (35.6)	–	129.1 (122.3)
Stack Gas	–	1,290 (1,222)	–	1,290 (1,222)
Sulfur	50.9 (48.2)	0.6 (0.6)	–	51.5 (48.8)
Motor Losses and Design Allowances	–	–	55.1 (52.2)	55.1 (52.2)
Cooling Tower Load ^A	–	2,676 (2,536)	–	2,676 (2,536)
CO ₂ Product Stream	–	-102.8 (-97.4)	–	-102.8 (-97.4)
Blowdown Streams	–	40.7 (38.5)	–	40.7 (38.5)
Ambient Losses ^B	–	143.9 (136.4)	–	143.9 (136.4)
Power	–	–	2,465 (2,336)	2,465 (2,336)
TOTAL	142.4 (135.0)	4,090 (3,877)	2,520 (2,388)	6,753 (6,400)
Unaccounted Energy ^C	–	72.3 (68.5)	–	72.3 (68.5)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers

^CBy difference

3.4.13.2 Energy and Mass Balance Diagrams

Energy and mass balance diagrams are shown for the following subsystems in Exhibit 3-130 through Exhibit 3-132:

- Coal gasification and ASU
- Syngas cleanup, sulfur recovery, and tail gas recycle
- Combined cycle power generation, steam, and FW

This page intentionally left blank

Exhibit 3-130. Case B5B-Q coal gasification and ASU energy and mass balance

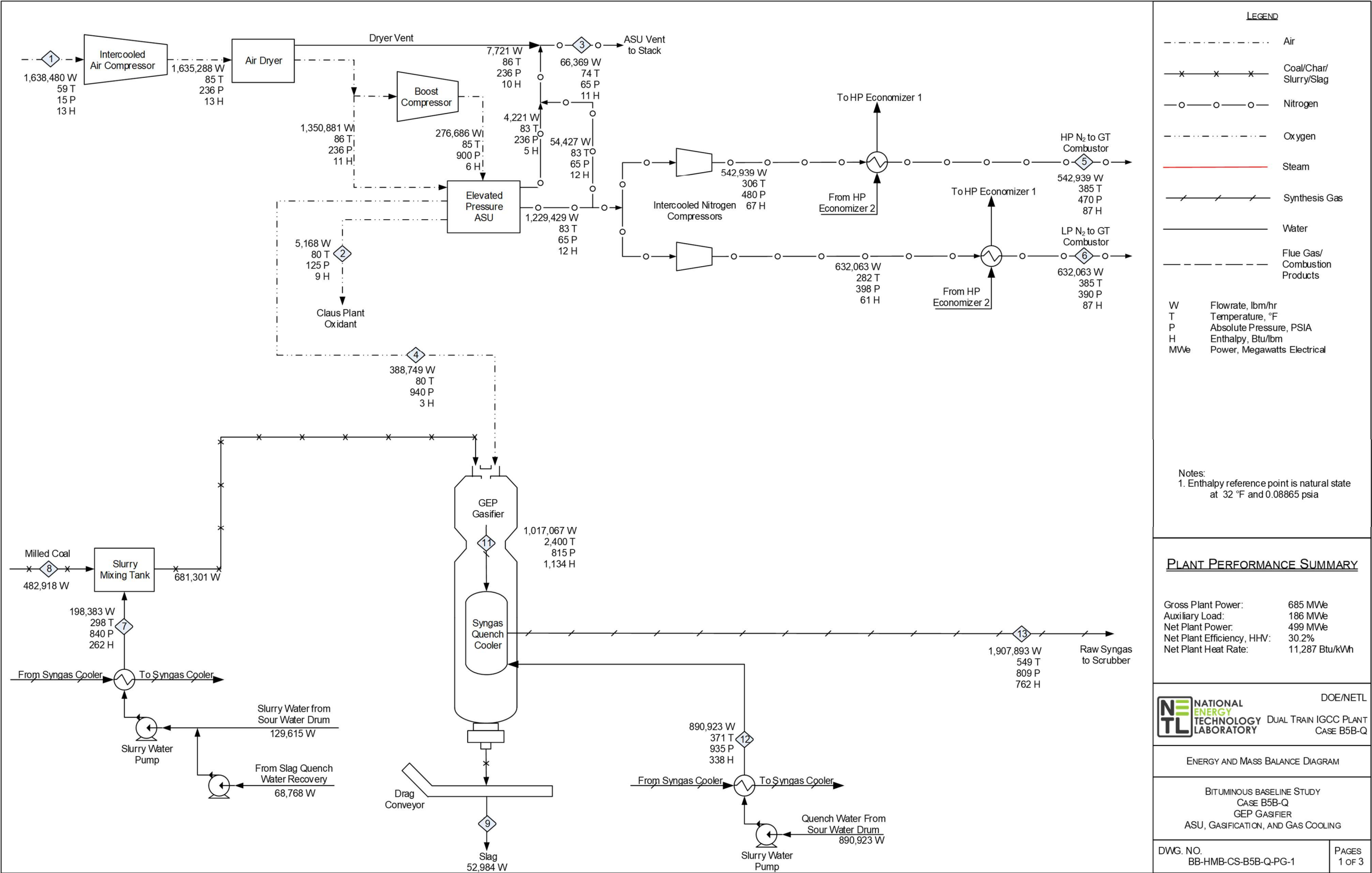


Exhibit 3-131. Case B5B-Q syngas cleanup energy and mass balance

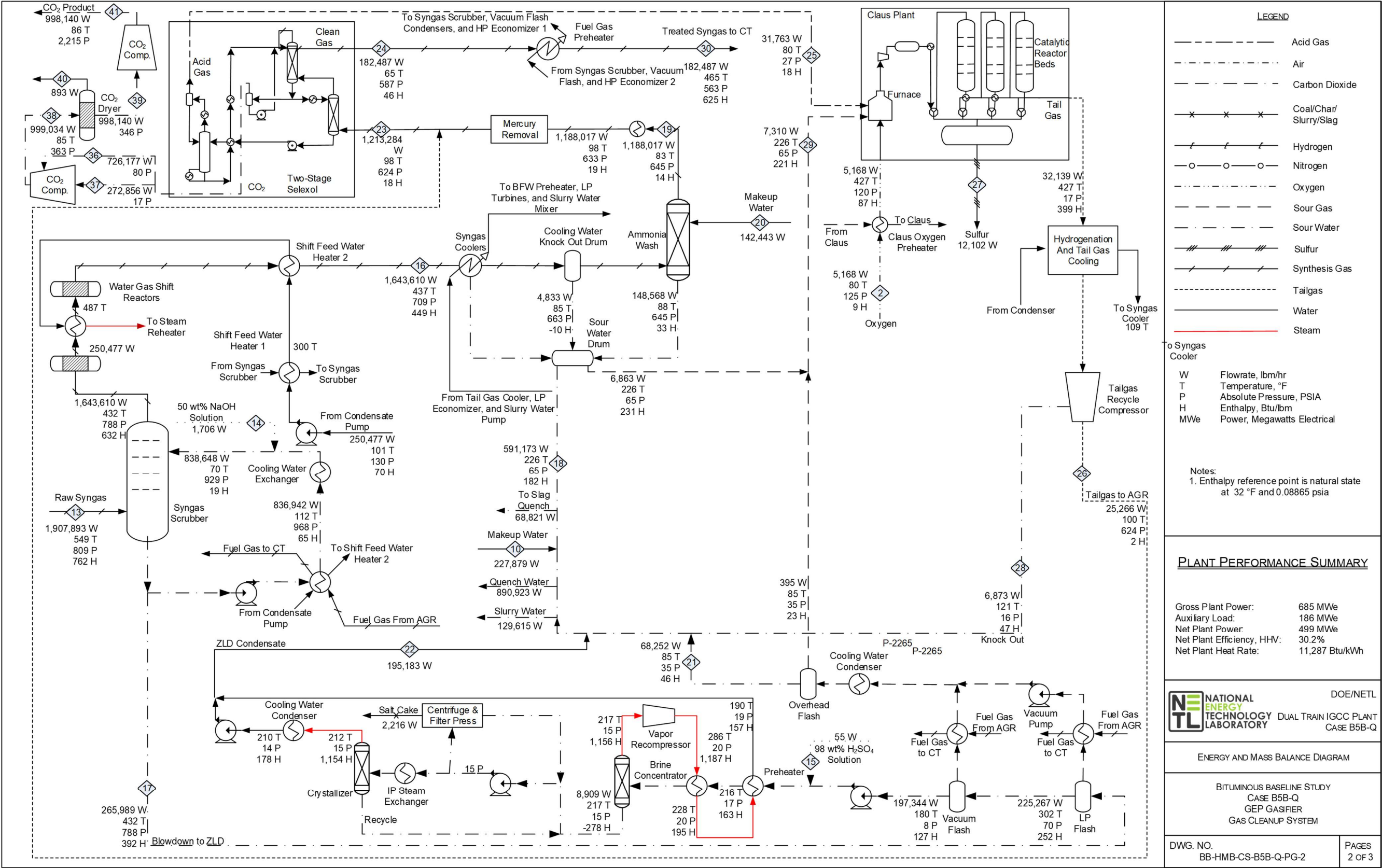
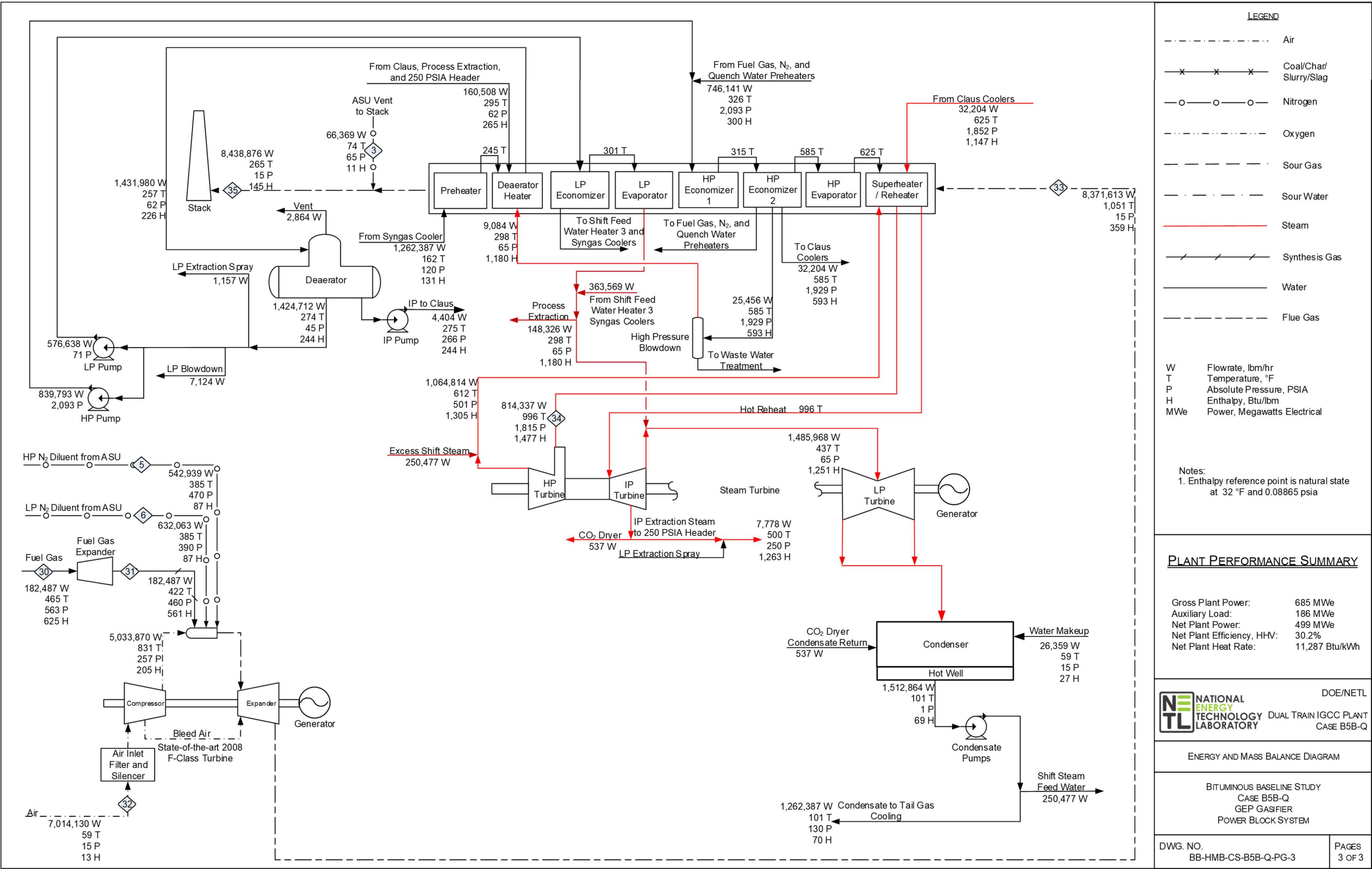


Exhibit 3-132. Case B5B-Q combined cycle power generation energy and mass balance



This page intentionally left blank

3.4.14 Case B5B-Q – Major Equipment List

Major equipment items for the GEP quench-only gasifier with CO₂ capture are shown in the following tables. In general, the design conditions include a 10 percent design allowance for flows and heat duties and a 21 percent design allowance for heads on pumps and fans.

Case B5B-Q – Account 1: Coal Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
5	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
6	Reclaim Hopper	N/A	50 tonne (50 ton)	2	1
7	Feeder	Vibratory	180 tonne/hr (200 tph)	2	1
8	Conveyor No. 3	Belt w/ tripper	360 tonne/hr (400 tph)	1	0
9	Coal Surge Bin w/ Vent Filter	Dual outlet	180 tonne (200 ton)	2	0
10	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
11	Conveyor No. 4	Belt w/tripper	360 tonne/hr (400 tph)	1	0
12	Conveyor No. 5	Belt w/ tripper	360 tonne/hr (400 tph)	1	0
13	Coal Silo w/ Vent Filter and Slide Gates	Field erected	800 tonne (890 ton)	3	0

Case B5B-Q – Account 2: Coal Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	80 tonne/hr (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	240 tonne/hr (270 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	480 tonne (530 ton)	1	0
4	Weigh Feeder	Belt	120 tonne/hr (130 tph)	2	0
5	Rod Mill	Rotary	120 tonne/hr (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	297,380 liters (78,560 gal)	2	0
7	Slurry Water Pumps	Centrifugal	830 lpm (220 gpm)	2	1
8	Trommel Screen	Coarse	170 tonne/hr (190 tph)	2	0
9	Rod Mill Discharge Tank with Agitator	Field erected	389,020 liters (102,770 gal)	2	0
10	Rod Mill Product Pumps	Centrifugal	3,200 lpm (900 gpm)	2	2
11	Slurry Storage Tank with Agitator	Field erected	1,167,100 liters (308,300 gal)	2	0
12	Slurry Recycle Pumps	Centrifugal	6,500 lpm (1,700 gpm)	2	2
13	Slurry Product Pumps	Positive displacement	3,200 lpm (900 gpm)	2	2

Case B5B-Q – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	790,000 liters (209,000 gal)	2	0

**COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY**

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
2	Condensate Pumps	Vertical canned	6,330 lpm @ 90 m H ₂ O (1,670 gpm @ 300 ft H ₂ O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	357,000 kg/hr (788,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	2,490 lpm @ 20 m H ₂ O (660 gpm @ 70 ft H ₂ O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 3,630 lpm @ 1,700 m H ₂ O (960 gpm @ 5,700 ft H ₂ O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 3,230 lpm @ 210 m H ₂ O (850 gpm @ 670 ft H ₂ O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	592 GJ/hr (561 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	212,300 lpm @ 20 m H ₂ O (56,100 gpm @ 70 ft H ₂ O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
14	Municipal Water Pumps	Stainless steel, single suction	2,890 lpm @ 20 m H ₂ O (760 gpm @ 60 ft H ₂ O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,890 lpm @ 270 m H ₂ O (760 gpm @ 880 ft H ₂ O)	2	1
16	Filtered Water Pumps	Stainless steel, single suction	1,710 lpm @ 50 m H ₂ O (450 gpm @ 160 ft H ₂ O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	819,000 liter (216,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	170 lpm (40 gpm)	2	0
19	Liquid Waste Treatment System	N/A	10 years, 24-hour storm	1	0
20	Process Water Treatment	Vacuum flash, brine concentrator, and crystallizer	Vacuum Flash - Inlet: 66,000 kg/hr (146,000 lb/hr) Outlet: 3,634 ppmw Cl- Brine Concentrator Inlet - 49,000 kg/hr (109,000 lb/hr) Crystallizer Inlet - 2,000 kg/hr (5,000 lb/hr)	2	0

Case B5B-Q – Account 4: Gasifier, ASU, and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized slurry-feed, entrained bed	2,900 tonne/day, 5.6 MPa (3,200 tpd, 815 psia)	2	0
2	Synthesis Gas Cooler	Vertical downflow radiant heat exchanger with outlet quench chamber	254,000 kg/hr (559,000 lb/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	N/A	2	0
4	HCl Scrubber	Ejector Venturi	476,000 kg/hr (1,049,000 lb/hr)	2	0
5	Ammonia Wash	Counter-flow spray tower	298,000 kg/hr (657,000 lb/hr) @ 4.6 MPa (663 psia)	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
6	Primary Sour Water Stripper	Counter-flow with external reboiler	N/A	2	0
7	Secondary Sour Water Stripper	Counter-flow with external reboiler	N/A	2	0
8	Low Temperature Heat Recovery Coolers	Shell and tube with condensate drain	410,000 kg/hr (904,000 lb/hr)	6	0
9	Low Temperature Heat Recovery Knockout Drum	Vertical with mist eliminator	299,000 kg/hr, 59°C, 4.6 MPa (659,000 lb/hr, 138°F, 667 psia)	2	0
10	Saturation Water Economizers	Shell and tube	N/A	4	0
11	HP Nitrogen Gas Saturator	Direct Injection	135,000 kg/hr, 196°C, 3.2 MPa (299,000 lb/hr, 385°F, 470 psia)	2	0
12	LP Nitrogen Gas Saturator	Direct Injection	158,000 kg/hr, 196°C, 2.7 MPa (348,000 lb/hr, 385°F, 390 psia)	2	0
13	Saturator Water Pump	Centrifugal	N/A	2	2
14	Saturated Nitrogen Reheaters	Shell and tube	N/A	4	0
15	Synthesis Gas Reheaters	Shell and tube	Reheater 1: 46,000 kg/hr (100,000 lb/hr) Reheater 2: N/A Reheater 3: N/A Reheater 4: N/A Reheater 5: 46,000 kg/hr (100,000 lb/hr) Reheater 6: 46,000 kg/hr (100,000 lb/hr)	2	0
16	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	410,000 kg/hr (904,000 lb/hr) syngas	2	0
17	ASU Main Air Compressor	Centrifugal, multi-stage	6,000 m ³ /min @ 1.6 MPa (198,000 scfm @ 236 psia)	2	0
18	Cold Box	Vendor design	2,400 tonne/day (2,600 tpd) of 95% purity O ₂	2	0
19	Gasifier O ₂ Pump	Centrifugal, multi-stage	1,000 m ³ /min (42,000 scfm) Suction - 1.0 MPa (130 psia) Discharge - 6.5 MPa (940 psia)	2	0
20	AGR Nitrogen Boost Compressor	Centrifugal, multi-stage	N/A	2	0
21	High Pressure Nitrogen Diluent Compressor	Centrifugal, multi-stage	2,000 m ³ /min (67,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - 3.3 MPa (480 psia)	2	0
22	Low Pressure Nitrogen Diluent Compressor	Centrifugal, single-stage	2,220 m ³ /min (78,000 scfm) Suction - 0.4 MPa (70 psia) Discharge - 2.7 MPa (400 psia)	2	0
23	Gasifier Nitrogen Boost Compressor	Centrifugal, single-stage	N/A	2	0

Case B5B-Q – Account 5: Syngas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber 1	Sulfated carbon bed	296,000 kg/hr (653,000 lb/hr) 28°C (83°F) 4.5 MPa (645 psia)	2	0
2	Mercury Adsorber 2	Sulfated carbon bed	296,000 kg/hr (653,000 lb/hr) 37°C (98°F) 4.3 MPa (628 psia)	2	0
3	Sulfur Plant	Claus type	145 tonne/day (160 tpd)	1	0
4	WGS Reactors	Fixed bed, catalytic	205,000 kg/hr (452,000 lb/hr) 227°C (440°F) 5.4 MPa (790 psia)	4	0
5	Shift Reactor Heat Recovery Exchangers	Shell and Tube	Exchanger 1: 125 GJ/hr (118 MMBtu/hr) Exchanger 2: 100 GJ/hr (95 MMBtu/hr) Exchanger 3: 41 GJ/hr (39 MMBtu/hr) Exchanger 4: 50 GJ/hr (48 MMBtu/hr)	8	0
6	Acid Gas Removal Plant	Two-stage Selexol	605,000 kg/hr (1,335,000 lb/hr) 37°C (98°F) 4.3 MPa (624 psia)	1	0
7	Hydrogenation Reactor	Fixed bed, catalytic	16,000 kg/hr (35,000 lb/hr) 219°C (427°F) 0.1 MPa (16.7743276 psia)	1	0
8	Tail Gas Recycle Compressor	Centrifugal	13,000 kg/hr (28,000 lb/hr) each	1	0
9	Candle Filter	Pressurized filter with pulse-jet cleaning	N/A	2	0
10	CO ₂ Dryer	Triethylene glycol	Inlet: 152 m ³ /min @ 2.5 MPa (5,355 acfm @ 363 psia) Outlet: 2.4 MPa (346 psia) Water Recovered: 405 kg/hr (893 lb/hr)	1	0
11	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	10 m ³ /min @ 15.3 MPa (350 acfm @ 2,217 psia)	1	0
12	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 78 GJ/hr (74 MMBtu/hr)	1	0

Case B5B-Q – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	State-of-the-art 2008 F-Class	232 MW	2	0
2	Combustion Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

Case B5B-Q – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.5 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 203,158 kg/hr, 12.4 MPa/535°C (447,885 lb/hr, 1,800 psig/996°F)	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
			Reheat steam - 265,646 kg/hr, 3.3 MPa/535°C (585,648 lb/hr, 477 psig/996°F)		

Case B5B-Q – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	229 MW 12.4 MPa/535°C/535°C (1,800 psig/996°F/996°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	250 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,600GJ/hr (1,510 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

Case B5B-Q – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	528,000 lpm @ 30 m (140,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/ 16°C (60°F) CWT/27°C (80°F) HWT/ 2,940 GJ/hr (2,790 MMBtu/hr) heat duty	1	0

Case B5B-Q – Account 10: Slag Recovery and Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	252,000 liters (67,000 gal)	2	0
2	Slag Crusher	Roll	13 tonne/hr (15 tph)	2	0
3	Slag Depressurizer	Lock Hopper	13 tonne/hr (15 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	152,000 liters (40,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	68,000 liters (18,000 gal)	2	0
6	Slag Conveyor	Drag chain	13 tonne/hr (15 tph)	2	0
7	Slag Separation Screen	Vibrating	13 tonne/hr (15 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	13 tonne/hr (15 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	216,000 liters (57,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	60 lpm @ 14 m H ₂ O (10 gpm @ 46 ft H ₂ O)	2	2
11	Grey Water Storage Tank	Field erected	69,000 liters (18,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	240 lpm @ 560 m H ₂ O (60 gpm @ 1,850 ft H ₂ O)	2	2
13	Slag Storage Bin	Vertical, field erected	1,000 tonne (1,000 tons)	2	0
14	Unloading Equipment	Telescoping chute	110 tonne/hr (120 tph)	1	0

Case B5B-Q – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
2	STG Transformer	Oil-filled	24 kV/345 kV, 210 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 81 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 42 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 6 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B5B-Q – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.4.15 Case B5B-Q – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 3-133 shows a detailed breakdown of the capital costs; Exhibit 3-134 shows the owner's costs, TOC, and TASC; Exhibit 3-135 shows the initial and annual O&M costs; and Exhibit 3-136 shows the LCOE breakdown.

The estimated TPC of the GEP gasifier with CO₂ capture in quench-only configuration is \$5,212/kW. Process contingency represents 5.0 percent of the TPC and project contingency represents 15.3 percent. The LCOE, including CO₂ T&S costs of \$9.1/MWh, is \$156.2/MWh. For comparison, the TPC and LCOE for Case B5B, GEP in radiant-only configuration with CO₂ capture, are \$5,568/kW and \$159.4/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-133. Case B5B-Q total plant cost details

Case:		B5B-Q	– GEP Quench IGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		499					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1											
Coal Handling											
1.1	Coal Receive & Unload	\$991	\$0	\$477	\$0	\$1,468	\$220	\$0	\$338	\$2,026	\$4
1.2	Coal Stackout & Reclaim	\$3,238	\$0	\$774	\$0	\$4,012	\$602	\$0	\$923	\$5,537	\$11
1.3	Coal Conveyors & Yard Crush	\$30,893	\$0	\$7,863	\$0	\$38,756	\$5,813	\$0	\$8,914	\$53,483	\$107
1.4	Other Coal Handling	\$4,812	\$0	\$1,083	\$0	\$5,895	\$884	\$0	\$1,356	\$8,135	\$16
1.9	Coal & Sorbent Handling Foundations	\$0	\$87	\$227	\$0	\$313	\$47	\$0	\$72	\$432	\$1
	Subtotal	\$39,933	\$87	\$10,424	\$0	\$50,444	\$7,567	\$0	\$11,602	\$69,612	\$139
2											
Coal Preparation & Feed											
2.1	Coal Crushing & Drying	\$2,401	\$145	\$345	\$0	\$2,891	\$434	\$0	\$665	\$3,989	\$8
2.2	Prepared Coal Storage & Feed	\$7,376	\$1,772	\$1,142	\$0	\$10,290	\$1,543	\$0	\$2,367	\$14,200	\$28
2.3	Slurry Coal Injection System	\$6,376	\$0	\$4,008	\$0	\$10,384	\$1,558	\$0	\$2,388	\$14,330	\$29
2.4	Miscellaneous Coal Preparation & Feed	\$728	\$532	\$1,568	\$0	\$2,828	\$424	\$0	\$650	\$3,902	\$8
2.9	Coal & Sorbent Feed Foundation	\$0	\$1,772	\$1,520	\$0	\$3,292	\$494	\$0	\$757	\$4,543	\$9
	Subtotal	\$16,881	\$4,221	\$8,583	\$0	\$29,685	\$4,453	\$0	\$6,827	\$40,965	\$82
3											
Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$1,402	\$2,404	\$1,202	\$0	\$5,009	\$751	\$0	\$1,152	\$6,912	\$14
3.2	Water Makeup & Pretreating	\$6,053	\$605	\$3,430	\$0	\$10,088	\$1,513	\$0	\$3,480	\$15,081	\$30
3.3	Other Feedwater Subsystems	\$725	\$238	\$226	\$0	\$1,188	\$178	\$0	\$273	\$1,640	\$3
3.4	Service Water Systems	\$1,809	\$3,453	\$11,181	\$0	\$16,443	\$2,466	\$0	\$5,673	\$24,582	\$49
3.5	Other Boiler Plant Systems	\$186	\$68	\$169	\$0	\$422	\$63	\$0	\$97	\$583	\$1
3.6	Natural Gas Pipeline and Start-Up System	\$7,254	\$312	\$234	\$0	\$7,800	\$1,170	\$0	\$1,794	\$10,764	\$22
3.7	Waste Water Treatment Equipment	\$8,013	\$0	\$4,911	\$0	\$12,924	\$1,939	\$0	\$4,459	\$19,322	\$39
3.8	Vacuum Flash, Brine Concentrator, & Crystallizer	\$42,058	\$0	\$26,042	\$0	\$68,100	\$10,215	\$0	\$23,495	\$101,810	\$204
3.9	Miscellaneous Plant Equipment	\$15,447	\$2,026	\$7,850	\$0	\$25,322	\$3,798	\$0	\$8,736	\$37,857	\$76
	Subtotal	\$82,946	\$9,105	\$55,245	\$0	\$147,296	\$22,094	\$0	\$49,159	\$218,549	\$438
4											
Gasifier, ASU, & Accessories											
4.1	Gasifier (Quench Only) & Auxiliaries (GEP)	\$258,840	\$0	\$222,447	\$0	\$481,287	\$72,193	\$67,380	\$93,129	\$713,989	\$1,430
4.2	Syngas Cooler	w/4.1	w/4.1	w/4.1	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.3	Air Separation Unit/Oxidant Compression	\$131,665	\$30,134	\$31,336	\$0	\$193,135	\$38,627	\$19,314	\$37,661	\$288,737	\$578
4.5	Miscellaneous Gasification Equipment	\$3,265	\$0	\$2,806	\$0	\$6,071	\$911	\$0	\$1,396	\$8,378	\$17
4.6	Low Temperature Heat Recovery & Flue Gas Saturation	\$45,026	\$0	\$17,106	\$0	\$62,132	\$9,320	\$0	\$14,290	\$85,742	\$172

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B5B-Q	– GEP Quench IGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		499					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
4.7	Flare Stack System	\$1,932	\$0	\$341	\$0	\$2,273	\$341	\$0	\$392	\$3,006	\$6
4.8	Black Water & Sour Gas Section	w/4.1	w/4.1	w/4.1	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4.15	Major Component Rigging	\$182	\$0	\$156	\$0	\$338	\$51	\$0	\$58	\$447	\$1
4.16	Gasification Foundations	\$0	\$407	\$356	\$0	\$763	\$114	\$0	\$219	\$1,097	\$2
	Subtotal	\$440,909	\$30,541	\$274,548	\$0	\$745,999	\$121,557	\$86,694	\$147,147	\$1,101,396	\$2,207
5		Syngas Cleanup									
5.1	Double Stage Selexol	\$124,947	\$0	\$51,035	\$0	\$175,982	\$26,397	\$35,196	\$47,515	\$285,091	\$571
5.2	Sulfur Removal	w/5.1	w/5.1	w/5.1	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5.3	Elemental Sulfur Plant	\$48,707	\$9,494	\$62,410	\$0	\$120,611	\$18,092	\$0	\$27,740	\$166,443	\$333
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$32,267	\$4,840	\$13,977	\$0	\$51,084	\$7,663	\$0	\$11,749	\$70,495	\$141
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$481	\$76	\$206	\$0	\$764	\$115	\$0	\$176	\$1,054	\$2
5.6	Mercury Removal (Carbon Bed)	\$279	\$0	\$211	\$0	\$490	\$73	\$24	\$118	\$705	\$1
5.7	Water Gas Shift (WGS) Reactors	\$61,197	\$0	\$24,468	\$0	\$85,664	\$12,850	\$0	\$19,703	\$118,217	\$237
5.10	Blowback Gas Systems	\$761	\$428	\$239	\$0	\$1,428	\$214	\$0	\$246	\$1,888	\$4
5.11	Fuel Gas Piping	\$0	\$960	\$628	\$0	\$1,587	\$238	\$0	\$365	\$2,191	\$4
5.12	Gas Cleanup Foundations	\$0	\$227	\$153	\$0	\$381	\$57	\$0	\$131	\$569	\$1
	Subtotal	\$268,639	\$16,025	\$153,326	\$0	\$437,991	\$65,699	\$35,221	\$107,744	\$646,654	\$1,296
6		Combustion Turbine & Accessories									
6.1	Combustion Turbine Generator	\$76,557	\$0	\$5,425	\$0	\$81,983	\$12,297	\$8,198	\$15,372	\$117,850	\$236
6.2	Syngas Expander	\$2,133	\$0	\$293	\$0	\$2,426	\$364	\$0	\$419	\$3,209	\$6
6.3	Combustion Turbine Accessories	\$2,687	\$0	\$164	\$0	\$2,851	\$428	\$0	\$492	\$3,770	\$8
6.4	Compressed Air Piping	\$0	\$509	\$333	\$0	\$843	\$126	\$0	\$194	\$1,163	\$2
6.5	Combustion Turbine Foundations	\$0	\$216	\$250	\$0	\$467	\$70	\$0	\$161	\$697	\$1
	Subtotal	\$81,378	\$726	\$6,465	\$0	\$88,569	\$13,285	\$8,198	\$16,637	\$126,690	\$254
7		HRSR, Ductwork, & Stack									
7.1	Heat Recovery Steam Generator	\$33,944	\$0	\$6,573	\$0	\$40,517	\$6,078	\$0	\$6,989	\$53,584	\$107
7.2	Heat Recovery Steam Generator Accessories	\$12,120	\$0	\$2,347	\$0	\$14,467	\$2,170	\$0	\$2,496	\$19,133	\$38
7.3	Ductwork	\$0	\$1,091	\$765	\$0	\$1,856	\$278	\$0	\$427	\$2,562	\$5
7.4	Stack	\$9,282	\$0	\$3,463	\$0	\$12,745	\$1,912	\$0	\$2,198	\$16,855	\$34
7.5	Heat Recovery Steam Generator, Ductwork & Stack Foundations	\$0	\$231	\$232	\$0	\$463	\$69	\$0	\$160	\$692	\$1
	Subtotal	\$55,346	\$1,322	\$13,380	\$0	\$70,048	\$10,507	\$0	\$12,270	\$92,825	\$186
8		Steam Turbine & Accessories									
8.1	Steam Turbine Generator & Accessories	\$32,004	\$0	\$4,419	\$0	\$36,423	\$5,463	\$0	\$6,283	\$48,169	\$97
8.2	Steam Turbine Plant Auxiliaries	\$1,525	\$0	\$3,479	\$0	\$5,003	\$751	\$0	\$863	\$6,617	\$13

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B5B-Q	– GEP Quench IGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		499					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
8.3	Condenser & Auxiliaries	\$6,875	\$0	\$3,893	\$0	\$10,767	\$1,615	\$0	\$1,857	\$14,240	\$29
8.4	Steam Piping	\$4,692	\$0	\$2,035	\$0	\$6,727	\$1,009	\$0	\$1,934	\$9,669	\$19
8.5	Turbine Generator Foundations	\$0	\$238	\$420	\$0	\$658	\$99	\$0	\$227	\$983	\$2
	Subtotal	\$45,095	\$238	\$14,245	\$0	\$59,578	\$8,937	\$0	\$11,164	\$79,679	\$160
9		Cooling Water System									
9.1	Cooling Towers	\$12,780	\$0	\$3,856	\$0	\$16,636	\$2,495	\$0	\$2,870	\$22,001	\$44
9.2	Circulating Water Pumps	\$1,659	\$0	\$126	\$0	\$1,785	\$268	\$0	\$308	\$2,361	\$5
9.3	Circulating Water System Auxiliaries	\$11,342	\$0	\$1,579	\$0	\$12,921	\$1,938	\$0	\$2,229	\$17,088	\$34
9.4	Circulating Water Piping	\$0	\$6,344	\$5,745	\$0	\$12,089	\$1,813	\$0	\$2,780	\$16,683	\$33
9.5	Make-up Water System	\$706	\$0	\$971	\$0	\$1,677	\$252	\$0	\$386	\$2,314	\$5
9.6	Component Cooling Water System	\$231	\$276	\$190	\$0	\$696	\$104	\$0	\$160	\$961	\$2
9.7	Circulating Water System Foundations	\$0	\$523	\$929	\$0	\$1,451	\$218	\$0	\$501	\$2,170	\$4
	Subtotal	\$26,719	\$7,143	\$13,395	\$0	\$47,256	\$7,088	\$0	\$9,234	\$63,578	\$127
10		Slag Recovery & Handling									
10.1	Slag Dewatering & Cooling	\$2,094	\$0	\$1,025	\$0	\$3,119	\$468	\$0	\$538	\$4,125	\$8
10.2	Gasifier Ash Depressurization	\$1,186	\$0	\$581	\$0	\$1,767	\$265	\$0	\$305	\$2,337	\$5
10.3	Cleanup Ash Depressurization	\$533	\$0	\$261	\$0	\$794	\$119	\$0	\$137	\$1,050	\$2
10.6	Ash Storage Silos	\$1,182	\$0	\$1,277	\$0	\$2,459	\$369	\$0	\$424	\$3,252	\$7
10.7	Ash Transport & Feed Equipment	\$455	\$0	\$106	\$0	\$562	\$84	\$0	\$97	\$743	\$1
10.8	Miscellaneous Ash Handling Equipment	\$65	\$80	\$24	\$0	\$169	\$25	\$0	\$29	\$223	\$0
10.9	Ash/Spent Sorbent Foundation	\$0	\$467	\$608	\$0	\$1,075	\$161	\$0	\$371	\$1,607	\$3
	Subtotal	\$5,515	\$547	\$3,882	\$0	\$9,945	\$1,492	\$0	\$1,901	\$13,337	\$27
11		Accessory Electric Plant									
11.1	Generator Equipment	\$2,384	\$0	\$1,798	\$0	\$4,182	\$627	\$0	\$721	\$5,531	\$11
11.2	Station Service Equipment	\$4,252	\$0	\$365	\$0	\$4,617	\$693	\$0	\$796	\$6,106	\$12
11.3	Switchgear & Motor Control	\$25,660	\$0	\$4,452	\$0	\$30,111	\$4,517	\$0	\$5,194	\$39,822	\$80
11.4	Conduit & Cable Tray	\$0	\$114	\$328	\$0	\$441	\$66	\$0	\$127	\$634	\$1
11.5	Wire & Cable	\$0	\$1,557	\$2,783	\$0	\$4,340	\$651	\$0	\$1,248	\$6,238	\$12
11.6	Protective Equipment	\$241	\$0	\$837	\$0	\$1,078	\$162	\$0	\$186	\$1,426	\$3
11.7	Standby Equipment	\$820	\$0	\$757	\$0	\$1,577	\$236	\$0	\$272	\$2,085	\$4
11.8	Main Power Transformers	\$6,071	\$0	\$124	\$0	\$6,195	\$929	\$0	\$1,069	\$8,192	\$16
11.9	Electrical Foundations	\$0	\$70	\$178	\$0	\$248	\$37	\$0	\$86	\$371	\$1
	Subtotal	\$39,427	\$1,741	\$11,621	\$0	\$52,789	\$7,918	\$0	\$9,699	\$70,406	\$141
12		Instrumentation & Control									
12.1	Integrated Gasification and Combined Cycle Control Equipment	\$535	\$0	\$460	\$0	\$995	\$149	\$0	\$172	\$1,316	\$3
12.2	Combustion Turbine Control Equipment	\$687	\$0	\$49	\$0	\$735	\$110	\$0	\$127	\$973	\$2
12.3	Steam Turbine Control Equipment	\$642	\$0	\$89	\$0	\$731	\$110	\$0	\$126	\$967	\$2

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO
ELECTRICITY

Case:		B5B-Q	– GEP Quench IGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		499					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
12.4	Other Major Component Control Equipment	\$1,225	\$0	\$835	\$0	\$2,060	\$309	\$103	\$371	\$2,843	\$6
12.5	Signal Processing Equipment	\$951	\$0	\$31	\$0	\$982	\$147	\$0	\$169	\$1,299	\$3
12.6	Control Boards, Panels & Racks	\$275	\$0	\$180	\$0	\$455	\$68	\$23	\$109	\$656	\$1
12.7	Distributed Control System Equipment	\$9,980	\$0	\$327	\$0	\$10,306	\$1,546	\$515	\$1,855	\$14,223	\$28
12.8	Instrument Wiring & Tubing	\$497	\$397	\$1,589	\$0	\$2,483	\$372	\$124	\$745	\$3,724	\$7
12.9	Other Instrumentation & Controls Equipment	\$1,114	\$0	\$552	\$0	\$1,666	\$250	\$83	\$300	\$2,299	\$5
	Subtotal	\$15,907	\$397	\$4,111	\$0	\$20,415	\$3,062	\$849	\$3,974	\$28,301	\$57
13		Improvements to Site									
13.1	Site Preparation	\$0	\$417	\$9,486	\$0	\$9,903	\$1,486	\$0	\$3,417	\$14,806	\$30
13.2	Site Improvements	\$0	\$1,885	\$2,666	\$0	\$4,551	\$683	\$0	\$1,570	\$6,804	\$14
13.3	Site Facilities	\$2,943	\$0	\$3,304	\$0	\$6,248	\$937	\$0	\$2,155	\$9,340	\$19
	Subtotal	\$2,943	\$2,303	\$15,456	\$0	\$20,702	\$3,105	\$0	\$7,142	\$30,950	\$62
14		Buildings & Structures									
14.1	Combustion Turbine Area	\$0	\$314	\$177	\$0	\$491	\$74	\$0	\$85	\$649	\$1
14.3	Steam Turbine Building	\$0	\$2,732	\$3,890	\$0	\$6,622	\$993	\$0	\$1,142	\$8,758	\$18
14.4	Administration Building	\$0	\$877	\$636	\$0	\$1,513	\$227	\$0	\$261	\$2,001	\$4
14.5	Circulation Water Pumphouse	\$0	\$153	\$81	\$0	\$234	\$35	\$0	\$40	\$310	\$1
14.6	Water Treatment Buildings	\$0	\$411	\$401	\$0	\$812	\$122	\$0	\$140	\$1,074	\$2
14.7	Machine Shop	\$0	\$485	\$331	\$0	\$816	\$122	\$0	\$141	\$1,079	\$2
14.8	Warehouse	\$0	\$378	\$244	\$0	\$622	\$93	\$0	\$107	\$822	\$2
14.9	Other Buildings & Structures	\$0	\$277	\$216	\$0	\$492	\$74	\$0	\$85	\$651	\$1
14.10	Waste Treating Building & Structures	\$0	\$775	\$1,480	\$0	\$2,256	\$338	\$0	\$389	\$2,983	\$6
	Subtotal	\$0	\$6,402	\$7,456	\$0	\$13,858	\$2,079	\$0	\$2,391	\$18,327	\$37
	Total	\$1,121,640	\$80,798	\$592,138	\$0	\$1,794,575	\$278,843	\$130,961	\$396,890	\$2,601,270	\$5,212

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-134. Case B5B-Q owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$21,729	\$44
1 Month Maintenance Materials	\$5,284	\$11
1 Month Non-fuel Consumables	\$1,162	\$2
1 Month Waste Disposal	\$785	\$2
25% of 1 Months Fuel Cost at 100% CF	\$2,290	\$5
2% of TPC	\$52,025	\$104
Total	\$83,275	\$167
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	\$20,117	\$40
0.5% of TPC (spare parts)	\$13,006	\$26
Total	\$33,124	\$66
Other Costs		
Initial Cost for Catalyst and Chemicals	\$26,621	\$53
Land	\$900	\$2
Other Owner's Costs	\$390,190	\$782
Financing Costs	\$70,234	\$141
Total Overnight Costs (TOC)	\$3,205,614	\$6,423
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	\$3,700,598	\$7,414

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-135. Case B5B-Q initial and annual operating and maintenance costs

Case:	B5B-Q	– GEP Quench IGCC w/ CO ₂ Capture		Cost Base:	Dec 2018
Plant Size (MW, net):	499	Heat Rate-net (Btu/kWh):	11,287	Capacity Factor (%):	80
Operating & Maintenance Labor					
Operating Labor			Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	2.0
Operating Labor Burden:		30.00	% of base	Operator:	11.0
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0
				Lab Techs, etc.:	3.0
				Total:	17.0
Fixed Operating Costs					
				Annual Cost	
				(\$)	(\$/kW-net)
Annual Operating Labor:				\$7,453,446	\$14.933
Maintenance Labor:				\$27,313,330	\$54.723
Administrative & Support Labor:				\$8,691,694	\$17.414
Property Taxes and Insurance:				\$52,025,391	\$104.234
Total:				\$95,483,861	\$191.304
Variable Operating Costs					
				(\$)	(\$/MWh-net)
Maintenance Material:				\$50,724,756	\$14.50177
Consumables					
	Initial Fill	Per Day	Per Unit	Initial Fill	
Water (gal/1000):	0	4,526	\$1.90	\$0	\$2,510,874
Makeup and Waste Water Treatment Chemicals (ton):	0	13.5	\$550.00	\$0	\$2,165,130
Sulfur-Impregnated Activated Carbon (ton):	77.6	0.106	\$12,000.00	\$931,641	\$372,656
Water Gas Shift (WGS) Catalyst (ft ³):	9,847	6.74	\$480.00	\$4,726,381	\$945,276
Selexol Solution (gal):	551,651	54.7	\$38.00	\$20,962,748	\$606,983
Sodium Hydroxide (50 wt%, ton):	0	20.5	\$600.00	\$0	\$3,585,735
Sulfuric Acid (98 wt%, ton):	0	0.655	\$210.00	\$0	\$40,154
Claus Catalyst (ft ³):	w/equip.	2.00	\$48.00	\$0	\$28,071
Triethylene Glycol (gal):	w/equip.	453	\$6.80	\$0	\$898,591
Subtotal:				\$26,620,770	\$11,153,471
Waste Disposal					
Sulfur-Impregnated Activated Carbon (ton):	0	0.106	\$80.00	\$0	\$2,484
WGS Catalyst (ft ³):	0	6.74	\$2.50	\$0	\$4,923
Selexol Solution (gal):	0	54.7	\$0.35	\$0	\$5,591
Claus Catalyst (ft ³):	0	2.00	\$2.50	\$0	\$1,462
Crystallizer Solids (ton):	0	38.2	\$38.00	\$0	\$423,833
Slag (ton):	0	636	\$38.00	\$0	\$7,054,976
Triethylene Glycol (gal):	0	453	\$0.35	\$0	\$46,251
Subtotal:				\$0	\$7,539,521
By-Products					
Sulfur (tons):	0	145	\$0.00	\$0	\$0
Subtotal:				\$0	\$0
Variable Operating Costs Total:				\$26,620,770	\$69,417,748
Fuel Cost					
Illinois Number 6 (ton):	0	5,795	\$51.96	\$0	\$87,920,591
Total:				\$0	\$87,920,591

Exhibit 3-136. Case B5B-Q LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	74.8	47.9%
Fixed	27.3	17.5%
Variable	19.8	12.7%
Fuel	25.1	16.1%
Total (Excluding T&S)	147.1	94.2%
CO ₂ T&S	9.1	5.8%
Total (Including T&S)	156.2	100.0%

3.5 IGCC CASE SUMMARY

The performance and cost results of the seven IGCC plant configurations modeled in this report are summarized in Exhibit 3-137. A graph of the net plant efficiency (HHV basis) is provided in Exhibit 3-138.

Exhibit 3-137. Estimated performance and cost results for all IGCC cases

Integrated Gasification Combined Cycle							
	Shell		E-Gas™ FSQ		GEP R+Q		
Case Name	B1A	B1B	B4A	B4B	B5A	B5B	B5B-Q
PERFORMANCE							
Nominal CO ₂ Capture (%)	0	90	0	90	0	90	90
Capacity Factor (%)	80	80	80	80	80	80	80
Gross Power Output (MWe)	765	696	763	742	765	741	685
Auxiliary Power Requirement (MWe)	125	177	122	185	131	185	186
Net Power Output (MWe)	640	519	641	557	634	556	499
Coal Flow Rate (lb/hr)	435,418	467,308	456,327	482,173	464,732	482,580	482,918
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HHV Thermal Input (kWt)	1,488,680	1,597,710	1,560,166	1,648,535	1,588,902	1,649,926	1,651,082
Net Plant HHV Efficiency (%)	43.0	32.5	41.1	33.8	39.9	33.7	30.2
Net Plant HHV Heat Rate (Btu/kWh)	7,940	10,497	8,308	10,101	8,554	10,118	11,287
Raw Water Withdrawal (gpm/MWnet)	6.5	9.8	6.8	9.3	7.6	9.9	12.6
Process Water Discharge (gpm/MWnet)	1.4	2.1	1.5	2.0	1.6	2.0	2.4
Raw Water Consumption (gpm/MWnet)	5.0	7.7	5.3	7.4	5.9	7.9	10.2
CO ₂ Capture Rate (%)	0	90	0	90	0	90	90
CO ₂ Emissions (lb/MMBtu)	200	21	199	20	197	20	20
CO ₂ Emissions (lb/MWh-gross)	1,328	161	1,391	153	1,396	151	163
CO ₂ Emissions (lb/MWh-net)	1,588	215	1,657	204	1,685	201	224
SO ₂ Emissions (lb/MMBtu) ^A	0.020	0.000	0.028	0.000	0.002	0.000	0.000
SO ₂ Emissions (lb/MWh-gross) ^A	0.130	0.000	0.192	0.000	0.015	0.000	0.000
NO _x Emissions (lb/MMBtu)	0.059	0.049	0.056	0.049	0.054	0.048	0.048
NO _x Emissions (lb/MWh-gross)	0.390	0.382	0.393	0.371	0.379	0.364	0.394
PM Emissions (lb/MMBtu)	0.007	0.007	0.007	0.007	0.007	0.007	0.007
PM Emissions (lb/MWh-gross)	0.047	0.056	0.050	0.054	0.050	0.054	0.058
Hg Emissions (lb/TBtu)	0.452	0.383	0.430	0.396	0.423	0.395	0.365
Hg Emissions (lb/MWh-gross) ^B	3.00x10 ⁻⁶	3.00x10 ⁻⁶	3.00x10 ⁻⁶	3.00x10 ⁻⁶	3.00x10 ⁻⁶	3.00x10 ⁻⁶	3.00x10 ⁻⁶

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Integrated Gasification Combined Cycle							
	Shell		E-Gas™ FSQ		GEP R+Q		
Case Name	B1A	B1B	B4A	B4B	B5A	B5B	B5B-Q
COST							
Total Plant Cost (2018\$/kW)	4,087	6,545	3,656	5,501	4,105	5,568	5,212
<i>Bare Erected Cost</i>	2,837	4,487	2,548	3,788	2,854	3,834	3,595
<i>Home Office Expenses</i>	439	691	396	585	443	592	559
<i>Project Contingency</i>	588	967	534	828	594	826	795
<i>Process Contingency</i>	222	401	179	300	214	316	262
Total Overnight Cost (2018\$/MM)	3,194	4,175	2,867	3,773	3,189	3,810	3,206
Total Overnight Cost (2018\$/kW)	4,993	8,039	4,474	6,776	5,032	6,847	6,423
<i>Owner's Costs</i>	906	1,493	818	1,275	927	1,279	1,211
Total As-Spent Cost (2018\$/kW)	5,764	9,280	5,165	7,822	5,809	7,904	7,414
LCOE (\$/MWh) (excluding T&S)^C	111.5	173.7	103.2	150.1	114.0	151.3	147.1
<i>Capital Costs</i>	58.2	93.7	52.1	79.0	58.6	79.8	74.8
<i>Fixed Costs</i>	21.3	33.5	19.2	28.4	21.4	28.7	27.3
<i>Variable Costs</i>	14.3	23.2	13.3	20.3	14.9	20.3	19.8
<i>Fuel Costs</i>	17.7	23.4	18.5	22.5	19.0	22.5	25.1
LCOE (\$/MWh) (including T&S)^C	111.5	182.3	103.2	158.3	114.0	159.4	156.2
<i>CO₂ T&S Costs</i>	N/A	8.6	N/A	8.2	N/A	8.1	9.1
Cost of CO₂ Captured (ex. T&S), \$/tonne^D	N/A	127.7	N/A	104.3	N/A	106.7	91.1
Cost of CO₂ Avoided (incl. T&S), \$/tonne^D	N/A	172.8	N/A	136.6	N/A	137.9	135.3

^ATrace amounts of sulfur emissions may exist in the flue gas stream to the stack in capture cases

^BAs discussed in Section 2.4.3, the mercury capture units were designed to attain the emissions target of 3.00x10⁻⁶ lb/MWh-gross

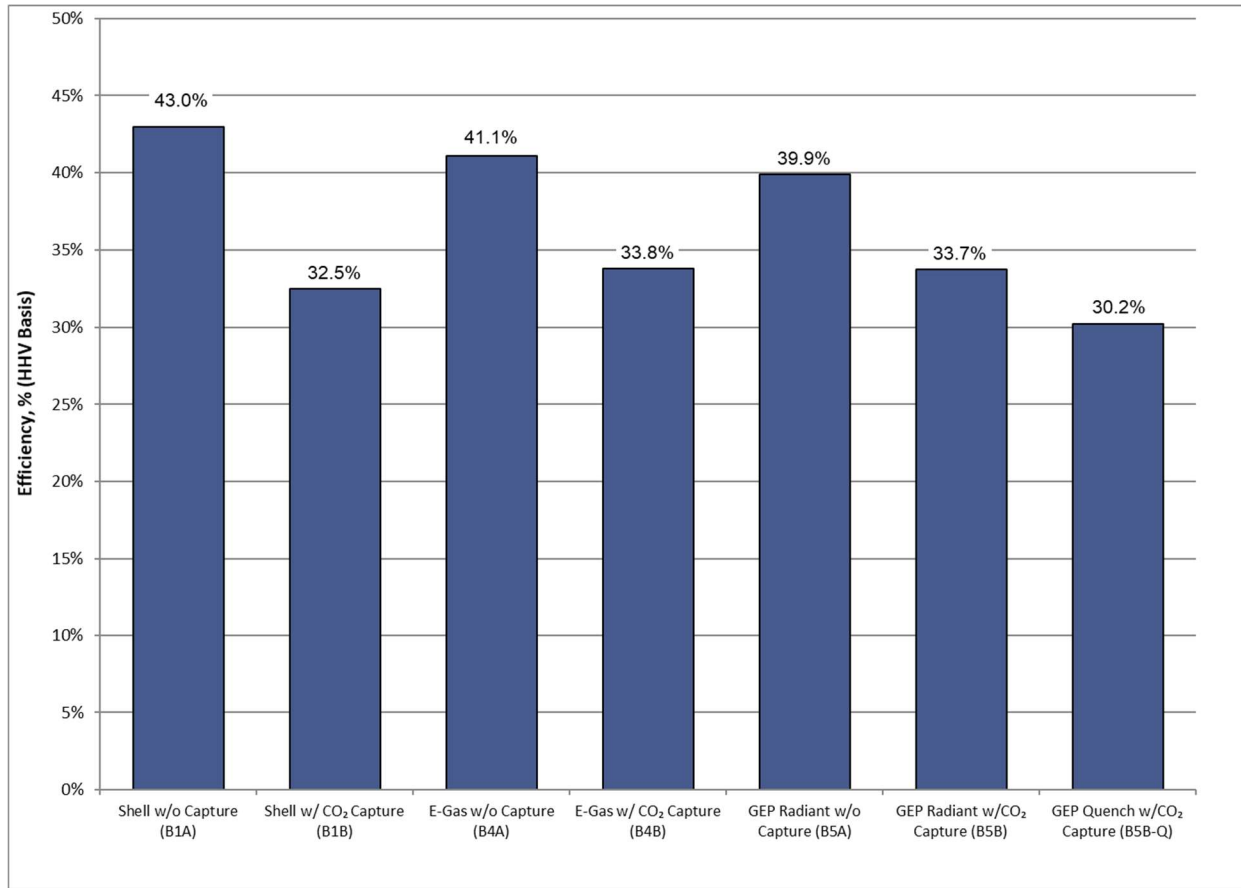
^CVarying incentives, such as tax credits, could impact the economics of the system

^DBoth the cost of CO₂ captured and cost of CO₂ avoided were calculated based on the non-capture SC PC Case B12A for all coal cases

The following observations can be made regarding plant performance:

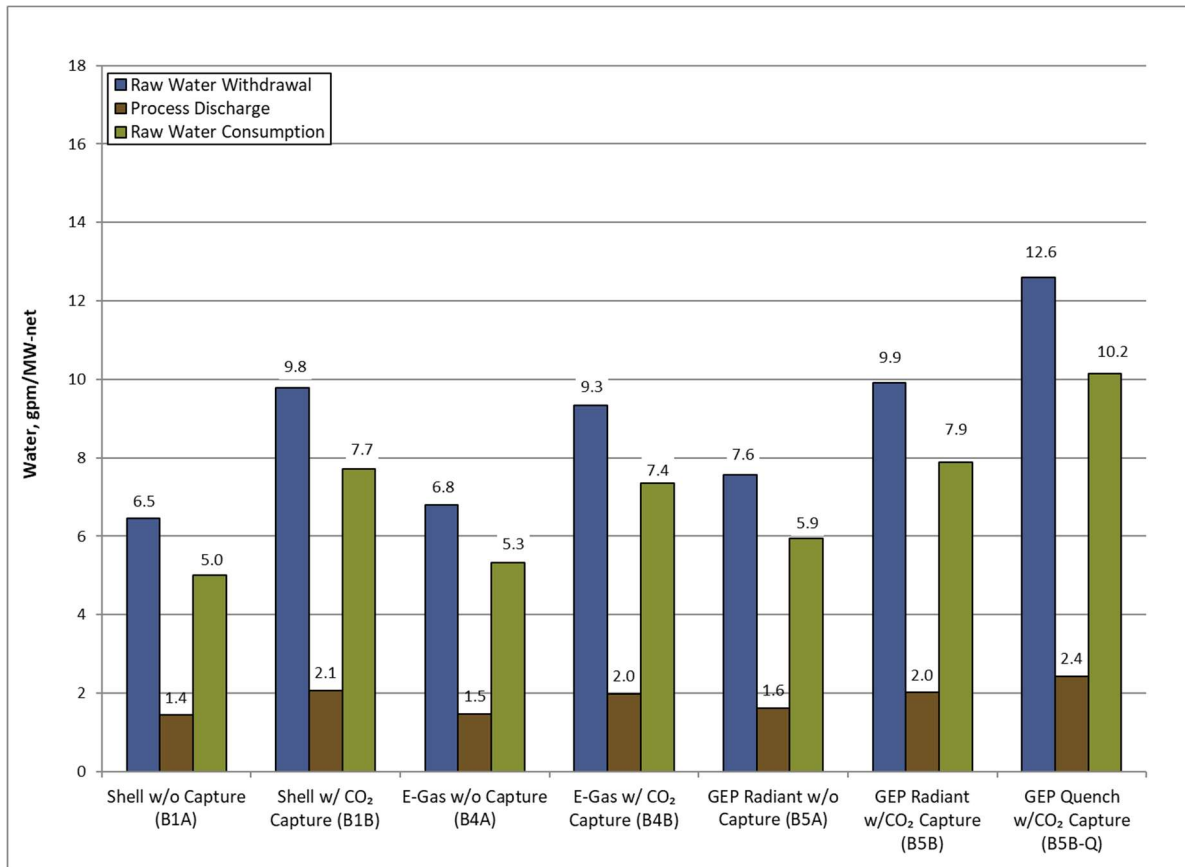
- In the non-carbon capture cases, the dry fed Shell gasifier has the highest net plant efficiency (43.0 percent), followed by the two-stage E-Gas™ slurry fed gasifier (41.1 percent) and the single-stage slurry fed GEP gasifier (39.9 percent). The absolute values of the GEP and E-Gas™ gasifiers are close to the reported values per the vendors. [30], [112] The Shell efficiency is slightly lower than reported by the vendor in other presentations. [106]
- The energy penalty associated with adding CO₂ capture is due to steam extraction for use in the WGS reaction, the auxiliary load for the CO₂ separation and compression equipment, and a slight derate of the gas turbine inlet temperature due to the higher moisture content of the working fluid. The reduction in net plant efficiency ranges 6–10 percentage points (16–24 percent relative to non-capture) with the variability being due to the different gasifier designs (e.g., slurry versus dry feed, syngas quench versus syngas heat recovery), which may vary between the capture and non-capture plant configurations.
- The lowest CO₂ capture energy penalty (6 percentage points) corresponds to the GEP Radiant gasifier cases primarily due to the non-capture plant design (slurry feed, water quench), which results in a high moisture content in the syngas and thus a low addition of shift steam for WGS for the capture plant design.
- The highest CO₂ capture energy penalty (10 percentage points) corresponds to the Shell gasifier cases. The design uses a dry feed system and, in the non-capture configuration, has relatively high heat recovery in the syngas cooler with no water quench, resulting in very low moisture content in the syngas. For the capture configuration, a water quench is added, which increases the moisture content of the syngas for the WGS reaction but decreases the heat recovery in the syngas cooler.
- CB&I E-Gas™ has the highest SO₂ emissions (0.192 lb/MWh-gross) of the seven cases because refrigerated MDEA has the lowest H₂S removal efficiency of the AGR technologies considered.
- Emissions of Hg, HCl, PM, NO_x, and SO₂ are all below the regulatory limits currently in effect and applicable to IGCC technology.

Exhibit 3-138. Net plant efficiency (HHV basis) for all IGCC cases



The normalized water withdrawal, process discharge, and water consumption are presented in Exhibit 3-139.

Exhibit 3-139. Raw water withdrawal and consumption in IGCC cases



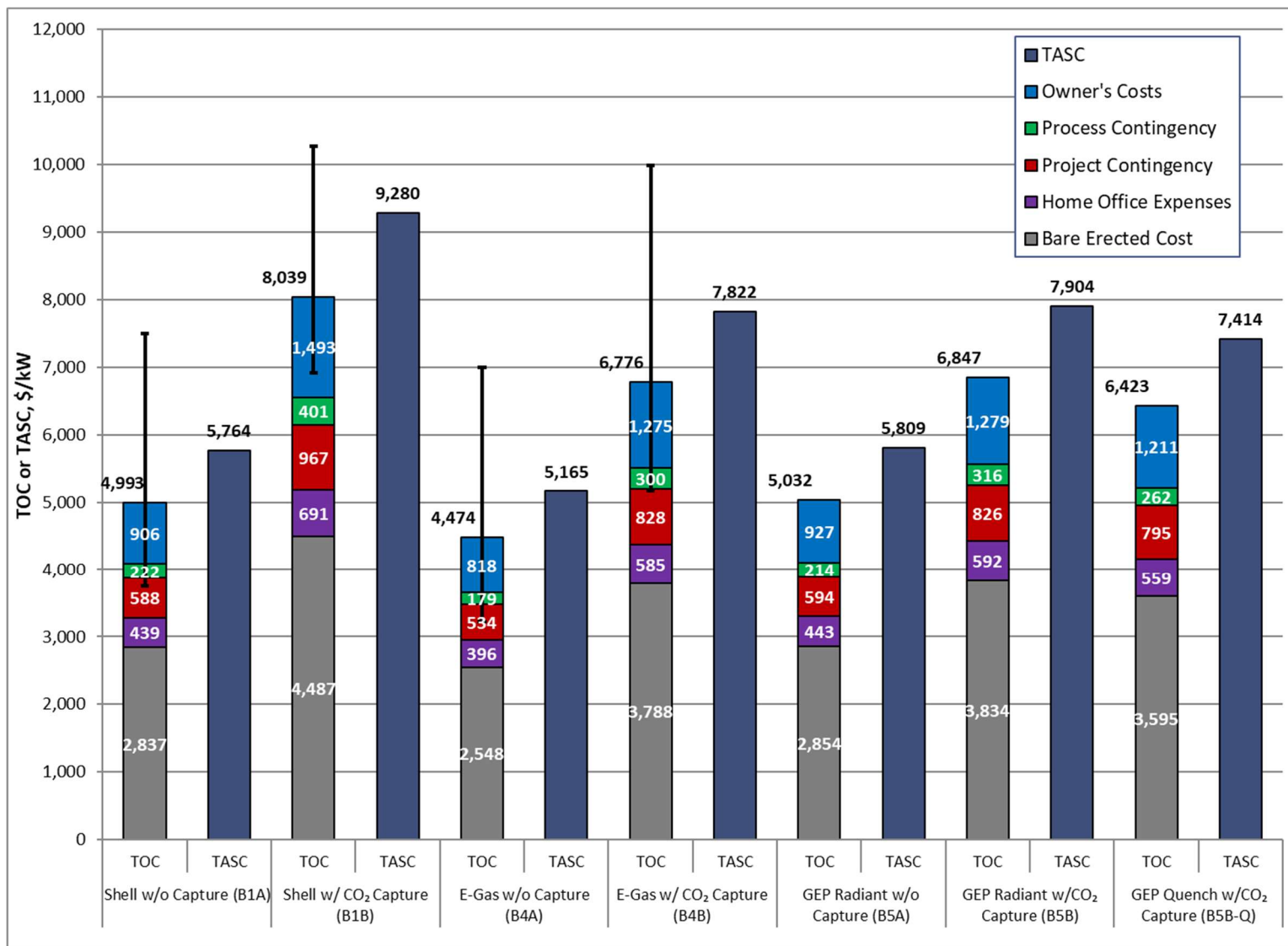
The following observations can be made:

- Normalized water consumption for the GEP non-capture case is 11 percent higher than the E-GasTM non-capture case and 18 percent higher than the Shell non-capture case primarily because of the large quench water requirement.
- While both the normalized raw water consumption and withdrawal rates are 11 percent and 12 percent greater in the GEP Radiant non-capture case than in the E-GasTM case, the normalized raw water withdrawal and consumption rates are 5 percent and 6 percent greater, respectively, in the E-GasTM non-capture case than the Shell case. The discrepancy between withdrawal and consumption is because very little water is available to recover for internal recycle in the dry-fed Shell system.
- The normalized raw water consumption for the four CO₂ capture cases varies by 38 percent from the highest to the lowest. The difference in technologies is where and how the water is introduced. Much of the water is introduced in the quench sections of the GEP and Shell cases while steam is added in the E-GasTM case.
- Raw water consumption for all cases is dominated by cooling tower makeup requirements, which account for 93–97 percent of raw water consumption in non-capture cases and 81–91 percent in CO₂ capture cases.

The components of TOC and the TASC of the seven cases are shown in Exhibit 3-140.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 3-140. Plant capital cost for all IGCC cases



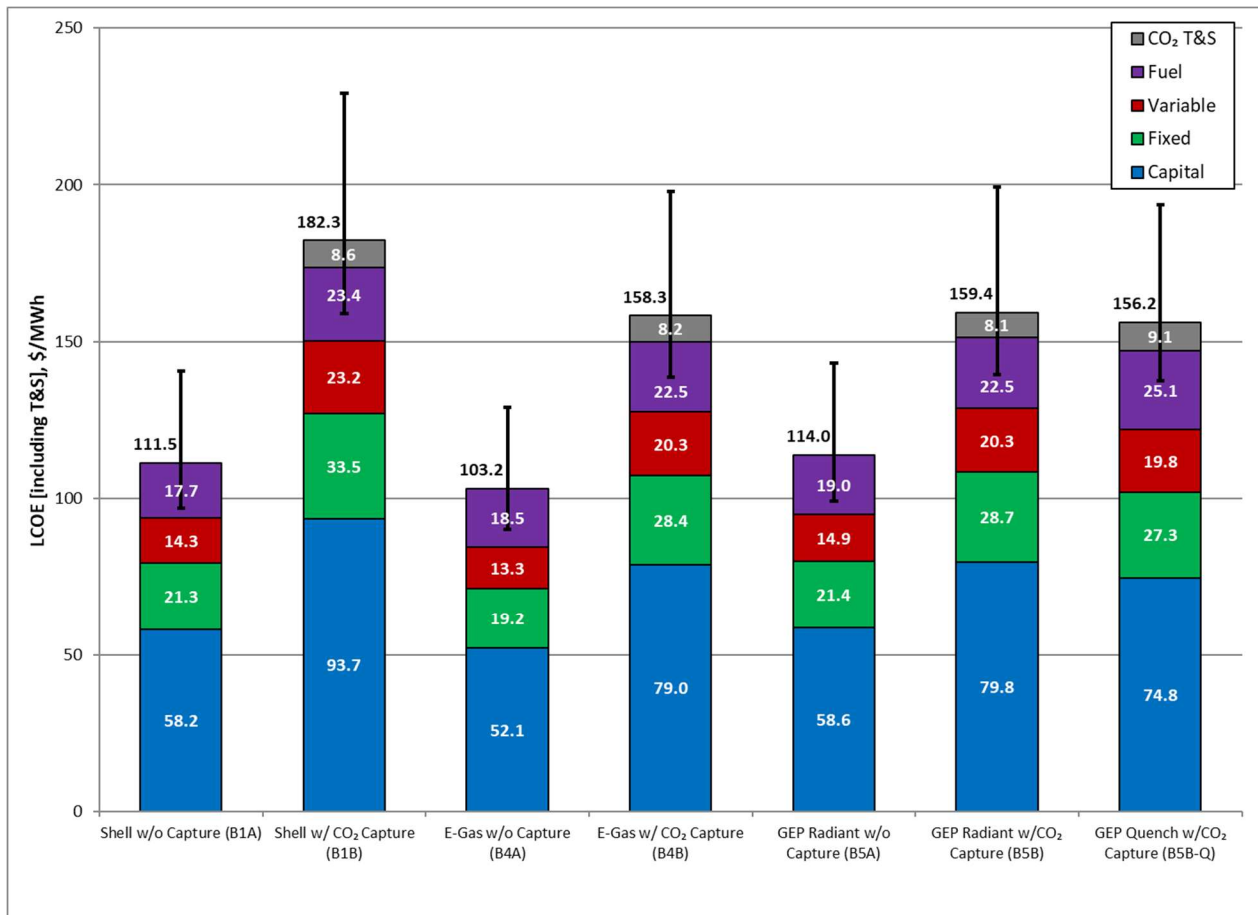
The IGCC capital cost estimate accuracy provides an AACE Class 5 range of -25 percent/+50 percent. The error bars included in Exhibit 3-140 represent the potential TOC range relative to the maximum and minimum of the capital cost uncertainty range.

The following normalized TOC (\$/kW) observations are made with the caveat that the differences between cases are less than the estimate accuracy. However, all cases are evaluated using a common set of technical and economic assumptions allowing meaningful comparison among the cases:

- E-Gas™ has the lowest TOC cost among the non-capture cases. The E-Gas™ technology has several features that lend it to being lower cost, such as:
 - The firetube syngas cooler is much smaller and less expensive than a radiant section. E-Gas™ can use a firetube boiler because the two-stage design reduces the gas temperature (slurry quench) into a range where a radiant cooler is not needed.
 - The firetube syngas cooler sits next to the gasifier instead of above or below it, which reduces the height of the main gasifier structure. The E-Gas™ proprietary slag removal system—used instead of lock hoppers below the gasifier—also contributes to the lower structure height.
- The normalized TOC of the GEP Radiant and Shell gasifier non-capture cases are approximately 12 percent greater than E-Gas™.
- The GEP Quench gasifier (GEP Radiant is 7 percent greater than GEP Quench) is the low-cost technology in the CO₂ capture cases, with E-Gas™ normalized TOC approximately 6 percent higher and Shell approximately 25 percent higher.
- The ASU cost represents 6–9 percent of the TOC. The ASU cost includes O₂ and N₂ compression. With N₂ dilution used to the maximum extent possible, N₂ compression costs are significant.
- The normalized TOC premium for adding CO₂ capture averages 44 percent, spanning a TOC increase range of \$1,390/kW to \$3,046/kW.

The LCOE is shown for all seven cases in Exhibit 3-141.

Exhibit 3-141. LCOE for all IGCC cases



Similar to Exhibit 3-140, the error bars included in Exhibit 3-141 represent the potential LCOE range relative to the maximum and minimum capital cost uncertainty ranges. The LCOE ranges presented are not reflective of other changes, such as variation in fuel price, labor price, CF, or other factors. As an example, if Case B1B's capital cost were determined to be at the high end of the uncertainty range (+50 percent), then the LCOE result would be \$229.1/MWh.

Conversely, if at the low end of the uncertainty range (-25 percent), the LCOE result would be \$158.9/MWh.

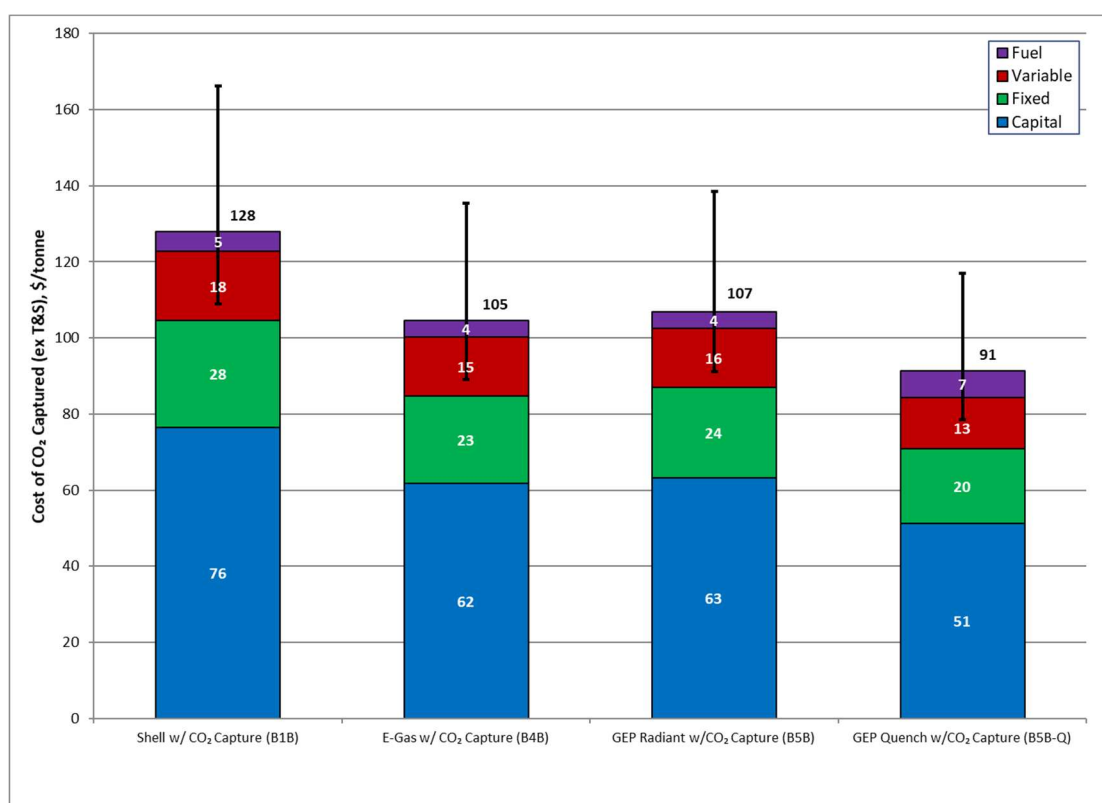
The following observations can be made:

- The LCOE is dominated by capital costs and is at least 50 percent of the total (excluding T&S costs) in all cases.
- In the non-capture cases the E-GasTM gasifier has the lowest LCOE, but the differential with Shell is reduced (relative to the normalized TOC comparison) primarily because of the higher efficiency of the Shell gasifier. The Shell LCOE is 8 percent higher than E-GasTM (compared to 12 percent higher normalized TOC). The GEP gasifier LCOE is about 10 percent higher than E-GasTM.

- In the capture cases, the order of the GEP Radiant and Shell gasifiers is reversed, with GEP Quench being the lowest LCOE option. The range is from \$156.2/MWh for GEP Quench to \$182.3/MWh for Shell with E-Gas™ and GEP Radiant intermediate at \$158.3/MWh and \$159.4/MWh, respectively, excluding T&S. The LCOE CO₂ capture premium for the cases averages 48 percent (range of 37-64 percent).
- The CO₂ T&S LCOE component composes 4–6 percent of the total LCOE in all capture cases.

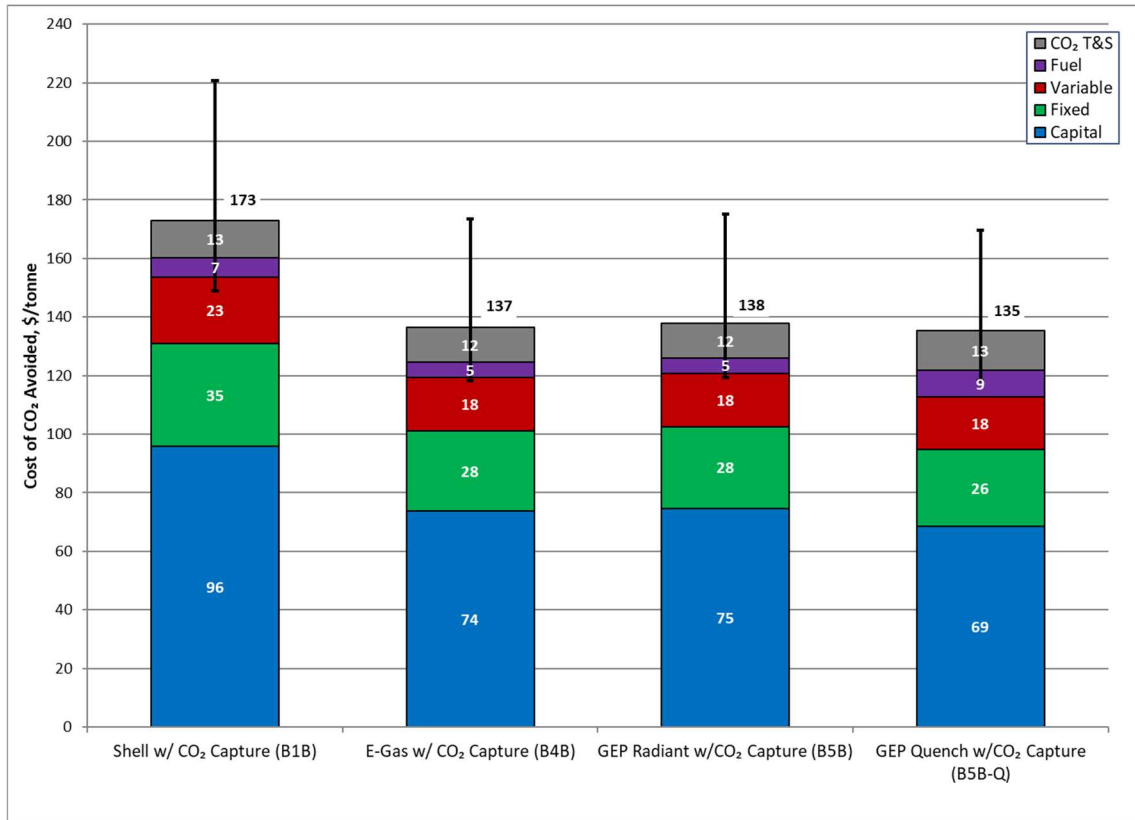
As presented in Section 2.7.4, the cost of CO₂ captured and avoided were calculated and the results for the CO₂ capture cases—using SC PC as the non-capture reference case (Case B12A, as presented in Section 4.2.11)ⁱ—are shown in Exhibit 3-142 and Exhibit 3-143. The cost of CO₂ capture represents the minimum CO₂ plant gate sales price that will incentivize carbon capture in lieu of a defined reference non-capture plant.

Exhibit 3-142. Breakdown of Cost of CO₂ Captured for IGCC cases



ⁱ Case B12A has a LCOE of \$64.3/MWh, a CO₂ emission rate of 1,628 lb/MWh-gross, a gross plant output of 686 MW, and a net plant output of 650 MW.

Exhibit 3-143. Breakdown of Cost of CO₂ Avoided for IGCC cases



The cost of CO₂ captured using SC PC as the non-capture reference case averages \$107/tonne (\$98/ton) with a range of \$91–128/tonne (\$82–116/ton). The cost of CO₂ avoided averages \$146/tonne (\$132/ton) with a range of \$135–176/tonne (\$122–157/ton).

PULVERIZED COAL RANKINE CYCLE PLANTS

4 PULVERIZED COAL RANKINE CYCLE PLANTS

Six PC-fired Rankine cycle power plant configurations were evaluated, and the results are presented in this section. Each design is based on a market-ready technology that is assumed to be commercially available at the time the project commences. All designs employ a one-on-one configuration comprising a state-of-the art PC steam generator firing Illinois No. 6 coal and a steam turbine.

The PC cases are evaluated with and without CO₂ capture on a common 650 MWe net basis. The designs that include CO₂ capture have a larger gross unit size to compensate for the higher auxiliary loads. The constant net output sizing basis is selected because it provides for a meaningful side-by-side comparison of the results. The boiler and steam turbine industry's ability to match unit size to a custom specification has been commercially demonstrated, enabling common net output comparison of the PC cases in this report.

Steam conditions for the Rankine cycle cases were selected based on a survey of boiler and steam turbine original equipment manufacturers (OEM), who were asked for the most advanced steam conditions that they would guarantee for a commercial project in the United States with SubC and SC PC units at a nominal rating and firing Illinois No. 6 coal. [113] Based on the OEM responses, the following single-reheat steam conditions were selected for the study:

- For SubC cases (B11A, B11B.90, and B11B.95) – 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F)
- For SC cases (B12A, B12B.90, and B12B.95) – 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F)

Steam temperature selection for boilers depends upon fuel corrosiveness. Most of the contacted OEMs believed the steam conditions above this range would be limited to low sulfur coal applications (such as Powder River Basin [PRB] coal). Their primary concern is that elevated temperature operation while firing high sulfur coal (such as Illinois No. 6) would result in an exponential increase of the material wastage rates of the highest temperature portions of the superheater and RH due to coal ash corrosion, requiring pressure parts replacement outages approximately every 10 or 15 years. This cost would offset the value of fuel savings and emissions reduction due to the higher efficiency. In addition, three of the most recently built SC units in North America have steam cycles similar to this report's design basis, namely James E. Rogers Energy Complex in North Carolina, which started operations in 2012 (27.0 MPa/568°C/579°C [3,922 psia/1,055°F/1,075°F]) and Prairie State Energy Campus units 1 and 2, which also started operation in 2012 (26.2 MPa/568°C/568°C [3,800 psig/1,055°F/1,055°F]).

The evaluation basis details, including site ambient conditions, fuel composition and the emissions control basis, are provided in Section 2 of this report.

4.1 PC COMMON PROCESS AREAS

The PC cases have process areas that are common to each plant configuration, such as coal receiving and storage, emissions control technologies, power generation, etc. As detailed descriptions of these process areas in each case section would be burdensome and repetitious, they are presented in this section for general background information. The performance features of these sections are then presented in the case-specific sections.

4.1.1 Coal, Activated Carbon, and Sorbent Receiving and Storage

The function of the Coal Receiving and Storage system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to and including the slide gate valves at the outlet of the coal storage silos. The system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation of 90 days or more at the maximum continuous rating (MCR).

The scope of the sorbent receiving and storage system includes truck roadways, turnarounds, unloading hoppers, conveyors, and day storage bins.

Operation Description – The coal is delivered to the site by 100-car unit trains comprising 91 tonne (100 ton) rail cars. The unloading is done by a trestle bottom dumper, which unloads the coal into two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 8 cm x 0 (3" x 0) coal from the feeder is discharged onto a belt conveyor. Two conveyors with an intermediate transfer tower are assumed to convey the coal to the coal stacker, which transfer the coal to either the long-term storage pile or to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor, which transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3 cm x 0 (1.25" x 0) by the coal crushers. The coal is then transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to the tripper that loads the coal into one of the six boiler silos.

Limestone is delivered to the site using 23 tonne (25 ton) trucks. The trucks empty into a below grade hopper where a feeder transfers the limestone to a conveyor for delivery to the storage pile. Limestone from the storage pile is transferred to a reclaim hopper and conveyed to a day bin.

Brominated powdered activated carbon (PAC) is delivered to the site in 9 tonne (10 ton) batches by self-unloading pneumatic trucks. The carbon is unloaded from the truck via an on-board compressor into the dry, welded-steel storage silo where the displaced air is vented through a silo vent filter. The carbon level in the silo is measured by system instrumentation.^j

^j The description of PAC and hydrated lime unloading were sourced from a quote provided by United Conveyor Corporation (UCC) to NETL, unless otherwise noted. The information relates to a mercury control system designed by UCC.

Hydrated lime is delivered and distributed in a manner very similar to that of the PAC. The hydrated lime is delivered in 11 tonne (12.5 ton) batches.^j More comprehensive descriptions of the hydrated lime and PAC systems are provided in sections 4.1.6.1 and 4.1.6.2, respectively.

4.1.2 Steam Generator and Ancillaries

The steam generator for the SubC PC plants is a drum-type, wall-fired, balanced draft, natural circulation, totally enclosed dry bottom furnace, with superheater, reheater, economizer and air preheater.

The steam generator for the SC plants is a once-through, spiral-wound, Benson-boiler, wall-fired, balanced draft type unit with a water-cooled dry bottom furnace. It includes a superheater, reheater, economizer, and air preheater.

The combustion systems for both SubC and SC steam conditions are equipped with LNBs and OFA. It is assumed for the purposes of this report that the power plant is designed for operation as a base-load unit but with some consideration for daily or weekly cycling.

4.1.2.1 Scope

The steam generator includes the following for both SubC and SC PCs, except where otherwise indicated:

- | | | |
|--|------------------------------------|--|
| • PC Combustor | • Three-stage superheater | • Low NO _x Coal burners and natural gas igniters/warm-up system |
| • Drum-type evaporator (SubC only) | • RH | • OFA system |
| • Once-through type steam generator (SC only) | • Economizer | • Forced draft (FD) fans |
| • Startup circuit, including integral separators (SC only) | • Spray type desuperheater | • Primary air (PA) fans |
| • Water cooled furnace, dry bottom | • Soot blower system | • Induced draft (ID) fans |
| | • Air preheaters (Ljungstrom type) | |
| | • Coal feeders and pulverizers | |

The following subsections describe the operation of the steam generator.

4.1.2.2 Feedwater and Steam

4.1.2.2.1 Feedwater

The function of the FW system is to pump the FW from the deaerator storage tank through the HP FW heaters to the economizer. One turbine-driven BFW pump sized at 100 percent capacity

is provided to pump FW through the HP FW heaters. One 25 percent motor driven BFW pump is provided for startup. The pumps are provided with inlet and outlet isolation valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by automatic recirculation valves, which are a combination check valve in the main line and in the bypass, bypass control valve, and flow sensing element. The suction of the boiler feed pump is equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each HP FW heater is provided with inlet/outlet isolation valves and a full capacity bypass. FW heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Pneumatic level control valves control normal drain level in the heaters. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

The deaerator is a horizontal, spray tray type with internal direct contact stainless steel (SS) vent condenser and storage tank.

The boiler feed pump turbine is driven by main steam up to 60 percent plant load. Above 60 percent load, extraction from the IP turbine exhaust provides steam to the boiler feed pump steam turbine.

4.1.2.2.2 Steam Generation

For the SubC steam system, FW enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the boiler drum, from where it is distributed to the water wall circuits enclosing the furnace. After passing through the lower and upper furnace circuits and steam drum in sequence, the steam passes through the convection enclosure circuits to the primary superheater and then to the secondary superheater.

The steam then exits the steam generator en route to the HP turbine. Steam from the HP turbine returns to the steam generator as cold reheat and returns to the IP turbine as hot reheat.

For the SC steam system, FW enters the bottom header of the economizer and passes upward through the economizer tube bank, through stringer tubes, which support the primary superheater, and discharges to the economizer outlet headers. From the outlet headers, water flows to the furnace hopper inlet headers via external downcomers. Water then flows upward through the furnace hopper and furnace wall tubes. From the furnace, water flows to the steam water separator. During low load operation (operation below the Benson point), the water from the separator is returned to the economizer inlet with the boiler recirculating pump. Operation at loads above the Benson point is once through.

Steam flows from the separator through the furnace roof to the convection pass enclosure walls, primary superheater, through the first stage of water attemperation, to the furnace platens. From the platens, the steam flows through the second stage of attemperation and then to the intermediate superheater. The steam then flows to the final superheater and on to

the outlet pipe terminal. Two stages of spray attemperation are used to provide tight temperature control in all high temperature sections during rapid load changes.

Steam returning from the turbine passes through the primary reheater surface, then through crossover piping containing inter-stage attemperation. The crossover piping feeds the steam to the final reheater banks and then out to the turbine. Inter-stage attemperation is used to provide outlet temperature control during load changes.

4.1.2.2.3 Main and Reheat Steam

The main steam system conveys high pressure (HP) steam, which exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve, to the HP turbine stop valves via a single line. The HP turbine receives HP steam from the steam generator, and the exhaust is routed back to the reheater in the steam generator. The reheater system conveys cold reheat steam from the HP turbine exhaust, through a motor-operated isolation gate valve and a flow control valve and enters the boiler reheater. The reheater system then conveys hot reheat steam exiting the boiler reheater outlet, through a motor-operated gate valve, to the IP turbine stop valves. The IP turbine exhaust is routed to the LP turbine where final steam expansion occurs before it is exhausted to a condenser. Along the steam turbine path, steam is extracted for feedwater and deaerator heating to improve Rankine cycle efficiency.

4.1.2.2.4 Condensate

The function of the condensate system is to pump condensate from the condenser hotwell through the LP FW heaters to the deaerator. Each system consists of one main condenser; two variable speed electric motor-driven vertical condensate pumps each sized for 50 percent capacity; four LP heaters (three in cases B12B.90 and B12B.95); and one deaerator with storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided downstream of the gland steam condenser to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

LP FW heaters 1 through 4 are 50 percent capacity, parallel flow, and are in the condenser neck. All remaining FW heaters are 100 percent capacity, shell and U-tube HXs. Each LP FW heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP FW heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Pneumatic level control valves control normal drain levels in the heaters. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Pneumatic level control valves control dump line flow.

While the SubC PC capture cases return all process extraction steam (CO₂ capture and drying requirements) condensate to the deaerator, the SC PC capture cases require this condensate to be returned after the condenser upstream of the condensate polisher. This is required because the SC cases do not have a blowdown stream. If the condensate was returned to the deaerator, there would be a buildup of contaminants. An impact of this design is that the SC capture cases

(B12B.90 and B12B.95) requires only three LP FW heaters rather than four, as the condensate return increases the FW temperature above that which would be exiting the first LP FW heater.

To account for any losses, makeup water is supplied to the condenser. The makeup water provides high-quality demineralized water for makeup to the steam cycle. The demineralizer is sized based on the requirements of the startup boiler.

4.1.2.2.5 Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From HP turbine extraction to heater 7 (and 8 in SC cases)
- From IP turbine extraction to heater 6 and the deaerator (heater 5)
- From LP turbine extraction to heaters 1, 2, 3, and 4

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disc, non-return valves located in all extraction lines except the lines to the LP FW heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

4.1.2.3 Air and Combustion Products

Combustion air from the FD fans is heated in Ljungstrom type air preheaters, recovering heat energy from the exhaust gases exiting the boiler. This air is distributed to the burner windbox as secondary air. Air for conveying PC to the burners is supplied by the PA fans. This air is heated in the Ljungstrom type air preheaters to permit drying of the PC, and a portion of the air from the PA fans bypasses the air preheaters to be used for regulating the outlet coal/air temperature leaving the mills.

The PC and air mixture flows to the coal nozzles at various elevations of the furnace. The hot combustion products rise to the top of the boiler and pass through the superheater, reheater, economizer, SCR, and air preheater. The gases exit the steam generator at this point and flow to the DSI manifold, ACI manifold, fabric filter, ID fan, FGD system, and stack or CDR system.

4.1.2.4 Fuel Feed

The crushed Illinois No. 6 bituminous coal is fed through feeders to each of the mills (pulverizers), where its size is reduced to approximately 72 percent passing 200 mesh and less than 0.5 percent remaining on 50 mesh. [114] The PC exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls using air supplied by the PA fans.

4.1.2.5 Ash Removal

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. Each hopper incorporates a dry seal trough and is of welded steel construction, lined with refractory and block insulation for personnel safety and heat retention. Each hopper is paired with a pneumatic bottom ash transport line and is fully isolatable, with shutoffs downstream of the screw feeder and upstream of the clinker grinder, for ease of maintenance. The description of the balance of the bottom ash handling system is presented in Section 4.1.11.

The steam generator incorporates fly ash hoppers under the economizer outlet and air preheater outlet.

4.1.2.6 Burners

A boiler of this capacity employs approximately 24 to 36 coal nozzles arranged at multiple elevations. Each burner is designed as a low-NO_x configuration, with staging of the coal combustion to minimize NO_x formation. In addition, OFA nozzles are provided to further stage combustion and thereby minimize NO_x formation.

Natural gas-fired pilot torches are provided for each coal burner for ignition, warm-up and flame stabilization at startup and low loads.

4.1.2.7 Dry Sorbent Injection

The hydrated lime injection manifold is located directly before the air preheaters. This SO₃ control system is discussed in detail in Section 4.1.6.

4.1.2.8 Air Preheaters

Each steam generator is furnished with two vertical-shaft Ljungstrom regenerative type air preheaters. These units are driven by electric motors through gear reducers.

4.1.2.9 Soot Blowers

The soot-blowing system utilizes an array of 50 to 150 retractable nozzles and lances that clean the furnace walls and convection surfaces with jets of HP steam. The blowers are sequenced to provide an effective cleaning cycle depending on the coal quality and design of the furnace and convection surfaces. Electric motors drive the soot blowers through their cycles.

4.1.3 NO_x Control System

The plants are designed to achieve the environmental target of 0.70 lb/MWh-gross. Two measures are taken to reduce the NO_x. The first is a combination of LNBs and the introduction of staged OFA in the boiler. The LNBs and OFA reduce the boiler emissions to about 0.15 kg/GJ (0.35 lb/MMBtu). This boiler NO_x production rate is equivalent to production rates of 2.8 – 3.4 lb/MWh-gross across the six PC cases considered.

The second measure taken to reduce the NO_x emissions is the installation of an SCR system prior to the air heater. SCR uses NH₃ and a catalyst to reduce NO_x to N₂ and H₂O. The SCR system consists of three subsystems: reactor vessel, NH₃ storage and injection, and gas flow

control. The SCR system is designed for 75–79 percent reduction with 2 ppmv NH_3 slip at the end of the catalyst life.

The SCR capital costs are reported separately from the boiler costs; the cost for the initial load of catalyst is broken out separately in the O&M cost table.

Selective non-catalytic reduction (SNCR) was considered for this application. However, with the installation of the LNBs and OFA system, the boiler exhaust gas contains relatively small amounts of NO_x , which makes removal of the quantity of NO_x with SNCR to reach the emissions limit difficult. SNCR works better in applications that contain medium to high quantities of NO_x and require removal efficiencies in the range of 40–60 percent. Because of the catalyst used, SCR can achieve higher efficiencies with lower concentrations of NO_x .

4.1.3.1 SCR Operation Description

The reactor vessel is designed to allow proper retention time for the NH_3 to contact the NO_x in the boiler exhaust gas, which flows down vertically through multiple catalyst layers. Flow distribution through the catalyst is important to help limit accumulation of ash in the catalyst. Sonic horns are used to help mitigate accumulation of ash on the catalyst.

NH_3 is mixed with dilution air before injection, and the mixture is injected into the gas path immediately prior to entering the reactor vessel, which is located between the economizer outlet and the air preheater inlet. The NH_3 injection grid is arranged into several sections and consists of multiple pipes with nozzles. The NH_3 flow rate into each injection grid section is controlled considering imbalances in the flue gas flow distribution.

The catalyst contained in the reactor vessel enhances the reaction between the NH_3 and the NO_x in the gas. The catalyst consists of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. Catalysts in flue gases with high SO_2 levels are designed with inhibitors to reduce the conversion of SO_2 to SO_3 . While the optimum inlet flue gas temperature range for the catalyst is 260°C (500°F) to 371°C (700°F), the typical operating range for vanadium/titanium-based catalysts in PC applications is 302°C (575°F) to 427°C (800°F), depending on the sulfur level of the coal, with higher sulfur coals requiring higher temperatures to prevent the formation of ammonium bisulfate in the catalyst. The boiler is equipped with an economizer bypass to provide flue gas to the reactors at the desired temperature during periods of low flow rate, such as low load operation. Also included with the reactor vessel is soot-blowing equipment used for cleaning the catalyst.

The NH_3 storage and injection system consists of the unloading facilities, bulk storage tank, vaporizers, dilution air skid, and injection grid.

The flue gas flow control consists of ductwork, dampers, and flow straightening devices required to route the boiler exhaust to the SCR reactor and then to the air heater. The economizer bypass and associated dampers for low load temperature control are also included.

4.1.4 Activated Carbon Injection

The PAC injection manifold is located directly before the baghouse. [115] This system will be discussed in detail in Section 4.1.6.

4.1.5 Particulate Control

The fabric filter (or baghouse) consists of two separate single-stage, in-line, multi-compartment units. Each unit is of high (0.9–1.5 m/min [3–5 ft/min]) air-to-cloth ratio design with a pulse-jet on-line cleaning system. The ash is collected on the outside of the bags, which are supported by steel cages. The dust cake is removed by a pulse of compressed air. Flue gas exits the baghouse and enters the induced draft (ID) fan suction.

The bag material is polyphenylensulfide with intrinsic Teflon Polytetrafluoroethylene coating. [116] The bags are rated for a continuous temperature of 180°C (356°F) and a peak temperature of 210°C (410°F). The baghouse is provided with an n+1 design, so a compartment can be taken offline for maintenance while maintaining particulate emission targets. Each compartment contains a number of gas passages with filter bags, and heated ash hoppers supported by a rigid steel casing. The fabric filter is provided with necessary control devices, inlet gas distribution devices, insulators, inlet and outlet nozzles, expansion joints, and other items as required.

The use of ACI and DSI increases the calcium content of the fly ash and adds an additional burden to the fabric filter. The addition of calcium is not expected to increase the leaching of trace metals from the fly ash significantly. The ACI and DSI systems increase the total amount of PM by approximately 17 percent.

Fly ash from bituminous-fired plants (Class F fly ash) is sometimes sold for use as filler material in concrete mixtures. The use of Class F fly ash for concrete manufacture is not as common as the use of Class C fly ash (from high-calcium-containing coals); the latter is more valuable as a replacement for Portland cement in concrete mixtures. Class F fly ash must have a low unburned carbon content to be used in cement mixtures. The inclusion of activated carbon and hydrated lime (or, rather, the calcium sulfate [CaSO₄] reaction product) will render the fly ash unsuitable for use in concrete mixtures.

4.1.6 Mercury Removal^k

Mercury removal is partially achieved through flue gas reactions between mercury and available halogens and carbon.

The fraction of chlorine, and other halogens in the coal, impacts the amount of mercury oxidized in the SCR and air preheater. As oxidized mercury is removed by the fabric filter and wet FGD, the chlorine content of the coal can have a significant impact on the mercury removal rate of the plant. Data presented by Reaction Engineering International suggest that as coal chlorine concentrations increase, up to 500 ppmwd, the fraction of oxidized mercury increases rapidly. However, the rate of mercury oxidation diminishes at chlorine concentrations above 500 ppmwd. [117]

^kMuch of the text, descriptions, and images within this section were sourced, with permission, from a quote provided by UCC to NETL, unless otherwise noted. The information relates to a mercury control system designed by UCC. The quote also provided all images credited to them.

The rate of mercury oxidation is also affected by the NH_3 concentration. Since the SCR is operated more aggressively for NO_x control, the NH_3 levels increase and the fraction of oxidized mercury decreases. [118]

In this study, it is assumed that 0.6 percent of the coal carbon is unreacted in the PC boiler. [79] This unburned carbon both promotes mercury oxidation and adsorbs mercury on the surface of the fabric filter. The unburned carbon, combined with the HCl in the flue gas, is sufficient to promote high levels of oxidized mercury and overall Hg removal in the plant. [119]

Depending on the chemistry in the wet FGD, a portion of the oxidized mercury that is captured by the scrubber could be reduced to elemental mercury and re-emitted. By minimizing the amount of mercury entering the wet FGD, and through careful operation of the scrubber, the risk of periodic spikes in mercury re-emissions can be minimized.

Wet FGD parameters such as oxidation reduction potential of the scrubber slurry, halogen concentration in the scrubber slurry, the form of Hg in the slurry (i.e., liquid or solid), and the effect of sulfite concentration were examined by Babcock & Wilcox Enterprises Inc. for their impact on mercury re-emissions. It was concluded that sulfite concentration in the slurry was the most cost-effective parameter that can be controlled as a strategy to minimize mercury re-emission. [120]

Without mitigation, the concentration of SO_3 in the flue gas is estimated to be 59 ppmvd at the air preheater inlet. This elevated SO_3 concentration is the result of combusting a relatively high sulfur coal (2.82 wt%) and from oxidation of SO_2 across the SCR catalyst.

The presence of SO_3 significantly inhibits Hg adsorption, as SO_3 is preferentially adsorbed onto carbon. This effect was demonstrated in a testing program conducted at the Mercury Research Center using an electrostatic precipitator (ESP)-configured system with an ACI rate of 10 lb/MMacf upstream of the air preheater at 300°F, which showed that at SO_3 levels above 20 ppm, less than 50 percent mercury removal was achieved (at SO_3 levels above 10 and 3 ppm, less than 70 and 80 percent mercury removal was achieved, respectively). [121] Therefore, DSI is included in the PC plant designs to reduce the SO_3 levels to approximately 5 ppmvd at the air preheater inlet, as discussed in Section 4.1.6.1.

EPA used a statistical method to calculate the Hg co-benefit capture from units using a “best demonstrated technology” approach, which for bituminous coals was considered to be a combination of a fabric filter and an FGD system. The statistical analysis resulted in a co-benefit capture estimate of 86.7 percent with an efficiency range of 83.8 to 98.8 percent. [122] EPA’s documentation for their Integrated Planning Model (IPM) provides mercury emission modification factors (EMF) based on 190 combinations of boiler types and control technologies. The EMF is simply one minus the removal efficiency.

For PC boilers (as opposed to cyclones, stokers, fluidized beds, and ‘others’) with a fabric filter, SCR and wet FGD, the EMF is 0.1, which corresponds to a removal efficiency of 90 percent; [123] the average reduction in total Hg emissions developed from EPA’s Information Collection Request (ICR) data on U.S. coal-fired boilers using bituminous coal, fabric filters, and wet FGD is 98 percent. [124] The referenced sources bound the co-benefit Hg capture for bituminous coal units employing SCR, a fabric filter, and a wet FGD system between 83.8 and 98 percent. It was

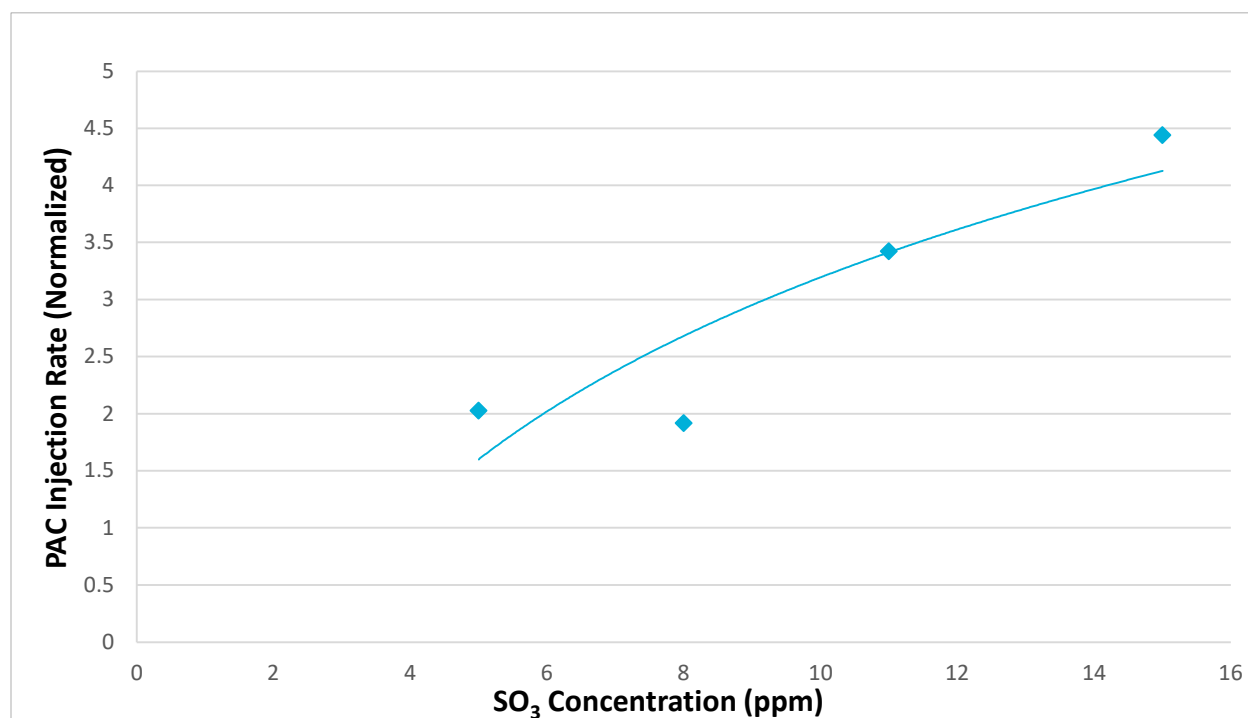
assumed that the co-benefit potential of the equipment utilized in the PC cases of this report is 90 percent, as it is near the mid-point of the previously mentioned range, and it also matches the value used by EPA in their IPM.

The Hg removal rate required to comply with the Hg emission limit (Section 2.4.3.2) is calculated to be approximately 97–98 percent. Therefore, the potential co-benefit Hg capture rate (90 percent) of the systems utilized in the PC cases is not sufficient to achieve compliance with applicable regulations. A cost and performance estimate was obtained from United Conveyor Corporation (UCC), which applies ACI and DSI to increase the overall Hg removal rate in the plant.

4.1.6.1 Dry Sorbent Injection

Exhibit 4-1 provides data from a full-scale DSI/ACI test conducted by UCC on a midwestern coal-fired unit, which demonstrates the impact of SO_3 concentration (at the PAC injection point) on the PAC injection rate required to achieve a given Hg removal rate. The exhibit and data contained were supplied by UCC in the quote provided to NETL.

Exhibit 4-1. Effect of SO_3 concentration on PAC injection rate



As shown in Exhibit 4-1, higher SO_3 concentrations in the flue gas require significantly greater injection rates of PAC. Therefore, the DSI system considered in this report, with enhanced hydrated lime as the sorbent, targets an SO_3 concentration of 5 ppmvd at the air preheater inlet, with an SO_3 concentration of 2 ppmvd at the outlet of the fabric filter.

As the flue gas temperature must be maintained above the acid dew point temperature in the air preheater, locating the DSI injection point upstream of the air preheater allows for a lower

operating temperature (289°F air preheater temperature with DSI upstream of the air preheater versus 337°F air preheater temperature with no DSI or DSI downstream of the air preheater) and higher overall plant efficiency, compared to a plant with no DSI or DSI downstream of the air preheater. Additionally, the reduction in operating temperature increases the Hg removal efficiency of carbon.

Since standard hydrated lime sorbents generally cannot achieve SO_3 removal rates greater than approximately 90 percent, the high level of SO_3 reduction required necessitates the use of an enhanced hydrated lime product to achieve the necessary Hg removal rate.

While DSI is included specifically to remove SO_3 from the flue gas, the enhanced hydrated lime also removes SO_2 and HCl, as shown in Exhibit 4-2. The rates shown are the total removal at the fabric filter outlet/FGD inlet, not the air preheater inlet.

Exhibit 4-2. Pollutant removal efficiency versus hydrated lime injection rate

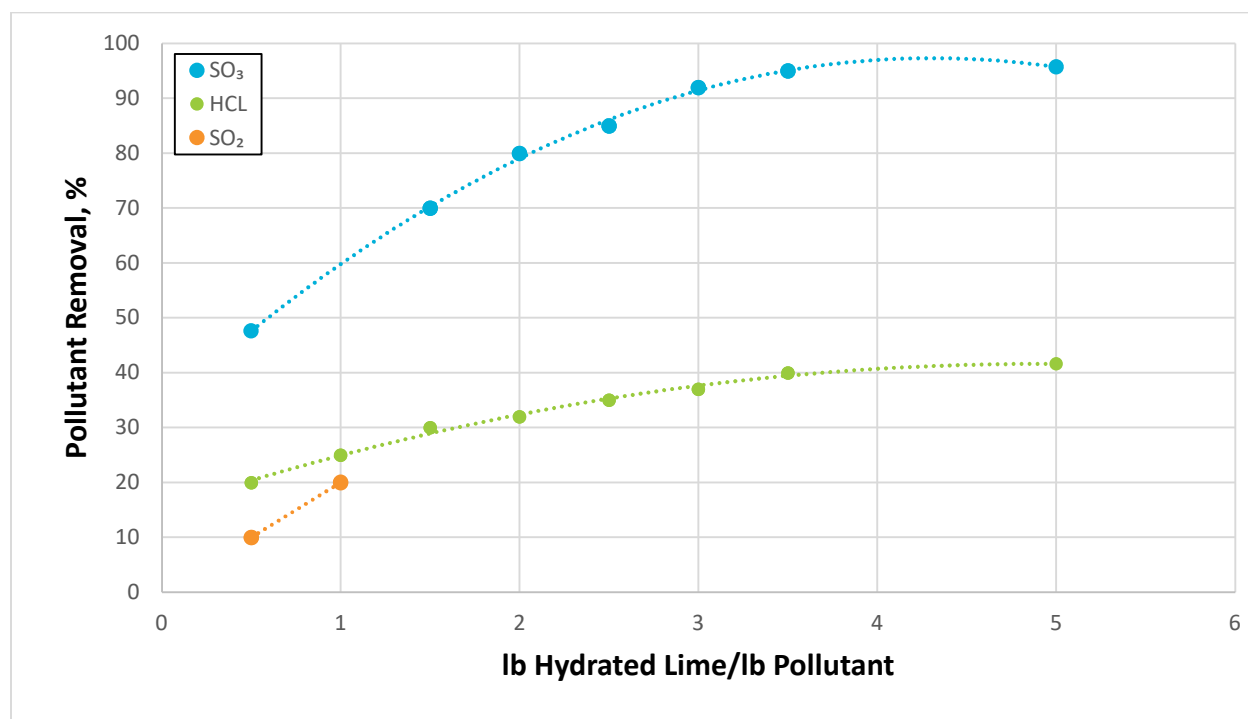


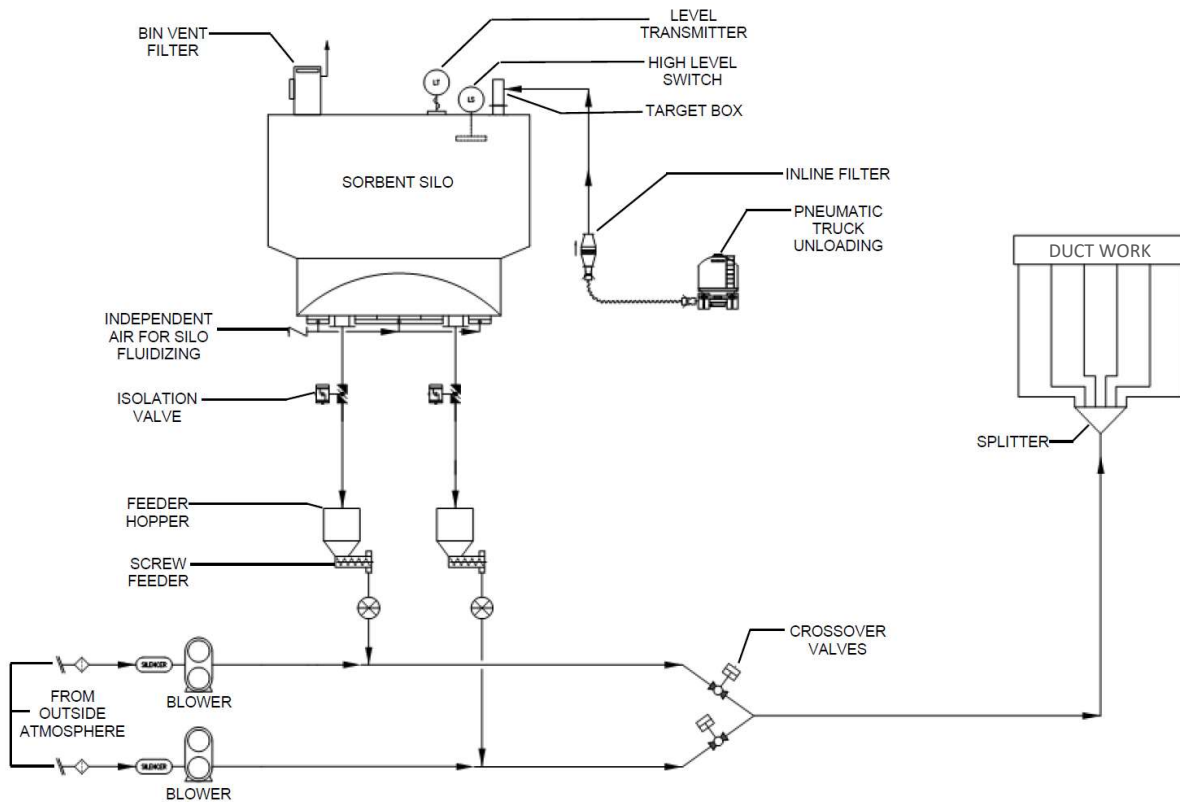
Exhibit 4-2 illustrates that approximately 3.5 lb of enhanced hydrated lime/lb of SO_3 is required to reduce the SO_3 concentration to 2 ppmvd at the outlet of the fabric filter (approximately 96.6 percent removal rate). At this injection rate, the enhanced hydrated lime is expected to also remove approximately 40 percent of HCl. The expected SO_2 reduction is very low, since SO_2 is a much weaker acid gas than SO_3 and HCl. In addition, the baseline SO_2 levels are far higher than either the SO_3 or HCl levels.

Operation Description – As shown in Exhibit 4-3, the DSI system is based on dilute-phase, pneumatic conveying of hydrated lime at a metered rate from a bulk storage silo to the flue gas ductwork where it mixes with the flue gas and reacts with the SO_3 to form CaSO_4 , which is captured in the fabric filter.

The sorbent is typically delivered in 11,340-kg (25,000-lb) batches by self-unloading pneumatic trucks equipped with manually operated discharge valves. The sorbent is unloaded from the truck via an on-board compressor into the dry, welded-steel storage silo where the displaced air is vented through a silo vent filter. The sorbent level in the silo is measured by system instrumentation.

Silos are typically 14-ft diameter with skirt support, made of CS and are designed to be shipped in one piece. Storage silos are often aerated with dry air through a fluidizing system to ensure reliable feeding. Silos usually have two or more outlets and are equipped with weigh hoppers to provide loss-in-weight (LIW) monitoring and feed control.

Exhibit 4-3. Typical DSI injection process flow diagram



Used with permission from UCC

The silo roof equipment includes a bin vent filter, relief valve, and level transmitters. The bin vent filter is enabled when the unloading system is started to filter this airflow and vent it to the atmosphere.

Compressed air is delivered to the fluidizing stones located in the chisel bottom of the silo. The fluidizing of the material in conjunction with the 60-degree silo cone promotes mass flow of the sorbent out of the silo.

The fluidized sorbent is then transferred from the silo by a rotary valve into the feeder hopper where it is temporarily stored until conveyed by the screw feeder into the intake tee. The speed

of the screw feeder determines the feed rate into the intake tee. Sorbent is fed through the intake tee directly into the conveying air stream.

Material fed from the storage silo typically discharges into one conveying line. The discharge of material is aided by the silo fluidizing system. Each silo discharge line has a CS weigh hopper equipped with load cells. The weigh hopper is vented via a small bin vent filter located on the weigh hopper. The material is metered from the weigh hopper using a variable speed rotary vane feeder.

The silo fluidizing system promotes constant fluid flow to the silo outlet by introducing air through a porous media. Cloth media is in trays on the silo floor and around the outlets. The pressure blower provides an air stream for conveying sorbent from the storage silo to a splitter and lances for duct injection. Two 100-percent blowers are provided in a typical system for redundancy. Pressure blowers are on non-elevated common bases, and come complete with a v-belt motor, inlet filter, inlet and discharge silencers, discharge check valve, discharge relief valve, discharge pressure gauge, and pressure transmitter.

The conveying lines are mild steel and are provided with a combination of flange and groove-less Victaulic couplings. The conveying line after the splitter is made of a gum rubber material handling hose designed for abrasion resistance.

The DSI system is typically monitored and controlled by the DCS. The feed rate of the system can be adjusted in the following ways:

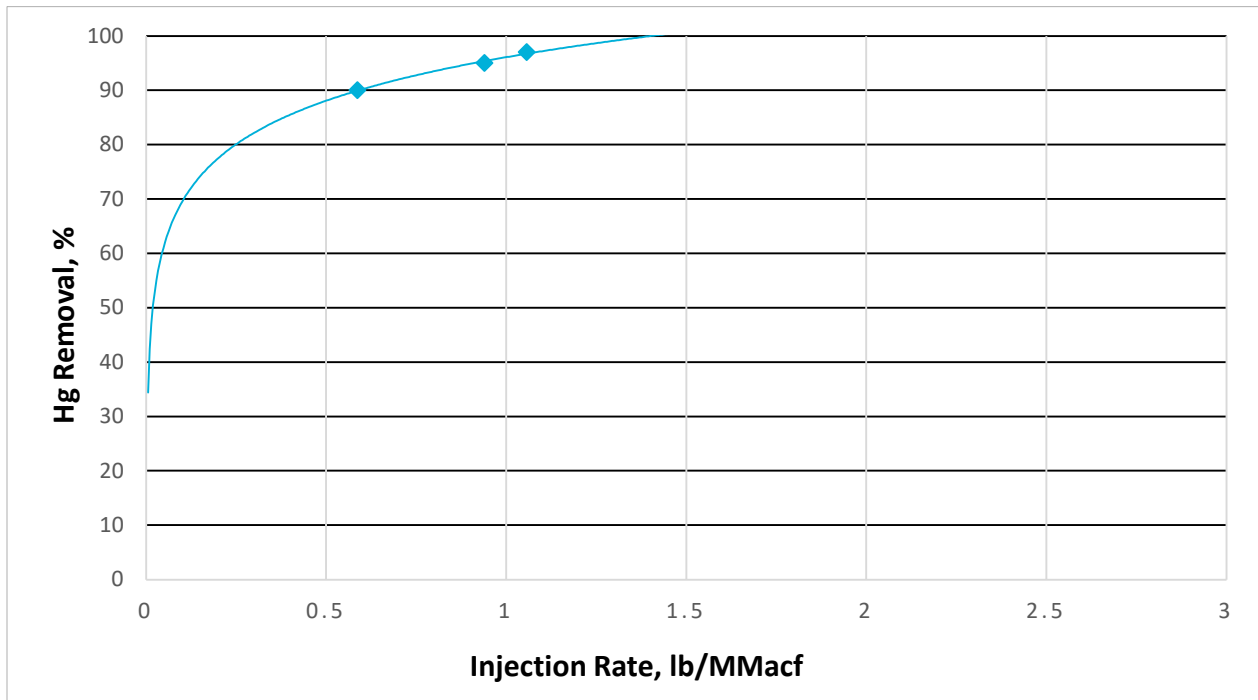
- Flat Rate (one continuous rate)
- Boiler Load Following (varies feed rate proportional to boiler load)
- Flue Gas Following (varies feed rate proportional to flue gas flow)

4.1.6.2 Activated Carbon Injection

By reducing the SO_3 with DSI (Section 4.1.6.1), most of the Hg will be oxidized in the SCR and removed in the fabric filter and wet FGD. Therefore, only a minimal amount of brominated PAC is injected upstream of the fabric filter to ensure the desired Hg emission rate is achieved.

Exhibit 4-4, provided by UCC, presents a typical performance curve for plants utilizing an SCR and a fabric filter firing bituminous coal. The points highlighted represent 90, 95, and 97 percent Hg removal.

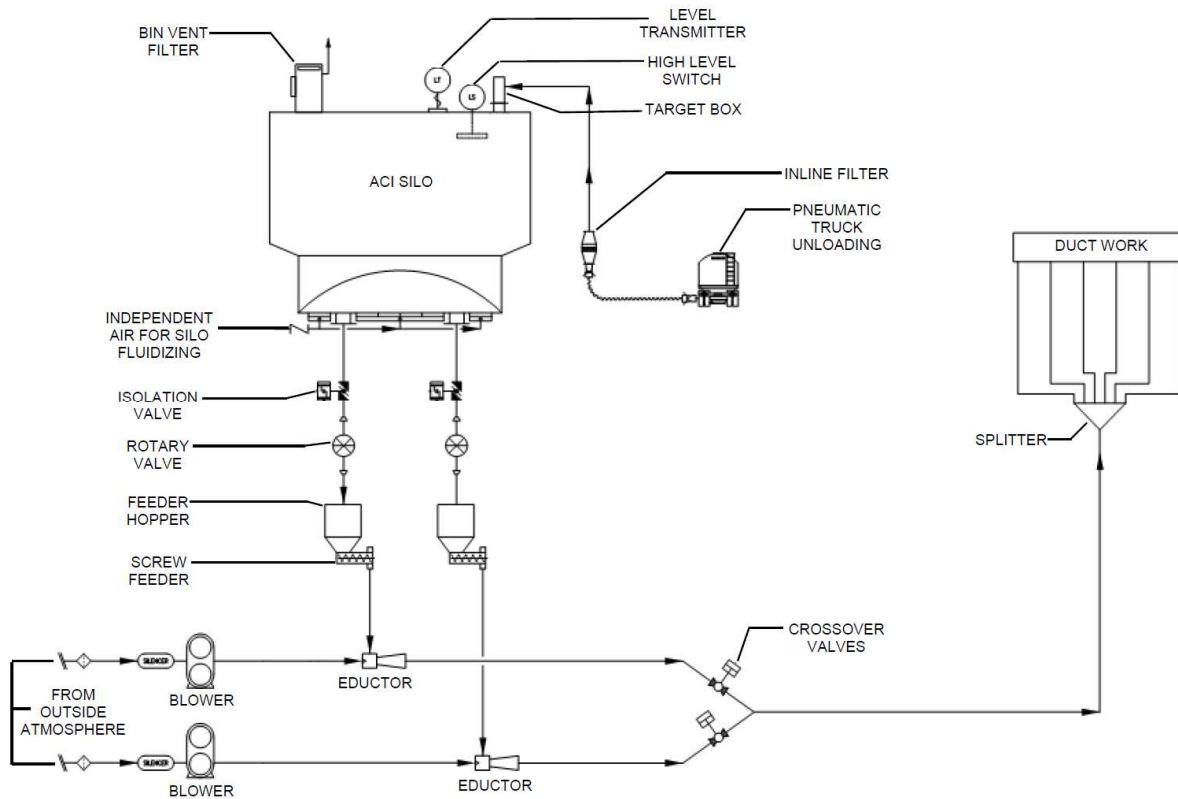
Exhibit 4-4. Mercury removal versus PAC injection rate for Case B12A



To meet the mercury emission limit, brominated PAC is injected at a rate of approximately 1.0 lb/MMacf in all PC cases.

Operation Description – As shown in Exhibit 4-5, the ACI system is based on dilute-phase, pneumatic conveying of activated carbon at a metered rate from a bulk storage silo to the flue gas ductwork where it mixes with the flue gas and absorbs Hg and SO₃, which is captured in the fabric filter.

Exhibit 4-5. Typical ACI injection process flow diagram



Used with permission from UCC

The activated carbon is typically delivered in 9,070-kg (20,000-lb) batches by self-unloading pneumatic trucks equipped with manually operated discharge valves. The carbon is unloaded from the truck via an on-board compressor into the dry, welded-steel storage silo where the displaced air is vented through a silo vent filter. The carbon level in the silo is measured by system instrumentation.

Silos are typically 14-ft diameter with skirt support, made of CS and are designed to be shipped in one piece. Storage silos are often aerated with dry air through a fluidizing system to ensure reliable feeding. Silos usually have two or more outlets and are equipped with weigh hoppers to provide LIW monitoring and feed control.

The silo roof equipment includes a bin vent filter, relief valve, and level transmitters. The bin vent filter is enabled when the unloading system is started to filter this airflow and vent it to the atmosphere.

Compressed air is delivered to the fluidizing stones located in the chisel bottom of the silo. The fluidizing of the material in conjunction with the 60-degree silo cone promotes mass flow of the sorbent out of the silo.

The fluidized carbon is then transferred from the silo by a rotary valve into the feeder hopper where it is temporarily stored until conveyed by the screw feeder into the drop tube. The speed

of the screw feeder determines the feed rate into the drop tube. Carbon is fed through the drop tube directly into the eductor suction port.

Motive air, provided by low-pressure blowers and fed into the eductors, produces a vacuum at the suction port. This helps draw the carbon and air into the mixing zone directly downstream of the eductor discharge. The carbon is transported through the piping system and is distributed to an array of injection lances specifically designed to disperse the carbon across the cross section of the flue gas ductwork.

Material fed from the storage silo typically discharges into one conveying line. The discharge of material is aided by the silo fluidizing system. Each silo discharge line has a CS weigh hopper equipped with load cells. The weigh hopper is vented via a small bin vent filter located on the weigh hopper. The material is metered from the weigh hopper using a screw feeder.

The silo fluidizing systems promotes constant fluid flow to the silo outlet by introducing air through a porous media. Cloth media is in trays on the silo floor and around the outlets.

The pressure blower provides an air stream for conveying carbon from the storage silo to a splitter and lances for duct injection. Two 100 percent blowers are provided in a typical system for redundancy. Pressure blowers are on non-elevated common bases, and come complete with a v-belt motor, inlet filter, inlet and discharge silencers, discharge check valve, discharge relief valve, discharge pressure gauge, and pressure transmitter.

The conveying lines are mild steel and are provided with a combination of flange and groove-less Victaulic couplings. The conveying line after the splitter is made of a gum rubber material handling hose designed for abrasion resistance.

The ACI system is typically monitored and controlled by the DCS. The feed rate of the system can be adjusted in the following ways:

- Flat Rate (one continuous rate)
- Boiler Load Following (varies feed rate proportional to boiler load)
- Flue Gas Following (varies feed rate proportional to flue gas flow)
- Mercury Emission Following (varies feed rate to keep the Hg emission concentration below a given set point)

4.1.7 Flue Gas Desulfurization

The FGD system is a wet limestone forced oxidation positive pressure absorber non-reheat unit, with wet-stack, and gypsum production. The function of the FGD system is to scrub the boiler exhaust gases to remove the SO₂ prior to release to the environment or entering the Carbon Dioxide Recovery (CDR) facility. Sulfur removal efficiency is 98 percent in the FGD unit for all cases. The CDR unit includes a polishing scrubber designed to reduce the flue gas SO₂ concentration from about 34 ppmv at the FGD exit to approximately 0.37 ppmv prior to the CDR absorber to minimize formation of amine HSS during the CO₂ absorption process. The FGD removal efficiency of HCl is 99 percent for all cases. To minimize the required capacity and cost

of specialized FGD wastewater treatment equipment, the FGD system is designed with materials capable of handling up to 20,000 ppm of chlorides.

While the PC cases of this study produce gypsum suitable for wallboard production, changes in coal or limestone characteristics or modifications to the wet FGD or dewatering system could impact the gypsum composition. Exhibit 4-6 provides the specification limits for gypsum used in wallboard and cement production, as well as typical characteristics of landfilled gypsum. The cases in this study do not consider a sale credit or a waste disposal cost for gypsum.

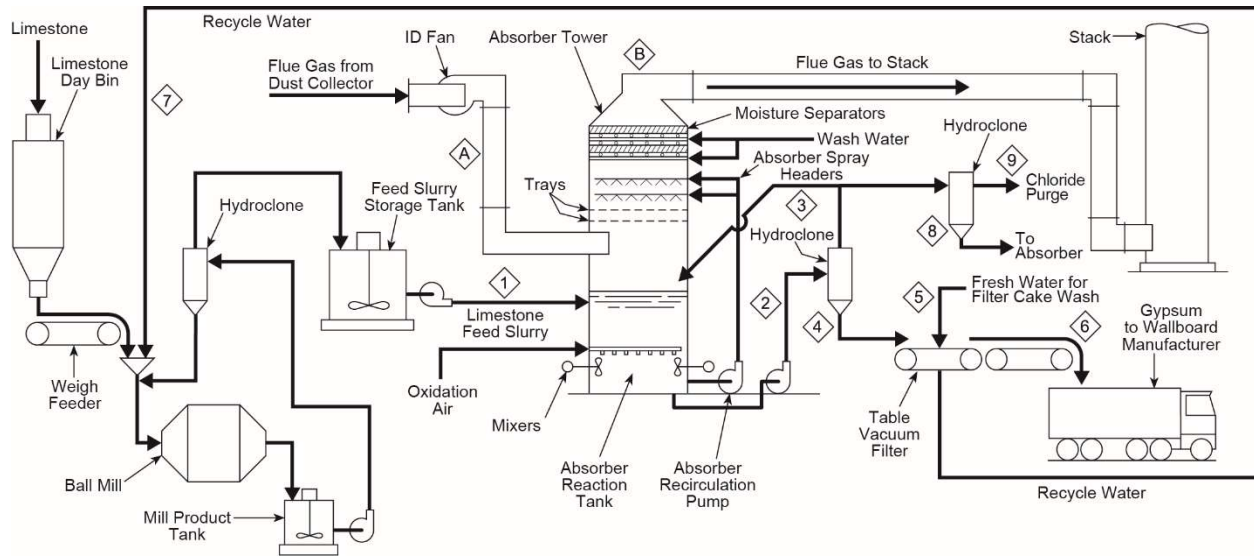
Exhibit 4-6. Typical disposal- and commercial-grade gypsum characteristics and limits

End Use	Disposal*	Wallboard	Cement
Moisture, % max	<20	<10	<14
CaSO ₄ •2H ₂ O, % min	80–95+	>95	85–88
CaSO ₃ •½H ₂ O, % max	<1–2+	0.5–1.0	
SiO ₂ , % max	<1–3+	1.0	2.0
Fe ₂ O ₃ , % max		1.5	1.0
Al ₂ O ₃ , % max			1.0
Fly ash, % max	<1–3+	1.0	
Total insolubles, % max	<5–20+	3.5	<15
Water soluble Cl ⁻ , ppm max	2,000–50,000	100–120	50,000
Total dissolved solids, ppm max	5,000–150,000	600	
Mean particle size, µm	<20–90+	20–75	

* Disposal gypsum characteristics are based on a range of potential limestone supplies

The scope of the FGD system is from the outlet of the ID fans to the stack inlet (Cases B11A and B12A) or to the CDR process inlet (cases B11B.90, B11B.95, B12B.90, and B12B.95). Exhibit 4-7 provides a process flow diagram of a typical wet limestone forced oxidation positive pressure absorber non-reheat FGD system. [79] The descriptions in Section 4.1.7.1 through Section 4.1.7.5 align with this diagram.

Exhibit 4-7. Wet flue gas desulfurization process flow diagram



Used with permission from Babcock & Wilcox

4.1.7.1 Limestone Handling and Reagent Preparation System

The function of the limestone reagent preparation system is to grind and slurry the limestone delivered to the plant. The scope of the system is from the day bin up to the limestone feed system. The system is designed to support continuous base load operation.

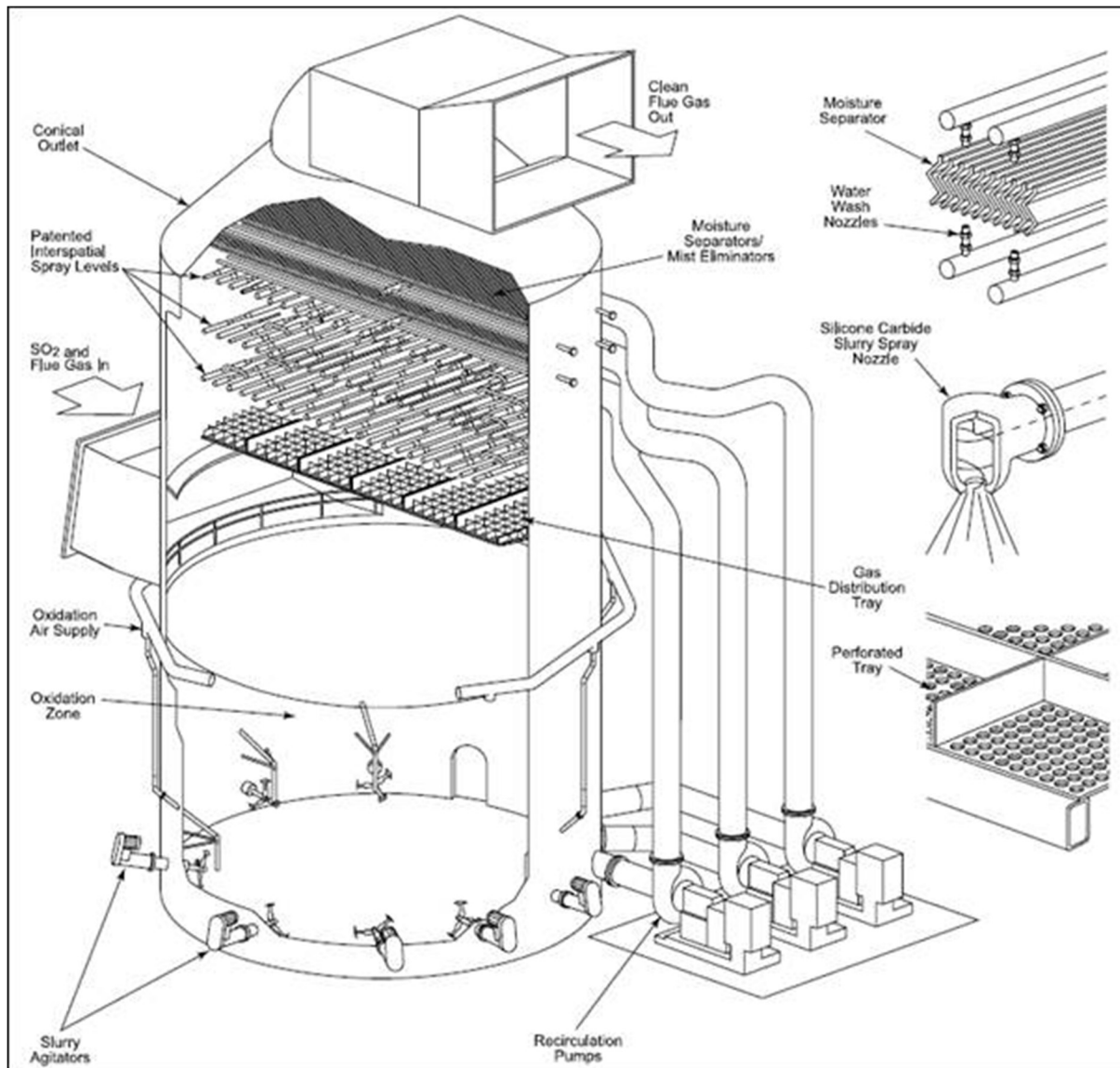
Operation Description – Each day bin supplies a 100 percent capacity ball mill via a weigh feeder. The wet ball mill accepts the limestone and grinds the limestone to 90 to 95 percent passing 325 mesh (44 microns). Water is added at the inlet to the ball mill to create limestone slurry. The reduced limestone slurry is then discharged into a mill product tank. Mill recycle pumps, two per tank, pump the limestone water slurry to an assembly of hydrocyclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

The hydrocyclone underflow with oversized limestone is directed back to the mill for further grinding. The hydrocyclone overflow with correctly sized limestone is routed to a feed slurry storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

4.1.7.2 FGD Absorber Tower

The description of the FGD absorber tower follows Exhibit 4-7. Additional detail for the absorber tower cross section is presented in Exhibit 4-8 for reference. [79]

Exhibit 4-8. Cross section of the wet FGD absorber tower



Used with permission from Babcock & Wilcox

Upon entering the bottom of the absorber tower, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through the spray zone, which provides enhanced contact between gas and reagent. Multiple spray elevations with header piping and nozzles maintain a consistent reagent concentration in the spray zone. Continuing upward, the reagent-laden gas passes through several levels of moisture separators. These consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating the entrained droplets of liquid by inertial effects. The scrubbed flue gas exits at the top of the absorber tower and is routed to the plant stack or CDR process.

The scrubbing slurry falls to the lower portion of the absorber tower, which contains a large inventory of liquid. Oxidation air is added to promote the oxidation of calcium sulfite contained in the slurry to calcium sulfate (gypsum). Multiple agitators (mixers) operate continuously to

prevent settling of solids and enhance mixture of the oxidation air and the slurry. Recirculation pumps recirculate the slurry from the lower portion of the absorber tower to the spray level. Spare recirculation pumps are provided to ensure availability of the absorber.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of byproduct solids via the bleed pumps (not labeled in Exhibit 4-7). A spare bleed pump is provided to ensure availability of the absorber. The byproduct solids are routed to the byproduct dewatering system. The circulating slurry is monitored for pH and density.

Scrubber bypass or reheat, which may be utilized at some older facilities to ensure the exhaust gas temperature is above the saturation temperature, is not employed in this reference plant design because new scrubbers have improved mist eliminator efficiency, and detailed flow modeling of the flue gas through the absorber enables the placement of gutters and drains to intercept moisture that may be present and convey it to a drain. Consequently, raising the exhaust gas temperature above the FGD discharge temperature of 57°C (135°F) is not necessary.

4.1.7.3 Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber tower modules. The dewatering process selected for this plant is gypsum dewatering producing wallboard grade gypsum. The scope of the system is from the bleed pump discharge connections to the gypsum storage pile.

Operation Description – The recirculating reagent in the FGD absorber tower accumulates dissolved and suspended solids on a continuous basis as byproducts from the SO₂ absorption process. Maintenance of the quality of the recirculating slurry requires that a portion be withdrawn and replaced by fresh reagent. This is accomplished on a continuous basis by the bleed pumps pulling off byproduct solids and the reagent distribution pumps supplying fresh reagent to the absorber.

Gypsum (calcium sulfate) is produced by the injection of O₂ into the calcium sulfite produced in the absorber tower sump. The bleed from the absorber contains approximately 20 wt% gypsum. The absorber slurry is pumped by an absorber bleed pump to a primary dewatering hydrocyclone cluster. The primary hydrocyclone performs two process functions. The first function is to dewater the slurry from 20 wt% to 50 wt% solids. The second function of the primary hydrocyclone is to perform a CaCO₃ and CaSO₄•2H₂O separation. This process ensures an overall limestone stoichiometry of 1.03. This system reduces the overall operating cost of the FGD process. The underflow from the hydrocyclone flows into the filter feed tank (not shown in Exhibit 4-7), from which it is pumped to a horizontal belt vacuum filter (represented as a table vacuum filter in Exhibit 4-7). Two 100 percent filter systems are provided for redundant capacity.

4.1.7.4 Hydrocyclones

The hydrocyclone is a simple and reliable device (no moving parts) designed to increase the slurry concentration in one step to approximately 50 wt%. This high slurry concentration is necessary to optimize operation of the vacuum belt filter.

The hydrocyclone feed enters tangentially and experiences centrifugal motion so that the heavy particles move toward the wall and flow out the bottom. Some of the lighter particles collect at the center of the cyclone and flow out the top. The underflow is thus concentrated from 20 wt% at the feed to 50 wt%.

Multiple hydrocyclones are used to process the bleed stream from the absorber. The hydrocyclones are configured in a cluster with a common feed header. The system has two hydrocyclone clusters, each with five 15 cm (6 in.) diameter units. Four cyclones are used to continuously process the bleed stream at design conditions, and one cyclone is spare.

Cyclone overflow and underflow are collected in separate launders. The overflow from the hydrocyclones contains about 5 wt% solids, consisting of gypsum, fly ash, and limestone residues and is sent back to the absorber.

The remainder of the overflow is fed to a secondary hydrocyclone, where the resulting underflow is returned to the absorber and the overflow is blown down to the process water treatment system, for chloride control (represented as chloride purge in Exhibit 4-7). The flow to the secondary hydrocyclones is controlled to maintain a chloride concentration of 20,000 ppmw in the blowdown.

The underflow of the primary hydrocyclones flows into the filter feed tank from where it is pumped to the horizontal belt vacuum filters.

4.1.7.5 Horizontal Vacuum Belt Filters

The secondary dewatering system consists of horizontal vacuum belt filters. The pre-concentrated gypsum slurry (50 wt%) is pumped to an overflow pan through which the slurry flows onto the vacuum belt. As the vacuum is pulled, a layer of cake is formed. The cake is dewatered to approximately 90 wt% solids as the belt travels to the discharge. At the discharge end of the filter, the filter cloth is turned over a roller where the solids are dislodged from the filter cloth. This cake falls through a chute onto the pile prior to the final byproduct uses. The required vacuum is provided by a vacuum pump. The filtrate is collected in a filtrate tank that provides surge volume for use of the filtrate in grinding the limestone. Filtrate that is not used for limestone slurry preparation is returned to the absorber.

4.1.7.6 FGD Wastewater Quality

The blowdown stream from the FGD process must be treated under the ELG rule, as stated in Section 2.4.2. The design wastewater composition for the FGD process blowdown considered is provided in Exhibit 4-9. The design water quality is based on a survey of plants burning bituminous, high sulfur coal [125] [126] and on internal information from Black & Veatch projects. Exhibit 4-9 includes a range of values, an average, and the final selected composition.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-9. FGD process wastewater quality

Parameter	FGD Wastewater (Range)	FGD Wastewater (Average)	FGD Wastewater (Final)
pH	5.5–7.4	6.6	7.2
Chemical O ₂ demand, ppm	304–1,060	682	350
Biological O ₂ demand, ppm	21–1,370	422	500
Specific Conductance, µS/cm	5,990–32,000	9,595	32,000
Ammonia as N, ppm	1.5–31.5	8.4	10
Suspended Solids, ppm	4,970–25,300	13,888	15,000
Total Dissolved Solids, ppm	4,740–44,600	21,310	43,494
Chloride as Cl, ppm	832–28,800	9,966	20,000
Sulfate as SO ₄ , ppm	1,290–11,900	4,212	7,600
Calcium as Ca, ppm	751–5,370	2,791	5,370
Magnesium as Mg, ppm	176–7,000	2,728	6,000
Sodium as Na, ppm	59–5,340	998	2900
Boron (total), ppm	3.0–626	220	430
Potassium as K, ppm	35–684	226	250
M-Alkalinity as CaCO ₃ , ppm ¹	131–625	275	200
Iron (total), ppm	3.4–824	200	290
Aluminum (total), ppm	1.0–289	93	150
Silica as SiO ₂ , ppm	1–91	33	100
Manganese (total), ppm	1.58–225	32.1	60
Nitrate/Nitrite as N, ppm	1.0–54.5	20.5	30
Total Kjeldahl N ₂ , ppm	6.2–51.6	19.2	20
Carbon, ppm			8
Phosphorus, ppm	0.05–10.5	4.61	7
Nickel (total), ppm	0.447–6.0	2.05	5
Selenium (total), ppm	0.651–8.66	2.75	5
Zinc (total), ppm	0.31–9.04	3.23	6
Barium (total), ppm	0.588–11.900	3.330	5
Titanium (total), ppm	0.377–8.18	2.57	4
Vanadium (total), ppm	0.078–1.58	0.67	1.3
Fluorine, ppm			1
Arsenic (total), ppm	0.0599–3.000	0.799	1.4

Parameter	FGD Wastewater (Range)	FGD Wastewater (Average)	FGD Wastewater (Final)
Copper (total), ppm	0.0376–2.130	0.788	1.4
Lead (total), ppm	0.0312–4.000	0.896	1.3
Molybdenum (total), ppm	0.065–1.340	0.59	0.9
Mercury (total), ppm	0.0164–1.070	0.255	0.7
Chromium, ppm	0.176–1.380	0.777	1
Cobalt, ppm			0.1
Lithium, ppm			0.1
Beryllium (total), ppm	0.0036–3.000	0.438	0.140
Cadmium (total), ppm	0.00484–0.238	0.0728	0.140
Thallium (total), ppm	0.00633–0.300	0.0864	0.140
Antimony (total), ppm	0.00923–0.0518	0.0269	0.040
Uranium, ppm			0.03
Thorium, ppm			0.02
Tin, ppm			0.01

¹Alkalinity is reported as CaCO₃ equivalent, rather than the concentration of HCO₃. The concentration of HCO₃ can be obtained by dividing the alkalinity by 0.82.

The wastewater composition reported in Exhibit 4-9 is based on water qualities from actual operations and adjusted to account for chloride. The design concentration of each constituent is individually representative of a plant configuration comparable to those in this study. However, due to the interaction and interdependencies of each constituent and the multitude of potential species, the wastewater quality cannot be considered representative as a whole. The wastewater quality is intended to inform users of the contaminants likely present, and at what concentrations they may be expected, to facilitate appropriate equipment selection and design.

The FGD process blowdown wastewater composition will be dependent on several factors, including composition of the coal, makeup water quality, flue gas treatment systems upstream of the FGD process, and other factors. The wastewater quality defined above will form the basis for discussion of the Spray Dryer Evaporator system, discussed in Section 4.1.10.

4.1.8 Carbon Dioxide Recovery Facility¹

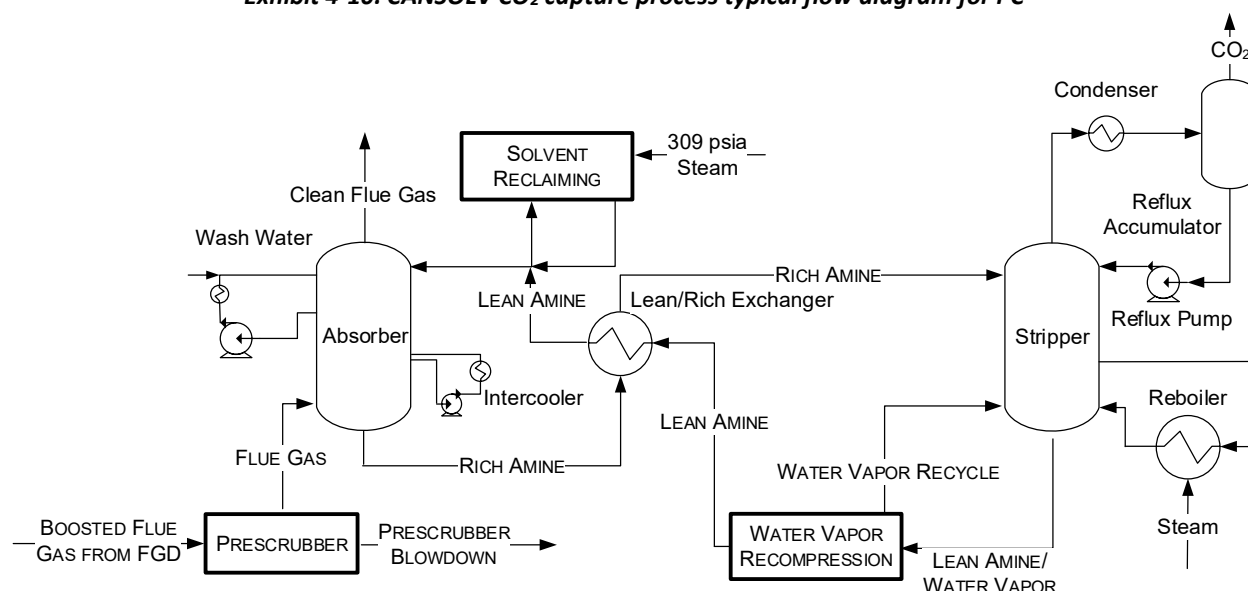
The updated Shell CANSOLV 90 percent capture cases are incorporated along with the higher capture rates.

¹ Much of the text and descriptions within this section were sourced, with permission, from data provided by Shell Catalysts & Technologies to NETL, unless otherwise noted. The information relates to a CO₂ removal system designed by Shell Catalysts & Technologies.

A CDR facility is used, along with compressors and a dryer, in cases B11B.90 and B12B.90 to remove 90 percent of the CO₂ in the flue gas exiting the FGD unit. In cases B11B.95 and B12B.95, 95 percent of the CO₂ is removed. The facility then purifies it and compresses it to a SC condition. The flue gas exiting the FGD unit contains about 1 percent more CO₂ than the raw flue gas because of the CO₂ liberated from the limestone in the FGD absorber tower. The CDR comprises the flue gas supply, pre-scrubber, CO₂ absorber, solvent stripping and reclaiming, and CO₂ compression and drying.

The CO₂ recovery process for the capture cases is based on data provided by Shell Catalyst & Technologies (SC&T) in 2021. A typical flowsheet is shown in Exhibit 4-10. This process is designed to recover high-purity CO₂ from LP streams that contain O₂, such as flue gas from coal-fired power plants, CT exhaust gas, and other waste gases.

Exhibit 4-10. CANSOLV CO₂ capture process typical flow diagram for PC



4.1.8.1 Pre-scrubber Section

The flue gas from the FGD section is sent through a booster fan to drive the gas through downstream equipment starting with the pre-scrubber inlet cooling section. The cooler is operated as a direct contact cooler that saturates and sub-cools the flue gas. Water discharged from the direct contact cooler is recycled to the wet FGD. While this water may need to be treated before reuse, the exact composition, and therefore required treatment equipment, is unknown and not considered in this study. Saturation and sub-cooling are beneficial to the system as they improve the amine absorption capacity, thus reducing amine circulation rate. After the cooling section, the flue gas is scrubbed with caustic in the pre-scrubber sulfur polishing section. This step reduces the SO₂ concentration entering the CO₂ absorber column to 0.37 ppmv.

4.1.8.2 CO₂ Absorber Section

The CANSOLV absorber is a single, rectangular, acid resistant, lined concrete structure containing stainless-steel packing.

There are several packed sections in the CANSOLV absorber. The first are used for CO₂ absorption, and the final section is a water-wash section. This specific absorber geometry and design provides several cost advantages over more traditional column configurations while maintaining equivalent or elevated performance. The flue gas enters the absorber and flows counter-current to the CANSOLV solvent. Depending on the rate of capture specified for the case, 90 percent or more of the inlet CO₂ is absorbed into the lean solvent and the remaining CO₂ exits the main absorber section and enters the water-wash section of the absorber. Prior to entering the bottom packing section, hot amine is collected, removed, and pumped through a HX to provide intercooling and limit water losses. The cooled amine is then sent back to the absorber just above the final packed section.

The water-wash section at the top of the absorber is used to remove volatiles or entrained amine from the flue gas, as well as to condense and retain water in the system. The wash water is removed from the bottom of the wash section, pumped through a HX, and is then re-introduced at the top of the wash section. This wash water is made up of recirculated wash water as well as water condensed from the flue gas. The flue gas treated in the water-wash section is then released to atmosphere.

4.1.8.3 Amine Regeneration Section

The rich amine is collected at the bottom of the absorber and pumped through multiple parallel rich/lean HXs where heat from the lean amine is exchanged with the rich amine. The CANSOLV rich/lean solvent HXs are a stainless-steel plate and frame type with a 5°C (9°F) approach temperature. Additional options for heat integration in the CANSOLV system include a second HX after the rich/lean solvent HX where LP steam condensate from the regenerator reboiler or intermediate-pressure (IP) steam condensate from the amine purification section may be used to further pre-heat the rich solvent. The rich amine continues and enters the stripper near the top of the column. The stripper is a stainless-steel vessel using structured stainless-steel packing. The regenerator reboiler indirectly uses LP steam to produce water vapor that flows upwards, counter-current to the rich amine flowing downwards, and removes CO₂ from the amine. The CANSOLV regenerator reboiler is a Compabloc-type welded heat and block exchanger with a steam temperature of 20–30°C (68–86°F). Lean amine is collected in the stripper bottoms and flows to a flash vessel where water vapor is released. Simultaneously, the condensate leaving the reboiler flows to a separate flash vessel, and water vapor is released. The water vapor recovered from both flash vessels is combined, and then recompressed and injected into the bottom of the stripper to enhance stripping of CO₂ within the column, thus reducing the amount of reboiler steam otherwise required. The lean amine is then pumped through the same rich/lean HX to exchange heat from the lean amine to the rich amine and continues to the lean amine tank.

The water vapor and stripped CO₂ flow up the stripper where they are contacted with recycled reflux to condense a portion of the vapor. The remaining gas continues to the condenser where

it is partially condensed. The two-phase mixture then flows to a reflux accumulator where the CO₂ product gas is separated and sent to the CO₂ compressor at approximately 0.2 MPa (29 psia), and the remaining water is collected and returned to the stripper as reflux.

The flow of steam to the regenerator reboiler is proportional to the rich amine flow to the stripper; however, the flow of low-pressure steam is also dependent on the stripper top temperature. For the steady-state case described here, the low-pressure steam requirement for the reboiler portion of the CANSOLV process is calculated as approximately 2.5 MJ/kg (1,070 Btu/lb) CO₂ for PC cases^m and approximately 2.7 MJ/kg (1,160 Btu/lb) for NGCC cases, which is satisfied by extracting steam from the crossover pipe between the IP and LP sections of the steam turbine.

4.1.8.4 Amine Purification Section

The purpose of the amine purification section is to remove a portion of the HSS as well as ionic and non-ionic amine degradation products.

4.1.8.4.1 Thermal Reclaimer

The degradation products are removed in the thermal reclaimer by distilling a slipstream—taken from the lean amine exiting the lean amine flash vessel, and prior to the lean solvent pump—under vacuum conditions to separate the amine from the less volatile degradation products and non-volatile salts and ionic species. This process leaves the non-ionic degradation products and salts in the bottom, which are pumped to a storage tank, diluted and cooled with process water, and then disposed. The condensed amine and water are returned to the lean amine tank.

At large scale, the thermal reclaimer operation is typically continuous, while, at smaller scale, it can be designed to operate in batch mode.

4.1.9 CO₂ Compression and Drying System

The compression system was modeled based on vendor supplied data, similar in design to that presented in the Carbon Capture Simulation Initiative’s paper “Centrifugal Compressor Simulation User Manual.” [67] The design is assumed to be an eight-stage front-loaded centrifugal compressor with stage discharge pressures presented in Exhibit 4-11.

Exhibit 4-11. CO₂ compressor interstage pressures

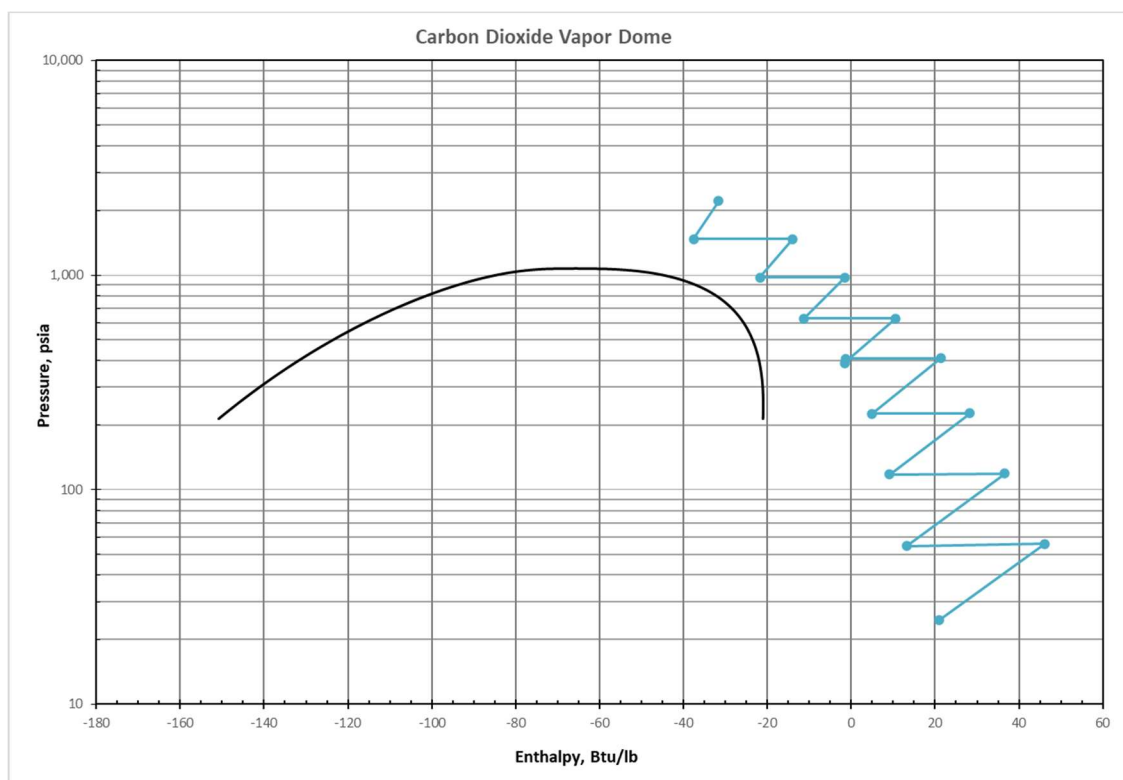
Stage	Outlet Pressure, MPa (psia)	Stage Pressure Ratio
1	0.39 (56)	2.27
2	0.82 (119)	2.13
3	1.57 (227)	1.91
4	2.82 (410)	1.80

^m Recent vendor feedback states that the PC reboiler energy requirement can be reduced to 2.4 MJ/kg (1,020 Btu/lb).

Stage	Outlet Pressure, MPa (psia)	Stage Pressure Ratio
5	4.33 (628)	1.53
6	6.72 (975)	1.55
7	10.17 (1,475)	1.51
8	15.28 (2,217)	1.50

Intercooling is included for each stage with the first three stages including water knockout. A CO₂ product aftercooler is also included to cool the CO₂ to 30°C (86°F). CO₂ transportation and storage costs assume that the CO₂ enters the transport pipeline as a dense phase liquid; thus, a pipeline inlet temperature of 30°C (86°F) is considered. Since all PC cases with CO₂ capture utilize the CANSOLV system, the compressor CO₂ suction pressure is identical, and the enthalpy versus pressure operating profile shown in Exhibit 4-12 is representative of all cases. Data points representing compression stage discharge pressures are labeled with the compression stage number (e.g., C1). Intercooling temperatures for the final two intercooling stages (after compression stages six and seven) were selected to provide a suitable buffer between the compressor operating profile and SC CO₂ dome. The base assumption that cooling water is available at a temperature of 60°F from the cooling tower is not a limiting factor in selection of these two stages' intercooling temperatures. Enthalpy reference conditions are 0.01°C and 0.0006 MPa (32.02°F and 0.089 psia), the same as those used for stream table results. The CO₂ aftercooler is not represented in the compressor operating profile plot.

Exhibit 4-12. PC CO₂ compressor enthalpy versus pressure operating profile



A TEG dehydration unit is included between stages 4 and 5, operating at 2.82 MPa (409 psia), to reduce the moisture concentration of the CO₂ stream to 500 ppmv. The dryer is designed based on a paper published by the Norwegian University of Science and Technology. [68]

In an absorption process, such as in a TEG dehydration unit, the gas containing water flows up through a column while the TEG flows downward. The solvent binds the water by physical absorption; water is more soluble in the solvent than in other components of the gas mixture. The dried gas exits at the top of the column while the solvent, rich in water, exits at the bottom. After depressurization to around atmospheric pressure, the solvent is regenerated by heating it and passing it through a regeneration column where the water is boiled off. A TEG unit is capable of reducing water concentrations to meet the QGESS design point of 500 ppmv. [69]

Several alternatives to rejecting the heat of CO₂ compression to cooling water were investigated in a separate study. [127] The first alternative consisted of using a portion of the heat to pre-heat BFW while the remaining heat was still rejected to cooling water. This configuration resulted in an increase in net plant efficiency of 0.3 percentage points (absolute). The second alternative modified the CO₂ compression intercooling configuration to enable integration into a LiBr-H₂O absorption refrigeration system, where water is the refrigerant. This configuration resulted in a net plant efficiency increase of 0.1 percentage points (absolute) and reduced the number of CO₂ compression stages necessary from eight to five.

It was concluded that the small increase in efficiency did not justify the added cost and operational complexity of the two configurations considered; hence, they were not incorporated into the base design.

4.1.10 Process Water Systems

4.1.10.1 Process Water Sources

As discussed in Section 2.4.2, the only system in the PC cases producing a wastewater stream that must be treated for compliance with the ELG rule is the wet FGD. A detailed process description of the wet FGD is provided in Section 4.1.7.

4.1.10.2 Process Water Treatment

The updated ELG rule established FGD wastewater as a new category, with discharge limits that must be met. The FGD wastewater is sourced from the overflow of the secondary hydrocyclone, as described in Section 4.1.7.3, with a composition described in Section 4.1.7.6.

Unlike in IGCC cases, the water recovered from the flue gas in PC cases with CO₂ capture is partially discharged from the plant. While the ELG rule does not regulate this water and therefore it does not need to be treated, the discharge of this water removes PC cases with CO₂ capture from qualifying for the ZLD designation.

A variety of technologies are currently installed at PC plants to treat FGD wastewater, including surface impoundments, chemical precipitation, biological treatment, ZLD operating practices,

evaporation ponds, and constructed wetlands. Approximately 37 percent of PC plants currently utilize ZLD operating practices. [128] [125]

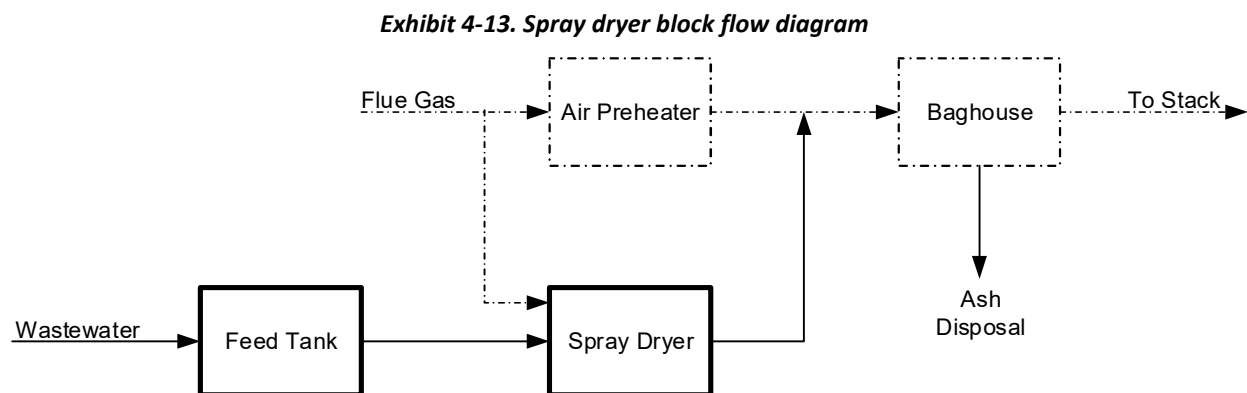
While multiple process configurations were assessed for feasibility of complying with the ELG, given this study's intention of maintaining general applicability of the cases presented, and the prevalence of utilizing ZLD operating practices in existing PC plants, systems that would enable ZLD were selected in all cases, specifically a spray dryer evaporator (SDE).

4.1.10.2.1 Spray Dryer Evaporator

A spray dryer is a technology commonly used in the power industry for FGD, which can also be applied as a thermal evaporation process to treat wastewater. An SDE has been constructed and is currently operating at Kansas City Power & Light's Iatan Plant Unit 2. Operation of the SDE has been described as straightforward, with periodic maintenance performed. [129] The feasibility of using an SDE as the sole treatment system in PC cases is limited by the flow rate of wastewater, as the cost and performance impact of the spray dryer increases with increasing wastewater flow rate. Typically, a spray dryer for FGD wastewater is limited to approximately 150–200 gpm, depending on the flue gas conditions. As the system is designed based on flow rate, the solids concentration of the FGD wastewater does not impact the sizing of the system.

Spray dryers typically require a flue gas temperature above 316°C (600°F). A slipstream of flue gas is taken upstream of the air preheater for use as the heat source to evaporate the wastewater, which is sprayed into a tall cylindrical vessel using rotary atomizers. The heat from the slipstream is used to evaporate the wastewater, which contains dissolved and suspended solids, to produce a humidified gas stream containing additional suspended particulates. All the suspended particulates are assumed to exit the spray dryer vessel. The humidified gas stream is returned downstream of the air preheater and the combined flue gas passes through a baghouse, which removes most of the suspended solids.

Exhibit 4-13 provides a simplified BFD of the spray dryer evaporation process.



The atomizers and the spray dryer vessel are designed so that the wastewater mist droplets are evaporated before reaching the vessel wall. Therefore, the vessel is constructed of CS without concerns for corrosion. However, the wall metal temperature must be monitored to ensure there is no temperature drop, which is an indication that moisture is reaching the wall and can cause corrosion issues.

4.1.10.2.2 Alternative Treatment Methods

There are several alternative treatment options for compliance with the ELG rule, spanning a range of technology maturation on a technology readiness scale. Of the more mature routes, deep-well injection and evaporation ponds were also considered. Summary descriptions of these treatment options are provided in Section 3.1.12.2.4.

4.1.11 Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing of the fly ash and bottom ash produced on a daily basis by the boiler, along with the hydrated lime and activated carbon injected for mercury control (discussed in Section 4.1.6), and dissolved solids from the SDE that are disposed of with the fly ash (discussed in Section 4.1.10.2.1). The scope of the system is from the baghouse hoppers, air heater and economizer hopper collectors, and bottom ash hoppers to the separate bottom ash/fly ash storage silos and truck filling stations. The system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

The fly ash collected in the baghouse and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using LP air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

As mentioned in Section 4.1.5, the use of ACI and DSI increases the calcium content of the fly ash and adds an additional burden to the fabric filter. The addition of calcium is not expected to increase the leaching of trace metals from the fly ash significantly. The ACI and DSI systems increase the total amount of PM by approximately 17 percent.

The bottom ash from the boiler is fed into a series of dry storage hoppers, each equipped with a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. Accumulated bottom ash discharged from the hoppers passes through the clinker grinder, then to a screw feeder and finally to a pneumatic ash conveying system for transport to the bottom ash silos, before being transferred to trucks for offsite disposal.

Ash from the economizer hoppers is pneumatically conveyed to the fly ash storage silo(s) with a 3-day storage capacity and pyrites (rejected from the coal pulverizers) are conveyed using water on a periodic basis to the dewatering system (i.e., dewatering bins) for offsite removal by truck.

The wet sluicing for the pyrite system is not an explicit requirement of the National Fire Protection Association (NFPA), but it is viewed as a risk mitigation measure to avoid accidental ignition of combustible materials clinging to the mill rejects. This can also come into effect when a mill trips and the contained solids need to be safely removed from the mills. Wet sluicing of the mill rejects further reduces potential ignition of this coal that is being swept from the mills. The water used for wet sluicing is regarded as low volume wastewater, which is not specifically regulated under the ELG rule, and is assumed to be treated for the pyrites within the plant's standard low volume wastewater treatment facility described in Section 4.1.13.6.

4.1.12 Power Generation

The steam turbine is designed for long-term operation (90 days or more) at MCR with throttle control valves 95 percent open. It is also capable of a short-term 5 percent OP/VWO condition (16 hours).

For the SubC cases, the steam turbine is a tandem compound type, consisting of HP-IP-two double flow LP (four flow) sections enclosed in three casings, all connected to the generator by a common shaft, designed for condensing single reheat operation, and equipped with non-automatic extractions and four-flow exhaust. The turbine drives a H₂-cooled generator. The HP and IP sections are contained in a single span, opposed-flow casing, with the two double-flow LP sections in a separate casing each. The turbine has DC motor-operated lube oil pumps, and main lube oil pumps, which are driven off the turbine shaft. [130] The exhaust pressure is 50.8 cm (2 in.) Hg in the single pressure condenser. There are seven extraction points. The condenser is two-shell, transverse, single pressure with divided waterbox for each shell.

The steam-turbine generator systems for the SC plants are similar in design to the SubC systems. The differences include steam cycle conditions and steam extractions points. The SubC design has seven steam extraction points for both capture and non-capture cases, whereas the capture SC plant has only seven extraction points and the non-capture SC plant has eight extraction points. The reason for the difference between the capture and non-capture supercritical plants is discussed in Section 4.1.2.2.4.

Turbine bearings are lubricated by a CL, water-cooled pressurized oil system. Turbine shafts are sealed against air in-leakage or steam blowout using a labyrinth gland arrangement connected to a LP steam seal system. The generator produces power at 24 kV. A static, transformer type exciter is provided. The STG is controlled by a triple-redundant microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color monitor/operator interfacing, and datalink interfaces to the balance-of-plant DCS and incorporates on-line repair capability. The generator stator is cooled with a CL water system consisting of circulating pumps, shell and tube or plate and frame type HXs, filters, and deionizers, all skid mounted. The generator rotor is cooled with a H₂ gas recirculation system using fans mounted on the generator rotor shaft.

Operation Description – The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at the conditions provided in Exhibit 4-14.

Exhibit 4-14. PC steam conditions

Steam Conditions		
Steam Parameter	SubC	SC
Main Pressure, MPa (psig)	16.5 (2,400)	24.1 (3,500)
Main Temperature, °C (°F)	566 (1,050)	593 (1,100)
Reheat Temperature, °C (°F)	566 (1,050)	593 (1,100)

The steam enters the turbine inlet, flows through the turbine, and returns to the boiler for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at the conditions provided in Exhibit 4-14. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the two double LP sections. The steam divides into four paths and flows through the LP sections exhausting downward into the condenser. The last stages of the LP sections operate as condensing turbines with an exhaust moisture content ranging 9.4–9.6 percent.

The turbine is designed to operate at constant inlet steam pressure over the entire load range.

4.1.13 Balance of Plant

The balance of plant components consists of the condensate, FW, main and reheat steam, extraction steam, ash handling, ducting and stack, waste treatment and miscellaneous systems as described below.

4.1.13.1 Circulating Water System

It is assumed that the plant is serviced by a public water facility and has access to groundwater for use as makeup cooling water with minimal pretreatment. All filtration and treatment of the circulating water are conducted on site. A mechanical draft, wood frame, counter-flow cooling tower is provided for the circulating water heat sink. Two 50 percent CWP are provided. The CWS provides cooling water to the condenser, the auxiliary cooling water system, and the CDR facility and CO₂ compressors in capture cases.

The auxiliary cooling water system is a CL system. Plate and frame HXs with circulating water as the cooling medium are provided. This system provides cooling water to the lube oil coolers, turbine generator, boiler feed pumps, etc. All pumps, vacuum breakers, air release valves, instruments, controls, etc., are included for a complete operable system.

The CDR and CO₂ compression systems in cases B11B.90, B11B.95, B12B.90, and B12B.95 require a substantial amount of cooling water that is provided by the PC plant CWS. The additional cooling loads imposed by the CDR and CO₂ compressors are reflected in the significantly larger CWPs and cooling tower in those cases.

4.1.13.2 Accessory Electric Plant

The accessory electric plant consists of switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, and wire and cable. It also includes the main power transformer, required foundations, and standby equipment.

4.1.13.3 Ducting and Stack

One stack is provided with a single fiberglass-reinforced plastic (FRP) liner. The stack is constructed of reinforced concrete and is 152 m (500 ft) high for adequate particulate dispersion.

4.1.13.4 Buildings and Structures

Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Coal crusher building
- Runoff water pump house
- Boiler building
- Continuous emissions monitoring building
- Industrial waste treatment building
- Administration and service building
- Pump house and electrical equipment building
- FGD system building
- Makeup water and pretreatment building
- Guard house
- Fuel oil pump house

4.1.13.5 Instrumentation and Control

An integrated plant-wide control and monitoring DCS is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor and keyboard units. The monitor/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual procedures, with operator selection of modular automation routines available.

4.1.13.6 Waste Treatment

An onsite water treatment facility treats all runoff, cleaning wastes, blowdown, and backwash. It is anticipated that the treated water will be suitable for discharge into existing systems and be within EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals.

The waste treatment system is minimal and consists, primarily, of neutralization and oil/water separators (along with the associated pumps, piping, etc.).

4.1.13.7 Miscellaneous Systems

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water are provided. A storage tank provides a supply of No. 2 fuel oil used for a small auxiliary boiler; start-up fuel is assumed to be natural gas. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

4.1.14 Performance Summary Metrics

This section details the methodologies of several metrics reported in the performance summaries of the PC cases.

4.1.14.1 *Steam Generator Efficiency*

The steam generator efficiency is equal to the amount of heat transferred in the boiler divided by the thermal input provided by the coal. This calculation is represented by the equation:

$$SGE = \frac{BH}{CH}$$

Where:

SGE – steam generator efficiency, percent

BH – boiler thermal output, Btu

CH – coal thermal input, Btu

The heat transferred in the boiler is calculated in the Aspen models, and the thermal input of the coal is the product of the coal feed rate and the heating value of the coal.

4.1.14.2 *Steam Turbine Efficiency*

The steam turbine efficiency is calculated by taking the steam turbine power produced and dividing it by the difference between the thermal input and thermal consumption. This calculation is represented by the equation:

$$STE = \frac{STP}{(TI - TC)}$$

Where:

STE – steam turbine efficiency, percent

STP – steam turbine power, after generator losses, kWh

TI – thermal input, kWh

TC – thermal consumption, kWh

The thermal input is considered to be the main steam.

The thermal consumption is only present in the capture cases. It is the enthalpy difference between the streams extracted for the capture and CO₂ dryer systems and the condensate returned to the condenser (steam extraction – condensate return).

4.1.14.3 *Steam Turbine Heat Rate*

The steam turbine heat rate is calculated by taking the inverse of the steam turbine efficiency. This calculation is represented by the equation:

$$STHR = \frac{1}{STE} * 3,412$$

Where:

STHR – steam turbine heat rate, Btu/kWh

STE – steam turbine efficiency, fraction

4.2 SUBCRITICAL PC CASES

This section contains an evaluation of plant designs for cases B11A, B11B.90, and B11B.95, which are based on a SubC PC plant with a nominal net output of 650 MWe. All cases use a single reheat 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F) cycle. The main difference between the three configurations is that cases B11B.90 and B11B.95 include CO₂ capture while Case B11A does not.

The balance of this section is organized as follows:

- Key Assumptions is a summary of study and modeling assumptions relevant to cases B11A, B11B.90, and B11B.95.
- Sparing Philosophy is provided for cases B11A, B11B.90, and B11B.95.
- Process and System Description provides an overview of the technology operation as applied to Case B11A. The systems that are common to all PC cases were covered in Section 4.1 and only features that are unique to Case B11A are discussed further in this section.
- Performance Results provides the main modeling results from Case B11A, including the performance summary, environmental performance, carbon/sulfur balances, water balance, mass and energy balance diagrams and energy balance table.
- Major Equipment List provides an itemized list of major equipment for Case B11A with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs for Case B11A.
- Process Description, Performance Results, Major Equipment List, and Cost Estimating are discussed for cases B11B.90 and B11B.95.

4.2.1 Key System Assumptions

System assumptions for cases B11A, B11B.90, and B11B.95, SubC PC with and without CO₂ capture, are compiled in Exhibit 4-15.

Exhibit 4-15. SubC PC plant study configuration matrix

	Case B11A w/o CO ₂ Capture	Case B11B.90 w/CO ₂ Capture	Case B11B.95 w/CO ₂ Capture
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2,400/1,050/1,050)		
Coal	Illinois No. 6		
Condenser Pressure, mm Hg (in. Hg)	50.8 (2)		
Boiler Efficiency, HHV %	88.0		
Carbon Conversion, %	99.4		
Cooling Water to Condenser, °C (°F)	16 (60)		

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

	Case B11A w/o CO ₂ Capture	Case B11B.90 w/CO ₂ Capture	Case B11B.95 w/CO ₂ Capture
Cooling Water from Condenser, °C (°F)	27 (80)		
Stack Temperature, °C (°F)	57 (135)	45 (113)	
SO ₂ Control	Wet Limestone Forced Oxidation		
FGD Efficiency, % ^A	98	98 ^{B, C}	
FGD Blowdown Treatment (Effluent Limitation Guidelines)	Spray dryer evaporator		
NO _x Control	LNB w/OFA, SCR		
SCR Efficiency, % ^A	76.1	79.1	79.3
Ammonia Slip (end of catalyst life), ppmv	2		
Particulate Control	Fabric Filter		
Fabric Filter efficiency, % ^A	99.9		
Ash Distribution, Fly/Bottom, %	80/20		
SO ₃ Control	DSI		
Mercury Control	Co-benefit Capture and ACI		
CO ₂ Control	N/A	CANSOLV	
Overall Carbon Capture, % ^A	N/A	90	95
CO ₂ Sequestration	N/A	Off-site Saline Formation	

^ARemoval efficiencies are based on the flue gas content.

^BA SO₂ polishing step is included to meet more stringent SO_x limits in the flue gas (0.37 ppmv) to reduce formation of amine HSS during the CO₂ absorption process.

^CSO₂ exiting the post-FGD polishing step is absorbed in the CO₂ capture process making stack emissions negligible.

4.2.1.1 Balance of Plant – Case B11A, Case B11B.90, Case B11B.95

The balance of plant assumptions are common to all PC cases and are presented in Exhibit 4-16.

Exhibit 4-16. Balance of plant assumptions

Parameter	Value
Cooling System	Recirculating Wet Cooling Tower
Fuel and Other Storage	
Coal	30 days
Ash	3 days
Gypsum	30 days
Limestone	30 days
Hydrated lime	7 days
Activated carbon	7 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 V
Motors between 1 hp and 250 hp	480 V
Motors between 250 hp and 5,000 hp	4,160 V
Motors above 5,000 hp	13,800 V
Steam and CT generators	24,000 V
Grid Interconnection voltage	345 kV
Water and Wastewater	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater and is assumed to be in sufficient quantities to meet plant makeup requirements Makeup for potable, process, and DI water is drawn from municipal sources
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	Blowdown will be treated for chloride and metals and discharged

4.2.2 Sparing Philosophy

Single trains are used throughout the design with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- One dry-bottom, wall-fired SubC PC boiler (1 x 100 percent)
- Two SCR reactors (2 x 50 percent)

- One DSI system (1 x 100 percent)
- One ACI system (1 x 100 percent)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50 percent)
- One wet limestone forced oxidation positive pressure absorber (1 x 100 percent)
- One steam turbine (1 x 100 percent)
- For cases B11B.90 and B11B.95, one CO₂ absorption system, consisting of an absorber, stripper, and ancillary equipment (1 x 100 percent) and two CO₂ compression systems (2 x 50 percent)

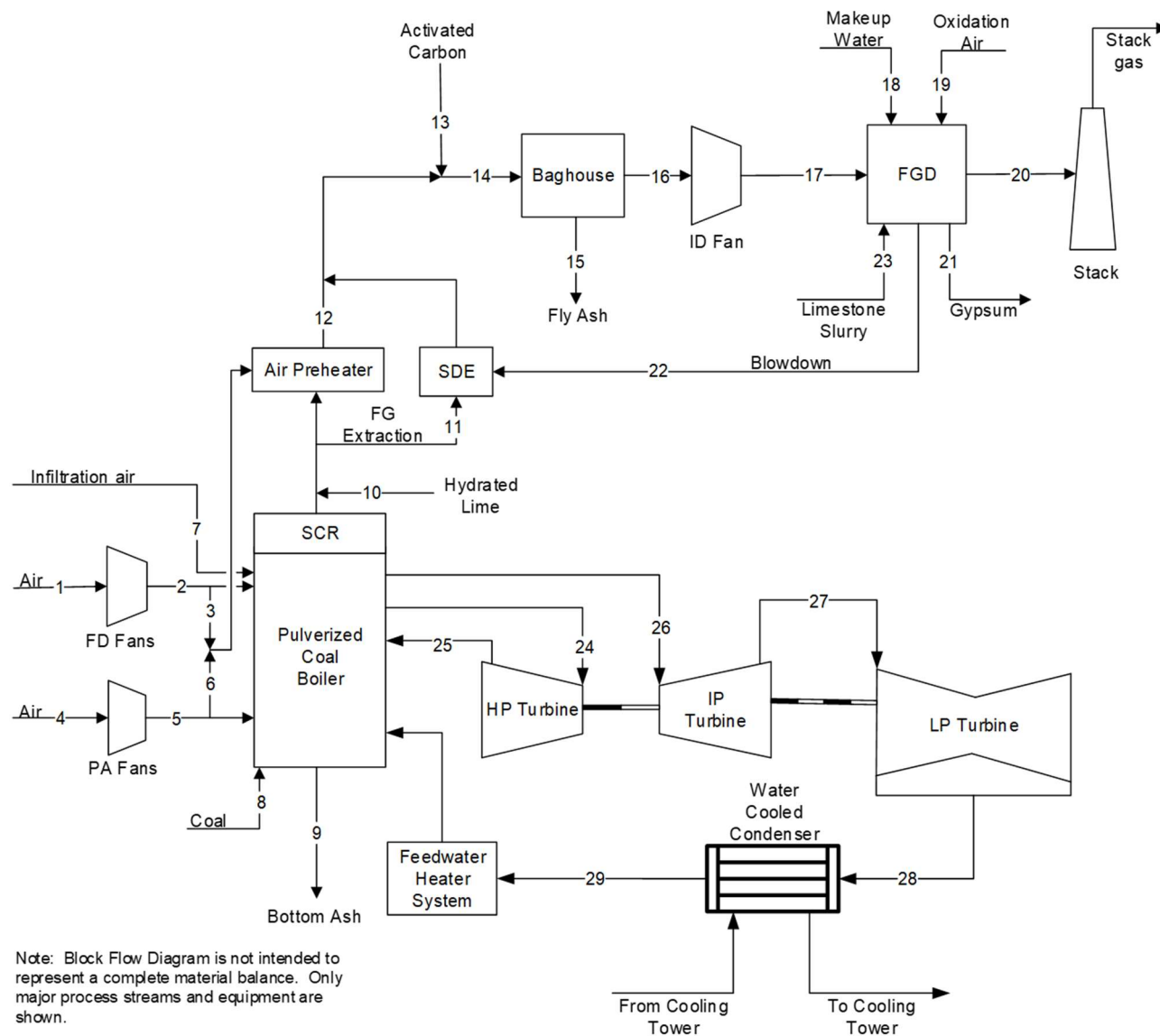
4.2.3 Case B11A – SubC PC without CO₂ Capture Process Description

In this section the SubC PC process without CO₂ capture is described. The system description follows the BFD in Exhibit 4-17 and stream numbers reference the same exhibit. Exhibit 4-18 provides process data for the numbered streams in the BFD.

Coal (stream 8) and PA (stream 4) are introduced into the boiler through the wall-fired burners. Additional combustion air, including the OFA, is provided by the FD fans (stream 1). The boiler operates at a slight negative pressure so air leakage is into the boiler, and the infiltration air is accounted for in stream 7. Streams 3 and 6 show Ljungstrom air preheater leakages from the FD and PA fan outlet streams to the boiler exhaust.

Flue gas exits the boiler through the SCR reactor where NH₃ is injected to reduce NO_x compounds, followed by hydrated lime injection (stream 10) for the reduction of SO₃. A small flue gas stream is extracted for use in the spray dryer evaporator (stream 11). The flue gas then passes through the combustion air preheater (where the air preheater leakages are introduced) and is cooled to 143°C (289°F) (stream 12) before PAC is injected (stream 13) for mercury reduction. The flue gas then passes through a fabric filter for particulate removal (stream 16). An ID fan provides the motive force for the flue gas (stream 17) to pass through the FGD unit and the plant stack. FGD inputs and outputs include makeup water (stream 18), oxidation air (stream 19), limestone slurry (stream 23) and product gypsum (stream 21). The clean, saturated flue gas exiting the FGD unit (stream 20) passes to the plant stack and is discharged to the atmosphere. The FGD blowdown (stream 22) is sent to the SDE where extracted flue gas (stream 11) is used to evaporate the FGD blowdown stream. The SDE outlet gas stream is recombined into the flue gas path after the air preheater, and before PAC injection.

Exhibit 4-17. Case B11A block flow diagram, SubC unit without CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-18. Case B11A stream table, SubC unit without capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0087	0.0088	0.0000	0.0087	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379	0.0000	0.1372	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837	0.0000	0.0911	0.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340	0.0000	0.7281	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336	0.0000	0.0329	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020	0.0000	0.0020	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1158
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.8842
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	60,980	60,980	1,806	18,732	18,732	2,578	1,348	0	0	1	4,018	81,515	0	86,215	5
V-L Flowrate (kg/hr)	1,759,698	1,759,698	52,120	540,561	540,561	74,394	38,896	0	0	12	119,511	2,420,545	0	2,552,647	552
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	223,673	4,509	1,219	965	18,528	49	19,734	19,747
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143	15	143	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.31	-6.79	-2,453.14	-1,066.09
Density (kg/m ³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8	---	0.8	2,150.2
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694	---	29.608	104.897
V-L Flowrate (lb _{mol} /hr)	134,438	134,438	3,982	41,298	41,298	5,684	2,972	0	0	2	8,859	179,711	0	190,070	12
V-L Flowrate (lb/hr)	3,879,469	3,879,469	114,905	1,191,732	1,191,732	164,011	85,750	0	0	27	263,476	5,336,389	0	5,627,624	1,217
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	493,115	9,940	2,687	2,128	40,848	108	43,506	43,535
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289	59	289	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1	14.7	14.1	14.1
Steam Table Enthalpy (Btu/lb) ^A	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4	-2.9	-1,054.7	-458.3
Density (lb/ft ³)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052	---	0.052	134.232

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-18. Case B11A stream table, SubC unit without capture (continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29
V-L Mole Fraction														
Ar	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.1372	0.1372	0.0000	0.0003	0.1245	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0911	0.0911	0.9999	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0001	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	86,209	86,209	5,037	3,609	96,375	203	681	2,805	103,895	96,973	96,973	82,051	65,522	83,314
V-L Flowrate (kg/hr)	2,552,082	2,552,082	90,763	104,139	2,769,828	3,656	12,591	50,543	1,871,700	1,746,999	1,746,999	1,478,180	1,180,392	1,500,921
Solids Flowrate (kg/hr)	0	0	0	0	0	32,887	192	21,637	0	0	0	0	0	0
Temperature (°C)	143	156	15	15	57	15	57	15	566	355	566	267	38	39
Pressure (MPa, abs)	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	16.65	4.28	4.19	0.52	0.01	1.32
Steam Table Enthalpy (kJ/kg) ^A	287.58	302.09	-47.80	30.23	297.00	---	---	---	3,473.89	3,098.44	3,593.58	2,994.07	2,340.01	162.43
AspenPlus Enthalpy (kJ/kg) ^B	-2,464.17	-2,449.66	-16,015.01	-97.58	-2,939.24	-12,513.34	-15,496.00	-14,994.25	-12,506.41	-12,881.86	-12,386.71	-12,986.23	-13,640.29	-15,817.87
Density (kg/m ³)	0.8	0.9	1,003.7	1.2	1.1	878.3	979.5	1,003.7	47.7	16.0	11.1	2.1	0.1	993.3
V-L Molecular Weight	29.603	29.603	18.019	28.857	28.740	18.021	18.495	18.019	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	190,059	190,059	11,105	7,956	212,470	447	1,501	6,184	229,050	213,789	213,789	180,893	144,451	183,675
V-L Flowrate (lb/hr)	5,626,378	5,626,378	200,098	229,587	6,106,425	8,060	27,759	111,429	4,126,393	3,851,475	3,851,475	3,258,829	2,602,318	3,308,965
Solids Flowrate (lb/hr)	0	0	0	0	0	72,504	423	47,701	0	0	0	0	0	0
Temperature (°F)	289	313	59	59	135	59	135	59	1,050	671	1,050	512	101	101
Pressure (psia)	13.9	15.3	14.7	14.7	14.8	14.7	14.7	14.7	2,414.7	620.5	608.1	75.0	1.0	190.7
Steam Table Enthalpy (Btu/lb) ^A	123.6	129.9	-20.5	13.0	127.7	---	---	---	1,493.5	1,332.1	1,545.0	1,287.2	1,006.0	69.8
AspenPlus Enthalpy (Btu/lb) ^B	-1,059.4	-1,053.2	-6,885.2	-42.0	-1,263.6	-5,379.8	-6,662.1	-6,446.4	-5,376.8	-5,538.2	-5,325.3	-5,583.1	-5,864.3	-6,800.5
Density (lb/ft ³)	0.051	0.055	62.658	0.076	0.067	54.833	61.145	62.658	2.975	1.000	0.692	0.132	0.003	62.010

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

4.2.4 Case B11A – Performance Results

The plant produces a net output of 650 MWe at a net plant efficiency of 38.6 percent (HHV basis). Overall performance for the plant is summarized in Exhibit 4-19. Exhibit 4-20 provides a detailed breakdown of the auxiliary power requirements.

Exhibit 4-19. Case B11A plant performance summary

Performance Summary	
Total Gross Power, MWe	688
CO ₂ Capture/Removal Auxiliaries, kWe	–
CO ₂ Compression, kWe	–
Balance of Plant, kWe	37,520
Total Auxiliaries, MWe	38
Net Power, MWe	650
HHV Net Plant Efficiency, %	38.6
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,336 (8,849)
LHV Net Plant Efficiency, %	40.0
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,005 (8,535)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	46.3
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,770 (7,365)
Condenser Duty, GJ/hr (MMBtu/hr)	2,793 (2,648)
CO ₂ Capture Rate, %	–
AGR Cooling Duty, GJ/hr (MMBtu/hr)	–
As-Received Coal Feed, kg/hr (lb/hr)	223,673 (493,115)
Limestone Sorbent Feed, kg/hr (lb/hr)	21,637 (47,701)
HHV Thermal Input, kWt	1,685,945
LHV Thermal Input, kWt	1,626,114
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.038 (10.0)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.030 (8.0)
Excess Air, %	20.3

Exhibit 4-20. Case B11A plant power summary

Power Summary	
Steam Turbine Power, MWe	688
Total Gross Power, MWe	688
Auxiliary Load Summary	
Activated Carbon Injection, kWe	30
Ash Handling, kWe	0
Baghouse, kWe	730
Circulating Water Pumps, kWe	100
CO ₂ Capture/Removal Auxiliaries, kWe	5,700
CO ₂ Compression, kWe	–
Coal Handling and Conveying, kWe	–
Condensate Pumps, kWe	480
Cooling Tower Fans, kWe	720
Dry Sorbent Injection, kWe	2,950
Flue Gas Desulfurizer, kWe	60
Forced Draft Fans, kWe	3,460
Ground Water Pumps, kWe	1,150
Induced Draft Fans, kWe	590
Miscellaneous Balance of Plant ^{A,B} , kWe	10,600
Primary Air Fans, kWe	2,250
Pulverizers, kWe	1,360
SCR, kWe	3,350
Sorbent Handling & Reagent Preparation, kWe	40
Spray Dryer Evaporator, kWe	1,040
Steam Turbine Auxiliaries, kWe	250
Transformer Losses, kWe	500
Total Auxiliaries, MWe	2,160
Net Power, MWe	38

^ABoiler feed pumps are turbine driven

^BIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

4.2.4.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B11A is presented in Exhibit 4-21. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 4-21. Case B11A air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.035 (0.081)	1,567 (1,727)	0.306 (0.675)
NO _x	0.036 (0.084)	1,626 (1,792)	0.318 (0.700)
Particulate	0.005 (0.011)	209 (230)	0.041 (0.090)
Hg	1.54E-7 (3.59E-7)	0.007 (0.008)	1.36E-6 (3.00E-6)
CO ₂	87 (202)	3,931,031 (4,333,220)	768 (1,693)
CO ₂ ^C	–	–	812 (1,790)
mg/Nm ³			
Particulate Concentration ^{D,E}	14.53		

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

^DConcentration of particles in the flue gas after the baghouse

^ENormal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NO_x boiler emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 76.1 percent to 0.04 kg/GJ (0.08 lb/MMBtu).

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and wet FGD) is 97.2 percent.

CO₂ emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 4-22. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO₂ through the stack; however, the PAC is captured in the fabric filter, unburned carbon remains in the bottom ash, and some leaves as gypsum.

Exhibit 4-22. Case B11A carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	142,580 (314,335)	Stack Gas	144,083 (317,649)
Air (CO ₂)	332 (733)	FGD Product	169 (373)
PAC	49 (108)	Baghouse	733 (1,617)
FGD Reagent	2,195 (4,840)	Bottom Ash	171 (377)
		CO ₂ Product	–
		CO ₂ Dryer Vent	–
		CO ₂ Knockout	–
Total	145,157 (320,016)	Total	145,157 (320,016)

Exhibit 4-23 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur captured in the fabric filter via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 4-23. Case B11A sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	5,606 (12,360)	FGD Product	5,271 (11,620)
		Stack Gas	110 (241)
		Polishing Scrubber and Solvent Reclaiming	–
		Baghouse	226 (498)
Total	5,606 (12,360)	Total	5,606 (12,360)

Water demand, recycle, withdrawal, discharge, and consumption were defined and discussed in Section 2.6. Exhibit 4-24 shows the water balance for Case B11A.

Exhibit 4-24. Case B11A water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
FGD Process Makeup	1.5 (400)	–	1.5 (400)	–	1.5 (400)
FGD Slurry Water	0.8 (223)	–	0.8 (223)	–	0.8 (223)
CO ₂ Drying	–	–	–	–	–

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
CO ₂ Capture Recovery	–	–	–	–	–
CO ₂ Compression KO	–	–	–	–	–
Deaerator Vent	–	–	–	0.1 (17)	-0.1 (-17)
Condenser Makeup	0.4 (100)	–	0.4 (100)	–	0.4 (100)
BFW Makeup	0.4 (100)	–	0.4 (100)	–	0.4 (100)
Cooling Tower	22 (5,864)	0.3 (84)	22 (5,781)	5.0 (1,319)	17 (4,462)
BFW Blowdown	–	0.3 (84)	-0.3 (-84)	–	-0.3 (-84)
Total	25 (6,588)	0.3 (84)	25 (6,504)	5.1 (1,336)	20 (5,169)

4.2.4.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for the PC boiler, FGD unit, and steam cycle of Case B11A in Exhibit 4-25 and Exhibit 4-26.

An overall plant energy balance is provided in tabular form in Exhibit 4-27. The power out is the steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a generator efficiency of 98.5 percent.

This page intentionally left blank

Exhibit 4-25. Case B11A energy and mass balance, SubC PC boiler without CO₂ capture

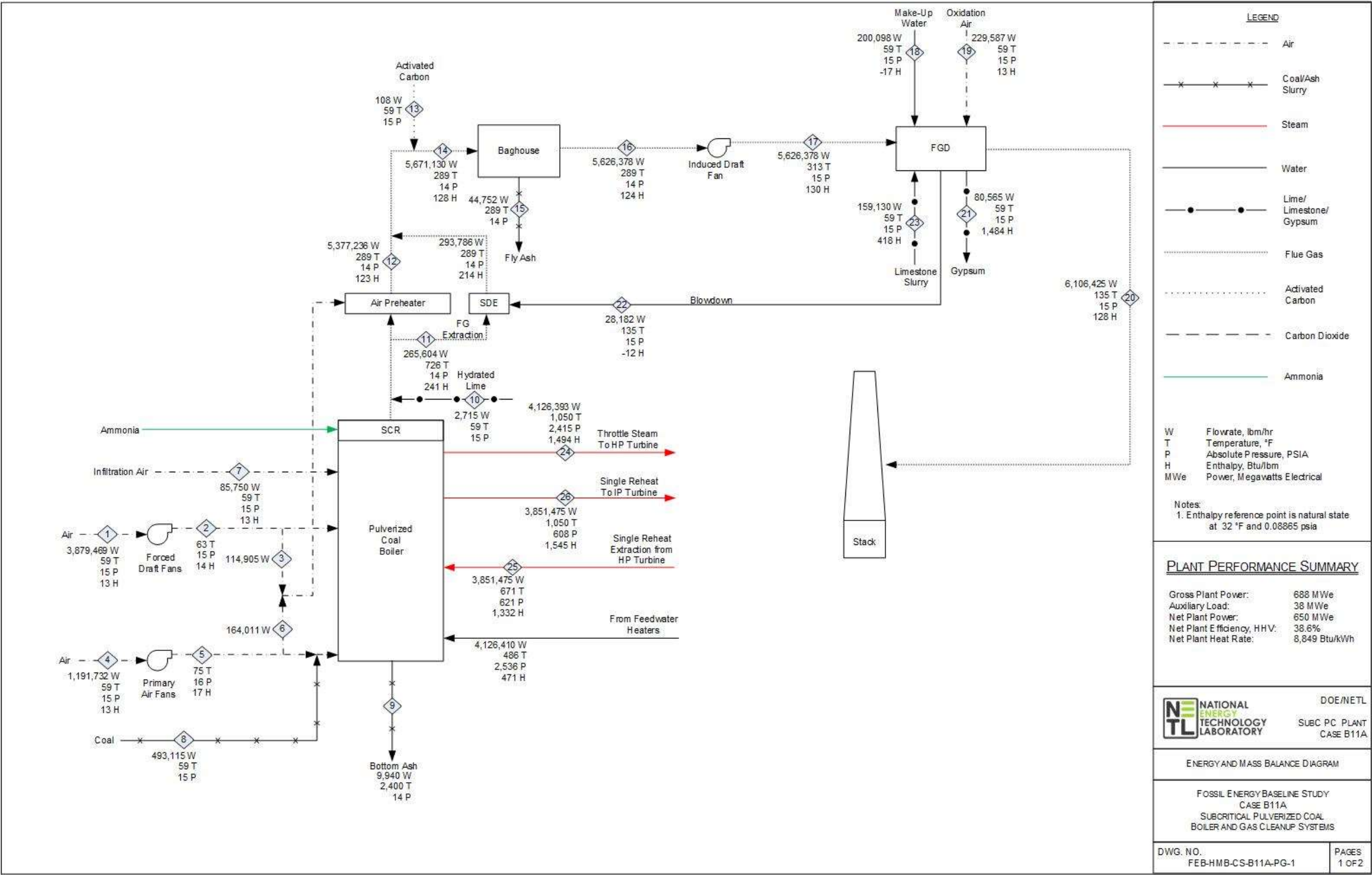


Exhibit 4-26. Case B11A energy and mass balance, SubC steam cycle

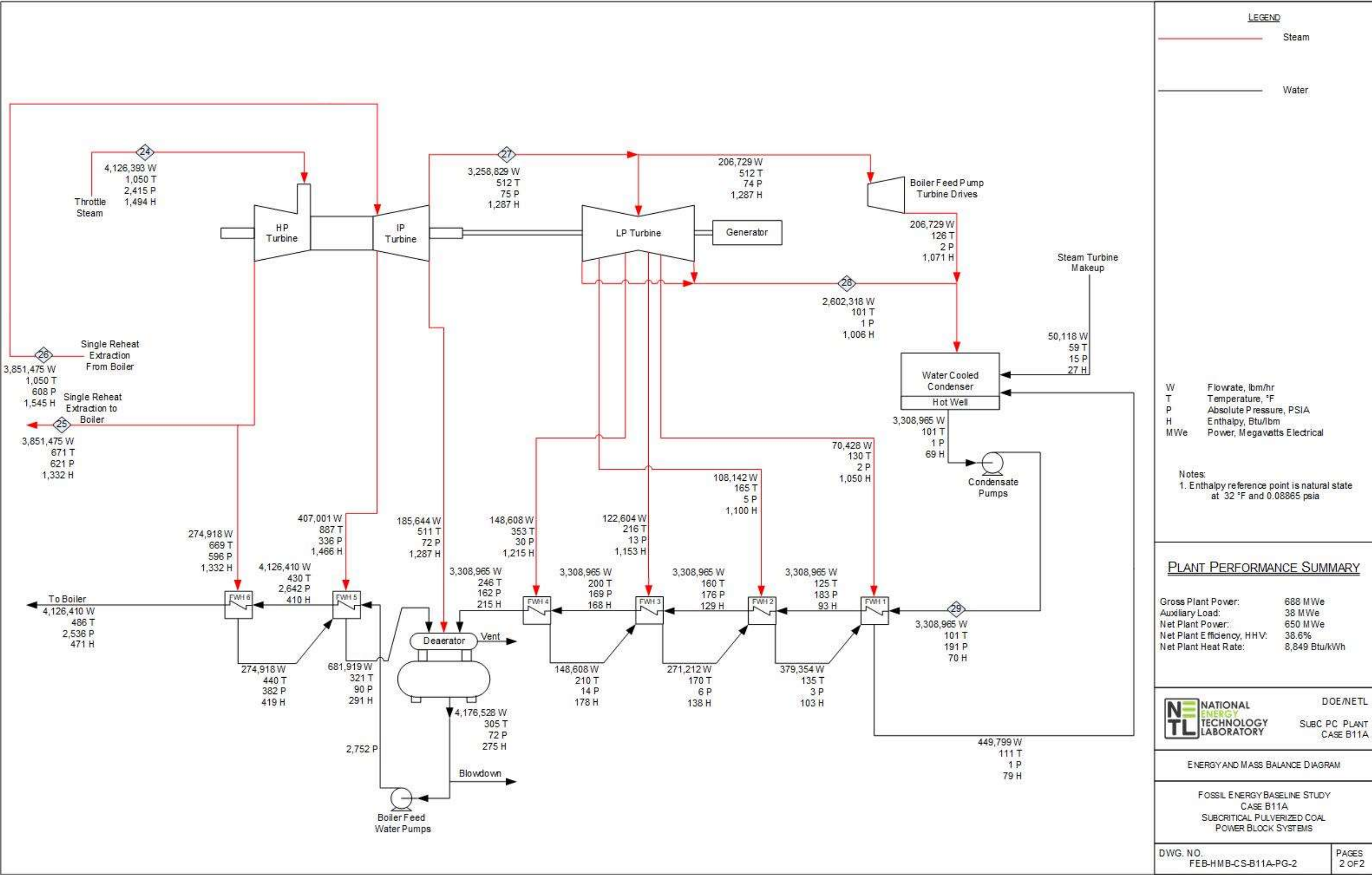


Exhibit 4-27. Case B11A overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	6,069 (5,753)	5.1 (4.8)	–	6,074 (5,757)
Air	–	71 (67)	–	71 (67)
Raw Water Makeup	–	93 (88)	–	93 (88)
Limestone	–	0.5 (0.4)	–	0.5 (0.4)
Auxiliary Power	–	–	135 (128)	135 (128)
TOTAL	6,069 (5,753)	169 (160)	135 (128)	6,373 (6,041)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	5.7 (5.4)	–	5.7 (5.4)
Fly Ash	–	2.1 (2.0)	–	2.1 (2.0)
Stack Gas	–	823 (780)	–	823 (780)
Sulfur	–	–	–	–
Gypsum	–	2.1 (2.0)	–	2.1 (2.0)
Motor Losses and Design Allowances	–	–	40 (38)	40 (38)
Cooling Tower Load ^A	–	2,899 (2,748)	–	2,899 (2,748)
CO ₂ Product Stream	–	–	–	–
AGR Effluent	–	–	–	–
Blowdown Streams and Deaerator Vent	–	14 (14)	–	14 (14)
<i>Ambient Losses^B</i>	–	<i>141 (134)</i>	–	<i>141 (134)</i>
Power	–	–	2,475 (2,346)	2,475 (2,346)
TOTAL	–	3,887 (3,684)	2,515 (2,384)	6,402 (6,068)
<i>Unaccounted Energy^C</i>	–	<i>-29 (-28)</i>	–	<i>-29 (-28)</i>

^AIncludes condenser and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^CBy difference

4.2.5 Case B11A – Major Equipment List

Major equipment items for the SubC PC plant with no CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.2.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B11A – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	50 tonne (50 ton)	2	1
9	Feeder	Vibratory	180 tonne/hr (200 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	370 tonne/hr (410 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	180 tonne (200 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/trippper	370 tonne/hr (410 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	370 tonne/hr (410 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	820 tonne (900 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 9 tonne (10 ton) Feeder - 50 kg/hr (120 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 230 tonne (250 ton) Feeder - 1,350 kg/hr (2,990 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	91 tonne/hr (100 tph)	1	0
23	Limestone Conveyor No. 1	Belt	91 tonne/hr (100 tph)	1	0
24	Limestone Reclaim Hopper	N/A	18 tonne (20 ton)	1	0
25	Limestone Reclaim Feeder	Belt	72 tonne/hr (79 tph)	1	0
26	Limestone Conveyor No. 2	Belt	72 tonne/hr (79 tph)	1	0
27	Limestone Day Bin	w/ actuator	286 tonne (315 ton)	2	0

Case B11A – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	41 tonne/hr (45 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	41 tonne/hr (45 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	24 tonne/hr (26 tph)	1	1
4	Limestone Ball Mill	Rotary	24 tonne/hr (26 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	91,000 liters (24,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,510 lpm @ 10m H ₂ O (400 gpm @ 40 ft H ₂ O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5-cyclone bank	380 lpm (100 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	515,000 liters (136,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,070 lpm @ 9m H ₂ O (280 gpm @ 30 ft H ₂ O)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B11A – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,503,000 liters (396,900 gal)	2	0
2	Condensate Pumps	Vertical canned	13,900 lpm @ 200 m H ₂ O (3,660 gpm @ 500 ft H ₂ O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,042,000 kg/hr (2,297,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	17,000 lpm @ 2,300 m H ₂ O (4,600 gpm @ 7,500 ft H ₂ O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	5,100 lpm @ 2,300 m H ₂ O (1,400 gpm @ 7,500 ft H ₂ O)	2	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	410,000 kg/hr (910,000 lb/hr)	4	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	410,000 kg/hr (910,000 lb/hr)	4	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	410,000 kg/hr (910,000 lb/hr)	4	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	410,000 kg/hr (910,000 lb/hr)	4	0
10	HP Feedwater Heater 5	Horizontal U-tube	1,030,000 kg/hr (2,270,000 lb/hr)	2	0
11	HP Feedwater Heater 6	Horizontal U-tube	1,030,000 kg/hr (2,270,000 lb/hr)	2	0
12	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
13	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
14	Service Air Compressors	Flooded Screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H ₂ O (5,500 gpm @ 100 ft H ₂ O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	6,600 lpm @ 20 m H ₂ O (1,740 gpm @ 60 ft H ₂ O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	2,640 lpm @ 270 m H ₂ O (700 gpm @ 880 ft H ₂ O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	1,200 lpm @ 50 m H ₂ O (320 gpm @ 160 ft H ₂ O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,159,000 liter (306,200 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	770 lpm (200 gpm)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,060 m ³ /min (72,700 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 120 lpm (30 gpm) @ 19,995 ppmw Cl ⁻	2	1

Case B11A – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum, wall-fired, low NOx burners, overfire air	2,060,000 kg/hr steam @ 16.5 MPa/566°C/566°C (4,540,000 lb/hr steam @ 2,400 psig/1,050°F/1,050°F)	1	0
2	Primary Air Fan	Centrifugal	297,000 kg/hr, 4,100 m ³ /min @ 101 cm WG (655,000 lb/hr, 143,300 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	968,000 kg/hr, 13,200 m ³ /min @ 26 cm WG (2,134,000 lb/hr, 466,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,404,000 kg/hr, 28,400 m ³ /min @ 114 cm WG (3,095,000 lb/hr, 1,004,000 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,660,000 kg/hr (5,850,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	100 m ³ /min @ 108 cm WG (3,500 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	109,000 liter (28,800 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	21 lpm @ 90 m H ₂ O (6 gpm @ 300 ft H ₂ O)	2	1

Case B11A – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,404,000 kg/hr (3,095,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	48,000 m ³ /min (1,680,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	165,000 lpm @ 65 m H ₂ O (44,000 gpm @ 210 ft H ₂ O)	5	1
4	Bleed Pumps	Horizontal centrifugal	4,570 lpm (1,210 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	780 m ³ /min @ 0.3 MPa (27,600 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,150 lpm (300 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	36 tonne/hr (40 tph) of 50 wt % slurry	2	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
9	Filtrate Water Return Pumps	Horizontal centrifugal	700 lpm @ 13 m H ₂ O (180 gpm @ 40 ft H ₂ O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	460,000 lpm (120,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	1,670 lpm @ 21 m H ₂ O (440 gpm @ 70 ft H ₂ O)	1	1
12	Activated Carbon Injectors	---	50 kg/hr (120 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,350 kg/hr (2,990 lb/hr)	1	0

Case B11A – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.4 m (21 ft) diameter	1	0

Case B11A – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	724 MW 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	800 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,540 GJ/hr (2,910 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0

Case B11A – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	572,000 lpm @ 30 m (151,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 3,190 GJ/hr (3,020 MMBtu/hr) heat duty	1	0

Case B11A – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	5.0 tonne/hr (5.5 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
9	Baghouse Hopper (part of baghouse scope of supply)	—	—	24	0
10	Air Heater Hopper (part of boiler scope of supply)	—	—	10	0
11	Air Blower	—	20 m ³ /min @ 0.2 MPa (708 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,320 tonne (1,450 ton)	2	0
13	Slide Gate Valves	—	—	2	0
14	Unloader	—	—	1	0
15	Telescoping Unloading Chute	—	120 tonne/hr (140 tph)	1	0

Case B11A – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
2	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 33 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 6 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B11A – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.2.6 Case B11A – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 4-28 shows a detailed breakdown of the capital costs; Exhibit 4-29 shows the owner's costs, TOC, and TASC; Exhibit 4-30 shows the initial and annual O&M costs; and Exhibit 4-31 shows the LCOE breakdown.

The estimated TPC of the SubC PC boiler with no CO₂ capture is \$2,015/kW. No process contingency is included in this case because all elements of the technology are commercially proven. The project contingency is 13.4 percent of the TPC. The LCOE is \$64.0/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-28. Case B11A total plant cost details

Case:		B11A	– SubC PC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1 Coal & Sorbent Handling											
1.1	Coal Receive & Unload	\$1,038	\$0	\$468	\$0	\$1,506	\$264	\$0	\$265	\$2,035	\$3
1.2	Coal Stackout & Reclaim	\$3,409	\$0	\$762	\$0	\$4,170	\$730	\$0	\$735	\$5,635	\$9
1.3	Coal Conveyors	\$31,401	\$0	\$7,471	\$0	\$38,872	\$6,803	\$0	\$6,851	\$52,526	\$81
1.4	Other Coal Handling	\$4,367	\$0	\$917	\$0	\$5,284	\$925	\$0	\$931	\$7,140	\$11
1.5	Sorbent Receive & Unload	\$200	\$0	\$60	\$0	\$259	\$45	\$0	\$46	\$350	\$1
1.6	Sorbent Stackout & Reclaim	\$1,454	\$0	\$263	\$0	\$1,717	\$300	\$0	\$303	\$2,320	\$4
1.7	Sorbent Conveyors	\$2,203	\$479	\$533	\$0	\$3,214	\$562	\$0	\$566	\$4,343	\$7
1.8	Other Sorbent Handling	\$106	\$25	\$55	\$0	\$186	\$33	\$0	\$33	\$251	\$0
1.9	Coal & Sorbent Handling Foundations	\$0	\$1,362	\$1,795	\$0	\$3,157	\$552	\$0	\$556	\$4,265	\$7
	Subtotal	\$44,177	\$1,865	\$12,323	\$0	\$58,365	\$10,214	\$0	\$10,287	\$78,866	\$121
2 Coal & Sorbent Preparation & Feed											
2.1	Coal Crushing & Drying	\$2,213	\$0	\$425	\$0	\$2,639	\$462	\$0	\$465	\$3,565	\$5
2.2	Prepared Coal Storage & Feed	\$7,450	\$0	\$1,604	\$0	\$9,054	\$1,585	\$0	\$1,596	\$12,235	\$19
2.5	Sorbent Preparation Equipment	\$977	\$42	\$200	\$0	\$1,219	\$213	\$0	\$215	\$1,647	\$3
2.6	Sorbent Storage & Feed	\$1,637	\$0	\$617	\$0	\$2,254	\$395	\$0	\$397	\$3,046	\$5
2.9	Coal & Sorbent Feed Foundation	\$0	\$649	\$570	\$0	\$1,219	\$213	\$0	\$215	\$1,647	\$3
	Subtotal	\$12,277	\$691	\$3,417	\$0	\$16,385	\$2,867	\$0	\$2,888	\$22,140	\$34
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$3,338	\$5,722	\$2,861	\$0	\$11,921	\$2,086	\$0	\$2,101	\$16,108	\$25
3.2	Water Makeup & Pretreating	\$6,020	\$602	\$3,411	\$0	\$10,033	\$1,756	\$0	\$2,358	\$14,146	\$22
3.3	Other Feedwater Subsystems	\$2,458	\$806	\$766	\$0	\$4,030	\$705	\$0	\$710	\$5,446	\$8
3.4	Service Water Systems	\$1,875	\$3,580	\$11,591	\$0	\$17,046	\$2,983	\$0	\$4,006	\$24,035	\$37
3.5	Other Boiler Plant Systems	\$605	\$220	\$550	\$0	\$1,375	\$241	\$0	\$242	\$1,858	\$3
3.6	Natural Gas Pipeline and Start-Up System	\$3,120	\$134	\$101	\$0	\$3,355	\$587	\$0	\$591	\$4,534	\$7
3.7	Waste Water Treatment Equipment	\$8,540	\$0	\$5,234	\$0	\$13,775	\$2,411	\$0	\$3,237	\$19,423	\$30
3.8	Spray Dryer Evaporator	\$14,457	\$0	\$8,371	\$0	\$22,828	\$3,995	\$0	\$5,364	\$32,187	\$50
3.9	Miscellaneous Plant Equipment	\$190	\$25	\$97	\$0	\$312	\$55	\$0	\$73	\$440	\$1
	Subtotal	\$40,604	\$11,089	\$32,982	\$0	\$84,675	\$14,818	\$0	\$18,684	\$118,176	\$182
4 Pulverized Coal Boiler & Accessories											
4.9	Pulverized Coal Boiler & Accessories	\$187,473	\$0	\$122,431	\$0	\$309,904	\$54,233	\$0	\$54,621	\$418,758	\$644
4.10	Selective Catalytic Reduction System	\$25,074	\$0	\$16,363	\$0	\$41,436	\$7,251	\$0	\$7,303	\$55,991	\$86
4.11	Boiler Balance of Plant	\$1,345	\$0	\$878	\$0	\$2,224	\$389	\$0	\$392	\$3,005	\$5
4.12	Primary Air System	\$1,402	\$0	\$916	\$0	\$2,318	\$406	\$0	\$409	\$3,132	\$5

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B11A	– SubC PC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
4.13	Secondary Air System	\$2,124	\$0	\$1,387	\$0	\$3,511	\$614	\$0	\$619	\$4,745	\$7
4.14	Induced Draft Fans	\$4,582	\$0	\$2,992	\$0	\$7,574	\$1,325	\$0	\$1,335	\$10,235	\$16
4.15	Major Component Rigging	\$77	\$0	\$50	\$0	\$127	\$22	\$0	\$22	\$172	\$0
4.16	Boiler Foundations	\$0	\$348	\$305	\$0	\$653	\$114	\$0	\$115	\$882	\$1
	Subtotal	\$222,078	\$348	\$145,323	\$0	\$367,748	\$64,356	\$0	\$64,816	\$496,919	\$764
5 Flue Gas Cleanup											
5.2	WFGD Absorber Vessels & Accessories	\$68,634	\$0	\$14,680	\$0	\$83,314	\$14,580	\$0	\$14,684	\$112,578	\$173
5.3	Other FGD	\$1,084	\$0	\$836	\$0	\$1,920	\$336	\$0	\$338	\$2,595	\$4
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$2,260	\$497	\$2,222	\$0	\$4,979	\$871	\$0	\$878	\$6,728	\$10
5.9	Particulate Removal (Bag House & Accessories) (included with 5.2)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5.12	Gas Cleanup Foundations	\$0	\$168	\$148	\$0	\$316	\$55	\$0	\$56	\$427	\$1
5.13	Gypsum Dewatering System	\$677	\$0	\$114	\$0	\$791	\$138	\$0	\$139	\$1,069	\$2
	Subtotal	\$72,655	\$666	\$18,000	\$0	\$91,321	\$15,981	\$0	\$16,095	\$123,397	\$190
7 Ductwork & Stack											
7.3	Ductwork	\$0	\$704	\$489	\$0	\$1,194	\$209	\$0	\$210	\$1,613	\$2
7.4	Stack	\$8,845	\$0	\$5,140	\$0	\$13,985	\$2,447	\$0	\$2,465	\$18,898	\$29
7.5	Duct & Stack Foundations	\$0	\$207	\$246	\$0	\$454	\$79	\$0	\$107	\$639	\$1
	Subtotal	\$8,845	\$912	\$5,876	\$0	\$15,633	\$2,736	\$0	\$2,782	\$21,150	\$33
8 Steam Turbine & Accessories											
8.1	Steam Turbine Generator & Accessories	\$60,034	\$0	\$6,749	\$0	\$66,784	\$11,687	\$0	\$11,771	\$90,241	\$139
8.2	Steam Turbine Plant Auxiliaries	\$1,365	\$0	\$2,902	\$0	\$4,266	\$747	\$0	\$752	\$5,765	\$9
8.3	Condenser & Auxiliaries	\$14,978	\$0	\$5,082	\$0	\$20,060	\$3,511	\$0	\$3,536	\$27,107	\$42
8.4	Steam Piping	\$32,023	\$0	\$12,978	\$0	\$45,001	\$7,875	\$0	\$7,931	\$60,808	\$94
8.5	Turbine Generator Foundations	\$0	\$213	\$351	\$0	\$564	\$99	\$0	\$133	\$795	\$1
	Subtotal	\$108,400	\$213	\$28,063	\$0	\$136,676	\$23,918	\$0	\$24,122	\$184,716	\$284
9 Cooling Water System											
9.1	Cooling Towers	\$13,653	\$0	\$4,222	\$0	\$17,875	\$3,128	\$0	\$3,151	\$24,154	\$37
9.2	Circulating Water Pumps	\$1,835	\$0	\$117	\$0	\$1,953	\$342	\$0	\$344	\$2,639	\$4
9.3	Circulating Water System Auxiliaries	\$12,003	\$0	\$1,589	\$0	\$13,591	\$2,378	\$0	\$2,395	\$18,365	\$28
9.4	Circulating Water Piping	\$0	\$5,550	\$5,026	\$0	\$10,576	\$1,851	\$0	\$1,864	\$14,291	\$22
9.5	Make-up Water System	\$1,052	\$0	\$1,352	\$0	\$2,403	\$421	\$0	\$424	\$3,247	\$5
9.6	Component Cooling Water System	\$865	\$0	\$664	\$0	\$1,528	\$267	\$0	\$269	\$2,065	\$3
9.7	Circulating Water System Foundations	\$0	\$530	\$880	\$0	\$1,410	\$247	\$0	\$331	\$1,988	\$3

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B11A	– SubC PC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
	Subtotal	\$29,408	\$6,080	\$13,849	\$0	\$49,337	\$8,634	\$0	\$8,778	\$66,750	\$103
10 Ash & Spent Sorbent Handling Systems											
10.6	Ash Storage Silos	\$1,047	\$0	\$3,202	\$0	\$4,249	\$744	\$0	\$749	\$5,741	\$9
10.7	Ash Transport & Feed Equipment	\$3,561	\$0	\$3,530	\$0	\$7,090	\$1,241	\$0	\$1,250	\$9,581	\$15
10.9	Ash/Spent Sorbent Foundation	\$0	\$729	\$895	\$0	\$1,624	\$284	\$0	\$382	\$2,290	\$4
	Subtotal	\$4,607	\$729	\$7,627	\$0	\$12,963	\$2,269	\$0	\$2,380	\$17,612	\$27
11 Accessory Electric Plant											
11.1	Generator Equipment	\$2,505	\$0	\$1,890	\$0	\$4,395	\$769	\$0	\$775	\$5,939	\$9
11.2	Station Service Equipment	\$4,680	\$0	\$402	\$0	\$5,082	\$889	\$0	\$896	\$6,867	\$11
11.3	Switchgear & Motor Control	\$7,266	\$0	\$1,261	\$0	\$8,526	\$1,492	\$0	\$1,503	\$11,521	\$18
11.4	Conduit & Cable Tray	\$0	\$945	\$2,722	\$0	\$3,666	\$642	\$0	\$646	\$4,954	\$8
11.5	Wire & Cable	\$0	\$2,501	\$4,471	\$0	\$6,972	\$1,220	\$0	\$1,229	\$9,422	\$14
11.6	Protective Equipment	\$55	\$0	\$191	\$0	\$246	\$43	\$0	\$43	\$332	\$1
11.7	Standby Equipment	\$785	\$0	\$724	\$0	\$1,509	\$264	\$0	\$266	\$2,039	\$3
11.8	Main Power Transformers	\$6,478	\$0	\$132	\$0	\$6,610	\$1,157	\$0	\$1,165	\$8,932	\$14
11.9	Electrical Foundations	\$0	\$206	\$524	\$0	\$730	\$128	\$0	\$172	\$1,029	\$2
	Subtotal	\$21,769	\$3,652	\$12,316	\$0	\$37,737	\$6,604	\$0	\$6,694	\$51,035	\$79
12 Instrumentation & Control											
12.1	Pulverized Coal Boiler Control Equipment	\$696	\$0	\$124	\$0	\$820	\$143	\$0	\$145	\$1,108	\$2
12.3	Steam Turbine Control Equipment	\$623	\$0	\$70	\$0	\$693	\$121	\$0	\$122	\$936	\$1
12.5	Signal Processing Equipment	\$790	\$0	\$141	\$0	\$931	\$163	\$0	\$164	\$1,258	\$2
12.6	Control Boards, Panels & Racks	\$242	\$0	\$148	\$0	\$390	\$68	\$0	\$69	\$526	\$1
12.7	Distributed Control System Equipment	\$6,818	\$0	\$1,216	\$0	\$8,033	\$1,406	\$0	\$1,416	\$10,855	\$17
12.8	Instrument Wiring & Tubing	\$477	\$382	\$1,528	\$0	\$2,387	\$418	\$0	\$421	\$3,225	\$5
12.9	Other Instrumentation & Controls Equipment	\$587	\$0	\$1,359	\$0	\$1,946	\$341	\$0	\$343	\$2,630	\$4
	Subtotal	\$10,233	\$382	\$4,585	\$0	\$15,200	\$2,660	\$0	\$2,679	\$20,539	\$32
13 Improvements to Site											
13.1	Site Preparation	\$0	\$414	\$8,848	\$0	\$9,263	\$1,621	\$0	\$2,177	\$13,060	\$20
13.2	Site Improvements	\$0	\$2,061	\$2,722	\$0	\$4,782	\$837	\$0	\$1,124	\$6,743	\$10
13.3	Site Facilities	\$2,354	\$0	\$2,470	\$0	\$4,824	\$844	\$0	\$1,134	\$6,802	\$10
	Subtotal	\$2,354	\$2,475	\$14,040	\$0	\$18,869	\$3,302	\$0	\$4,434	\$26,606	\$41
14 Buildings & Structures											
14.2	Boiler Building	\$0	\$11,587	\$10,183	\$0	\$21,771	\$3,810	\$0	\$3,837	\$29,418	\$45
14.3	Steam Turbine Building	\$0	\$16,106	\$15,001	\$0	\$31,107	\$5,444	\$0	\$5,483	\$42,033	\$65
14.4	Administration Building	\$0	\$1,046	\$1,106	\$0	\$2,152	\$377	\$0	\$379	\$2,909	\$4
14.5	Circulation Water Pump House	\$0	\$140	\$111	\$0	\$251	\$44	\$0	\$44	\$339	\$1
14.6	Water Treatment Buildings	\$0	\$390	\$355	\$0	\$745	\$130	\$0	\$131	\$1,006	\$2

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B11A	– SubC PC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
14.7	Machine Shop	\$0	\$552	\$371	\$0	\$922	\$161	\$0	\$163	\$1,246	\$2
14.8	Warehouse	\$0	\$415	\$415	\$0	\$831	\$145	\$0	\$146	\$1,123	\$2
14.9	Other Buildings & Structures	\$0	\$290	\$247	\$0	\$537	\$94	\$0	\$95	\$725	\$1
14.10	Waste Treating Building & Structures	\$0	\$629	\$1,910	\$0	\$2,539	\$444	\$0	\$448	\$3,431	\$5
	Subtotal	\$0	\$31,156	\$29,699	\$0	\$60,855	\$10,650	\$0	\$10,726	\$82,230	\$126
	Total	\$577,407	\$60,257	\$328,099	\$0	\$965,764	\$169,009	\$0	\$175,365	\$1,310,137	\$2,015

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-29. Case B11A owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$9,077	\$14
1 Month Maintenance Materials	\$1,233	\$2
1 Month Non-Fuel Consumables	\$1,748	\$3
1 Month Waste Disposal	\$760	\$1
25% of 1 Months Fuel Cost at 100% CF	\$2,338	\$4
2% of TPC	\$26,203	\$40
Total	\$41,359	\$64
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	\$21,659	\$33
0.5% of TPC (spare parts)	\$6,551	\$10
Total	\$28,210	\$43
Other Costs		
Initial Cost for Catalyst and Chemicals	\$2,135	\$3
Land	\$900	\$1
Other Owner's Costs	\$196,521	\$302
Financing Costs	\$35,374	\$54
Total Overnight Costs (TOC)	\$1,614,635	\$2,484
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	\$1,863,954	\$2,867

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-30. Case B11A initial and annual operating and maintenance costs

Case:	B11A	– SubC PC w/o CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):		8,849	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	% of base	Operator:	9.0	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	2.0	
				Total:	14.0	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$6,138,132	\$9.442
Maintenance Labor:					\$8,384,879	\$12.898
Administrative & Support Labor:					\$3,630,753	\$5.585
Property Taxes and Insurance:					\$26,202,747	\$40.307
Total:					\$44,356,511	\$68.232
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$12,577,319	\$2.59835
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (gal/1000):	0	4,683	\$1.90	\$0	\$2,760,524	\$0.57030
Makeup and Waste Water Treatment Chemicals (ton):	0	14.0	\$550.00	\$0	\$2,380,404	\$0.49177
Brominated Activated Carbon (ton):	0	1.29	\$1,600.00	\$0	\$642,680	\$0.13277
Enhanced Hydrated Lime (ton):	0	32.6	\$240.00	\$0	\$2,425,548	\$0.50110
Limestone (ton):	0	572	\$22.00	\$0	\$3,906,999	\$0.80715
Ammonia (19 wt%, ton):	0	54.9	\$300.00	\$0	\$5,111,783	\$1.05605
SCR Catalyst (ft³):	14,235	13.0	\$150.00	\$2,135,241	\$604,985	\$0.12498
Subtotal:				\$2,135,241	\$17,832,923	\$3.68411
Waste Disposal						
Fly Ash (ton):	0	537	\$38.00	\$0	\$6,331,262	\$1.30798
Bottom Ash (ton):	0	119	\$38.00	\$0	\$1,406,321	\$0.29053
SCR Catalyst (ft³):	0	13.0	\$2.50	\$0	\$10,083	\$0.00208
Subtotal:				\$0	\$7,747,666	\$1.60059
By-Products						
Gypsum (ton):	0	870	\$0.00	\$0	\$0	\$0.00000
Subtotal:				\$0	\$0	\$0.00000
Variable Operating Costs Total:				\$2,135,241	\$38,157,907	\$7.88306
Fuel Cost						
Illinois Number 6 (ton):	0	5,917	\$51.96	\$0	\$95,388,074	\$19.70626
Total:				\$0	\$95,388,074	\$19.70626

Exhibit 4-31. Case B11A LCOE breakdown

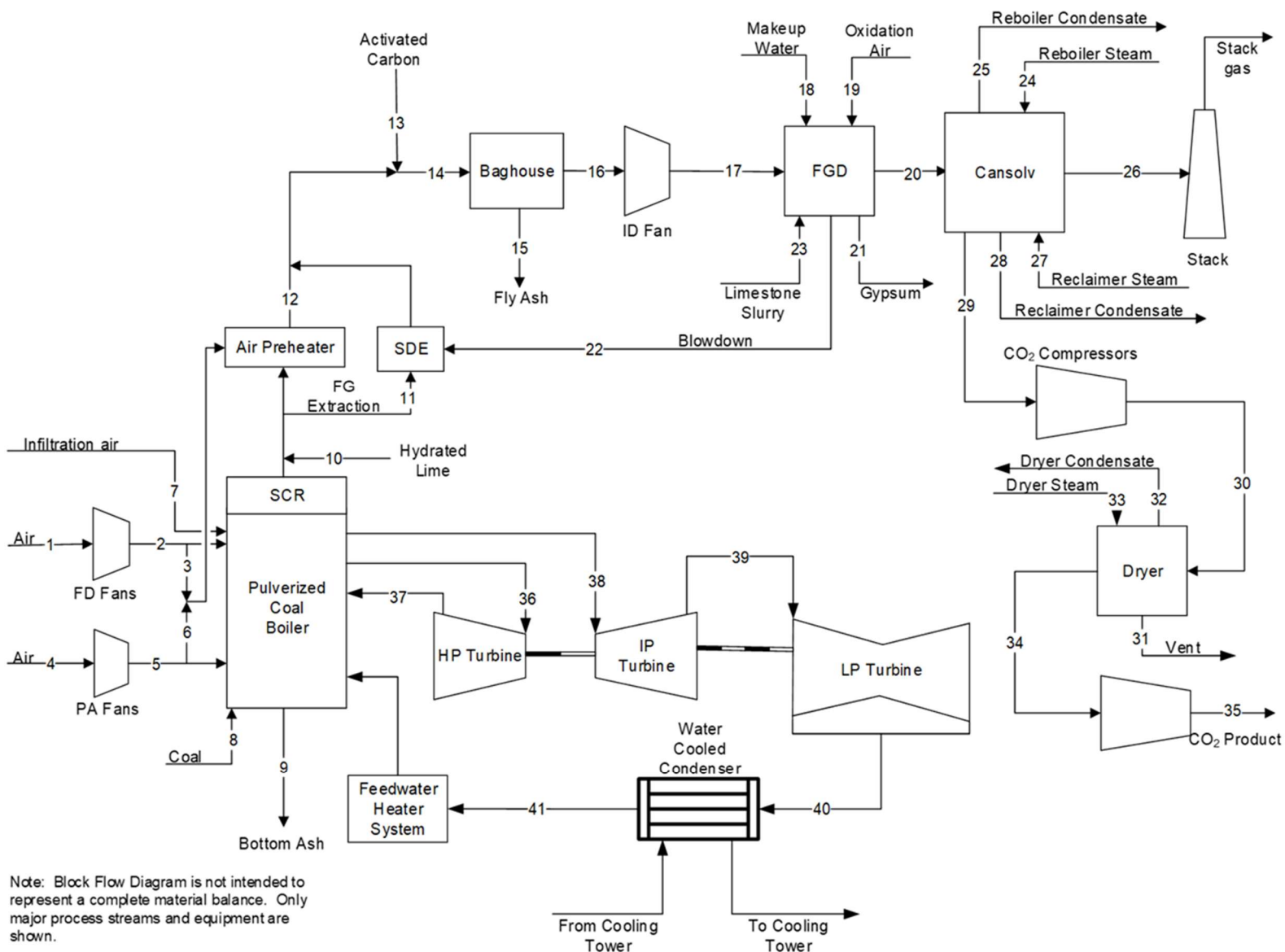
Component	Value, \$/MWh	Percentage
Capital	27.2	43%
Fixed	9.2	14%
Variable	7.9	12%
Fuel	19.7	31%
Total (Excluding T&S)	64.0	N/A
CO ₂ T&S	–	–
Total (Including T&S)	64.0	N/A

4.2.7 Case B11B.90 – SubC PC with 90 Percent CO₂ Capture Process Description

The plant configuration and process description for Case B11B.90 are nearly the same as Case B11A, with the exception that the CANSOLV system was used for the CDR facility. Since the process descriptions of the plant and CDR facility were provided in Section 4.2.3 and Section 4.1.8, respectively, they are not repeated here.

The BFD for Case B11B.90 is shown in Exhibit 4-32. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 4-33. The modeling assumptions were presented previously in Section 4.2.1.

Exhibit 4-32. Case B11B.90 block flow diagram, SubC unit with CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-33. Case B11B.90 stream table, SubC unit with capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0087	0.0088	0.0000	0.0087	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379	0.0000	0.1372	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837	0.0000	0.0911	0.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340	0.0000	0.7281	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336	0.0000	0.0329	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020	0.0000	0.0020	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1158
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.8842
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	78,024	78,024	2,311	23,968	23,968	3,299	1,725	0	0	1	5,141	104,299	0	110,311	7
V-L Flowrate (kg/hr)	2,251,529	2,251,529	66,687	691,646	691,646	95,187	49,767	0	0	16	152,916	3,097,080	0	3,266,106	706
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	286,189	5,769	1,560	1,235	23,707	63	25,250	25,267
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143	15	143	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.31	-6.79	-2,453.14	-1,065.95
Density (kg/m ³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8	---	0.8	2,150.2
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694	---	29.608	104.898
V-L Flowrate (lb _{mol} /hr)	172,013	172,013	5,095	52,841	52,841	7,272	3,802	0	0	2	11,335	229,939	0	243,195	15
V-L Flowrate (lb/hr)	4,963,772	4,963,772	147,020	1,524,819	1,524,819	209,852	109,717	0	0	35	337,123	6,827,892	0	7,200,532	1,556
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	630,940	12,719	3,439	2,723	52,264	138	55,666	55,703
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289	59	289	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1	14.7	14.1	14.1
Steam Table Enthalpy (Btu/lb) ^A	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4	-2.9	-1,054.7	-458.3
Density (lb/ft ³)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052	---	0.052	134.232

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-33. Case B11B.90 stream table, SubC unit with capture (continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0101	0.0000	0.0000	0.0000	0.0000
CO ₂	0.1372	0.1372	0.9999	0.0003	0.1245	0.0001	0.0000	0.0000	0.0000	0.0000	0.0156	0.0000	0.0000	0.9783	0.9975
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0911	0.0911	0.0000	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000	1.0000	0.0807	1.0000	1.0000	0.0217	0.0025
HCl	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000	0.0000	0.8483	0.0000	0.0000	0.0000	0.0000
O ₂	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000	0.0000	0.0453	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0020	0.0020	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	1.0000	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000		0.0000	0.0000	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	6,444	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
			116,116												
V-L Flowrate (kg _{mol} /hr)	110,305	110,305	0	4,617	123,311	260	871	3,589	35,464	32,481	98,889	397	397	14,114	13,842
V-L Flowrate (kg/hr)	3,265,384	3,265,384		133,245	3,543,988	4,678	16,110	64,670	638,896	585,162	2,744,882	7,146	7,146	613,197	608,296
Solids Flowrate (kg/hr)	0	0	15	0	0	42,080	245	27,684	0	0	0	0	0	0	0
			0.10												
Temperature (°C)	143	156	-47.80	15	57	15	57	15	266	105	45	355	214	31	29
Pressure (MPa, abs)	0.10	0.11	16,015.01	0.10	0.10	0.10	0.10	0.10	0.48	0.12	0.10	4.28	2.04	0.17	2.81
Steam Table Enthalpy (kJ/kg) ^A	287.58	302.09	1,003.7	30.23	297.00	---	---	---	2,994.07	439.34	178.41	3,098.44	913.81	46.68	-3.05
AspenPlus Enthalpy (kJ/kg) ^B	-2,464.17	-2,449.66	18.019	-97.58	-2,939.24	-12,513.34	-15,496.21	14,994.25	12,986.23	-15,540.95	-903.21	12,881.86	15,066.49	-8,978.62	-8,972.51
Density (kg/m ³)	0.8	0.9		1.2	1.1	878.3	979.4	1,003.7	2.0	954.9	1.1	16.0	848.5	3.0	57.8
V-L Molecular Weight	29.603	29.603	14,207	28.857	28.740	18.021	18.494	18.019	18.015	18.015	27.757	18.015	18.015	43.445	43.945
			255,993												
V-L Flowrate (lb _{mol} /hr)	243,180	243,180	0	10,180	271,854	572	1,920	7,913	78,185	71,609	218,012	874	874	31,116	30,517
V-L Flowrate (lb/hr)	7,198,939	7,198,939		293,755	7,813,157	10,313	35,517	142,573	1,408,525	1,290,060	6,051,428	15,753	15,753	1,351,867	1,341,063
Solids Flowrate (lb/hr)	0	0	59	0	0	92,769	541	61,033	0	0	0	0	0	0	0
			14.7												
Temperature (°F)	289	313	-20.5	59	135	59	135	59	511	221	113	671	416	87	85
Pressure (psia)	13.9	15.3	-6,885.2	14.7	14.8	14.7	14.7	14.7	70.0	17.4	14.8	620.5	296.6	24.7	407.6
Steam Table Enthalpy (Btu/lb) ^A	123.6	129.9	62.658	13.0	127.7	---	---	---	1,287.2	188.9	76.7	1,332.1	392.9	20.1	-1.3
AspenPlus Enthalpy (Btu/lb) ^B	-1,059.4	-1,053.2	0.0000	-42.0	-1,263.6	-5,379.8	-6,662.2	-6,446.4	-5,583.1	-6,681.4	-388.3	-5,538.2	-6,477.4	-3,860.1	-3,857.5
Density (lb/ft ³)	0.051	0.055	0.9999	0.076	0.067	54.833	61.145	62.658	0.123	59.612	0.067	1.000	52.968	0.184	3.609

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-33. Case B11B.90 stream table, SubC unit with capture (continued)

	31	32	33	34	35	36	37	38	39	40	41
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0500	0.0000	0.0000	0.9995	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	29	18	18	13,813	13,813	133,003	123,745	123,745	103,920	51,884	73,055
V-L Flowrate (kg/hr)	561	320	320	607,735	607,735	2,396,093	2,229,310	2,229,310	1,872,154	934,712	1,316,103
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	29	203	476	29	30	566	355	566	267	38	39
Pressure (MPa, abs)	2.81	1.64	2.42	2.68	15.27	16.65	4.28	4.19	0.52	0.01	1.32
Steam Table Enthalpy (kJ/kg) ^A	137.94	863.65	3,408.95	-3.59	-231.09	3,473.89	3,098.44	3,593.58	2,994.07	2,340.01	162.43
AspenPlus Enthalpy (kJ/kg) ^B	-15,225.22	-15,116.65	-12,571.34	-8,967.15	-9,194.65	-12,506.41	-12,881.86	-12,386.71	-12,986.23	-13,640.29	-15,817.87
Density (kg/m ³)	351.5	861.8	7.1	54.7	630.1	47.7	16.0	11.1	2.1	0.1	993.3
V-L Molecular Weight	19.315	18.015	18.015	43.997	43.997	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	64	39	39	30,453	30,453	293,222	272,812	272,812	229,105	114,386	161,058
V-L Flowrate (lb/hr)	1,236	705	705	1,339,827	1,339,827	5,282,481	4,914,787	4,914,787	4,127,393	2,060,687	2,901,511
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	85	397	888	85	86	1,050	671	1,050	512	101	101
Pressure (psia)	407.6	237.4	350.5	389.1	2,214.7	2,414.7	620.5	608.1	75.0	1.0	190.7
Steam Table Enthalpy (Btu/lb) ^A	59.3	371.3	1,465.6	-1.5	-99.4	1,493.5	1,332.1	1,545.0	1,287.2	1,006.0	69.8
AspenPlus Enthalpy (Btu/lb) ^B	-6,545.7	-6,499.0	-5,404.7	-3,855.2	-3,953.0	-5,376.8	-5,538.2	-5,325.3	-5,583.1	-5,864.3	-6,800.5
Density (lb/ft ³)	21.943	53.801	0.446	3.416	39.338	2.975	1.000	0.692	0.132	0.003	62.010

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

4.2.8 Case B11B.90 – Performance Results

Overall plant performance is summarized in Exhibit 4-34; Exhibit 4-35 provides a detailed breakdown of the auxiliary power requirements.

The CDR facility, including CO₂ compression, accounts for over half of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for over 12 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility and CO₂ compressors.

Unlike the NGCC cases where gross output was fixed by the available size of the CTs, the PC cases utilize boilers and steam turbines that can be procured at nearly any desired output. By increasing the boiler and turbine/generator size to account for the greater auxiliary load imposed by the CDR facility and CO₂ compressors, a net output of 650 MW is maintained at a reduced net plant efficiency of 30.2 percent (HHV basis).

Exhibit 4-34. Case B11B.90 plant performance summary

Performance Summary	
Total Gross Power, MWe	769
CO ₂ Capture/Removal Auxiliaries, kWe	18,800
CO ₂ Compression, kWe	48,660
Balance of Plant, kWe	50,620
Total Auxiliaries, MWe	118
Net Power, MWe	650
HHV Net Plant Efficiency, %	30.2
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,940 (11,317)
LHV Net Plant Efficiency, %	31.3
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,516 (10,915)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	55.1
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	6,532 (6,191)
Condenser Duty, GJ/hr (MMBtu/hr)	2,312 (2,191)
CO ₂ Capture Rate, %	90
AGR Duty, GJ/hr (MMBtu/hr)	2,162 (2,050)
As-Received Coal Feed, kg/hr (lb/hr)	286,189 (630,940)
Limestone Sorbent Feed, kg/hr (lb/hr)	27,684 (61,033)
HHV Thermal Input, kWt	2,157,162
LHV Thermal Input, kWt	2,080,609
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.058 (15.3)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.043 (11.4)
Excess Air, %	20.3

Exhibit 4-35. Case B11B.90 plant power summary

Power Summary	
Steam Turbine Power, MWe	769
Total Gross Power, MWe	769
Auxiliary Load Summary	
Activated Carbon Injection, kWe	40
Ash Handling, kWe	940
Baghouse, kWe	120
Circulating Water Pumps, kWe	9,670
CO ₂ Capture/Removal Auxiliaries, kWe	18,800
CO ₂ Compression, kWe	48,660
Coal Handling and Conveying, kWe	540
Condensate Pumps, kWe	720
Cooling Tower Fans, kWe	5,000
Dry Sorbent Injection, kWe	80
Flue Gas Desulfurizer, kWe	4,420
Forced Draft Fans, kWe	1,470
Ground Water Pumps, kWe	900
Induced Draft Fans, kWe	13,570
Miscellaneous Balance of Plant ^{A,B} , kWe	2,250
Primary Air Fans, kWe	1,740
Pulverizers, kWe	4,290
SCR, kWe	50
Sorbent Handling & Reagent Preparation, kWe	1,330
Spray Dryer Evaporator, kWe	320
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,670
Total Auxiliaries, MWe	118
Net Power, MWe	650

^ABoiler feed pumps are turbine driven

^BIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

4.2.8.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B11B.90 is presented in Exhibit 4-36. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 4-36. Case B11B.90 air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.031 (0.073)	1,817 (2,003)	0.318 (0.700)
Particulate	0.004 (0.009)	234 (258)	0.041 (0.090)
Hg	1.35E-7 (3.13E-7)	0.008 (0.009)	1.36E-6 (3.00E-6)
CO ₂	9 (20)	504,986 (556,652)	88 (195)
CO ₂ ^C	—	—	104 (230)
mg/Nm ³			
Particulate Concentration ^{D,E}	12.69		

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

^DConcentration of particles in the flue gas after the baghouse

^ENormal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The SO₂ emissions are further reduced to 0.37 ppmv using a NaOH based polishing scrubber in the CDR facility. The remaining low concentration of SO₂ is essentially completely removed in the CDR absorber vessel resulting in very low SO₂ emissions (reported as zero here).

NO_x boiler emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 79.1 percent to 0.03 kg/GJ (0.07 lb/MMBtu).

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and wet FGD) is 97.6 percent.

Ninety percent of the CO₂ in the flue gas is removed in CDR facility.

The carbon balance for the plant is shown in Exhibit 4-37. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon leaves the plant mostly as CO₂ product from the CO₂ compression train; however, some CO₂ exits through the stack, the PAC is captured in the fabric filter, unburned carbon remains in the bottom ash, and some leaves as gypsum. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in (minus unburnt carbon in ash), represented by the following fraction:

$$1 - \frac{\text{Carbon in Stack}}{\text{Total Carbon In} - \text{Unburnt Carbon}} = \left(1 - \left(\frac{40,806}{409,459 - 483} \right) \right) * 100 = 90\%$$

Exhibit 4-37. Case B11B.90 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	182,431 (402,191)	Stack Gas	18,509 (40,806)
Air (CO ₂)	425 (937)	FGD Product	216 (477)
PAC	63 (138)	Baghouse	938 (2,069)
FGD Reagent	2,809 (6,193)	Bottom Ash	219 (483)
		CO ₂ Product	165,827 (365,586)
		CO ₂ Dryer Vent	17 (38)
		CO ₂ Knockout	0.5 (1.0)
Total	185,728 (409,459)	Total	185,728 (409,459)

Exhibit 4-38 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur removed in the polishing scrubber, and sulfur removed in the baghouse.

Exhibit 4-38. Case B11B.90 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	7,173 (15,814)	FGD Product	6,744 (14,868)
		Stack Gas	0.0 (0.0)
		Polishing Scrubber and Solvent Reclaiming	140 (309)
		Baghouse	289 (637)
Total	7,173 (15,814)	Total	7,173 (15,814)

Exhibit 4-39 shows the overall water balance for the plant. The exhibit is presented in an identical manner as was for Case B11A. The only notable difference is the FGD makeup water source. In CO₂ capture cases, a significant amount of water is recovered from the initial CDR facility cooling step. This water would otherwise be discharged; however, it is suitable to be used as FGD makeup. The balance of the water from the CDR facility is sent to discharge.

Exhibit 4-39. Case B11B.90 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
FGD Process Makeup	1.9 (512)	1.9 (512)	–	–	–
FGD Slurry Water	1.1 (285)	1.1 (285)	–	–	–
CO ₂ Drying	–	–	–	0.0 (2.5)	0.0 (-2.5)
CO ₂ Capture Recovery	–	–	–	1.0 (258)	-1.0 (-258)
CO ₂ Compression KO	–	–	–	0.1 (22)	-0.1 (-22)
Deaerator Vent	–	–	–	0.1 (21)	-0.1 (-21)
Condenser Makeup	0.5 (128)	–	0.5 (128)	–	0.5 (128)
BFW Makeup	0.5 (128)	–	0.5 (128)	–	0.5 (128)
Cooling Tower	38 (9,952)	0.4 (107)	37 (9,845)	8.5 (2,238)	29 (7,607)
BFW Blowdown	–	0.4 (107)	-0.4 (-107)	–	-0.4 (-107)
Total	41 (10,877)	3.4 (904)	38 (9,973)	9.6 (2,542)	28 (7,431)

4.2.8.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for the Case B11B.90 PC boiler, FGD unit, CDR system and steam cycle in Exhibit 4-40 and Exhibit 4-41. An overall plant energy balance is provided in tabular form in Exhibit 4-42.

The power out is the steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a generator efficiency of 98.5 percent. The cooling tower load includes the condenser, capture process heat rejected to cooling water, the CO₂ compressor intercooler load, and other miscellaneous cooling loads.

Exhibit 4-40. Case B11B.90 energy and mass balance, SubC PC boiler with CO₂ capture

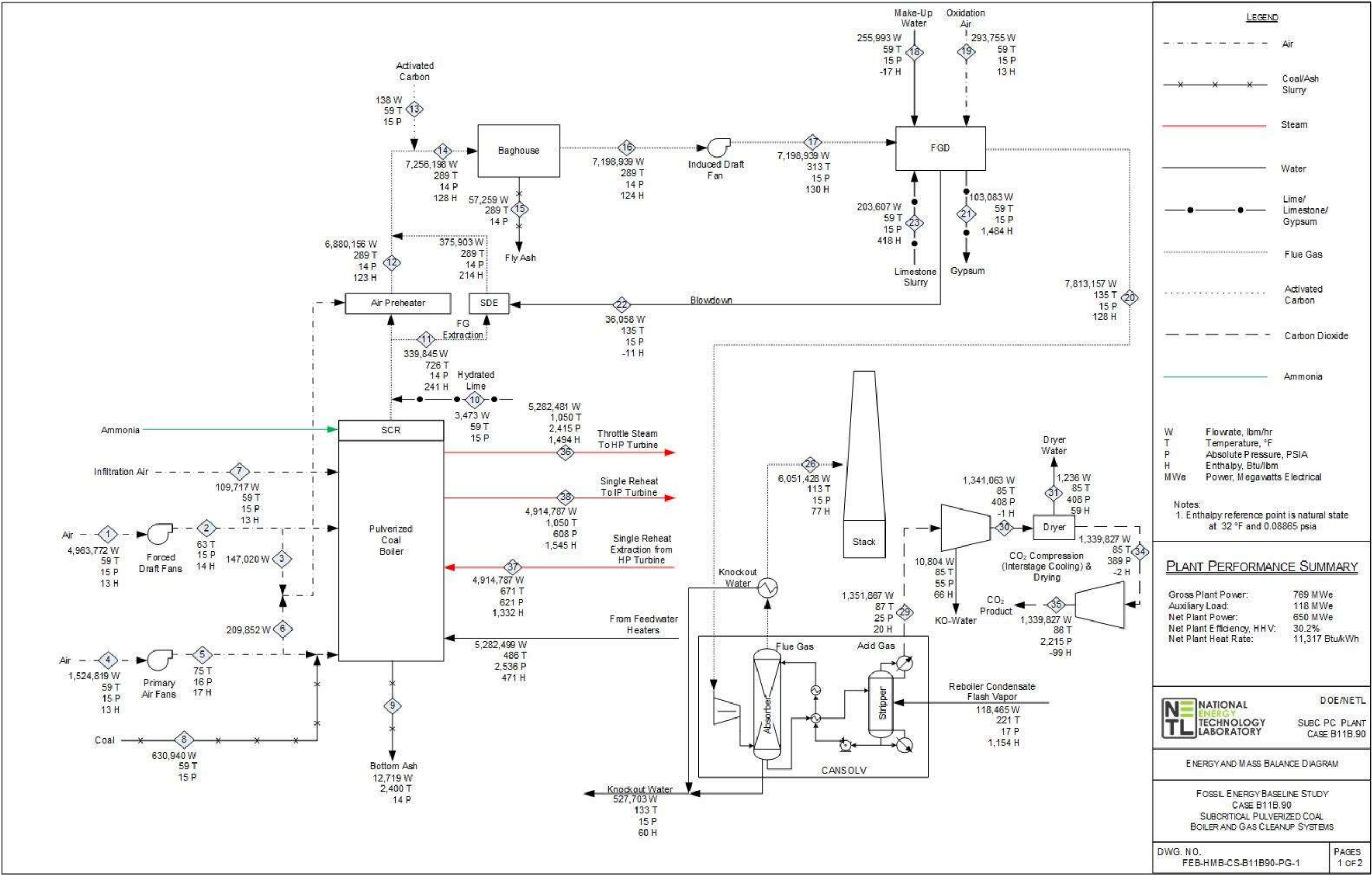


Exhibit 4-41. Case B11B.90 energy and mass balance, SubC steam cycle

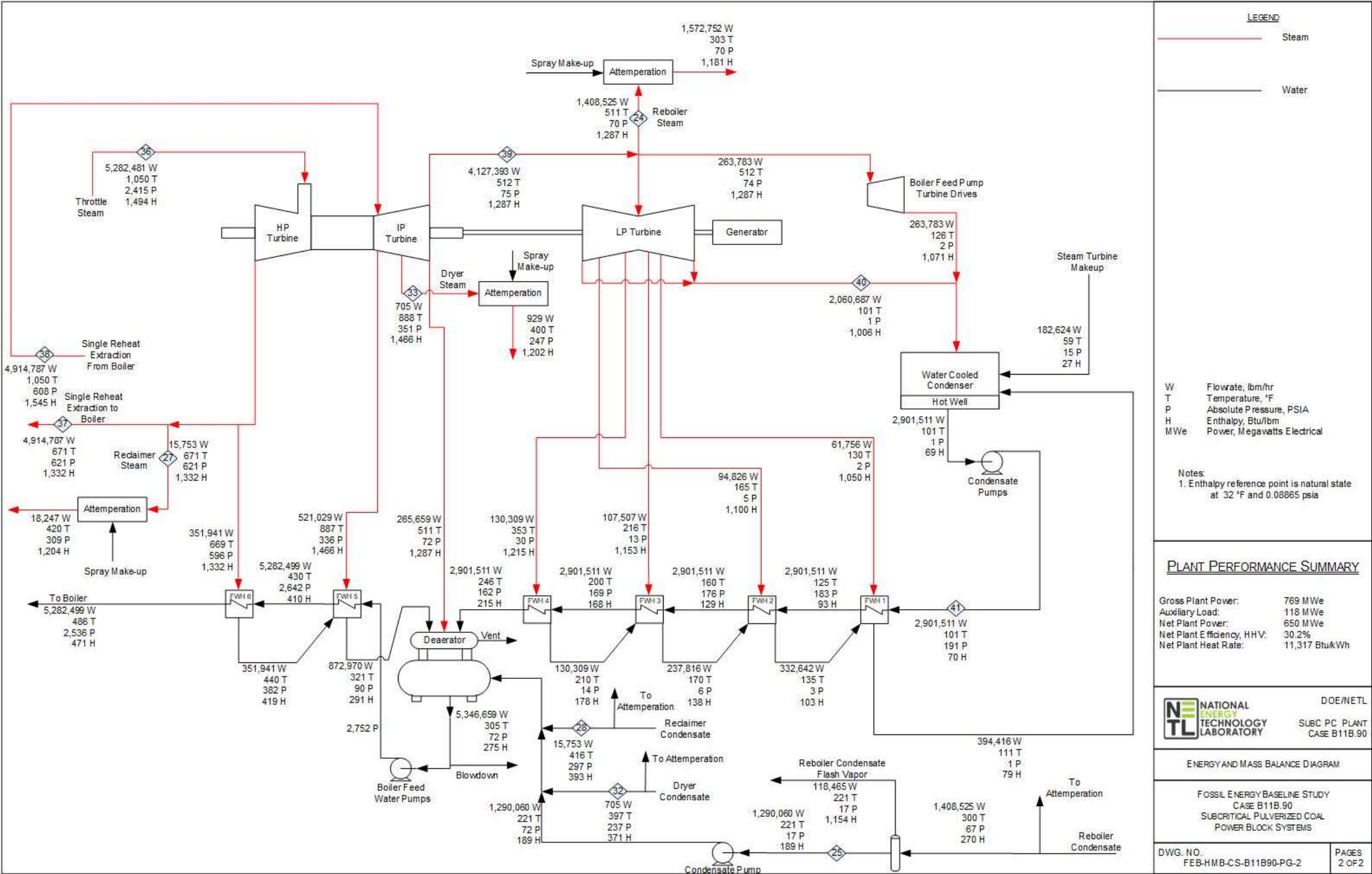


Exhibit 4-42. Case B11B.90 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	7,766 (7,361)	6.5 (6.1)	—	7,772 (7,367)
Air	—	90 (86)	—	90 (86)
Raw Water Makeup	—	142 (135)	—	142 (135)
Limestone	—	0.6 (0.6)	—	0.6 (0.6)
Auxiliary Power	—	—	425 (403)	425 (403)
TOTAL	7,766 (7,361)	240 (227)	425 (403)	8,430 (7,990)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	—	7.4 (7.0)	—	7.4 (7.0)
Fly Ash	—	2.7 (2.5)	—	2.7 (2.5)
Stack Gas	—	490 (464)	—	490 (464)
Sulfur	2.6 (2.5)	0.0 (0.0)	—	2.6 (2.5)
Gypsum	—	2.7 (2.6)	—	2.7 (2.6)
Motor Losses and Design Allowances	—	—	51 (48)	51 (48)
Cooling Tower Load ^A	—	4,919 (4,663)	—	4,919 (4,663)
CO ₂ Product Stream	—	-140 (-133)	—	-140 (-133)
AGR Effluent	—	56 (53)	—	56 (53)
Blowdown Streams and Deaerator Vent	—	18 (18)	—	18 (18)
Ambient Losses ^B	—	181 (172)	—	181 (172)
Power	—	—	2,767 (2,622)	2,767 (2,622)
TOTAL	2.6 (2.5)	5,537 (5,248)	2,817 (2,670)	8,357 (7,921)
<i>Unaccounted Energy^C</i>	—	73 (69)	—	73 (69)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^CBy difference

4.2.9 Case B11B.90 – Major Equipment List

Major equipment items for the SubC PC plant with CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.2.10. In general, the design conditions include a 10 percent

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

Case B11B.90 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	60 tonne (70 ton)	2	1
9	Feeder	Vibratory	240 tonne/hr (260 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	470 tonne/hr (520 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	240 tonne (260 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	470 tonne/hr (520 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	470 tonne/hr (520 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,050 tonne (1,160 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 12 tonne (13 ton) Feeder - 70 kg/hr (150 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 290 tonne (320 ton) Feeder - 1,730 kg/hr (3,820 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	116 tonne/hr (128 tph)	1	0
23	Limestone Conveyor No. 1	Belt	116 tonne/hr (128 tph)	1	0
24	Limestone Reclaim Hopper	N/A	23 tonne (25 ton)	1	0
25	Limestone Reclaim Feeder	Belt	92 tonne/hr (101 tph)	1	0
26	Limestone Conveyor No. 2	Belt	92 tonne/hr (101 tph)	1	0
27	Limestone Day Bin	w/ actuator	365 tonne (403 ton)	2	0

Case B11B.90 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	52 tonne/hr (58 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	52 tonne/hr (58 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	30 tonne/hr (34 tph)	1	1
4	Limestone Ball Mill	Rotary	30 tonne/hr (34 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	115,800 liters (30,600 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,950 lpm @ 10m H ₂ O (510 gpm @ 40 ft H ₂ O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5-cyclone bank	490 lpm (130 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
9	Limestone Slurry Storage Tank with Agitator	Field erected	658,000 liters (174,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,370 lpm @ 9m H ₂ O (360 gpm @ 30 ft H ₂ O)	1	1

Case B11B.90 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,924,000 liters (508,100 gal)	2	0
2	Condensate Pumps	Vertical canned	12,100 lpm @ 200 m H ₂ O (3,210 gpm @ 500 ft H ₂ O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,334,000 kg/hr (2,941,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	22,000 lpm @ 2,300 m H ₂ O (5,800 gpm @ 7,500 ft H ₂ O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	6,600 lpm @ 2,300 m H ₂ O (1,700 gpm @ 7,500 ft H ₂ O)	2	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	360,000 kg/hr (800,000 lb/hr)	4	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	360,000 kg/hr (800,000 lb/hr)	4	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	360,000 kg/hr (800,000 lb/hr)	4	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	360,000 kg/hr (800,000 lb/hr)	4	0
10	HP Feedwater Heater 5	Horizontal U-tube	1,320,000 kg/hr (2,910,000 lb/hr)	2	0
11	HP Feedwater Heater 6	Horizontal U-tube	1,320,000 kg/hr (2,910,000 lb/hr)	2	0
12	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
13	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
14	Service Air Compressors	Flooded Screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H ₂ O (5,500 gpm @ 100 ft H ₂ O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	10,200 lpm @ 20 m H ₂ O (2,680 gpm @ 60 ft H ₂ O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	4,060 lpm @ 270 m H ₂ O (1,070 gpm @ 880 ft H ₂ O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	1,560 lpm @ 50 m H ₂ O (410 gpm @ 160 ft H ₂ O)	2	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
23	Filtered Water Tank	Vertical, cylindrical	1,499,000 liter (396,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	980 lpm (260 gpm)	1	1
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,630 m ³ /min (93,100 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 150 lpm (40 gpm) @ 19,983 ppmw Cl ⁻	2	1

Case B11B.90 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum, wall-fired, low NOx burners, overfire air	2,640,000 kg/hr steam @ 16.5 MPa/566°C/566°C (5,810,000 lb/hr steam @ 2,400 psig/1,050°F/1,050°F)	1	0
2	Primary Air Fan	Centrifugal	380,000 kg/hr, 5,200 m ³ /min @ 101 cm WG (839,000 lb/hr, 183,300 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,238,000 kg/hr, 16,900 m ³ /min @ 26 cm WG (2,730,000 lb/hr, 597,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,796,000 kg/hr, 36,400 m ³ /min @ 114 cm WG (3,959,000 lb/hr, 1,284,800 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,400,000 kg/hr (7,490,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	130 m ³ /min @ 108 cm WG (4,700 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	145,000 liter (38,400 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	28 lpm @ 90 m H ₂ O (7 gpm @ 300 ft H ₂ O)	2	1

Case B11B.90 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,796,000 kg/hr (3,960,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	60,900 m ³ /min (2,150,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	212,000 lpm @ 65 m H ₂ O (55,900 gpm @ 210 ft H ₂ O)	5	1
4	Bleed Pumps	Horizontal centrifugal	5,850 lpm (1,540 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	1,000 m ³ /min @ 0.3 MPa (35,320 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,460 lpm (390 gpm) per cyclone	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
8	Vacuum Filter Belt	Horizontal belt	46 tonne/hr (51 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	890 lpm @ 13 m H ₂ O (240 gpm @ 40 ft H ₂ O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	580,000 lpm (150,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	2,130 lpm @ 21 m H ₂ O (560 gpm @ 70 ft H ₂ O)	1	1
12	Activated Carbon Injectors	---	70 kg/hr (150 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,730 kg/hr (3,820 lb/hr)	1	0
14	CANSOLV	Amine-based CO ₂ capture technology	3,898,000 kg/hr (8,594,000 lb/hr) 19.1 wt % CO ₂ concentration	1	0
15	CANSOLV LP Condensate Pump	Centrifugal	1,368 lpm @ 1 m H ₂ O (361 gpm @ 3 ft H ₂ O)	1	1
16	CANSOLV IP Condensate Pump	Centrifugal	21 lpm @ 4.6 m H ₂ O (6 gpm @ 15 ft H ₂ O)	1	1
17	CO ₂ Dryer	Triethylene glycol	Inlet: 175 m ³ /min @ 2.8 MPa (6,193 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Recovered: 561 kg/hr (1,236 lb/hr)	1	0
18	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	9.0 m ³ /min @ 15.3 MPa, 82°C (312 acfm @ 2,217 psia, 180°F)	2	0
19	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 96 GJ/hr (91 MMBtu/hr)	1	0

Case B11B.90 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.4 m (21 ft) diameter	1	0

Case B11B.90 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	809 MW 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F)	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

2	Steam Turbine Generator	Hydrogen cooled, static excitation	900 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,270 GJ/hr (2,410 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0

Case B11B.90 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	971,000 lpm @ 30 m (256,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 5,410 GJ/hr (5,130 MMBtu/hr) heat duty	1	0

Case B11B.90 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	6.3 tonne/hr (7 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	26 m ³ /min @ 0.2 MPa (906 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,680 tonne (1,860 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	160 tonne/hr (170 tph)	1	0

Case B11B.90 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 27 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 55 MVA, 3-ph, 60 Hz	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 19 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B11B.90 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.2.10 Case B11B.90 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 4-43 shows a detailed breakdown of the capital costs; Exhibit 4-44 shows the owner's costs, TOC, and TASC; Exhibit 4-45 shows the initial and annual O&M costs; and Exhibit 4-46 shows the LCOE breakdown.

The estimated TPC of the SubC PC boiler with CO₂ capture is \$3,393/kW. Process contingency represents 2.7 percent of the TPC and project contingency represents 13.9 percent. The LCOE, including CO₂ T&S costs of \$9.3/MWh, is \$108.4/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-43. Case B11B.90 total plant cost details

Case:		B11B.90	– SubC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1		Coal & Sorbent Handling									
1.1	Coal Receive & Unload	\$1,210	\$0	\$545	\$0	\$1,755	\$307	\$0	\$309	\$2,371	\$4
1.2	Coal Stackout & Reclaim	\$3,971	\$0	\$888	\$0	\$4,859	\$850	\$0	\$856	\$6,566	\$10
1.3	Coal Conveyors	\$36,591	\$0	\$8,699	\$0	\$45,290	\$7,926	\$0	\$7,982	\$61,198	\$94
1.4	Other Coal Handling	\$5,086	\$0	\$1,070	\$0	\$6,156	\$1,077	\$0	\$1,085	\$8,319	\$13
1.5	Sorbent Receive & Unload	\$233	\$0	\$69	\$0	\$302	\$53	\$0	\$53	\$408	\$1
1.6	Sorbent Stackout & Reclaim	\$1,702	\$0	\$308	\$0	\$2,010	\$352	\$0	\$354	\$2,716	\$4
1.7	Sorbent Conveyors	\$2,580	\$561	\$625	\$0	\$3,766	\$659	\$0	\$664	\$5,088	\$8
1.8	Other Sorbent Handling	\$124	\$29	\$64	\$0	\$217	\$38	\$0	\$38	\$294	\$0
1.9	Coal & Sorbent Handling Foundations	\$0	\$1,586	\$2,092	\$0	\$3,678	\$644	\$0	\$648	\$4,970	\$8
	Subtotal	\$51,498	\$2,176	\$14,359	\$0	\$68,033	\$11,906	\$0	\$11,991	\$91,930	\$141
2		Coal & Sorbent Preparation & Feed									
2.1	Coal Crushing & Drying	\$2,604	\$0	\$500	\$0	\$3,105	\$543	\$0	\$547	\$4,195	\$6
2.2	Prepared Coal Storage & Feed	\$8,766	\$0	\$1,888	\$0	\$10,654	\$1,864	\$0	\$1,878	\$14,396	\$22
2.5	Sorbent Preparation Equipment	\$1,146	\$50	\$235	\$0	\$1,431	\$250	\$0	\$252	\$1,933	\$3
2.6	Sorbent Storage & Feed	\$1,919	\$0	\$727	\$0	\$2,646	\$463	\$0	\$466	\$3,575	\$5
2.9	Coal & Sorbent Feed Foundation	\$0	\$761	\$667	\$0	\$1,428	\$250	\$0	\$252	\$1,930	\$3
	Subtotal	\$14,436	\$811	\$4,017	\$0	\$19,264	\$3,371	\$0	\$3,395	\$26,030	\$40
3		Feedwater & Miscellaneous BOP Systems									
3.1	Feedwater System	\$3,948	\$6,768	\$3,384	\$0	\$14,101	\$2,468	\$0	\$2,485	\$19,054	\$29
3.2	Water Makeup & Pretreating	\$8,293	\$829	\$4,699	\$0	\$13,821	\$2,419	\$0	\$3,248	\$19,488	\$30
3.3	Other Feedwater Subsystems	\$3,064	\$1,005	\$954	\$0	\$5,023	\$879	\$0	\$885	\$6,788	\$10
3.4	Service Water Systems	\$2,638	\$5,037	\$16,311	\$0	\$23,986	\$4,198	\$0	\$5,637	\$33,821	\$52
3.5	Other Boiler Plant Systems	\$755	\$275	\$686	\$0	\$1,716	\$300	\$0	\$302	\$2,318	\$4
3.6	Natural Gas Pipeline and Start-Up System	\$3,537	\$152	\$114	\$0	\$3,803	\$666	\$0	\$670	\$5,139	\$8
3.7	Waste Water Treatment Equipment	\$13,708	\$0	\$8,402	\$0	\$22,110	\$3,869	\$0	\$5,196	\$31,175	\$48
3.8	Spray Dryer Evaporator	\$17,402	\$0	\$10,074	\$0	\$27,476	\$4,808	\$0	\$6,457	\$38,741	\$60
3.9	Miscellaneous Plant Equipment	\$202	\$27	\$103	\$0	\$332	\$58	\$0	\$78	\$468	\$1
	Subtotal	\$53,548	\$14,093	\$44,727	\$0	\$112,368	\$19,664	\$0	\$24,959	\$156,991	\$241
4		Pulverized Coal Boiler & Accessories									
4.9	Pulverized Coal Boiler & Accessories	\$227,400	\$0	\$148,505	\$0	\$375,905	\$65,783	\$0	\$66,253	\$507,942	\$781
4.10	Selective Catalytic Reduction System	\$29,738	\$0	\$19,406	\$0	\$49,143	\$8,600	\$0	\$8,661	\$66,405	\$102
4.11	Boiler Balance of Plant	\$1,594	\$0	\$1,041	\$0	\$2,636	\$461	\$0	\$465	\$3,562	\$5
4.12	Primary Air System	\$1,662	\$0	\$1,086	\$0	\$2,748	\$481	\$0	\$484	\$3,713	\$6
4.13	Secondary Air System	\$2,518	\$0	\$1,644	\$0	\$4,162	\$728	\$0	\$734	\$5,624	\$9

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B11B.90	– SubC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
4.14	Induced Draft Fans	\$5,431	\$0	\$3,547	\$0	\$8,978	\$1,571	\$0	\$1,582	\$12,132	\$19
4.15	Major Component Rigging	\$91	\$0	\$60	\$0	\$151	\$26	\$0	\$27	\$204	\$0
4.16	Boiler Foundations	\$0	\$412	\$362	\$0	\$774	\$135	\$0	\$136	\$1,046	\$2
	Subtotal	\$268,435	\$412	\$175,651	\$0	\$444,498	\$77,787	\$0	\$78,343	\$600,627	\$923
5 Flue Gas Cleanup											
5.1	CANSOLV Carbon Dioxide (CO ₂) Removal System	\$146,195	\$64,002	\$134,405	\$0	\$344,603	\$60,306	\$58,582	\$81,111	\$544,602	\$837
5.2	WFGD Absorber Vessels & Accessories	\$82,164	\$0	\$17,574	\$0	\$99,738	\$17,454	\$0	\$17,579	\$134,771	\$207
5.3	Other FGD	\$1,312	\$0	\$1,009	\$0	\$2,321	\$406	\$0	\$409	\$3,137	\$5
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$43,952	\$6,593	\$14,471	\$0	\$65,016	\$11,378	\$0	\$15,279	\$91,673	\$141
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$485	\$77	\$208	\$0	\$769	\$135	\$0	\$181	\$1,085	\$2
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$2,755	\$606	\$2,709	\$0	\$6,071	\$1,062	\$0	\$1,070	\$8,203	\$13
5.9	Particulate Removal (Bag House & Accessories) (included with 5.2)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5.12	Gas Cleanup Foundations	\$0	\$205	\$180	\$0	\$385	\$67	\$0	\$68	\$520	\$1
5.13	Gypsum Dewatering System	\$785	\$0	\$132	\$0	\$917	\$160	\$0	\$162	\$1,239	\$2
	Subtotal	\$277,647	\$71,484	\$170,689	\$0	\$519,819	\$90,968	\$58,582	\$115,858	\$785,228	\$1,207
7 Ductwork & Stack											
7.3	Ductwork	\$0	\$757	\$526	\$0	\$1,282	\$224	\$0	\$226	\$1,733	\$3
7.4	Stack	\$8,840	\$0	\$5,137	\$0	\$13,977	\$2,446	\$0	\$2,463	\$18,886	\$29
7.5	Duct & Stack Foundations	\$0	\$211	\$250	\$0	\$460	\$81	\$0	\$108	\$649	\$1
	Subtotal	\$8,840	\$967	\$5,913	\$0	\$15,720	\$2,751	\$0	\$2,798	\$21,268	\$33
8 Steam Turbine & Accessories											
8.1	Steam Turbine Generator & Accessories	\$64,771	\$0	\$7,421	\$0	\$72,191	\$12,634	\$0	\$12,724	\$97,549	\$150
8.2	Steam Turbine Plant Auxiliaries	\$1,476	\$0	\$3,139	\$0	\$4,615	\$808	\$0	\$813	\$6,236	\$10
8.3	Condenser & Auxiliaries	\$12,691	\$0	\$4,306	\$0	\$16,997	\$2,974	\$0	\$2,996	\$22,967	\$35
8.4	Steam Piping	\$38,066	\$0	\$15,428	\$0	\$53,495	\$9,362	\$0	\$9,428	\$72,285	\$111
8.5	Turbine Generator Foundations	\$0	\$230	\$380	\$0	\$611	\$107	\$0	\$143	\$861	\$1
	Subtotal	\$117,004	\$230	\$30,674	\$0	\$147,908	\$25,884	\$0	\$26,105	\$199,897	\$307
9 Cooling Water System											
9.1	Cooling Towers	\$20,151	\$0	\$6,232	\$0	\$26,383	\$4,617	\$0	\$4,650	\$35,650	\$55
9.2	Circulating Water Pumps	\$2,871	\$0	\$203	\$0	\$3,074	\$538	\$0	\$542	\$4,153	\$6
9.3	Circulating Water System Auxiliaries	\$16,739	\$0	\$2,215	\$0	\$18,953	\$3,317	\$0	\$3,340	\$25,610	\$39

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B11B.90	– SubC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
9.4	Circulating Water Piping	\$0	\$7,740	\$7,010	\$0	\$14,750	\$2,581	\$0	\$2,600	\$19,931	\$31
9.5	Make-up Water System	\$1,299	\$0	\$1,668	\$0	\$2,966	\$519	\$0	\$523	\$4,008	\$6
9.6	Component Cooling Water System	\$1,206	\$0	\$926	\$0	\$2,131	\$373	\$0	\$376	\$2,880	\$4
9.7	Circulating Water System Foundations	\$0	\$720	\$1,195	\$0	\$1,914	\$335	\$0	\$450	\$2,699	\$4
	Subtotal	\$42,265	\$8,460	\$19,447	\$0	\$70,172	\$12,280	\$0	\$12,480	\$94,932	\$146
10 Ash & Spent Sorbent Handling Systems											
10.6	Ash Storage Silos	\$1,202	\$0	\$3,676	\$0	\$4,878	\$854	\$0	\$860	\$6,591	\$10
10.7	Ash Transport & Feed Equipment	\$4,088	\$0	\$4,052	\$0	\$8,140	\$1,424	\$0	\$1,435	\$10,999	\$17
10.9	Ash/Spent Sorbent Foundation	\$0	\$838	\$1,031	\$0	\$1,869	\$327	\$0	\$439	\$2,635	\$4
	Subtotal	\$5,289	\$838	\$8,759	\$0	\$14,886	\$2,605	\$0	\$2,733	\$20,225	\$31
11 Accessory Electric Plant											
11.1	Generator Equipment	\$2,669	\$0	\$2,013	\$0	\$4,683	\$819	\$0	\$825	\$6,327	\$10
11.2	Station Service Equipment	\$7,662	\$0	\$657	\$0	\$8,319	\$1,456	\$0	\$1,466	\$11,241	\$17
11.3	Switchgear & Motor Control	\$11,894	\$0	\$2,064	\$0	\$13,958	\$2,443	\$0	\$2,460	\$18,861	\$29
11.4	Conduit & Cable Tray	\$0	\$1,546	\$4,456	\$0	\$6,002	\$1,050	\$0	\$1,058	\$8,110	\$12
11.5	Wire & Cable	\$0	\$4,095	\$7,319	\$0	\$11,414	\$1,997	\$0	\$2,012	\$15,423	\$24
11.6	Protective Equipment	\$55	\$0	\$191	\$0	\$246	\$43	\$0	\$43	\$332	\$1
11.7	Standby Equipment	\$826	\$0	\$762	\$0	\$1,588	\$278	\$0	\$280	\$2,146	\$3
11.8	Main Power Transformers	\$7,003	\$0	\$143	\$0	\$7,146	\$1,250	\$0	\$1,259	\$9,655	\$15
11.9	Electrical Foundations	\$0	\$223	\$566	\$0	\$788	\$138	\$0	\$185	\$1,111	\$2
	Subtotal	\$30,109	\$5,864	\$18,172	\$0	\$54,144	\$9,475	\$0	\$9,589	\$73,208	\$113
12 Instrumentation & Control											
12.1	Pulverized Coal Boiler Control Equipment	\$808	\$0	\$144	\$0	\$952	\$167	\$0	\$168	\$1,286	\$2
12.3	Steam Turbine Control Equipment	\$722	\$0	\$83	\$0	\$804	\$141	\$0	\$142	\$1,087	\$2
12.5	Signal Processing Equipment	\$917	\$0	\$164	\$0	\$1,080	\$189	\$0	\$190	\$1,460	\$2
12.6	Control Boards, Panels & Racks	\$281	\$0	\$171	\$0	\$452	\$79	\$23	\$83	\$636	\$1
12.7	Distributed Control System Equipment	\$7,913	\$0	\$1,411	\$0	\$9,324	\$1,632	\$466	\$1,713	\$13,136	\$20
12.8	Instrument Wiring & Tubing	\$554	\$443	\$1,773	\$0	\$2,771	\$485	\$139	\$509	\$3,903	\$6
12.9	Other Instrumentation & Controls Equipment	\$681	\$0	\$1,577	\$0	\$2,258	\$395	\$113	\$415	\$3,181	\$5
	Subtotal	\$11,875	\$443	\$5,323	\$0	\$17,641	\$3,087	\$740	\$3,220	\$24,689	\$38
13 Improvements to Site											
13.1	Site Preparation	\$0	\$459	\$9,763	\$0	\$10,222	\$1,789	\$0	\$2,402	\$14,413	\$22
13.2	Site Improvements	\$0	\$2,274	\$3,004	\$0	\$5,278	\$924	\$0	\$1,240	\$7,442	\$11
13.3	Site Facilities	\$2,598	\$0	\$2,726	\$0	\$5,324	\$932	\$0	\$1,251	\$7,506	\$12
	Subtotal	\$2,598	\$2,733	\$15,493	\$0	\$20,824	\$3,644	\$0	\$4,894	\$29,362	\$45
14 Buildings & Structures											

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B11B.90	– SubC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
14.2	Boiler Building	\$0	\$11,588	\$10,183	\$0	\$21,771	\$3,810	\$0	\$3,837	\$29,418	\$45
14.3	Steam Turbine Building	\$0	\$16,106	\$15,001	\$0	\$31,107	\$5,444	\$0	\$5,483	\$42,033	\$65
14.4	Administration Building	\$0	\$1,046	\$1,106	\$0	\$2,152	\$377	\$0	\$379	\$2,909	\$4
14.5	Circulation Water Pumphouse	\$0	\$192	\$152	\$0	\$344	\$60	\$0	\$61	\$464	\$1
14.6	Water Treatment Buildings	\$0	\$482	\$440	\$0	\$922	\$161	\$0	\$162	\$1,246	\$2
14.7	Machine Shop	\$0	\$553	\$371	\$0	\$923	\$162	\$0	\$163	\$1,248	\$2
14.8	Warehouse	\$0	\$415	\$416	\$0	\$831	\$145	\$0	\$146	\$1,123	\$2
14.9	Other Buildings & Structures	\$0	\$291	\$248	\$0	\$539	\$94	\$0	\$95	\$728	\$1
14.10	Waste Treating Building & Structures	\$0	\$644	\$1,956	\$0	\$2,600	\$455	\$0	\$458	\$3,513	\$5
	Subtotal	\$0	\$31,317	\$29,873	\$0	\$61,189	\$10,708	\$0	\$10,785	\$82,682	\$127
	Total	\$883,543	\$139,827	\$543,096	\$0	\$1,566,466	\$274,132	\$59,323	\$307,149	\$2,207,069	\$3,393

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-44. Case B11B.90 owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$13,304	\$20
1 Month Maintenance Materials	\$2,077	\$3
1 Month Non-Fuel Consumables	\$3,388	\$5
1 Month Waste Disposal	\$988	\$2
25% of 1 Months Fuel Cost at 100% CF	\$2,991	\$5
2% of TPC	\$44,141	\$68
Total	\$66,890	\$103
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	\$29,878	\$46
0.5% of TPC (spare parts)	\$11,035	\$17
Total	\$40,913	\$63
Other Costs		
Initial Cost for Catalyst and Chemicals	\$2,732	\$4
Land	\$900	\$1
Other Owner's Costs	\$331,060	\$509
Financing Costs	\$59,591	\$92
Total Overnight Costs (TOC)	\$2,709,156	\$4,165
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	\$3,127,481	\$4,808

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-45. Case B11B.90 initial and annual operating and maintenance costs

Case:	B11B.90	– SubC PC w/ CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):	11,317	Capacity Factor (%):	85	
Operating & Maintenance Labor						
Operating Labor			Operating Labor Requirements per Shift			
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:		2.0
Operating Labor Burden:		30.00	% of base	Operator:		11.3
Labor O-H Charge Rate:		25.00	% of labor	Foreman:		1.0
				Lab Techs, etc.:		2.0
				Total:		16.3
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$7,161,008	\$11.010
Maintenance Labor:					\$14,125,243	\$21.717
Administrative & Support Labor:					\$5,321,563	\$8.182
Property Taxes and Insurance:					\$44,141,385	\$67.866
Total:					\$70,749,199	\$108.775
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$21,187,865	\$4.37492
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	7,180	\$1.90	\$0	\$4,232,720	\$0.87398
Makeup and Waste Water Treatment Chemicals (ton):	0	21.4	\$550.00	\$0	\$3,649,880	\$0.75364
Brominated Activated Carbon (ton):	0	1.66	\$1,600.00	\$0	\$822,308	\$0.16979
Enhanced Hydrated Lime (ton):	0	41.7	\$240.00	\$0	\$3,103,484	\$0.64081
Limestone (ton):	0	732	\$22.00	\$0	\$4,998,996	\$1.03220
Ammonia (19 wt%, ton):	0	73.1	\$300.00	\$0	\$6,800,415	\$1.40417
SCR Catalyst (ft ³):	18,214	16.6	\$150.00	\$2,732,036	\$774,077	\$0.15983
CO ₂ Capture System Chemicals ^A :	Proprietary				\$8,857,728	\$1.82897
Triethylene Glycol (gal):	w/equip.	626	\$6.80	\$0	\$1,321,278	\$0.27282
Subtotal:				\$2,732,036	\$34,560,885	\$7.13622
Waste Disposal						
Fly Ash (ton):	0	687	\$38.00	\$0	\$8,100,679	\$1.67265
Bottom Ash (ton):	0	153	\$38.00	\$0	\$1,799,384	\$0.37154
SCR Catalyst (ft ³):	0	16.6	\$2.50	\$0	\$12,901	\$0.00266
Triethylene Glycol (gal):	0	626	\$0.35	\$0	\$68,007	\$0.01404
Thermal Reclaimer Unit Waste (ton):	0	8.07	\$38.00	\$0	\$95,098	\$0.01964
Subtotal:				\$0	\$10,076,070	\$2.08053
By-Products						
Gypsum (ton):	0	1,113	\$0.00	\$0	\$0	\$0.00000
Subtotal:				\$0	\$0	\$0.00000
Variable Operating Costs Total:				\$2,732,036	\$65,824,820	\$13.59167
Fuel Cost						
Illinois Number 6 (ton):	0	7,571	\$51.96	\$0	\$122,048,822	\$25.20094
Total:				\$0	\$122,048,822	\$25.20094

^ACO₂ Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit 4-46. Case B11B.90 LCOE breakdown

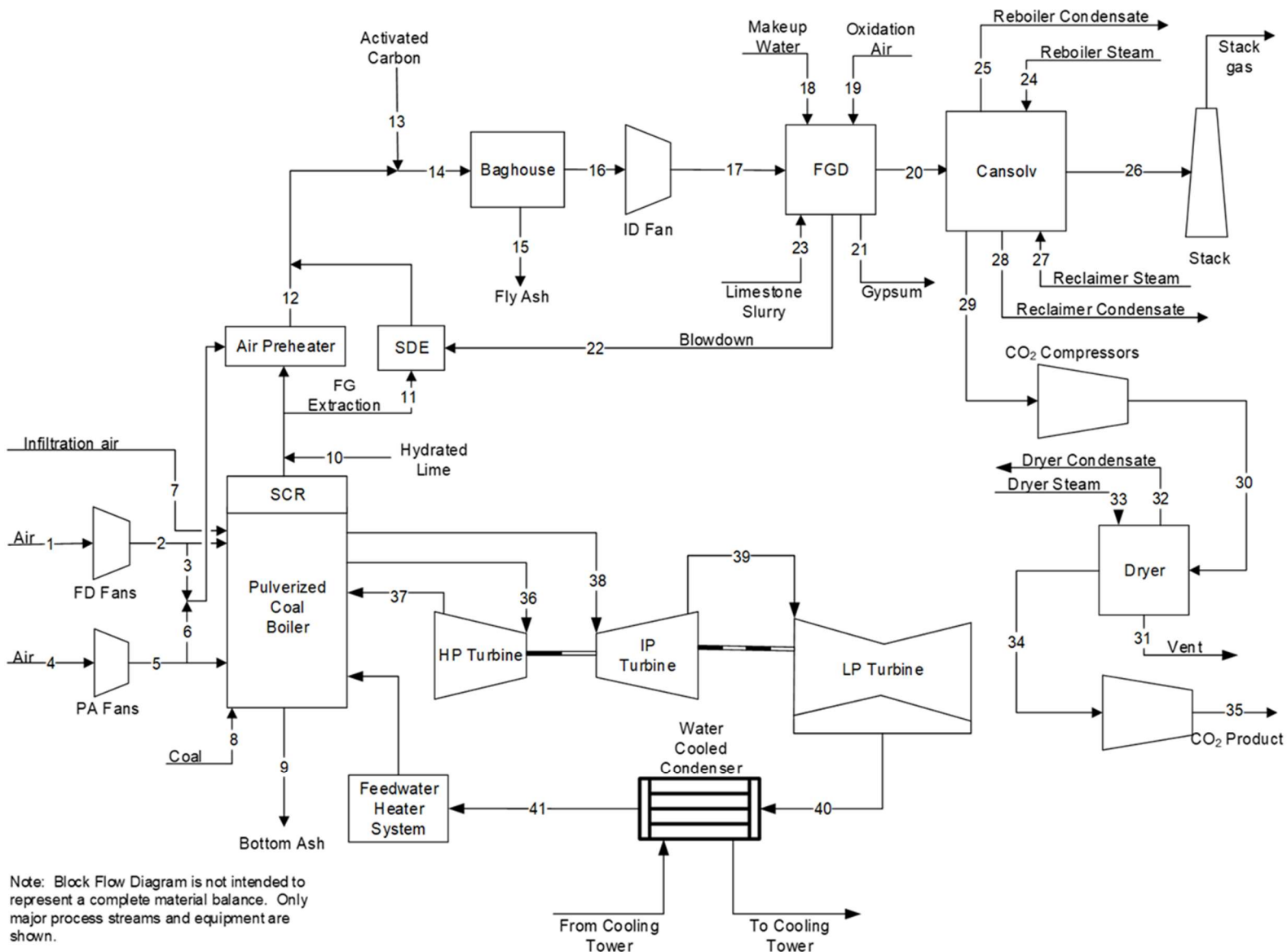
Component	Value, \$/MWh	Percentage
Capital	45.7	42%
Fixed	14.6	13%
Variable	13.6	13%
Fuel	25.2	23%
Total (Excluding T&S)	99.1	N/A
CO ₂ T&S	9.3	9%
Total (Including T&S)	108.4	N/A

4.2.11 Case B11B.95 – SubC PC with 95 Percent CO₂ Capture Process Description

The plant configuration and process description for Case B11B.95 are nearly the same as Case B11B.90, with the exception that the capture rate is 95 percent. Since the process descriptions of the plant and CDR facility were provided in Section 4.2.3 and Section 4.1.8, respectively, they are not repeated here.

The BFD for Case B11B.95 is shown in Exhibit 4-47. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 4-48. The modeling assumptions were presented previously in Section 4.2.1.

Exhibit 4-47. Case B11B.95 block flow diagram, SubC unit with CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-48. Case B11B.95 stream table, SubC unit with capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0087	0.0088	0.0000	0.0087	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379	0.0000	0.1372	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837	0.0000	0.0911	0.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340	0.0000	0.7281	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336	0.0000	0.0329	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020	0.0000	0.0020	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1158
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.8842
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	79,245	79,245	2,347	24,343	24,343	3,350	1,752	0	0	1	5,222	105,932	0	112,038	7
V-L Flowrate (kg/hr)	2,286,782	2,286,782	67,731	702,476	702,476	96,678	50,546	0	0	16	155,310	3,145,573	0	3,317,245	717
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	290,670	5,859	1,584	1,254	24,078	64	25,645	25,662
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143	15	143	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.31	-6.79	-2,453.14	-1,065.98
Density (kg/m ³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8	---	0.8	2,150.2
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694	---	29.608	104.898
V-L Flowrate (lb _{mol} /hr)	174,706	174,706	5,175	53,668	53,668	7,386	3,862	0	0	2	11,512	233,540	0	247,003	15
V-L Flowrate (lb/hr)	5,041,492	5,041,492	149,322	1,548,694	1,548,694	213,138	111,435	0	0	35	342,400	6,934,801	0	7,313,274	1,580
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	640,819	12,918	3,492	2,765	53,083	140	56,538	56,575
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289	59	289	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1	14.7	14.1	14.1
Steam Table Enthalpy (Btu/lb) ^A	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4	-2.9	-1,054.7	-458.3
Density (lb/ft ³)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052	---	0.052	134.232

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-48. Case B11B.95 stream table, SubC unit with capture (continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0102	0.0000	0.0000	0.0000	0.0000
CO ₂	0.1372	0.1372	0.0000	0.0003	0.1245	0.0001	0.0000	0.0000	0.0000	0.0000	0.0079	0.0000	0.0000	0.9783	0.9975
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0911	0.0911	0.9999	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000	1.0000	0.0807	1.0000	1.0000	0.0217	0.0025
HCl	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000	0.0000	0.8555	0.0000	0.0000	0.0000	0.0000
O ₂	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000	0.0000	0.0457	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0001	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	112,032	112,032	6,546	4,690	125,242	264	885	3,645	38,028	34,830	99,587	403	403	15,134	14,842
V-L Flowrate (kg/hr)	3,316,511	3,316,511	117,944	135,332	3,599,478	4,751	16,363	65,683	685,085	627,466	2,752,249	7,259	7,259	657,482	652,228
Solids Flowrate (kg/hr)	0	0	0	0	0	42,738	249	28,118	0	0	0	0	0	0	0
Temperature (°C)	143	156	15	15	57	15	57	15	266	105	45	355	214	31	29
Pressure (MPa, abs)	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.48	0.12	0.10	4.28	2.04	0.17	2.81
Steam Table Enthalpy (kJ/kg) ^A	287.58	302.09	-47.80	30.23	297.00	---	---	---	2,994.07	439.34	179.09	3,098.44	913.81	46.68	-3.05
AspenPlus Enthalpy (kJ/kg) ^B	-2,464.17	-2,449.66	-16,015.01	-97.58	-2,939.24	-12,513.34	-15,496.18	-14,994.25	-12,986.23	-15,540.95	-797.41	-12,881.86	-15,066.49	-8,978.62	-8,972.51
Density (kg/m ³)	0.8	0.9	1,003.7	1.2	1.1	878.3	979.4	1,003.7	2.0	954.9	1.1	16.0	848.5	3.0	57.8
V-L Molecular Weight	29.603	29.603	18.019	28.857	28.740	18.021	18.494	18.019	18.015	18.015	27.637	18.015	18.015	43.445	43.945
V-L Flowrate (lb _{mol} /hr)	246,987	246,987	14,431	10,339	276,111	581	1,950	8,037	83,837	76,786	219,552	888	888	33,364	32,721
V-L Flowrate (lb/hr)	7,311,656	7,311,656	260,022	298,355	7,935,491	10,475	36,073	144,806	1,510,355	1,383,326	6,067,670	16,003	16,003	1,449,501	1,437,916
Solids Flowrate (lb/hr)	0	0	0	0	0	94,222	549	61,989	0	0	0	0	0	0	0
Temperature (°F)	289	313	59	59	135	59	135	59	511	221	113	671	416	87	85
Pressure (psia)	13.9	15.3	14.7	14.7	14.8	14.7	14.7	14.7	70.0	17.4	14.8	620.5	296.6	24.7	407.6
Steam Table Enthalpy (Btu/lb) ^A	123.6	129.9	-20.5	13.0	127.7	---	---	---	1,287.2	188.9	77.0	1,332.1	392.9	20.1	-1.3
AspenPlus Enthalpy (Btu/lb) ^B	-1,059.4	-1,053.2	-6,885.2	-42.0	-1,263.6	-5,379.8	-6,662.2	-6,446.4	-5,583.1	-6,681.4	-342.8	-5,538.2	-6,477.4	-3,860.1	-3,857.5
Density (lb/ft ³)	0.051	0.055	62.658	0.076	0.067	54.833	61.145	62.658	0.123	59.612	0.066	1.000	52.968	0.184	3.609

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-48. Case B11B.95 stream table, SubC unit with capture (continued)

	31	32	33	34	35	36	37	38	39	40	41
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0500	0.0000	0.0000	0.9995	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	31	19	19	14,811	14,811	135,086	125,684	125,684	105,503	50,879	72,314
V-L Flowrate (kg/hr)	601	343	343	651,626	651,626	2,433,620	2,264,224	2,264,224	1,900,672	916,600	1,302,760
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	29	203	476	29	30	566	355	566	267	38	39
Pressure (MPa, abs)	2.81	1.64	2.42	2.68	15.27	16.65	4.28	4.19	0.52	0.01	1.32
Steam Table Enthalpy (kJ/kg) ^A	137.94	863.65	3,408.95	-3.59	-231.09	3,473.89	3,098.44	3,593.58	2,994.07	2,340.01	162.43
AspenPlus Enthalpy (kJ/kg) ^B	-15,225.22	-15,116.65	-12,571.34	-8,967.15	-9,194.65	-12,506.41	-12,881.86	-12,386.71	-12,986.23	-13,640.29	-15,817.87
Density (kg/m ³)	351.5	861.8	7.1	54.7	630.1	47.7	16.0	11.1	2.1	0.1	993.3
V-L Molecular Weight	19.315	18.015	18.015	43.997	43.997	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	69	42	42	32,652	32,652	297,815	277,085	277,085	232,595	112,169	159,425
V-L Flowrate (lb/hr)	1,326	756	756	1,436,590	1,436,590	5,365,214	4,991,760	4,991,760	4,190,265	2,020,758	2,872,095
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	85	397	888	85	86	1,050	671	1,050	512	101	101
Pressure (psia)	407.6	237.4	350.5	389.1	2,214.7	2,414.7	620.5	608.1	75.0	1.0	190.7
Steam Table Enthalpy (Btu/lb) ^A	59.3	371.3	1,465.6	-1.5	-99.4	1,493.5	1,332.1	1,545.0	1,287.2	1,006.0	69.8
AspenPlus Enthalpy (Btu/lb) ^B	-6,545.7	-6,499.0	-5,404.7	-3,855.2	-3,953.0	-5,376.8	-5,538.2	-5,325.3	-5,583.1	-5,864.3	-6,800.5
Density (lb/ft ³)	21.943	53.801	0.446	3.416	39.338	2.975	1.000	0.692	0.132	0.003	62.010

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

4.2.12 Case B11B.95 – Performance Results

Overall plant performance is summarized in Exhibit 4-49; Exhibit 4-50 provides a detailed breakdown of the auxiliary power requirements.

The CDR facility, including CO₂ compression, accounts for over half of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for over 12 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility and CO₂ compressors.

Unlike the NGCC cases where gross output was fixed by the available size of the CTs, the PC cases utilize boilers and steam turbines that can be procured at nearly any desired output. By increasing the boiler and turbine/generator size to account for the greater auxiliary load imposed by the CDR facility and CO₂ compressors, a net output of 650 MW is maintained at a reduced net plant efficiency of 29.7 percent (HHV basis).

Exhibit 4-49. Case B11B.95 plant performance summary

Performance Summary	
Total Gross Power, MWe	774
CO ₂ Capture/Removal Auxiliaries, kWe	20,200
CO ₂ Compression, kWe	52,170
Balance of Plant, kWe	51,470
Total Auxiliaries, MWe	124
Net Power, MWe	650
HHV Net Plant Efficiency, %	29.7
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	12,128 (11,495)
LHV Net Plant Efficiency, %	30.8
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,697 (11,087)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	55.8
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	6,453 (6,116)
Condenser Duty, GJ/hr (MMBtu/hr)	2,277 (2,158)
CO ₂ Capture Rate, %	95
AGR Duty, GJ/hr (MMBtu/hr)	2,288 (2,169)
As-Received Coal Feed, kg/hr (lb/hr)	290,670 (640,819)
Limestone Sorbent Feed, kg/hr (lb/hr)	28,118 (61,989)
HHV Thermal Input, kWt	2,190,938
LHV Thermal Input, kWt	2,113,187
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.059 (15.7)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.044 (11.7)
Excess Air, %	20.3

Exhibit 4-50. Case B11B.95 plant power summary

Power Summary	
Steam Turbine Power, MWe	774
Total Gross Power, MWe	774
Auxiliary Load Summary	
Activated Carbon Injection, kWe	40
Ash Handling, kWe	950
Baghouse, kWe	120
Circulating Water Pumps, kWe	9,900
CO ₂ Capture/Removal Auxiliaries, kWe	20,200
CO ₂ Compression, kWe	52,170
Coal Handling and Conveying, kWe	550
Condensate Pumps, kWe	720
Cooling Tower Fans, kWe	5,120
Dry Sorbent Injection, kWe	80
Flue Gas Desulfurizer, kWe	4,490
Forced Draft Fans, kWe	1,490
Ground Water Pumps, kWe	920
Induced Draft Fans, kWe	13,780
Miscellaneous Balance of Plant ^{A,B} , kWe	2,250
Primary Air Fans, kWe	1,770
Pulverizers, kWe	4,360
SCR, kWe	50
Sorbent Handling & Reagent Preparation, kWe	1,350
Spray Dryer Evaporator, kWe	320
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,710
Total Auxiliaries, MWe	124
Net Power, MWe	650

^ABoiler feed pumps are turbine driven

^BIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

4.2.12.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B11B.95 is presented in Exhibit 4-51. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 4-51. Case B11B.95 air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.031 (0.072)	1,830 (2,018)	0.318 (0.700)
Particulate	0.004 (0.009)	235 (259)	0.041 (0.090)
Hg	1.34E-7 (3.11E-7)	0.008 (0.009)	1.36E-6 (3.00E-6)
CO ₂	4 (10)	256,957 (283,247)	45 (98)
CO ₂ ^C	–	–	53 (117)
mg/Nm ³			
Particulate Concentration ^{D,E}	12.59		

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

^DConcentration of particles in the flue gas after the baghouse

^ENormal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The SO₂ emissions are further reduced to 0.37 ppmv using a NaOH based polishing scrubber in the CDR facility. The remaining low concentration of SO₂ is essentially completely removed in the CDR absorber vessel resulting in very low SO₂ emissions (reported as zero here).

NO_x boiler emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 79.3 percent to 0.03 kg/GJ (0.07 lb/MMBtu).

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and wet FGD) is 97.6 percent.

Ninety-five percent of the CO₂ in the flue gas is removed in CDR facility.

The carbon balance for the plant is shown in Exhibit 4-52. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon leaves the plant mostly as CO₂ product from the CO₂ compression train; however, some CO₂ exits through the stack, the PAC is captured in the fabric filter, unburned carbon remains in the bottom ash, and some leaves as gypsum. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in (minus unburnt carbon in the ash), represented by the following fraction:

$$1 - \frac{\text{Carbon in Stack}}{\text{Total Carbon In} - \text{Unburnt Carbon}} = \left(1 - \left(\frac{20,764}{415,870 - 490} \right) \right) * 100 = 95\%$$

Exhibit 4-52. Case B11B.95 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	185,287 (408,488)	Stack Gas	9,418 (20,764)
Air (CO ₂)	432 (952)	FGD Product	220 (484)
PAC	64 (140)	Baghouse	953 (2,101)
FGD Reagent	2,853 (6,290)	Bottom Ash	222 (490)
		CO ₂ Product	177,803 (391,989)
		CO ₂ Dryer Vent	19 (41)
		CO ₂ Knockout	0.5 (1.1)
Total	188,636 (415,870)	Total	188,636 (415,870)

Exhibit 4-53 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur removed in the polishing scrubber, and sulfur removed in the baghouse.

Exhibit 4-53. Case B11B.95 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	7,285 (16,062)	FGD Product	6,850 (15,101)
		Stack Gas	—
		Polishing Scrubber and Solvent Reclaiming	142 (314)
		Baghouse	294 (647)
Total	7,285 (16,062)	Total	7,285 (16,062)

Exhibit 4-54 shows the overall water balance for the plant. The exhibit is presented in an identical manner as was for Case B11B.90. The only notable difference is the higher capture rate. In CO₂ capture cases, a significant amount of water is recovered from the initial CDR facility cooling step. This water would otherwise be discharged; however, it is suitable to be used as FGD makeup. The balance of the water from the CDR facility is sent to discharge.

Exhibit 4-54. Case B11B.95 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
FGD Process Makeup	2.0 (520)	2.0 (520)	–	–	–
FGD Slurry Water	1.1 (290)	1.1 (290)	–	–	–
CO ₂ Drying	–	–	–	0.0 (2.7)	0.0 (-2.7)
CO ₂ Capture Recovery	–	–	–	1.1 (280)	-1.1 (-280)
CO ₂ Compression KO	–	–	–	0.1 (23)	-0.1 (-23)
Deaerator Vent	–	–	–	0.1 (22)	-0.1 (-22)
Condenser Makeup	0.5 (130)	–	0.5 (130)	–	0.5 (130)
BFW Makeup	0.5 (130)	–	0.5 (130)	–	0.5 (130)
Cooling Tower	39 (10,186)	0.4 (109)	38 (10,077)	8.7 (2,291)	29 (7,786)
BFW Blowdown	–	0.4 (109)	-0.4 (-109)	–	-0.4 (-109)
Total	42 (11,126)	3.5 (918)	39 (10,207)	9.9 (2,618)	29 (7,589)

4.2.12.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for the Case B11B.95 PC boiler, FGD unit, CDR system and steam cycle in Exhibit 4-55 and Exhibit 4-56. An overall plant energy balance is provided in tabular form in Exhibit 4-57.

The power out is the steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a generator efficiency of 98.5 percent. The cooling tower load includes the condenser, capture process heat rejected to cooling water, the CO₂ compressor intercooler load, and other miscellaneous cooling loads.

This page intentionally left blank

Exhibit 4-55. Case B11B.95 energy and mass balance, SubC PC boiler with CO₂ capture

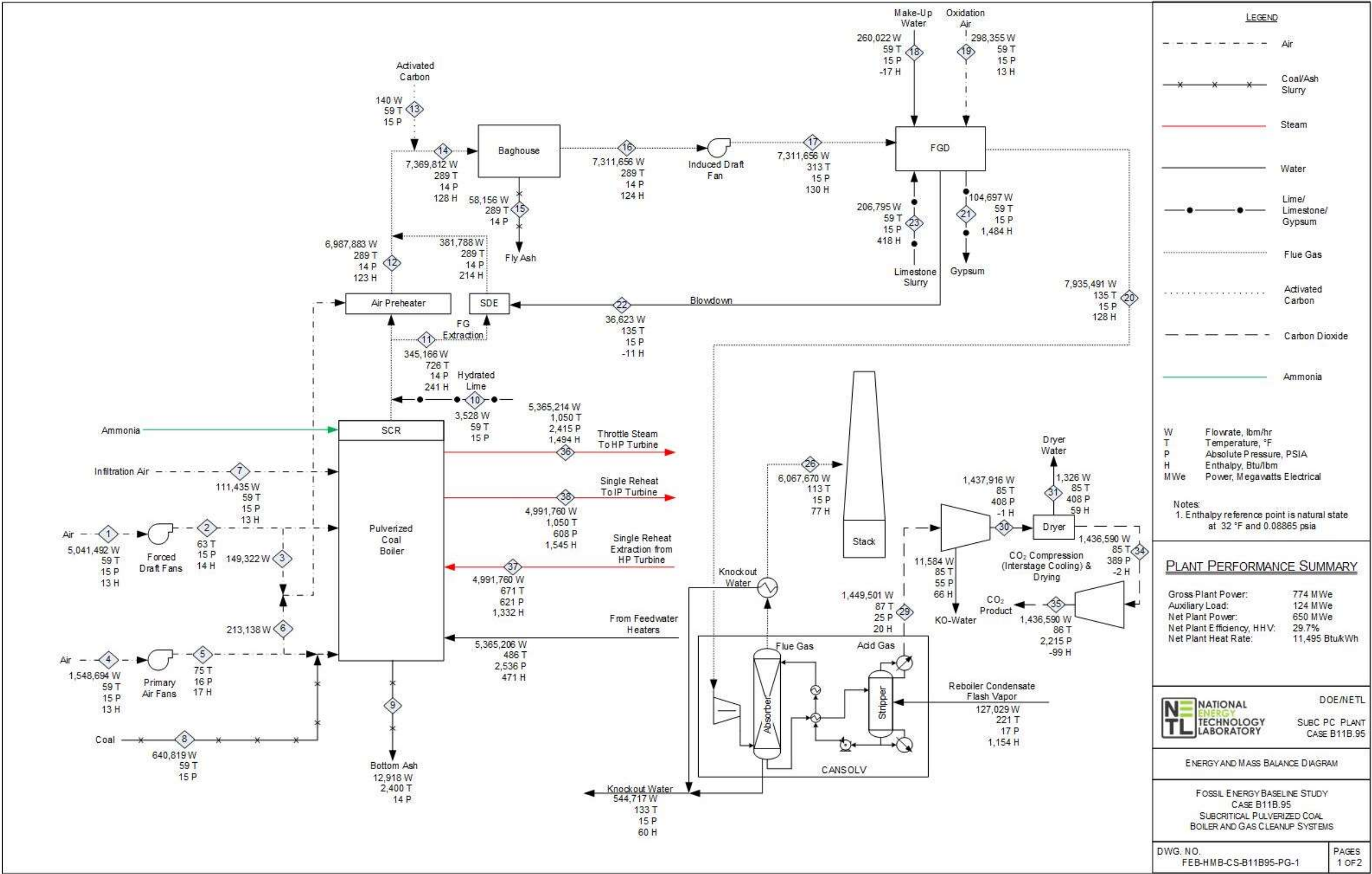


Exhibit 4-56. Case B11B.95 energy and mass balance, SubC steam cycle

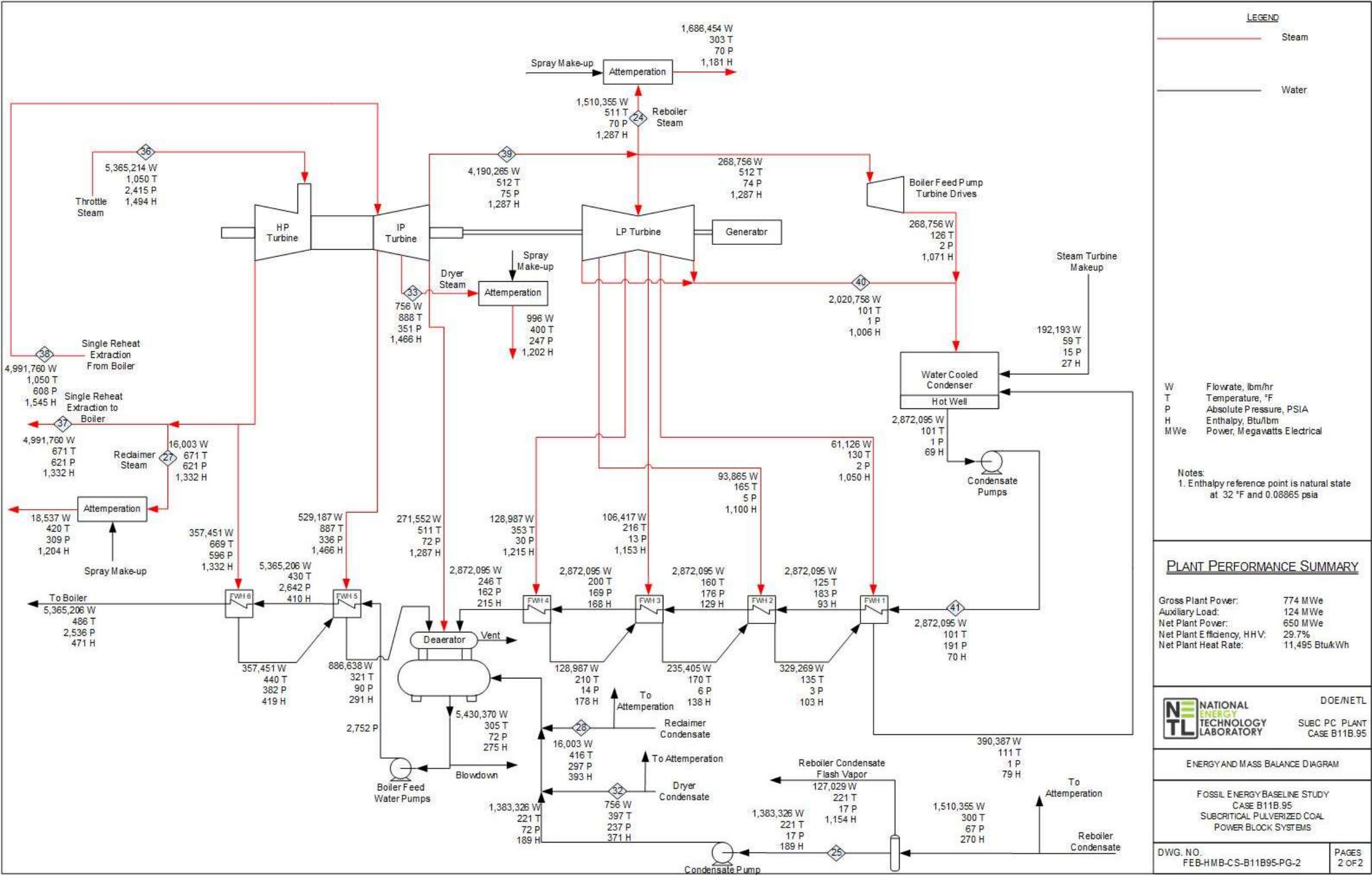


Exhibit 4-57. Case B11B.95 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	7,887 (7,476)	6.6 (6.2)	—	7,894 (7,482)
Air	—	92 (87)	—	92 (87)
Raw Water Makeup	—	145 (138)	—	145 (138)
Limestone	—	0.6 (0.6)	—	0.6 (0.6)
Auxiliary Power	—	—	446 (423)	446 (423)
TOTAL	7,887 (7,476)	244 (232)	446 (423)	8,578 (8,130)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	—	7.5 (7.1)	—	7.5 (7.1)
Fly Ash	—	2.7 (2.6)	—	2.7 (2.6)
Stack Gas	—	493 (467)	—	493 (467)
Sulfur	2.7 (2.5)	0.0 (0.0)	—	2.7 (2.5)
Gypsum	—	2.8 (2.6)	—	2.8 (2.6)
Motor Losses and Design Allowances	—	—	52 (49)	52 (49)
Cooling Tower Load ^A	—	5,035 (4,772)	—	5,035 (4,772)
CO ₂ Product Stream	—	-151 (-143)	—	-151 (-143)
AGR Effluent	—	58 (55)	—	58 (55)
Blowdown Streams and Deaerator Vent	—	19 (18)	—	19 (18)
<i>Ambient Losses^B</i>	—	184 (175)	—	184 (175)
Power	—	—	2,787 (2,642)	2,787 (2,642)
TOTAL	2.7 (2.5)	5,651 (5,356)	2,839 (2,691)	8,492 (8,049)
<i>Unaccounted Energy^C</i>	—	85 (81)	—	85 (81)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^CBy difference

4.2.13 Case B11B.95 – Major Equipment List

Major equipment items for the SubC PC plant with CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.2.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B11B.95 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	60 tonne (70 ton)	2	1
9	Feeder	Vibratory	240 tonne/hr (260 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	480 tonne/hr (530 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	240 tonne (260 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	480 tonne/hr (530 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	480 tonne/hr (530 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,070 tonne (1,170 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 12 tonne (13 ton) Feeder - 70 kg/hr (150 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 300 tonne (330 ton) Feeder - 1,760 kg/hr (3,880 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	118 tonne/hr (130 tph)	1	0
23	Limestone Conveyor No. 1	Belt	118 tonne/hr (130 tph)	1	0
24	Limestone Reclaim Hopper	N/A	23 tonne (26 ton)	1	0
25	Limestone Reclaim Feeder	Belt	93 tonne/hr (102 tph)	1	0
26	Limestone Conveyor No. 2	Belt	93 tonne/hr (102 tph)	1	0
27	Limestone Day Bin	w/ actuator	371 tonne (409 ton)	2	0

Case B11B.95 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	53 tonne/hr (59 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	53 tonne/hr (59 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	31 tonne/hr (34 tph)	1	1
4	Limestone Ball Mill	Rotary	31 tonne/hr (34 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	120,000 liters (31,800 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	2,000 lpm @ 10m H ₂ O (530 gpm @ 40 ft H ₂ O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5-cyclone bank	500 lpm (130 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	669,000 liters (177,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,390 lpm @ 9m H ₂ O (370 gpm @ 30 ft H ₂ O)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B11B.95 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,954,000 liters (516,100 gal)	2	0
2	Condensate Pumps	Vertical canned	12,000 lpm @ 200 m H ₂ O (3,180 gpm @ 500 ft H ₂ O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,355,000 kg/hr (2,987,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	22,000 lpm @ 2,300 m H ₂ O (5,900 gpm @ 7,500 ft H ₂ O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	6,700 lpm @ 2,300 m H ₂ O (1,800 gpm @ 7,500 ft H ₂ O)	2	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	360,000 kg/hr (790,000 lb/hr)	4	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	360,000 kg/hr (790,000 lb/hr)	4	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	360,000 kg/hr (790,000 lb/hr)	4	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	360,000 kg/hr (790,000 lb/hr)	4	0
10	HP Feedwater Heater 5	Horizontal U-tube	1,340,000 kg/hr (2,950,000 lb/hr)	2	0
11	HP Feedwater Heater 6	Horizontal U-tube	1,340,000 kg/hr (2,950,000 lb/hr)	2	0
12	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
13	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
14	Service Air Compressors	Flooded Screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H ₂ O (5,500 gpm @ 100 ft H ₂ O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	10,400 lpm @ 20 m H ₂ O (2,740 gpm @ 60 ft H ₂ O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	4,160 lpm @ 270 m H ₂ O (1,100 gpm @ 880 ft H ₂ O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	1,600 lpm @ 50 m H ₂ O (420 gpm @ 160 ft H ₂ O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,519,000 liter (401,300 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	990 lpm (260 gpm)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,680 m ³ /min (94,500 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 160 lpm (40 gpm) @ 19,985 ppmw Cl ⁻	2	1

Case B11B.95 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum, wall-fired, low NOx burners, overfire air	2,680,000 kg/hr steam @ 16.5 MPa/566°C/566°C (5,900,000 lb/hr steam @ 2,400 psig/1,050°F/1,050°F)	1	0
2	Primary Air Fan	Centrifugal	386,000 kg/hr, 5,300 m ³ /min @ 101 cm WG (852,000 lb/hr, 186,200 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,258,000 kg/hr, 17,200 m ³ /min @ 26 cm WG (2,773,000 lb/hr, 606,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,824,000 kg/hr, 36,900 m ³ /min @ 114 cm WG (4,021,000 lb/hr, 1,305,000 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,450,000 kg/hr (7,610,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	130 m ³ /min @ 108 cm WG (4,700 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	148,000 liter (39,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	28 lpm @ 90 m H ₂ O (7 gpm @ 300 ft H ₂ O)	2	1

Case B11B.95 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,824,000 kg/hr (4,022,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	61,800 m ³ /min (2,180,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	215,000 lpm @ 65 m H ₂ O (56,800 gpm @ 210 ft H ₂ O)	5	1
4	Bleed Pumps	Horizontal centrifugal	5,940 lpm (1,570 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	1,020 m ³ /min @ 0.3 MPa (35,870 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,490 lpm (390 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	47 tonne/hr (52 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	900 lpm @ 13 m H ₂ O (240 gpm @ 40 ft H ₂ O)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
10	Filtrate Water Return Storage Tank	Vertical, lined	590,000 lpm (160,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	2,170 lpm @ 21 m H ₂ O (570 gpm @ 70 ft H ₂ O)	1	1
12	Activated Carbon Injectors	---	70 kg/hr (150 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,760 kg/hr (3,880 lb/hr)	1	0
14	CANSOLV	Amine-based CO ₂ capture technology	3,959,000 kg/hr (8,729,000 lb/hr) 19.1 wt % CO ₂ concentration	1	0
15	CANSOLV LP Condensate Pump	Centrifugal	1,466 lpm @ 1 m H ₂ O (387 gpm @ 3 ft H ₂ O)	1	1
16	CANSOLV IP Condensate Pump	Centrifugal	21 lpm @ 4.6 m H ₂ O (6 gpm @ 15 ft H ₂ O)	1	1
17	CO ₂ Dryer	Triethylene glycol	Inlet: 188 m ³ /min @ 2.8 MPa (6,640 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Recovered: 601 kg/hr (1,326 lb/hr)	1	0
18	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	9.0 m ³ /min @ 15.3 MPa, 82°C (335 acfm @ 2,217 psia, 180°F)	2	0
19	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 103 GJ/hr (97 MMBtu/hr)	1	0

Case B11B.95 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.4 m (21 ft) diameter	1	0

Case B11B.95 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	815 MW 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	910 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,250 GJ/hr (2,370 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B11B.95 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	994,000 lpm @ 30 m (262,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 5,540 GJ/hr (5,250 MMBtu/hr) heat duty	1	0

Case B11B.95 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	6.4 tonne/hr (7.1 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	26 m ³ /min @ 0.2 MPa (920 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,710 tonne (1,890 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	160 tonne/hr (180 tph)	1	0

Case B11B.95 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 29 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 56 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 20 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B11B.95 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.2.14 Case B11B.95 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 4-58 shows a detailed breakdown of the capital costs; Exhibit 4-59 shows the owner's costs, TOC, and TASC; Exhibit 4-60 shows the initial and annual O&M costs; and Exhibit 4-61 shows the LCOE breakdown.

The estimated TPC of the SubC PC boiler with CO₂ capture is \$3,458/kW. Process contingency represents 2.7 percent of the TPC and project contingency represents 13.9 percent. The LCOE, including CO₂ T&S costs of \$10.0/MWh, is \$110.9/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-58. Case B11B.95 total plant cost details

Case:		B11B.95	– SubC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1		Coal & Sorbent Handling									
1.1	Coal Receive & Unload	\$1,221	\$0	\$550	\$0	\$1,772	\$310	\$0	\$312	\$2,394	\$4
1.2	Coal Stackout & Reclaim	\$4,010	\$0	\$896	\$0	\$4,906	\$859	\$0	\$865	\$6,629	\$10
1.3	Coal Conveyors	\$36,945	\$0	\$8,783	\$0	\$45,728	\$8,002	\$0	\$8,060	\$61,790	\$95
1.4	Other Coal Handling	\$5,136	\$0	\$1,080	\$0	\$6,216	\$1,088	\$0	\$1,096	\$8,399	\$13
1.5	Sorbent Receive & Unload	\$235	\$0	\$70	\$0	\$305	\$53	\$0	\$54	\$412	\$1
1.6	Sorbent Stackout & Reclaim	\$1,719	\$0	\$311	\$0	\$2,030	\$355	\$0	\$358	\$2,743	\$4
1.7	Sorbent Conveyors	\$2,606	\$567	\$631	\$0	\$3,803	\$666	\$0	\$670	\$5,139	\$8
1.8	Other Sorbent Handling	\$125	\$30	\$65	\$0	\$219	\$38	\$0	\$39	\$297	\$0
1.9	Coal & Sorbent Handling Foundations	\$0	\$1,602	\$2,112	\$0	\$3,713	\$650	\$0	\$654	\$5,018	\$8
	Subtotal	\$51,997	\$2,198	\$14,498	\$0	\$68,693	\$12,021	\$0	\$12,107	\$92,822	\$143
2		Coal & Sorbent Preparation & Feed									
2.1	Coal Crushing & Drying	\$2,631	\$0	\$505	\$0	\$3,137	\$549	\$0	\$553	\$4,238	\$7
2.2	Prepared Coal Storage & Feed	\$8,856	\$0	\$1,907	\$0	\$10,764	\$1,884	\$0	\$1,897	\$14,544	\$22
2.5	Sorbent Preparation Equipment	\$1,158	\$50	\$237	\$0	\$1,445	\$253	\$0	\$255	\$1,953	\$3
2.6	Sorbent Storage & Feed	\$1,939	\$0	\$734	\$0	\$2,673	\$468	\$0	\$471	\$3,612	\$6
2.9	Coal & Sorbent Feed Foundation	\$0	\$769	\$674	\$0	\$1,443	\$252	\$0	\$254	\$1,949	\$3
	Subtotal	\$14,584	\$819	\$4,058	\$0	\$19,461	\$3,406	\$0	\$3,430	\$26,297	\$40
3		Feedwater & Miscellaneous BOP Systems									
3.1	Feedwater System	\$3,990	\$6,840	\$3,420	\$0	\$14,251	\$2,494	\$0	\$2,512	\$19,256	\$30
3.2	Water Makeup & Pretreating	\$8,438	\$844	\$4,782	\$0	\$14,064	\$2,461	\$0	\$3,305	\$19,830	\$30
3.3	Other Feedwater Subsystems	\$3,107	\$1,019	\$968	\$0	\$5,093	\$891	\$0	\$898	\$6,882	\$11
3.4	Service Water Systems	\$2,688	\$5,132	\$16,617	\$0	\$24,436	\$4,276	\$0	\$5,743	\$34,455	\$53
3.5	Other Boiler Plant Systems	\$766	\$278	\$696	\$0	\$1,740	\$304	\$0	\$307	\$2,351	\$4
3.6	Natural Gas Pipeline and Start-Up System	\$3,565	\$153	\$115	\$0	\$3,833	\$671	\$0	\$676	\$5,180	\$8
3.7	Waste Water Treatment Equipment	\$14,007	\$0	\$8,585	\$0	\$22,592	\$3,954	\$0	\$5,309	\$31,855	\$49
3.8	Spray Dryer Evaporator	\$17,606	\$0	\$10,192	\$0	\$27,798	\$4,865	\$0	\$6,532	\$39,195	\$60
3.9	Miscellaneous Plant Equipment	\$203	\$27	\$103	\$0	\$333	\$58	\$0	\$78	\$470	\$1
	Subtotal	\$54,370	\$14,293	\$45,477	\$0	\$114,141	\$19,975	\$0	\$25,359	\$159,474	\$245
4		Pulverized Coal Boiler & Accessories									
4.9	Pulverized Coal Boiler & Accessories	\$230,173	\$0	\$150,316	\$0	\$380,490	\$66,586	\$0	\$67,061	\$514,137	\$791
4.10	Selective Catalytic Reduction System	\$30,059	\$0	\$19,616	\$0	\$49,675	\$8,693	\$0	\$8,755	\$67,123	\$103
4.11	Boiler Balance of Plant	\$1,612	\$0	\$1,052	\$0	\$2,664	\$466	\$0	\$470	\$3,600	\$6
4.12	Primary Air System	\$1,680	\$0	\$1,097	\$0	\$2,778	\$486	\$0	\$490	\$3,753	\$6
4.13	Secondary Air System	\$2,545	\$0	\$1,662	\$0	\$4,207	\$736	\$0	\$741	\$5,685	\$9

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B11B.95	– SubC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
4.14	Induced Draft Fans	\$5,490	\$0	\$3,585	\$0	\$9,075	\$1,588	\$0	\$1,599	\$12,263	\$19
4.15	Major Component Rigging	\$92	\$0	\$60	\$0	\$152	\$27	\$0	\$27	\$206	\$0
4.16	Boiler Foundations	\$0	\$416	\$366	\$0	\$782	\$137	\$0	\$138	\$1,057	\$2
	Subtotal	\$271,651	\$416	\$177,755	\$0	\$449,823	\$78,719	\$0	\$79,281	\$607,823	\$935
5 Flue Gas Cleanup											
5.1	CANSOLV Carbon Dioxide (CO ₂) Removal System	\$152,438	\$66,349	\$139,334	\$0	\$358,121	\$62,671	\$60,881	\$84,293	\$565,966	\$870
5.2	WFGD Absorber Vessels & Accessories	\$83,101	\$0	\$17,775	\$0	\$100,875	\$17,653	\$0	\$17,779	\$136,308	\$210
5.3	Other FGD	\$1,328	\$0	\$1,021	\$0	\$2,349	\$411	\$0	\$414	\$3,174	\$5
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$45,859	\$6,879	\$15,099	\$0	\$67,838	\$11,872	\$0	\$15,942	\$95,651	\$147
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$514	\$82	\$220	\$0	\$815	\$143	\$0	\$192	\$1,149	\$2
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$2,790	\$614	\$2,743	\$0	\$6,147	\$1,076	\$0	\$1,083	\$8,306	\$13
5.9	Particulate Removal (Bag House & Accessories) (included with 5.2)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5.12	Gas Cleanup Foundations	\$0	\$207	\$182	\$0	\$389	\$68	\$0	\$69	\$526	\$1
5.13	Gypsum Dewatering System	\$792	\$0	\$134	\$0	\$925	\$162	\$0	\$163	\$1,251	\$2
	Subtotal	\$286,821	\$74,131	\$176,508	\$0	\$537,460	\$94,056	\$60,881	\$119,935	\$812,331	\$1,249
7 Ductwork & Stack											
7.3	Ductwork	\$0	\$760	\$528	\$0	\$1,288	\$225	\$0	\$227	\$1,740	\$3
7.4	Stack	\$8,843	\$0	\$5,139	\$0	\$13,983	\$2,447	\$0	\$2,464	\$18,894	\$29
7.5	Duct & Stack Foundations	\$0	\$211	\$250	\$0	\$461	\$81	\$0	\$108	\$650	\$1
	Subtotal	\$8,843	\$971	\$5,918	\$0	\$15,732	\$2,753	\$0	\$2,800	\$21,285	\$33
8 Steam Turbine & Accessories											
8.1	Steam Turbine Generator & Accessories	\$65,106	\$0	\$7,459	\$0	\$72,566	\$12,699	\$0	\$12,790	\$98,055	\$151
8.2	Steam Turbine Plant Auxiliaries	\$1,484	\$0	\$3,155	\$0	\$4,639	\$812	\$0	\$818	\$6,268	\$10
8.3	Condenser & Auxiliaries	\$12,527	\$0	\$4,250	\$0	\$16,778	\$2,936	\$0	\$2,957	\$22,671	\$35
8.4	Steam Piping	\$38,483	\$0	\$15,597	\$0	\$54,080	\$9,464	\$0	\$9,532	\$73,075	\$112
8.5	Turbine Generator Foundations	\$0	\$231	\$382	\$0	\$614	\$107	\$0	\$144	\$865	\$1
	Subtotal	\$117,600	\$231	\$30,844	\$0	\$148,676	\$26,018	\$0	\$26,240	\$200,934	\$309
9 Cooling Water System											
9.1	Cooling Towers	\$20,510	\$0	\$6,343	\$0	\$26,853	\$4,699	\$0	\$4,733	\$36,285	\$56
9.2	Circulating Water Pumps	\$2,929	\$0	\$207	\$0	\$3,136	\$549	\$0	\$553	\$4,237	\$7
9.3	Circulating Water System Auxiliaries	\$16,986	\$0	\$2,247	\$0	\$19,233	\$3,366	\$0	\$3,390	\$25,988	\$40
9.4	Circulating Water Piping	\$0	\$7,854	\$7,113	\$0	\$14,968	\$2,619	\$0	\$2,638	\$20,225	\$31

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B11B.95	– SubC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
9.5	Make-up Water System	\$1,313	\$0	\$1,687	\$0	\$3,000	\$525	\$0	\$529	\$4,054	\$6
9.6	Component Cooling Water System	\$1,224	\$0	\$939	\$0	\$2,163	\$379	\$0	\$381	\$2,923	\$4
9.7	Circulating Water System Foundations	\$0	\$729	\$1,211	\$0	\$1,940	\$340	\$0	\$456	\$2,736	\$4
	Subtotal	\$42,962	\$8,584	\$19,747	\$0	\$71,293	\$12,476	\$0	\$12,679	\$96,449	\$148
10 Ash & Spent Sorbent Handling Systems											
10.6	Ash Storage Silos	\$1,212	\$0	\$3,708	\$0	\$4,920	\$861	\$0	\$867	\$6,649	\$10
10.7	Ash Transport & Feed Equipment	\$4,123	\$0	\$4,088	\$0	\$8,211	\$1,437	\$0	\$1,447	\$11,095	\$17
10.9	Ash/Spent Sorbent Foundation	\$0	\$845	\$1,040	\$0	\$1,885	\$330	\$0	\$443	\$2,658	\$4
	Subtotal	\$5,336	\$845	\$8,835	\$0	\$15,016	\$2,628	\$0	\$2,757	\$20,401	\$31
11 Accessory Electric Plant											
11.1	Generator Equipment	\$2,680	\$0	\$2,022	\$0	\$4,702	\$823	\$0	\$829	\$6,354	\$10
11.2	Station Service Equipment	\$7,820	\$0	\$671	\$0	\$8,491	\$1,486	\$0	\$1,497	\$11,474	\$18
11.3	Switchgear & Motor Control	\$12,140	\$0	\$2,106	\$0	\$14,247	\$2,493	\$0	\$2,511	\$19,251	\$30
11.4	Conduit & Cable Tray	\$0	\$1,578	\$4,548	\$0	\$6,126	\$1,072	\$0	\$1,080	\$8,278	\$13
11.5	Wire & Cable	\$0	\$4,180	\$7,471	\$0	\$11,650	\$2,039	\$0	\$2,053	\$15,742	\$24
11.6	Protective Equipment	\$55	\$0	\$191	\$0	\$246	\$43	\$0	\$43	\$332	\$1
11.7	Standby Equipment	\$829	\$0	\$765	\$0	\$1,594	\$279	\$0	\$281	\$2,153	\$3
11.8	Main Power Transformers	\$7,039	\$0	\$144	\$0	\$7,183	\$1,257	\$0	\$1,266	\$9,705	\$15
11.9	Electrical Foundations	\$0	\$224	\$569	\$0	\$792	\$139	\$0	\$186	\$1,117	\$2
	Subtotal	\$30,564	\$5,981	\$18,486	\$0	\$55,031	\$9,630	\$0	\$9,746	\$74,408	\$114
12 Instrumentation & Control											
12.1	Pulverized Coal Boiler Control Equipment	\$813	\$0	\$145	\$0	\$958	\$168	\$0	\$169	\$1,294	\$2
12.3	Steam Turbine Control Equipment	\$726	\$0	\$83	\$0	\$809	\$142	\$0	\$143	\$1,094	\$2
12.5	Signal Processing Equipment	\$923	\$0	\$165	\$0	\$1,087	\$190	\$0	\$192	\$1,469	\$2
12.6	Control Boards, Panels & Racks	\$282	\$0	\$172	\$0	\$454	\$80	\$23	\$84	\$640	\$1
12.7	Distributed Control System Equipment	\$7,962	\$0	\$1,420	\$0	\$9,382	\$1,642	\$469	\$1,724	\$13,217	\$20
12.8	Instrument Wiring & Tubing	\$558	\$446	\$1,784	\$0	\$2,788	\$488	\$139	\$512	\$3,927	\$6
12.9	Other Instrumentation & Controls Equipment	\$685	\$0	\$1,587	\$0	\$2,272	\$398	\$114	\$418	\$3,201	\$5
	Subtotal	\$11,949	\$446	\$5,356	\$0	\$17,751	\$3,106	\$745	\$3,240	\$24,842	\$38
13 Improvements to Site											
13.1	Site Preparation	\$0	\$461	\$9,800	\$0	\$10,261	\$1,796	\$0	\$2,411	\$14,469	\$22
13.2	Site Improvements	\$0	\$2,282	\$3,016	\$0	\$5,298	\$927	\$0	\$1,245	\$7,470	\$11
13.3	Site Facilities	\$2,608	\$0	\$2,736	\$0	\$5,344	\$935	\$0	\$1,256	\$7,535	\$12
	Subtotal	\$2,608	\$2,743	\$15,552	\$0	\$20,904	\$3,658	\$0	\$4,912	\$29,474	\$45
14 Buildings & Structures											
14.2	Boiler Building	\$0	\$11,588	\$10,183	\$0	\$21,771	\$3,810	\$0	\$3,837	\$29,418	\$45

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B11B.95	– SubC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
14.3	Steam Turbine Building	\$0	\$16,106	\$15,001	\$0	\$31,107	\$5,444	\$0	\$5,483	\$42,033	\$65
14.4	Administration Building	\$0	\$1,046	\$1,106	\$0	\$2,152	\$377	\$0	\$379	\$2,909	\$4
14.5	Circulation Water Pumphouse	\$0	\$194	\$154	\$0	\$348	\$61	\$0	\$61	\$471	\$1
14.6	Water Treatment Buildings	\$0	\$488	\$445	\$0	\$933	\$163	\$0	\$164	\$1,260	\$2
14.7	Machine Shop	\$0	\$553	\$371	\$0	\$923	\$162	\$0	\$163	\$1,248	\$2
14.8	Warehouse	\$0	\$415	\$416	\$0	\$831	\$145	\$0	\$146	\$1,123	\$2
14.9	Other Buildings & Structures	\$0	\$291	\$248	\$0	\$539	\$94	\$0	\$95	\$728	\$1
14.10	Waste Treating Building & Structures	\$0	\$645	\$1,958	\$0	\$2,603	\$456	\$0	\$459	\$3,517	\$5
	Subtotal	\$0	\$31,326	\$29,882	\$0	\$61,208	\$10,711	\$0	\$10,788	\$82,707	\$127
	Total	\$899,286	\$142,985	\$552,918	\$0	\$1,595,188	\$279,158	\$61,625	\$313,275	\$2,249,247	\$3,458

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-59. Case B11B.95 owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$13,473	\$21
1 Month Maintenance Materials	\$2,117	\$3
1 Month Non-Fuel Consumables	\$3,471	\$5
1 Month Waste Disposal	\$1,004	\$2
25% of 1 Months Fuel Cost at 100% CF	\$3,038	\$5
2% of TPC	\$44,985	\$69
Total	\$68,088	\$105
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	\$30,399	\$47
0.5% of TPC (spare parts)	\$11,246	\$17
Total	\$41,645	\$64
Other Costs		
Initial Cost for Catalyst and Chemicals	\$2,775	\$4
Land	\$900	\$1
Other Owner's Costs	\$337,387	\$519
Financing Costs	\$60,730	\$93
Total Overnight Costs (TOC)	\$2,760,772	\$4,245
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	\$3,187,068	\$4,900

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-60. Case B11B.95 initial and annual operating and maintenance costs

Case:	B11B.95	– SubC PC w/ CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):	11,495		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	% of base	Operator:	11.3	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	2.0	
				Total:	16.3	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$7,161,008	\$11.011
Maintenance Labor:					\$14,395,182	\$22.134
Administrative & Support Labor:					\$5,389,047	\$8.286
Property Taxes and Insurance:					\$44,984,943	\$69.169
Total:					\$71,930,180	\$110.601
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$21,592,773	\$4.45894
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	7,349	\$1.90	\$0	\$4,332,202	\$0.89461
Makeup and Waste Water Treatment Chemicals (ton):	0	21.9	\$550.00	\$0	\$3,735,664	\$0.77142
Brominated Activated Carbon (ton):	0	1.68	\$1,600.00	\$0	\$835,183	\$0.17247
Enhanced Hydrated Lime (ton):	0	42.3	\$240.00	\$0	\$3,152,076	\$0.65091
Limestone (ton):	0	744	\$22.00	\$0	\$5,077,268	\$1.04846
Ammonia (19 wt%, ton):	0	74.4	\$300.00	\$0	\$6,921,682	\$1.42934
SCR Catalyst (ft³):	18,499	16.9	\$150.00	\$2,774,813	\$786,197	\$0.16235
CO ₂ Capture System Chemicals ^A :	Proprietary				\$9,151,263	\$1.88975
Triethylene Glycol (gal):	w/equip.	672	\$6.80	\$0	\$1,416,702	\$0.29255
Subtotal:				\$2,774,813	\$35,408,238	\$7.31185
Waste Disposal						
Fly Ash (ton):	0	698	\$38.00	\$0	\$8,227,549	\$1.69900
Bottom Ash (ton):	0	155	\$38.00	\$0	\$1,827,558	\$0.37739
SCR Catalyst (ft³):	0	16.9	\$2.50	\$0	\$13,103	\$0.00271
Triethylene Glycol (gal):	0	672	\$0.35	\$0	\$72,919	\$0.01506
Thermal Reclaimer Unit Waste (ton):	0	8.35	\$38.00	\$0	\$98,415	\$0.02032
Subtotal:				\$0	\$10,239,543	\$2.11448
By-Products						
Gypsum (ton):	0	1,131	\$0.00	\$0	\$0	\$0.00000
Subtotal:				\$0	\$0	\$0.00000
Variable Operating Costs Total:				\$2,774,813	\$67,240,554	\$13.88527
Fuel Cost						
Illinois Number 6 (ton):	0	7,690	\$51.96	\$0	\$123,959,803	\$25.59788
Total:				\$0	\$123,959,803	\$25.59788

^ACO₂ Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit 4-61. Case B11B.95 LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	46.6	42%
Fixed	14.9	13%
Variable	13.9	13%
Fuel	25.6	23%
Total (Excluding T&S)	100.9	N/A
CO ₂ T&S	10.0	9%
Total (Including T&S)	110.9	N/A

4.3 SUPERCRITICAL PC CASES

This section contains an evaluation of plant designs for cases B12A, B12B.90, and B12B.95, which are based on a SC PC plant with a nominal net output of 650 MWe. Both plants use a single reheat 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F) cycle. The only difference between the three plants is that cases B12B.90 and B12B.95 include CO₂ capture while Case B12A does not.

The balance of this section is organized in an analogous manner to the SubC PC section:

- Key Assumptions for cases B12A, B12B.90, and B12B.95
- Sparing Philosophy for cases B12A, B12B.90, and B12B.95
- Process and System Description for Case B12A
- Performance Results for Case B12A
- Major Equipment List for Case B12A
- Cost Estimates for Case B12A
- Process Description, Performance Results, Major Equipment List, and Cost Estimating for cases B12B.90 and B12B.95

4.3.1 Key System Assumptions

System assumptions for cases B12A, B12B.90, and B12B.95, SC PC with and without CO₂ capture, are compiled in Exhibit 4-62.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-62. SC PC plant study configuration matrix

	Case B12A w/o CO ₂ Capture	Case B12B.90 w/CO ₂ Capture	Case B12B.95 w/CO ₂ Capture
Steam Cycle, MPa/°C/°C (psig/°F/°F)	24.1/593/593 (3,500/1,100/1,100)		
Coal	Illinois No. 6		
Condenser Pressure, mm Hg (in. Hg)	50.8 (2)		
Boiler Efficiency, HHV %	88.0		
Carbon Conversion, %	99.4		
Cooling Water to Condenser, °C (°F)	16 (60)		
Cooling Water from Condenser, °C (°F)	27 (80)		
Stack Temperature, °C (°F)	57 (135)	45 (113)	
SO ₂ Control	Wet Limestone Forced Oxidation		
FGD Efficiency, % ^A	98	98 ^{B, C}	
FGD Blowdown Treatment (Effluent Limitation Guidelines)	Spray dryer evaporator		
NO _x Control	LNB w/OFA, SCR		
SCR Efficiency, % ^A	75.1	78.2	78.4
Ammonia Slip (end of catalyst life), ppmv	2		
Particulate Control	Fabric Filter		
Fabric Filter efficiency, % ^A	99.9		
Ash Distribution, Fly/Bottom, %	80/20		
SO ₃ Control	DSI		
Mercury Control	Co-benefit Capture and ACI		
CO ₂ Control	N/A	CANSOLV	
Overall Carbon Capture, % ^A	N/A	90	95
CO ₂ Sequestration	N/A	Off-site Saline Formation	

^ARemoval efficiencies are based on the flue gas content

^BAn SO₂ polishing step is included to meet more stringent SO_x content limits in the flue gas (0.37 ppmv) to reduce formation of amine HSS during the CO₂ absorption process

^CSO₂ exiting the post-FGD polishing step is absorbed in the CO₂ capture process making stack emissions negligible

4.3.1.1 Balance of Plant – Case B12A, Case B12B.90, Case B12B.95

The balance of plant assumptions are common to all PC cases and were presented previously in Exhibit 4-16.

4.3.2 Sparing Philosophy

Single trains are used throughout the design with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- One dry-bottom, wall-fired SC PC boiler (1 x 100 percent)
- Two SCR reactors (2 x 50 percent)
- One DSI system (1 x 100 percent)
- One ACI system (1 x 100 percent)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50 percent)
- One wet limestone forced oxidation positive pressure absorber (1 x 100 percent)
- One steam turbine (1 x 100 percent)
- For case B12B.90 and B12B.95, one CO₂ absorption system, consisting of an absorber, stripper, and ancillary equipment (1 x 100 percent) and two CO₂ compression systems (2 x 50 percent)

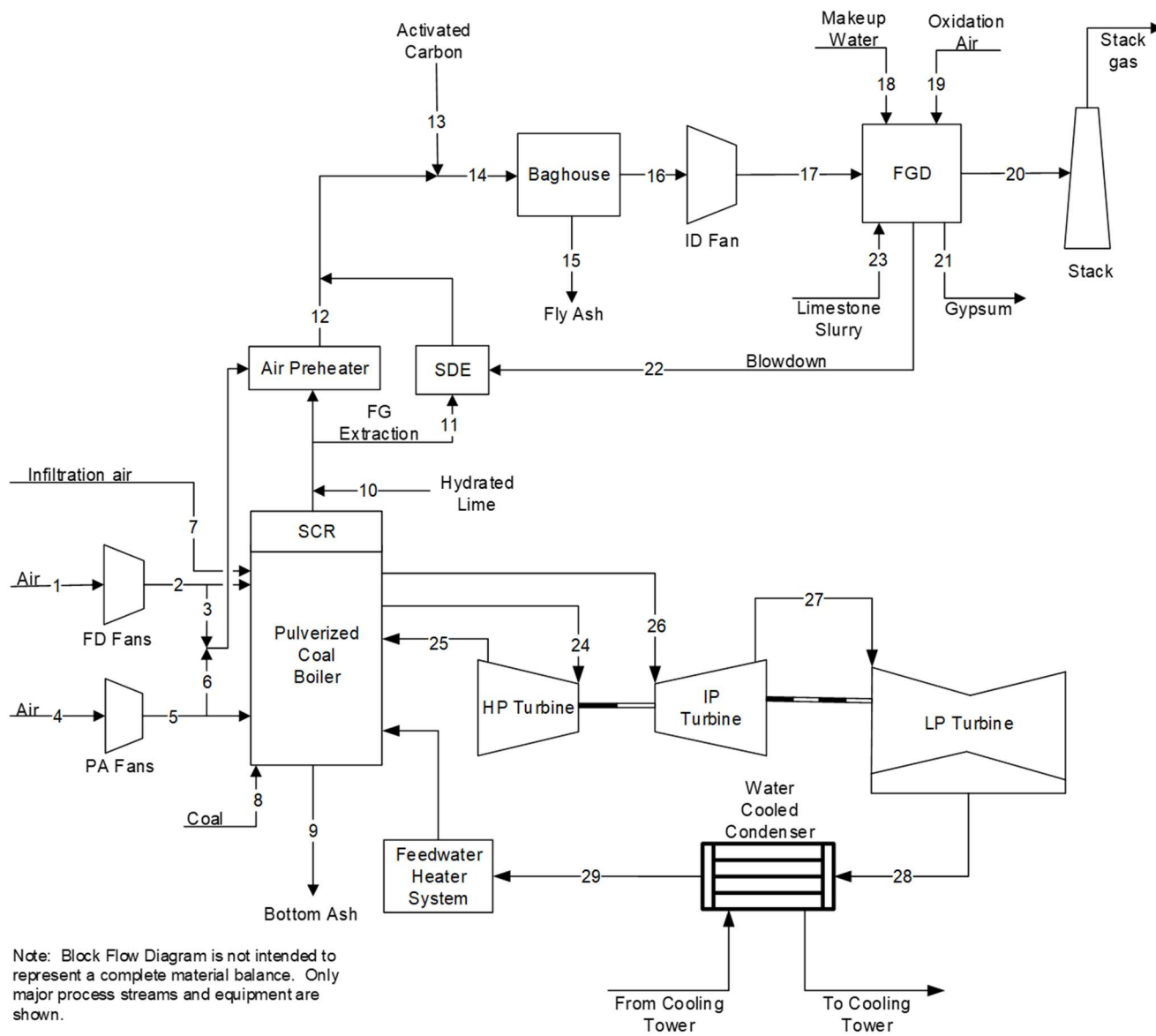
4.3.3 Case B12A – SC PC without CO₂ Capture Process Description

In this section, the SC PC process without CO₂ capture is described. The system description is nearly identical to the SubC PC case without CO₂ capture but is repeated here for completeness. The description follows the BFD in Exhibit 4-63 and stream numbers reference the same exhibit. Exhibit 4-64 provides process data for the numbered streams in the BFD.

Coal (stream 8) and PA (stream 4) are introduced into the boiler through the wall-fired burners. Additional combustion air, including the OFA, is provided by the FD fans (stream 1). The boiler operates at a slight negative pressure, so air leakage is into the boiler, and the infiltration air is accounted for in stream 7. Streams 3 and 6 show Ljungstrom air preheater leakages from the FD and PA fan outlet streams to the boiler exhaust.

Flue gas exits the boiler through the SCR reactor where hydrated lime is injected (stream 10) for the reduction of SO₃. A small flue gas stream is extracted for use in the SDE (stream 11). The flue gas then passes through the combustion air preheater (where the air preheater leakages are introduced) and is cooled to 143°C (289°F) (stream 12) before PAC is injected (stream 13) for mercury reduction. The flue gas then passes through a fabric filter for particulate removal (stream 16). An ID fan provides the motive force for the flue gas (stream 17) to pass through the FGD unit and the plant stack. FGD inputs and outputs include makeup water (stream 18), oxidation air (stream 19), limestone slurry (stream 23), and product gypsum (stream 21). The clean, saturated flue gas exiting the FGD unit (stream 20) passes to the plant stack and is discharged to the atmosphere. The FGD blowdown (stream 22) is sent to the SDE where extracted flue gas (stream 11) is used to evaporate the FGD blowdown stream. The SDE outlet gas stream is recombined into the flue gas path after the air preheater, and before PAC injection.

Exhibit 4-63. Case B12A block flow diagram, SC unit without CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-64. Case B12A stream table, SC unit without capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0087	0.0088	0.0000	0.0087	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379	0.0000	0.1372	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837	0.0000	0.0911	0.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340	0.0000	0.7281	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336	0.0000	0.0329	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020	0.0000	0.0020	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1158
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.8842
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	58,499	58,499	1,733	17,970	17,970	2,473	1,293	0	0	1	3,855	78,199	0	82,707	5
V-L Flowrate (kg/hr)	1,688,112	1,688,112	50,000	518,570	518,570	71,368	37,313	0	0	12	114,649	2,322,076	0	2,448,804	529
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	214,574	4,326	1,169	926	17,774	47	18,931	18,944
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143	15	143	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.31	-6.79	-2,453.14	-1,066.10
Density (kg/m ³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8	---	0.8	2,150.2
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694	---	29.608	104.897
V-L Flowrate (lb _{mol} /hr)	128,969	128,969	3,820	39,618	39,618	5,452	2,851	0	0	1	8,498	172,400	0	182,338	11
V-L Flowrate (lb/hr)	3,721,650	3,721,650	110,230	1,143,252	1,143,252	157,339	82,262	0	0	26	252,758	5,119,302	0	5,398,689	1,167
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	473,055	9,536	2,578	2,041	39,186	104	41,736	41,764
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289	59	289	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1	14.7	14.1	14.1
Steam Table Enthalpy (Btu/lb) ^A	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4	-2.9	-1,054.7	-458.3
Density (lb/ft ³)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052	---	0.052	134.232

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-64. Case B12A stream table, SC unit without capture (continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29
V-L Mole Fraction														
Ar	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.1372	0.1372	0.0000	0.0003	0.1245	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0911	0.0911	0.9999	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0001	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	82,702	82,702	4,832	3,462	92,454	195	653	2,691	104,862	87,665	87,665	75,546	57,259	75,757
V-L Flowrate (kg/hr)	2,448,262	2,448,262	87,072	99,902	2,657,150	3,507	12,079	48,487	1,889,118	1,579,312	1,579,312	1,360,986	1,031,543	1,364,788
Solids Flowrate (kg/hr)	0	0	0	0	0	31,549	184	20,757	0	0	0	0	0	0
Temperature (°C)	143	156	15	15	57	15	57	15	593	342	593	270	38	39
Pressure (MPa, abs)	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	24.23	4.90	4.80	0.52	0.01	1.32
Steam Table Enthalpy (kJ/kg) ^A	287.58	302.09	-47.80	30.23	297.00	---	---	---	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.43
AspenPlus Enthalpy (kJ/kg) ^B	-2,464.17	-2,449.66	-16,015.01	-97.58	-2,939.24	-12,513.34	-15,496.00	-14,994.25	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.87
Density (kg/m ³)	0.8	0.9	1,003.7	1.2	1.1	878.3	979.5	1,003.7	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	29.603	29.603	18.019	28.857	28.740	18.021	18.495	18.019	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	182,327	182,327	10,654	7,632	203,826	429	1,440	5,933	231,181	193,269	193,269	166,551	126,235	167,016
V-L Flowrate (lb/hr)	5,397,494	5,397,494	191,961	220,247	5,858,012	7,732	26,630	106,896	4,164,793	3,481,788	3,481,788	3,000,461	2,274,164	3,008,843
Solids Flowrate (lb/hr)	0	0	0	0	0	69,555	406	45,761	0	0	0	0	0	0
Temperature (°F)	289	313	59	59	135	59	135	59	1,100	648	1,100	517	101	101
Pressure (psia)	13.9	15.3	14.7	14.7	14.8	14.7	14.7	14.7	3,514.7	710.8	696.6	75.0	1.0	190.7
Steam Table Enthalpy (Btu/lb) ^A	123.6	129.9	-20.5	13.0	127.7	---	---	---	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb) ^B	-1,059.4	-1,053.2	-6,885.2	-42.0	-1,263.6	-5,379.8	-6,662.1	-6,446.4	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft ³)	0.051	0.055	62.658	0.076	0.067	54.833	61.145	62.658	4.319	1.197	0.768	0.131	0.003	62.010

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

4.3.4 Case B12A – Performance Results

The plant produces a net output of 650 MWe at a net plant efficiency of 40.2 percent (HHV basis). Overall performance for the plant is summarized in Exhibit 4-65; Exhibit 4-66 provides a detailed breakdown of the auxiliary power requirements.

Exhibit 4-65. Case B12A plant performance summary

Performance Summary	
Total Gross Power, MWe	686
CO ₂ Capture/Removal Auxiliaries, kWe	–
CO ₂ Compression, kWe	–
Balance of Plant, kWe	35,950
Total Auxiliaries, MWe	36
Net Power, MWe	650
HHV Net Plant Efficiency, %	40.2
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,957 (8,490)
LHV Net Plant Efficiency, %	41.7
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,639 (8,188)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	48.2
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,471 (7,081)
Condenser Duty, GJ/hr (MMBtu/hr)	2,592 (2,457)
CO ₂ Capture Rate, %	–
AGR Duty, GJ/hr (MMBtu/hr)	–
As-Received Coal Feed, kg/hr (lb/hr)	214,574 (473,055)
Limestone Sorbent Feed, kg/hr (lb/hr)	20,757 (45,761)
HHV Thermal Input, kWt	1,617,359
LHV Thermal Input, kWt	1,559,963
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.035 (9.3)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.028 (7.4)
Excess Air, %	20.3

Exhibit 4-66. Case B12A plant power summary

Power Summary	
Steam Turbine Power, MWe	686
Total Gross Power, MWe	686
Auxiliary Load Summary	
Activated Carbon Injection, kWe	30
Ash Handling, kWe	700
Baghouse, kWe	90
Circulating Water Pumps, kWe	5,300
CO ₂ Capture/Removal Auxiliaries, kWe	–
CO ₂ Compression, kWe	–
Coal Handling and Conveying, kWe	470
Condensate Pumps, kWe	660
Cooling Tower Fans, kWe	2,740
Dry Sorbent Injection, kWe	60
Flue Gas Desulfurizer, kWe	3,320
Forced Draft Fans, kWe	1,100
Ground Water Pumps, kWe	500
Induced Draft Fans, kWe	10,230
Miscellaneous Balance of Plant ^{A,B} , kWe	2,250
Primary Air Fans, kWe	1,310
Pulverizers, kWe	3,220
SCR, kWe	30
Sorbent Handling & Reagent Preparation, kWe	1,000
Spray Dryer Evaporator, kWe	240
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,150
Total Auxiliaries, MWe	36
Net Power, MWe	650

^ABoiler feed pumps are turbine driven

^BIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

4.3.4.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B12A is presented in Exhibit 4-67.

Exhibit 4-67. Case B12A air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.035 (0.081)	1,503 (1,657)	0.294 (0.649)
NO _x	0.037 (0.087)	1,622 (1,788)	0.318 (0.700)
Particulate	0.005 (0.011)	209 (230)	0.041 (0.090)
Hg	1.60E-7 (3.73E-7)	0.007 (0.008)	1.36E-6 (3.00E-6)
CO ₂	87 (202)	3,771,114 (4,156,942)	738 (1,628)
CO ₂ ^C	—	—	779 (1,718)
mg/Nm ³			
Particulate Concentration ^{D,E}	15.11		

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

^DConcentration of particles in the flue gas after the baghouse

^ENormal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NO_x boiler emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 75.1 percent to 0.04 kg/GJ (0.09 lb/MMBtu).

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and wet FGD) is 97.1 percent.

CO₂ emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 4-68. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO₂ through the stack; however, the PAC is captured in the fabric filter, unburned carbon remains in the bottom ash, and some leaves as gypsum.

Exhibit 4-68. Case B12A carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	136,780 (301,548)	Stack Gas	138,222 (304,727)
Air (CO ₂)	319 (703)	FGD Product	162 (358)
PAC	47 (104)	Baghouse	703 (1,551)
FGD Reagent	2,106 (4,643)	Bottom Ash	164 (362)
		CO ₂ Product	–
		CO ₂ Dryer Vent	–
		CO ₂ Knockout	–
Total	139,252 (306,997)	Total	139,252 (306,997)

Exhibit 4-69 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur captured in the fabric filter via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 4-69. Case B12A sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	5,378 (11,857)	FGD Product	5,056 (11,147)
		Stack Gas	105 (232)
		Polishing Scrubber and Solvent Reclaiming	–
		Baghouse	217 (478)
Total	5,378 (11,857)	Total	5,378 (11,857)

Water demand, recycle, withdrawal, discharge, and consumption were defined and discussed in Section 2.6. Exhibit 4-70 shows the overall water balance for the plant.

Exhibit 4-70. Case B12A water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
FGD Process Makeup	1.5 (384)	–	1.5 (384)	–	1.5 (384)
FGD Slurry Water	0.8 (214)	–	0.8 (214)	–	0.8 (214)
CO ₂ Drying	–	–	–	–	–
CO ₂ Capture Recovery	–	–	–	–	–

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
CO ₂ Compression KO	–	–	–	–	–
Deaerator Vent	–	–	–	0.1 (17)	-0.1 (-17)
Condenser Makeup	0.1 (17)	–	0.1 (17)	–	0.1 (17)
BFW Makeup	0.1 (17)	–	0.1 (17)	–	0.1 (17)
Cooling Tower	21 (5,458)	–	21 (5,458)	4.6 (1,227)	16 (4,230)
BFW Blowdown	–	–	–	–	–
Total	23 (6,072)	–	23 (6,072)	4.7 (1,244)	18 (4,828)

4.3.4.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for the Case B12A PC boiler, FGD unit and steam cycle in Exhibit 4-71 and Exhibit 4-72.

An overall plant energy balance is provided in tabular form in Exhibit 4-73. The power out is the steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a generator efficiency of 98.5 percent.

Exhibit 4-71. Case B12A energy and mass balance, SC PC boiler without CO₂ capture

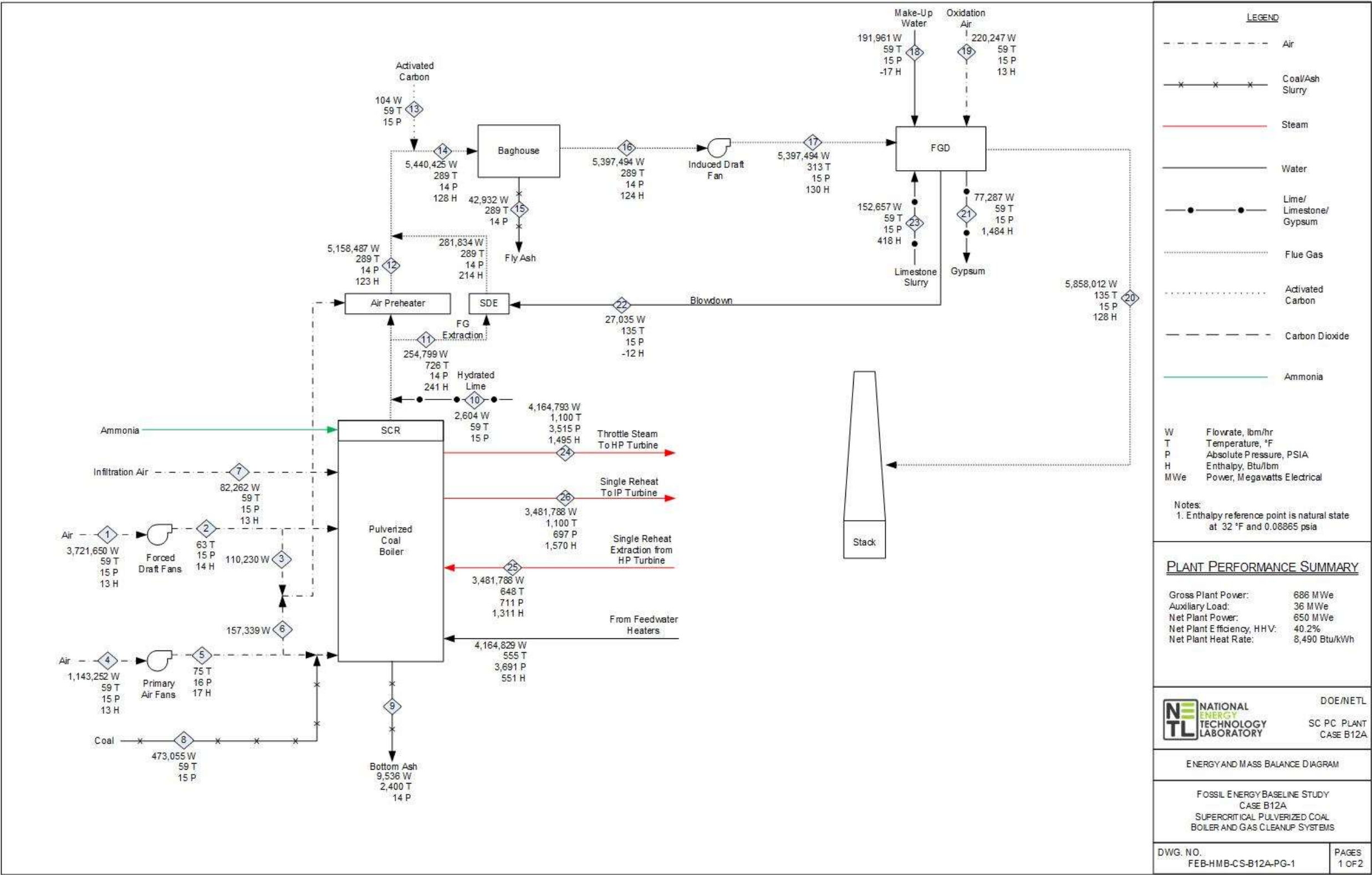


Exhibit 4-72. Case B12A energy and mass balance, SC steam cycle

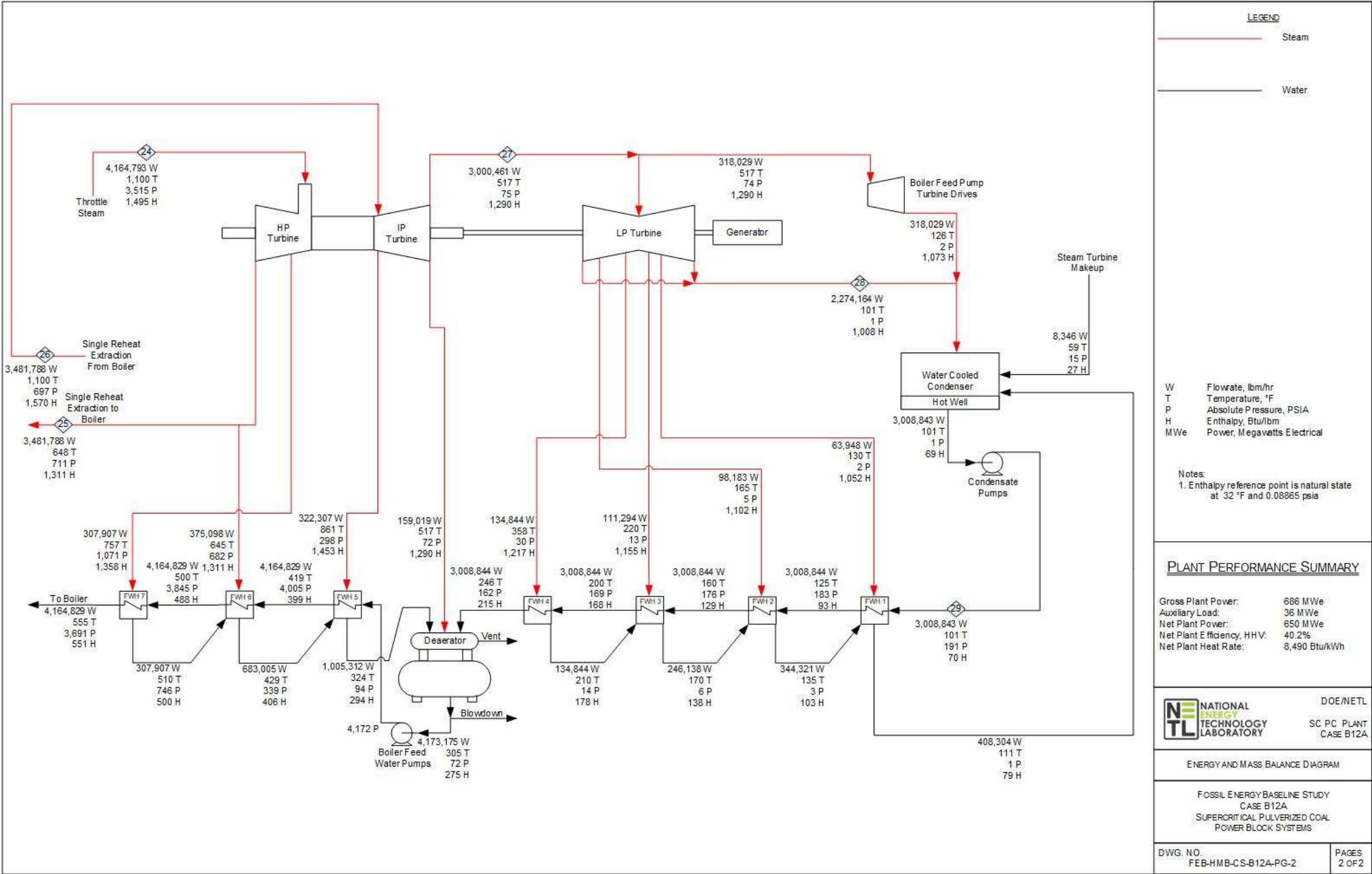


Exhibit 4-73. Case B12A overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,822 (5,519)	4.9 (4.6)	–	5,827 (5,523)
Air	–	68 (64)	–	68 (64)
Raw Water Makeup	–	86 (82)	–	86 (82)
Limestone	–	0.5 (0.4)	–	0.5 (0.4)
Auxiliary Power	–	–	129 (123)	129 (123)
TOTAL	5,822 (5,519)	160 (151)	129 (123)	6,111 (5,793)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	5.5 (5.2)	–	5.5 (5.2)
Fly Ash	–	2.0 (1.9)	–	2.0 (1.9)
Stack Gas	–	789 (748)	–	789 (748)
Sulfur	–	–	–	–
Gypsum	–	2.0 (1.9)	–	2.0 (1.9)
Motor Losses and Design Allowances	–	–	40 (38)	40 (38)
Cooling Tower Load ^A	–	2,698 (2,557)	–	2,698 (2,557)
CO ₂ Product Stream	–	–	–	–
AGR Effluent	–	–	–	–
Blowdown Streams and Deaerator Vent	–	2.4 (2.3)	–	2.4 (2.3)
<i>Ambient Losses^B</i>	–	<i>137 (130)</i>	–	<i>137 (130)</i>
Power	–	–	2,470 (2,341)	2,470 (2,341)
TOTAL	–	3,636 (3,446)	2,510 (2,379)	6,145 (5,825)
<i>Unaccounted Energy^C</i>	–	<i>-34 (-32)</i>	–	<i>-34 (-32)</i>

^AIncludes condenser and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^CBy difference

4.3.5 Case B12A – Major Equipment List

Major equipment items for the SC PC plant with no CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.3.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B12A – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	40 tonne (50 ton)	2	1
9	Feeder	Vibratory	180 tonne/hr (200 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	350 tonne/hr (390 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	180 tonne (200 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/trippper	350 tonne/hr (390 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	350 tonne/hr (390 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	790 tonne (870 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 9 tonne (10 ton) Feeder - 50 kg/hr (110 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 220 tonne (240 ton) Feeder - 1,300 kg/hr (2,860 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	87 tonne/hr (96 tph)	1	0
23	Limestone Conveyor No. 1	Belt	87 tonne/hr (96 tph)	1	0
24	Limestone Reclaim Hopper	N/A	17 tonne (19 ton)	1	0
25	Limestone Reclaim Feeder	Belt	69 tonne/hr (76 tph)	1	0
26	Limestone Conveyor No. 2	Belt	69 tonne/hr (76 tph)	1	0
27	Limestone Day Bin	w/ actuator	274 tonne (302 ton)	2	0

Case B12A – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	39 tonne/hr (43 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	39 tonne/hr (43 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	23 tonne/hr (25 tph)	1	1
4	Limestone Ball Mill	Rotary	23 tonne/hr (25 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	89,000 liters (23,400 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,460 lpm @ 10m H ₂ O (390 gpm @ 40 ft H ₂ O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5-cyclone bank	370 lpm (100 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	494,000 liters (130,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,030 lpm @ 9m H ₂ O (270 gpm @ 30 ft H ₂ O)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B12A – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	250,000 liters (66,100 gal)	2	0
2	Condensate Pumps	Vertical canned	12,600 lpm @ 200 m H ₂ O (3,330 gpm @ 500 ft H ₂ O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,041,000 kg/hr (2,295,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	17,000 lpm @ 3,500 m H ₂ O (4,600 gpm @ 11,400 ft H ₂ O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	5,200 lpm @ 3,500 m H ₂ O (1,400 gpm @ 11,400 ft H ₂ O)	2	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	380,000 kg/hr (830,000 lb/hr)	4	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	380,000 kg/hr (830,000 lb/hr)	4	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	380,000 kg/hr (830,000 lb/hr)	4	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	380,000 kg/hr (830,000 lb/hr)	4	0
10	HP Feedwater Heater 5	Horizontal U-tube	1,040,000 kg/hr (2,290,000 lb/hr)	2	0
11	HP Feedwater Heater 6	Horizontal U-tube	1,040,000 kg/hr (2,290,000 lb/hr)	2	0
12	HP Feedwater heater 7	Horizontal U-tube	1,040,000 kg/hr (2,290,000 lb/hr)	2	0
13	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
15	Service Air Compressors	Flooded Screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H ₂ O (5,500 gpm @ 100 ft H ₂ O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	6,100 lpm @ 20 m H ₂ O (1,620 gpm @ 60 ft H ₂ O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	2,460 lpm @ 270 m H ₂ O (650 gpm @ 880 ft H ₂ O)	5	1
23	Filtered Water Pumps	Stainless steel, single suction	1,000 lpm @ 50 m H ₂ O (250 gpm @ 160 ft H ₂ O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	919,000 liter (242,900 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
26	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
27	Process Water Treatment	Spray dryer evaporator	Flue Gas - 1,980 m ³ /min (69,800 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 110 lpm (30 gpm) @ 19,996 ppmw Cl ⁻	2	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B12A – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, once-through, wall-fired, low NO _x burners, overfire air	2,080,000 kg/hr steam @ 24.1 MPa/593°C/593°C (4,580,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	285,000 kg/hr, 3,900 m ³ /min @ 101 cm WG (629,000 lb/hr, 137,400 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	928,000 kg/hr, 12,700 m ³ /min @ 26 cm WG (2,047,000 lb/hr, 447,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,347,000 kg/hr, 27,300 m ³ /min @ 114 cm WG (2,969,000 lb/hr, 963,000 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,550,000 kg/hr (5,620,000 lb/hr)	2	0
6	SCR Catalyst	—	—	3	0
7	Dilution Air Blower	Centrifugal	90 m ³ /min @ 108 cm WG (3,300 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	103,000 liter (27,300 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	20 lpm @ 90 m H ₂ O (5 gpm @ 300 ft H ₂ O)	2	1

Case B12A – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,347,000 kg/hr (2,969,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	46,000 m ³ /min (1,612,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	159,000 lpm @ 65 m H ₂ O (42,000 gpm @ 210 ft H ₂ O)	5	1
4	Bleed Pumps	Horizontal centrifugal	4,380 lpm (1,160 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	750 m ³ /min @ 0.3 MPa (26,480 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,100 lpm (290 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	35 tonne/hr (38 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	670 lpm @ 13 m H ₂ O (180 gpm @ 40 ft H ₂ O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	440,000 lpm (120,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	1,600 lpm @ 21 m H ₂ O (420 gpm @ 70 ft H ₂ O)	1	1
12	Activated Carbon Injectors	---	50 kg/hr (110 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,300 kg/hr (2,860 lb/hr)	1	0

Case B12A – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.3 m (21 ft) diameter	1	0

Case B12A – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	722 MW 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	800 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,430 GJ/hr (2,700 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0

Case B12A – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	532,000 lpm @ 30 m (141,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 2,970 GJ/hr (2,810 MMBtu/hr) heat duty	1	0

Case B12A – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	4.8 tonne/hr (5.2 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	19 m ³ /min @ 0.2 MPa (679 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,260 tonne (1,390 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	120 tonne/hr (130 tph)	1	0

Case B12A – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
N/A	N/A	N/A	N/A	N/A	N/A
2	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 32 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 6 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B12A – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.3.6 Case B12A – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 4-74 shows a detailed breakdown of the capital costs; Exhibit 4-75 shows the owner's costs, TOC, and TASC; Exhibit 4-76 shows the initial and annual O&M costs; and Exhibit 4-77 shows the LCOE breakdown.

The estimated TPC of the SC PC boiler with no CO₂ capture is \$2,103/kW. No process contingency was included in this case because all elements of the technology are commercially proven. The project contingency is 13.4 percent of the TPC. The LCOE is \$64.5/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO
ELECTRICITY

Exhibit 4-74. Case B12A total plant cost details

Case:		B12A	– SC PC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1											
Coal & Sorbent Handling											
1.1	Coal Receive & Unload	\$1,012	\$0	\$456	\$0	\$1,468	\$257	\$0	\$259	\$1,983	\$3
1.2	Coal Stackout & Reclaim	\$3,322	\$0	\$743	\$0	\$4,065	\$711	\$0	\$716	\$5,493	\$8
1.3	Coal Conveyors	\$30,608	\$0	\$7,276	\$0	\$37,884	\$6,630	\$0	\$6,677	\$51,191	\$79
1.4	Other Coal Handling	\$4,256	\$0	\$894	\$0	\$5,150	\$901	\$0	\$908	\$6,959	\$11
1.5	Sorbent Receive & Unload	\$193	\$0	\$57	\$0	\$250	\$44	\$0	\$44	\$338	\$1
1.6	Sorbent Stackout & Reclaim	\$1,416	\$0	\$256	\$0	\$1,672	\$293	\$0	\$295	\$2,259	\$3
1.7	Sorbent Conveyors	\$2,144	\$465	\$519	\$0	\$3,128	\$547	\$0	\$551	\$4,226	\$7
1.8	Other Sorbent Handling	\$103	\$24	\$53	\$0	\$181	\$32	\$0	\$32	\$245	\$0
1.9	Coal & Sorbent Handling Foundations	\$0	\$1,327	\$1,749	\$0	\$3,076	\$538	\$0	\$542	\$4,157	\$6
	Subtotal	\$43,054	\$1,816	\$12,003	\$0	\$56,873	\$9,953	\$0	\$10,024	\$76,850	\$118
2											
Coal & Sorbent Preparation & Feed											
2.1	Coal Crushing & Drying	\$2,154	\$0	\$413	\$0	\$2,567	\$449	\$0	\$452	\$3,469	\$5
2.2	Prepared Coal Storage & Feed	\$7,248	\$0	\$1,560	\$0	\$8,808	\$1,541	\$0	\$1,552	\$11,902	\$18
2.5	Sorbent Preparation Equipment	\$951	\$41	\$195	\$0	\$1,186	\$208	\$0	\$209	\$1,603	\$2
2.6	Sorbent Storage & Feed	\$1,592	\$0	\$602	\$0	\$2,194	\$384	\$0	\$387	\$2,965	\$5
2.9	Coal & Sorbent Feed Foundation	\$0	\$632	\$555	\$0	\$1,187	\$208	\$0	\$209	\$1,604	\$2
	Subtotal	\$11,945	\$673	\$3,325	\$0	\$15,943	\$2,790	\$0	\$2,810	\$21,543	\$33
3											
Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$3,366	\$5,771	\$2,885	\$0	\$12,023	\$2,104	\$0	\$2,119	\$16,245	\$25
3.2	Water Makeup & Pretreating	\$5,776	\$578	\$3,273	\$0	\$9,627	\$1,685	\$0	\$2,262	\$13,573	\$21
3.3	Other Feedwater Subsystems	\$2,506	\$822	\$781	\$0	\$4,109	\$719	\$0	\$724	\$5,552	\$9
3.4	Service Water Systems	\$1,766	\$3,371	\$10,917	\$0	\$16,054	\$2,809	\$0	\$3,773	\$22,636	\$35
3.5	Other Boiler Plant Systems	\$618	\$225	\$562	\$0	\$1,404	\$246	\$0	\$248	\$1,898	\$3
3.6	Natural Gas Pipeline and Start-Up System	\$2,972	\$128	\$96	\$0	\$3,196	\$559	\$0	\$563	\$4,319	\$7
3.7	Waste Water Treatment Equipment	\$8,148	\$0	\$4,994	\$0	\$13,143	\$2,300	\$0	\$3,089	\$18,531	\$29
3.8	Spray Dryer Evaporator	\$14,140	\$0	\$8,188	\$0	\$22,327	\$3,907	\$0	\$5,247	\$31,481	\$48
3.9	Miscellaneous Plant Equipment	\$212	\$28	\$108	\$0	\$348	\$61	\$0	\$82	\$491	\$1
	Subtotal	\$39,505	\$10,922	\$31,803	\$0	\$82,230	\$14,390	\$0	\$18,106	\$114,726	\$176
4											
Pulverized Coal Boiler & Accessories											
4.9	Pulverized Coal Boiler & Accessories	\$223,120	\$0	\$127,133	\$0	\$350,253	\$61,294	\$0	\$61,732	\$473,280	\$728
4.10	Selective Catalytic Reduction System	\$25,629	\$0	\$14,634	\$0	\$40,262	\$7,046	\$0	\$7,096	\$54,405	\$84
4.11	Boiler Balance of Plant	\$1,495	\$0	\$852	\$0	\$2,347	\$411	\$0	\$414	\$3,171	\$5
4.12	Primary Air System	\$1,435	\$0	\$818	\$0	\$2,253	\$394	\$0	\$397	\$3,044	\$5
4.13	Secondary Air System	\$2,174	\$0	\$1,239	\$0	\$3,412	\$597	\$0	\$601	\$4,611	\$7
4.14	Induced Draft Fans	\$4,689	\$0	\$2,672	\$0	\$7,360	\$1,288	\$0	\$1,297	\$9,946	\$15
4.15	Major Component Rigging	\$79	\$0	\$45	\$0	\$123	\$22	\$0	\$22	\$167	\$0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B12A	– SC PC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
4.16	Boiler Foundations	\$0	\$338	\$297	\$0	\$635	\$111	\$0	\$112	\$858	\$1
	Subtotal	\$258,620	\$338	\$147,688	\$0	\$406,646	\$71,163	\$0	\$71,671	\$549,480	\$845
5	Flue Gas Cleanup										
5.2	WFGD Absorber Vessels & Accessories	\$66,585	\$0	\$14,242	\$0	\$80,826	\$14,145	\$0	\$14,246	\$109,216	\$168
5.3	Other FGD	\$1,050	\$0	\$810	\$0	\$1,860	\$325	\$0	\$328	\$2,513	\$4
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$2,208	\$485	\$2,171	\$0	\$4,864	\$851	\$0	\$857	\$6,572	\$10
5.9	Particulate Removal (Bag House & Accessories) (included with 5.2)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5.12	Gas Cleanup Foundations	\$0	\$163	\$143	\$0	\$306	\$54	\$0	\$54	\$414	\$1
5.13	Gypsum Dewatering System	\$663	\$0	\$112	\$0	\$775	\$136	\$0	\$137	\$1,048	\$2
	Subtotal	\$70,506	\$648	\$17,477	\$0	\$88,631	\$15,510	\$0	\$15,621	\$119,763	\$184
7	Ductwork & Stack										
7.3	Ductwork	\$0	\$696	\$484	\$0	\$1,179	\$206	\$0	\$208	\$1,594	\$2
7.4	Stack	\$8,824	\$0	\$5,128	\$0	\$13,951	\$2,442	\$0	\$2,459	\$18,852	\$29
7.5	Duct & Stack Foundations	\$0	\$207	\$246	\$0	\$453	\$79	\$0	\$106	\$638	\$1
	Subtotal	\$8,824	\$903	\$5,857	\$0	\$15,584	\$2,727	\$0	\$2,773	\$21,084	\$32
8	Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	\$67,827	\$0	\$7,396	\$0	\$75,224	\$13,164	\$0	\$13,258	\$101,646	\$156
8.2	Steam Turbine Plant Auxiliaries	\$1,536	\$0	\$3,270	\$0	\$4,806	\$841	\$0	\$847	\$6,494	\$10
8.3	Condenser & Auxiliaries	\$13,906	\$0	\$4,718	\$0	\$18,624	\$3,259	\$0	\$3,283	\$25,166	\$39
8.4	Steam Piping	\$36,363	\$0	\$14,738	\$0	\$51,101	\$8,943	\$0	\$9,007	\$69,051	\$106
8.5	Turbine Generator Foundations	\$0	\$240	\$396	\$0	\$636	\$111	\$0	\$149	\$896	\$1
	Subtotal	\$119,632	\$240	\$30,519	\$0	\$150,390	\$26,318	\$0	\$26,544	\$203,252	\$313
9	Cooling Water System										
9.1	Cooling Towers	\$12,953	\$0	\$4,005	\$0	\$16,958	\$2,968	\$0	\$2,989	\$22,915	\$35
9.2	Circulating Water Pumps	\$1,728	\$0	\$108	\$0	\$1,836	\$321	\$0	\$324	\$2,481	\$4
9.3	Circulating Water System Auxiliaries	\$11,468	\$0	\$1,527	\$0	\$12,995	\$2,274	\$0	\$2,290	\$17,559	\$27
9.4	Circulating Water Piping	\$0	\$5,307	\$4,806	\$0	\$10,112	\$1,770	\$0	\$1,782	\$13,664	\$21
9.5	Make-up Water System	\$1,008	\$0	\$1,294	\$0	\$2,302	\$403	\$0	\$406	\$3,110	\$5
9.6	Component Cooling Water System	\$827	\$0	\$635	\$0	\$1,461	\$256	\$0	\$258	\$1,975	\$3
9.7	Circulating Water System Foundations	\$0	\$508	\$844	\$0	\$1,353	\$237	\$0	\$318	\$1,907	\$3
	Subtotal	\$27,983	\$5,815	\$13,219	\$0	\$47,017	\$8,228	\$0	\$8,366	\$63,611	\$98
10	Ash & Spent Sorbent Handling Systems										
10.6	Ash Storage Silos	\$1,022	\$0	\$3,129	\$0	\$4,151	\$726	\$0	\$732	\$5,609	\$9
10.7	Ash Transport & Feed Equipment	\$3,479	\$0	\$3,449	\$0	\$6,927	\$1,212	\$0	\$1,221	\$9,361	\$14
10.9	Ash/Spent Sorbent Foundation	\$0	\$712	\$874	\$0	\$1,587	\$278	\$0	\$373	\$2,237	\$3
	Subtotal	\$4,501	\$712	\$7,452	\$0	\$12,665	\$2,216	\$0	\$2,326	\$17,207	\$26
11	Accessory Electric Plant										
11.1	Generator Equipment	\$2,502	\$0	\$1,887	\$0	\$4,389	\$768	\$0	\$774	\$5,931	\$9

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B12A	– SC PC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
11.2	Station Service Equipment	\$4,595	\$0	\$394	\$0	\$4,989	\$873	\$0	\$879	\$6,742	\$10
11.3	Switchgear & Motor Control	\$7,133	\$0	\$1,238	\$0	\$8,371	\$1,465	\$0	\$1,475	\$11,311	\$17
11.4	Conduit & Cable Tray	\$0	\$927	\$2,672	\$0	\$3,600	\$630	\$0	\$634	\$4,864	\$7
11.5	Wire & Cable	\$0	\$2,456	\$4,390	\$0	\$6,845	\$1,198	\$0	\$1,207	\$9,250	\$14
11.6	Protective Equipment	\$55	\$0	\$191	\$0	\$246	\$43	\$0	\$43	\$332	\$1
11.7	Standby Equipment	\$784	\$0	\$724	\$0	\$1,507	\$264	\$0	\$266	\$2,037	\$3
11.8	Main Power Transformers	\$6,467	\$0	\$132	\$0	\$6,599	\$1,155	\$0	\$1,163	\$8,918	\$14
11.9	Electrical Foundations	\$0	\$206	\$523	\$0	\$729	\$128	\$0	\$171	\$1,028	\$2
	Subtotal	\$21,537	\$3,589	\$12,151	\$0	\$37,276	\$6,523	\$0	\$6,613	\$50,412	\$78
12	Instrumentation & Control										
12.1	Pulverized Coal Boiler Control Equipment	\$692	\$0	\$123	\$0	\$815	\$143	\$0	\$144	\$1,102	\$2
12.3	Steam Turbine Control Equipment	\$621	\$0	\$68	\$0	\$689	\$121	\$0	\$121	\$931	\$1
12.5	Signal Processing Equipment	\$785	\$0	\$140	\$0	\$925	\$162	\$0	\$163	\$1,251	\$2
12.6	Control Boards, Panels & Racks	\$240	\$0	\$147	\$0	\$387	\$68	\$0	\$68	\$523	\$1
12.7	Distributed Control System Equipment	\$6,779	\$0	\$1,209	\$0	\$7,988	\$1,398	\$0	\$1,408	\$10,793	\$17
12.8	Instrument Wiring & Tubing	\$475	\$380	\$1,519	\$0	\$2,374	\$415	\$0	\$418	\$3,208	\$5
12.9	Other Instrumentation & Controls Equipment	\$584	\$0	\$1,351	\$0	\$1,935	\$339	\$0	\$341	\$2,615	\$4
	Subtotal	\$10,177	\$380	\$4,557	\$0	\$15,114	\$2,645	\$0	\$2,664	\$20,422	\$31
13	Improvements to Site										
13.1	Site Preparation	\$0	\$419	\$8,931	\$0	\$9,350	\$1,636	\$0	\$2,197	\$13,183	\$20
13.2	Site Improvements	\$0	\$2,080	\$2,747	\$0	\$4,827	\$845	\$0	\$1,134	\$6,807	\$10
13.3	Site Facilities	\$2,376	\$0	\$2,493	\$0	\$4,869	\$852	\$0	\$1,144	\$6,866	\$11
	Subtotal	\$2,376	\$2,499	\$14,171	\$0	\$19,046	\$3,333	\$0	\$4,476	\$26,855	\$41
14	Buildings & Structures										
14.2	Boiler Building	\$0	\$11,588	\$10,184	\$0	\$21,772	\$3,810	\$0	\$3,837	\$29,419	\$45
14.3	Steam Turbine Building	\$0	\$16,107	\$15,002	\$0	\$31,109	\$5,444	\$0	\$5,483	\$42,036	\$65
14.4	Administration Building	\$0	\$1,046	\$1,106	\$0	\$2,152	\$377	\$0	\$379	\$2,909	\$4
14.5	Circulation Water Pump House	\$0	\$134	\$107	\$0	\$240	\$42	\$0	\$42	\$325	\$0
14.6	Water Treatment Buildings	\$0	\$373	\$340	\$0	\$713	\$125	\$0	\$126	\$963	\$1
14.7	Machine Shop	\$0	\$552	\$370	\$0	\$922	\$161	\$0	\$163	\$1,246	\$2
14.8	Warehouse	\$0	\$415	\$416	\$0	\$831	\$145	\$0	\$146	\$1,123	\$2
14.9	Other Buildings & Structures	\$0	\$291	\$247	\$0	\$538	\$94	\$0	\$95	\$727	\$1
14.10	Waste Treating Building & Structures	\$0	\$627	\$1,901	\$0	\$2,528	\$442	\$0	\$446	\$3,416	\$5
	Subtotal	\$0	\$31,134	\$29,672	\$0	\$60,806	\$10,641	\$0	\$10,717	\$82,164	\$126
	Total	\$618,660	\$59,668	\$329,894	\$0	\$1,008,222	\$176,439	\$0	\$182,711	\$1,367,371	\$2,103

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-75. Case B12A owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$9,306	\$14
1 Month Maintenance Materials	\$1,287	\$2
1 Month Non-Fuel Consumables	\$1,658	\$3
1 Month Waste Disposal	\$729	\$1
25% of 1 Months Fuel Cost at 100% CF	\$2,243	\$3
2% of TPC	\$27,347	\$42
Total	\$42,570	\$65
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	\$20,754	\$32
0.5% of TPC (spare parts)	\$6,837	\$11
Total	\$27,591	\$42
Other Costs		
Initial Cost for Catalyst and Chemicals	\$2,048	\$3
Land	\$900	\$1
Other Owner's Costs	\$205,106	\$316
Financing Costs	\$36,919	\$57
Total Overnight Costs (TOC)	\$1,682,505	\$2,588
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	\$1,942,303	\$2,988

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-76. Case B12A initial and annual operating and maintenance costs

Case:	B12A	– SC PC w/o CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):	8,490	Capacity Factor (%):	85	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	% of base	Operator:	9.0	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	2.0	
				Total:	14.0	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$6,138,132	\$9.443
Maintenance Labor:					\$8,751,176	\$13.462
Administrative & Support Labor:					\$3,722,327	\$5.726
Property Taxes and Insurance:					\$27,347,424	\$42.070
Total:					\$45,959,058	\$70.701
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$13,126,763	\$2.71199
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	4,372	\$1.90	\$0	\$2,577,157	\$0.53244
Makeup and Waste Water Treatment Chemicals (lbs):	0	13.0	\$550.00	\$0	\$2,222,286	\$0.45912
Brominated Activated Carbon (ton):	0	1.24	\$1,600.00	\$0	\$616,535	\$0.12738
Enhanced Hydrated Lime (ton):	0	31.3	\$240.00	\$0	\$2,326,876	\$0.48073
Limestone (ton):	0	549	\$22.00	\$0	\$3,748,060	\$0.77435
Ammonia (19 wt%, ton):	0	52.0	\$300.00	\$0	\$4,842,241	\$1.00041
SCR Catalyst (ft ³):	13,656	12.5	\$150.00	\$2,048,378	\$580,374	\$0.11991
Subtotal:				\$2,048,378	\$16,913,529	\$3.49433
Waste Disposal						
Fly Ash (ton):	0	515	\$38.00	\$0	\$6,073,708	\$1.25483
Bottom Ash (ton):	0	114	\$38.00	\$0	\$1,349,111	\$0.27873
SCR Catalyst (ft ³):	0	12.5	\$2.50	\$0	\$9,673	\$0.00200
Subtotal:				\$0	\$7,432,491	\$1.53555
By-Products						
Gypsum (ton):	0	835	\$0.00	\$0	\$0	\$0.00000
Subtotal:				\$0	\$0	\$0.00000
Variable Operating Costs Total:				\$2,048,378	\$37,472,784	\$7.74188
Fuel Cost						
Illinois Number 6 (ton):	0	5,677	\$51.96	\$0	\$91,507,629	\$18.90547
Total:				\$0	\$91,507,629	\$18.90547

Exhibit 4-77. Case B12A LCOE breakdown

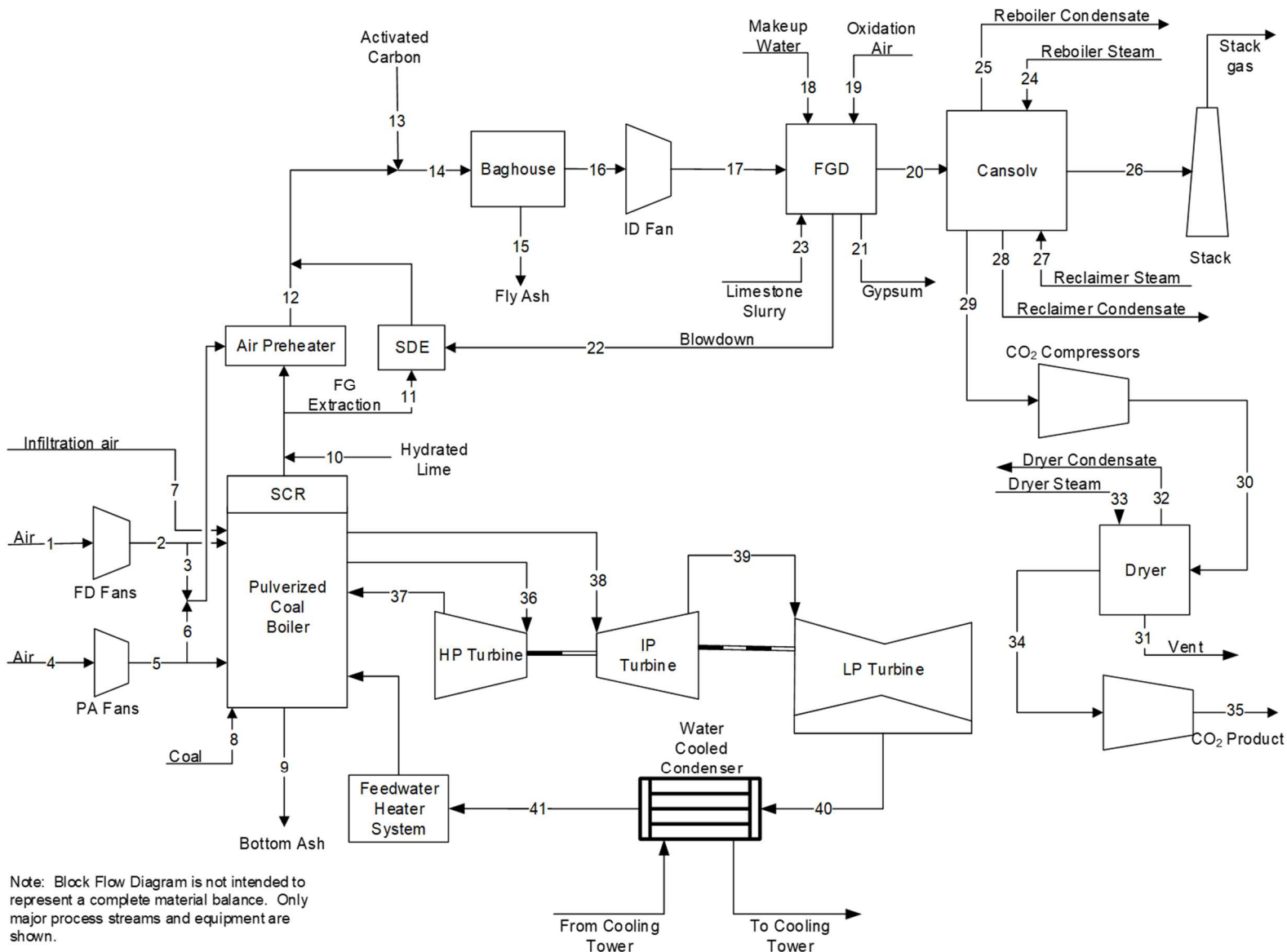
Component	Value, \$/MWh	Percentage
Capital	28.4	44%
Fixed	9.5	15%
Variable	7.7	12%
Fuel	18.9	29%
Total (Excluding T&S)	64.5	N/A
CO ₂ T&S	–	–
Total (Including T&S)	64.5	N/A

4.3.7 Case B12B.90 – SC PC with 90 Percent CO₂ Capture Process Description

The plant configuration and process description for Case B12B.90 are nearly the same as Case B12A, with the exception that the CANSOLV system was used for the CDR facility. Since the process descriptions of the plant and CDR facility were provided in Section 4.3.3 and Section 4.1.8, respectively, they are not repeated here.

The BFD for Case B12B.90 is shown in Exhibit 4-78. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 4-79. The modeling assumptions were presented previously in Section 4.3.1.

Exhibit 4-78. Case B12B.90 block flow diagram, SC unit with CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-79. Case B12B.90 stream table, SC unit with capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0087	0.0088	0.0000	0.0087	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379	0.0000	0.1372	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837	0.0000	0.0911	0.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340	0.0000	0.7281	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336	0.0000	0.0329	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020	0.0000	0.0020	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1158
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.8842
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	74,297	74,297	2,201	22,823	22,823	3,141	1,642	0	0	1	4,896	99,317	0	105,042	6
V-L Flowrate (kg/hr)	2,143,977	2,143,977	63,502	658,607	658,607	90,640	47,389	0	0	15	145,610	2,949,138	0	3,110,089	672
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	272,519	5,494	1,485	1,176	22,574	60	24,043	24,060
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143	15	143	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.31	-6.79	-2,453.14	-1,065.96
Density (kg/m ³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8	---	0.8	2,150.2
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694	---	29.608	104.898
V-L Flowrate (lb _{mol} /hr)	163,796	163,796	4,851	50,316	50,316	6,925	3,620	0	0	2	10,793	218,956	0	231,578	14
V-L Flowrate (lb/hr)	4,726,660	4,726,660	139,997	1,451,980	1,451,980	199,828	104,476	0	0	33	321,016	6,501,737	0	6,856,573	1,482
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	600,801	12,111	3,274	2,593	49,768	131	53,007	53,042
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289	59	289	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1	14.7	14.1	14.1
Steam Table Enthalpy (Btu/lb) ^A	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4	-2.9	-1,054.7	-458.3
Density (lb/ft ³)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052	---	0.052	134.232

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-79. Case B12B.90 stream table, SC unit with capture (continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0101	0.0000	0.0000	0.0000	0.0000
CO ₂	0.1372	0.1372	0.0000	0.0003	0.1245	0.0001	0.0000	0.0000	0.0000	0.0000	0.0156	0.0000	0.0000	0.9783	0.9975
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0911	0.0911	0.9999	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000	1.0000	0.0807	1.0000	1.0000	0.0217	0.0025
HCl	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000	0.0000	0.8483	0.0000	0.0000	0.0000	0.0000
O ₂	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000	0.0000	0.0453	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0001	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	105,035	105,035	6,136	4,397	117,421	247	829	3,418	33,684	30,851	94,165	386	386	13,440	13,181
V-L Flowrate (kg/hr)	3,109,401	3,109,401	110,565	126,880	3,374,697	4,455	15,341	61,581	606,834	555,796	2,613,763	6,959	6,959	583,905	579,239
Solids Flowrate (kg/hr)	0	0	0	0	0	40,069	233	26,362	0	0	0	0	0	0	0
Temperature (°C)	143	156	15	15	57	15	57	15	269	105	45	342	214	31	29
Pressure (MPa, abs)	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.48	0.12	0.10	4.90	2.04	0.17	2.81
Steam Table Enthalpy (kJ/kg) ^A	287.58	302.09	-47.80	30.23	297.00	---	---	---	3,000.14	439.34	178.41	3,049.81	913.81	46.68	-3.05
AspenPlus Enthalpy (kJ/kg) ^B	-2,464.17	-2,449.66	-16,015.01	-97.58	-2,939.24	-12,513.34	-15,496.14	-14,994.25	-12,980.15	-15,540.95	-903.21	-12,930.48	-15,066.49	-8,978.62	-8,972.51
Density (kg/m ³)	0.8	0.9	1,003.7	1.2	1.1	878.3	979.5	1,003.7	2.0	954.9	1.1	19.2	848.5	3.0	57.8
V-L Molecular Weight	29.603	29.603	18.019	28.857	28.740	18.021	18.495	18.019	18.015	18.015	27.757	18.015	18.015	43.445	43.945
V-L Flowrate (lb _{mol} /hr)	231,564	231,564	13,528	9,693	258,868	545	1,829	7,535	74,261	68,016	207,598	852	852	29,630	29,059
V-L Flowrate (lb/hr)	6,855,055	6,855,055	243,754	279,723	7,439,934	9,821	33,821	135,763	1,337,840	1,225,320	5,762,360	15,343	15,343	1,287,291	1,277,003
Solids Flowrate (lb/hr)	0	0	0	0	0	88,338	515	58,118	0	0	0	0	0	0	0
Temperature (°F)	289	313	59	59	135	59	135	59	516	221	113	648	416	87	85
Pressure (psia)	13.9	15.3	14.7	14.7	14.8	14.7	14.7	14.7	70.0	17.4	14.8	710.8	296.6	24.7	407.6
Steam Table Enthalpy (Btu/lb) ^A	123.6	129.9	-20.5	13.0	127.7	---	---	---	1,289.8	188.9	76.7	1,311.2	392.9	20.1	-1.3
AspenPlus Enthalpy (Btu/lb) ^B	-1,059.4	-1,053.2	-6,885.2	-42.0	-1,263.6	-5,379.8	-6,662.1	-6,446.4	-5,580.5	-6,681.4	-388.3	-5,559.1	-6,477.4	-3,860.1	-3,857.5
Density (lb/ft ³)	0.051	0.055	62.658	0.076	0.067	54.833	61.145	62.658	0.122	59.612	0.067	1.197	52.968	0.184	3.609

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-79. Case B12B.90 stream table, SC unit with capture (continued)

	31	32	33	34	35	36	37	38	39	40	41
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0500	0.0000	0.0000	0.9995	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	28	17	17	13,153	13,153	133,266	111,025	111,025	95,607	42,151	65,023
V-L Flowrate (kg/hr)	534	307	307	578,705	578,705	2,400,833	2,000,151	2,000,151	1,722,380	759,359	1,171,406
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	29	203	461	29	30	593	342	593	270	38	39
Pressure (MPa, abs)	2.81	1.64	2.14	2.68	15.27	24.23	4.90	4.80	0.52	0.01	1.26
Steam Table Enthalpy (kJ/kg) ^A	137.94	863.65	3,379.61	-3.59	-231.09	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.36
AspenPlus Enthalpy (kJ/kg) ^B	-15,225.22	-15,116.65	-12,600.69	-8,967.15	-9,194.65	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.93
Density (kg/m ³)	351.5	861.8	6.4	54.7	630.1	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	19.315	18.015	18.015	43.997	43.997	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	61	38	38	28,998	28,998	293,802	244,769	244,769	210,776	92,927	143,351
V-L Flowrate (lb/hr)	1,177	677	677	1,275,825	1,275,825	5,292,930	4,409,577	4,409,577	3,797,197	1,674,099	2,582,509
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	85	397	862	85	86	1,100	648	1,100	517	101	101
Pressure (psia)	407.6	237.4	310.1	389.1	2,214.7	3,514.7	710.8	696.6	75.0	1.0	183.1
Steam Table Enthalpy (Btu/lb) ^A	59.3	371.3	1,453.0	-1.5	-99.4	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb) ^B	-6,545.7	-6,499.0	-5,417.3	-3,855.2	-3,953.0	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft ³)	21.943	53.801	0.402	3.416	39.338	4.319	1.197	0.768	0.131	0.003	62.009

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

4.3.8 Case B12B.90 – Performance Results

Overall plant performance is summarized in Exhibit 4-80; Exhibit 4-81 provides a detailed breakdown of the auxiliary power requirements.

The CDR facility, including CO₂ compression, accounts for over half of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for over 12 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility and CO₂ compressors.

Unlike the NGCC cases where gross output was fixed by the available size of the CTs, the PC cases utilize boilers and steam turbines that can be procured at nearly any desired output. By increasing the boiler and turbine/generator size to account for the greater auxiliary load imposed by the CDR facility and CO₂ compressors, a net output of 650 MW is maintained at a reduced net plant efficiency of 31.7 percent (HHV basis).

Exhibit 4-80. Case B12B.90 plant performance summary

Performance Summary	
Total Gross Power, MWe	763
CO ₂ Capture/Removal Auxiliaries, kWe	17,900
CO ₂ Compression, kWe	46,330
Balance of Plant, kWe	48,270
Total Auxiliaries, MWe	113
Net Power, MWe	650
HHV Net Plant Efficiency, %	31.7
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,371 (10,778)
LHV Net Plant Efficiency, %	32.8
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,968 (10,396)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	57.4
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	6,267 (5,940)
Condenser Duty, GJ/hr (MMBtu/hr)	2,100 (1,990)
CO ₂ Capture Rate, %	90
AGR Duty, GJ/hr (MMBtu/hr)	2,059 (1,952)
As-Received Coal Feed, kg/hr (lb/hr)	272,519 (600,801)
Limestone Sorbent Feed, kg/hr (lb/hr)	26,362 (58,118)
HHV Thermal Input, kWt	2,054,118
LHV Thermal Input, kWt	1,981,222
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.054 (14.3)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.040 (10.6)
Excess Air, %	20.3

Exhibit 4-81. Case B12B.90 plant power summary

Power Summary	
Steam Turbine Power, MWe	763
Total Gross Power, MWe	763
Auxiliary Load Summary	
Activated Carbon Injection, kWe	40
Ash Handling, kWe	890
Baghouse, kWe	120
Circulating Water Pumps, kWe	9,020
CO ₂ Capture/Removal Auxiliaries, kWe	17,900
CO ₂ Compression, kWe	46,330
Coal Handling and Conveying, kWe	530
Condensate Pumps, kWe	790
Cooling Tower Fans, kWe	4,670
Dry Sorbent Injection, kWe	80
Flue Gas Desulfurizer, kWe	4,210
Forced Draft Fans, kWe	1,400
Ground Water Pumps, kWe	840
Induced Draft Fans, kWe	12,920
Miscellaneous Balance of Plant ^{A,B} , kWe	2,250
Primary Air Fans, kWe	1,660
Pulverizers, kWe	4,090
SCR, kWe	50
Sorbent Handling & Reagent Preparation, kWe	1,270
Spray Dryer Evaporator, kWe	300
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,640
Total Auxiliaries, MWe	113
Net Power, MWe	650

^ABoiler feed pumps are turbine driven

^BIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

4.3.8.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B12B.90 is presented in Exhibit 4-82. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 4-82. Case B12B.90 air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.033 (0.076)	1,803 (1,988)	0.318 (0.700)
Particulate	0.004 (0.010)	232 (256)	0.041 (0.090)
Hg	1.40E-7 (3.26E-7)	0.008 (0.009)	1.36E-6 (3.00E-6)
CO ₂	9 (20)	480,864 (530,061)	85 (187)
CO ₂ ^C	—	—	99 (219)
mg/Nm ³			
Particulate Concentration ^{D,E}	13.23		

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

^DConcentration of particles in the flue gas after the baghouse

^ENormal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The SO₂ emissions are further reduced to 0.37 ppmv using a NaOH based polishing scrubber in the CDR facility. The remaining low concentration of SO₂ is essentially completely removed in the CDR absorber vessel resulting in very low SO₂ emissions (reported as zero here).

NO_x emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 78.2 percent to 0.03 kg/GJ (0.08 lb/MMBtu).

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and wet FGD) is 97.5 percent.

Ninety percent of the CO₂ in the flue gas is removed in CDR facility.

The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD. Carbon leaves the plant mostly as CO₂ product from the CO₂ compression train; however, some CO₂ exits through the stack, the PAC is captured in the fabric filter, unburned carbon remains in the bottom ash, and some leaves as gypsum. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in (minus unburnt carbon in the ash), represented by the following fraction:

$$1 - \frac{\text{Carbon in Stack}}{\text{Total Carbon In} - \text{Unburnt Carbon}} = \left(1 - \left(\frac{38,856}{389,900 - 460} \right) \right) * 100 = 90\%$$

Exhibit 4-83. Case B12B.90 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	173,716 (382,979)	Stack Gas	17,625 (38,856)
Air (CO ₂)	405 (893)	FGD Product	206 (454)
PAC	60 (131)	Baghouse	893 (1,970)
FGD Reagent	2,675 (5,897)	Bottom Ash	208 (460)
		CO ₂ Product	157,906 (348,122)
		CO ₂ Dryer Vent	17 (37)
		CO ₂ Knockout	0.4 (1.0)
Total	176,856 (389,900)	Total	176,856 (389,900)

Exhibit 4-84 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur emitted in the stack gas, and sulfur removed in the polishing scrubber.

Exhibit 4-84. Case B12B.90 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	6,830 (15,059)	FGD Product	6,422 (14,158)
		Stack Gas	0 (0)
		Polishing Scrubber and Solvent Reclaiming	133 (294)
		Baghouse	275 (607)
Total	6,830 (15,059)	Total	6,830 (15,059)

Exhibit 4-85 shows the overall water balance for the plant. The exhibit is presented in an identical manner as for Case B12A. The only notable difference is the FGD makeup water source. In CO₂ capture cases, a significant amount of water is recovered from the initial CDR facility cooling step. This water would otherwise be discharged; however, it is suitable to be used as FGD makeup. The balance of the water from the CDR facility is sent to discharge.

Exhibit 4-85. Case B12B.90 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
FGD Process Makeup	1.8 (488)	1.8 (488)	–	–	–
FGD Slurry Water	1.0 (272)	1.0 (272)	–	–	–
CO ₂ Drying	–	–	–	0.0 (2.4)	0.0 (-2.4)
CO ₂ Capture Recovery	–	–	–	0.9 (245)	-0.9 (-245)
CO ₂ Compression KO	–	–	–	0.1 (21)	-0.1 (-21)
Deaerator Vent	–	–	–	0.1 (21)	-0.1 (-21)
Condenser Makeup	0.1 (21)	–	0.1 (21)	–	0.1 (21)
BFW Makeup	0.1 (21)	–	0.1 (21)	–	0.1 (21)
Cooling Tower	35 (9,281)	–	35 (9,281)	7.9 (2,087)	27 (7,194)
BFW Blowdown	–	–	–	–	–
Total	38 (10,061)	2.9 (759)	35 (9,302)	9.0 (2,377)	26 (6,925)

4.3.8.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for the Case B12B.90 PC boiler, FGD unit, CDR system, and steam cycle in Exhibit 4-86 and Exhibit 4-87. An overall plant energy balance is provided in tabular form in Exhibit 4-88.

The power out is the steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a generator efficiency of 98.5 percent. The cooling tower load includes the condenser, capture process heat rejected to cooling water, the CO₂ compressor intercooler load, and other miscellaneous cooling loads.

This page intentionally left blank.

Exhibit 4-86. Case B12B.90 energy and mass balance, SC PC boiler with CO₂ capture

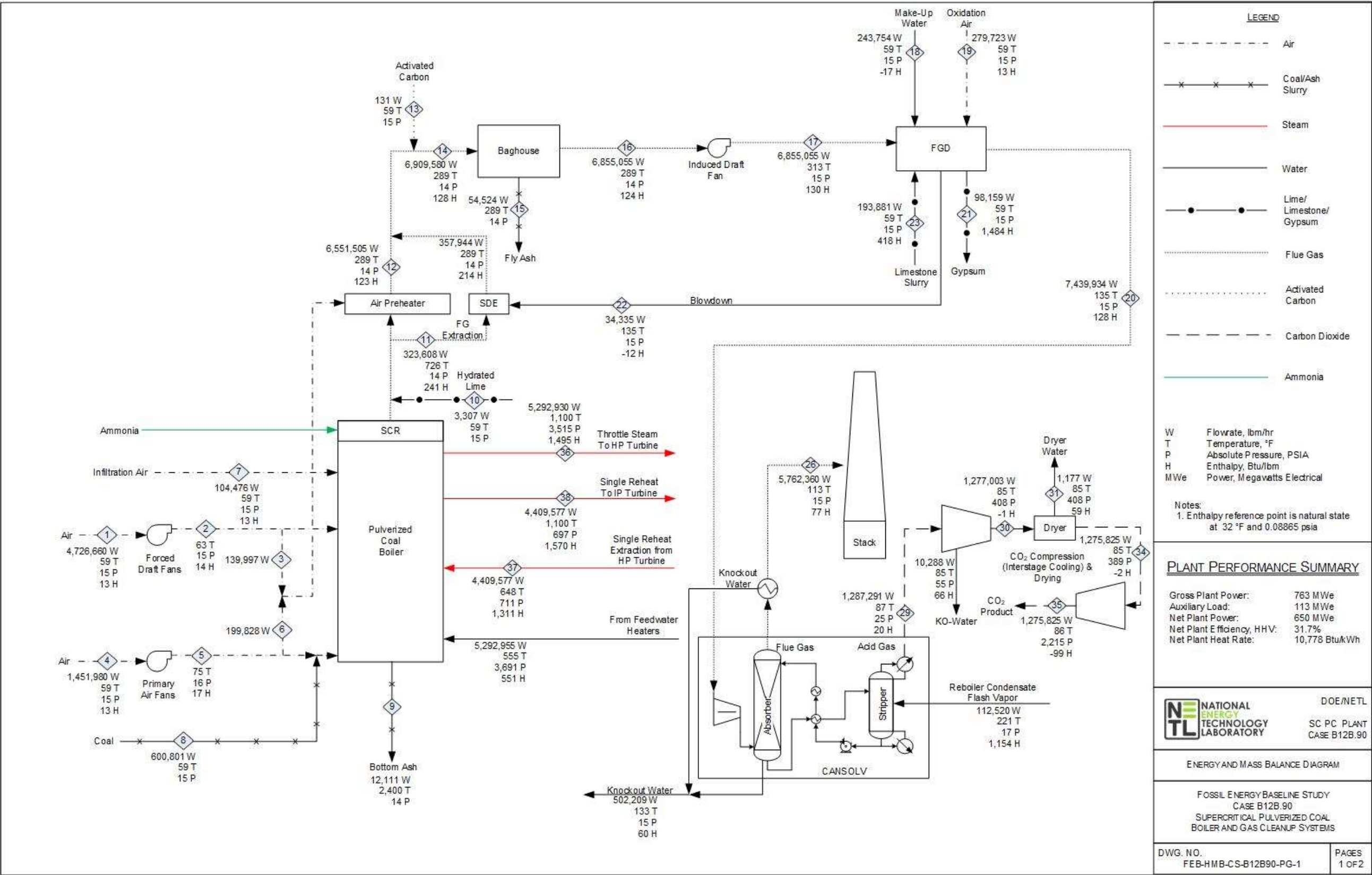


Exhibit 4-87. Case B12B.90 energy and mass balance, SC steam cycle

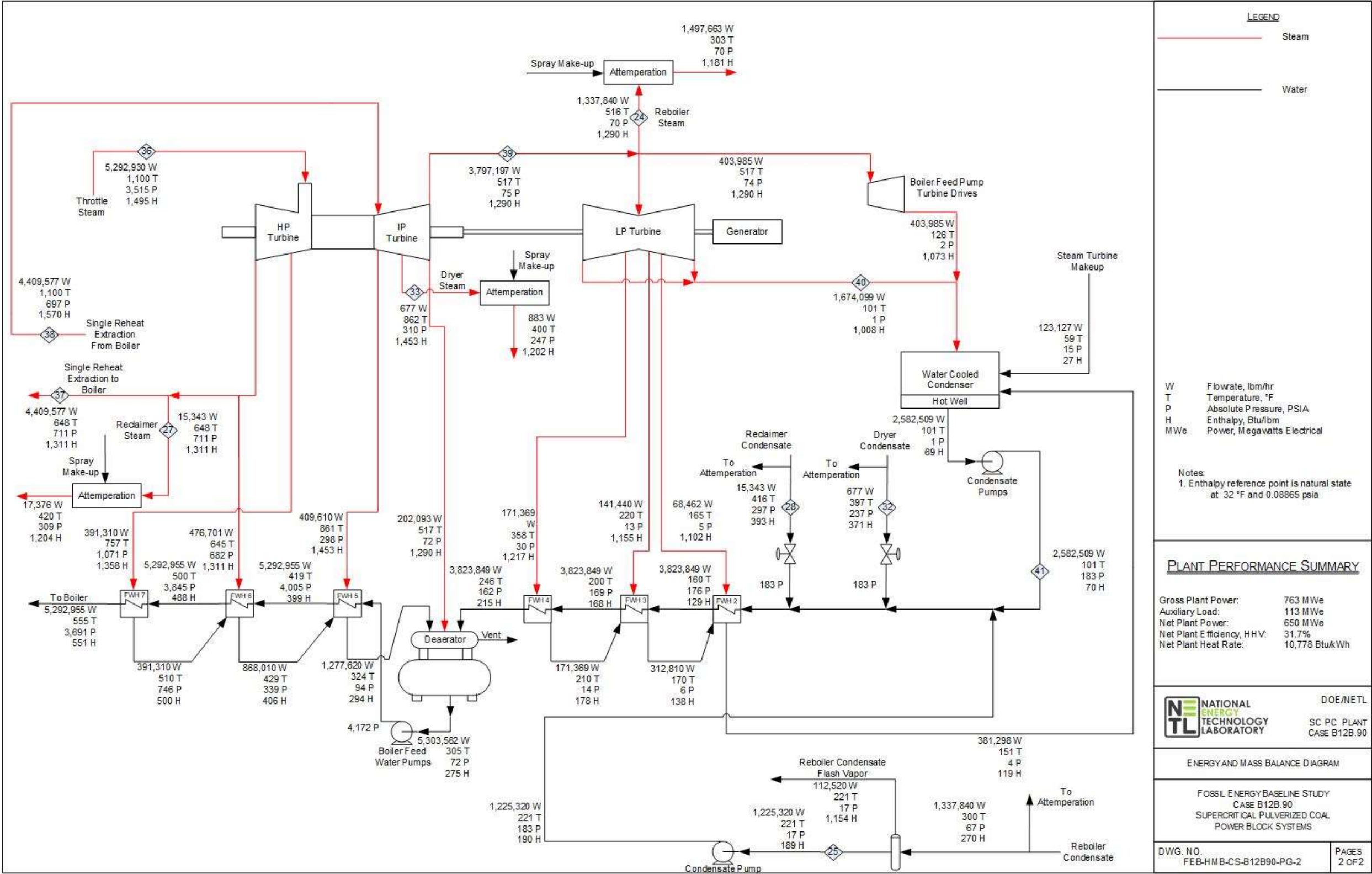


Exhibit 4-88. Case B12B.90 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	7,395 (7,009)	6.2 (5.9)	—	7,401 (7,015)
Air	—	86 (82)	—	86 (82)
Raw Water Makeup	—	132 (125)	—	132 (125)
Limestone	—	0.6 (0.5)	—	0.6 (0.5)
Auxiliary Power	—	—	405 (384)	405 (384)
TOTAL	7,395 (7,009)	225 (214)	405 (384)	8,025 (7,606)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	—	7.0 (6.6)	—	7.0 (6.6)
Fly Ash	—	2.5 (2.4)	—	2.5 (2.4)
Stack Gas	—	466 (442)	—	466 (442)
Sulfur	2.5 (2.4)	0.0 (0.0)	—	2.5 (2.4)
Gypsum	—	2.6 (2.5)	—	2.6 (2.5)
Motor Losses and Design Allowances	—	—	50 (47)	50 (47)
Cooling Tower Load ^A	—	4,588 (4,348)	—	4,588 (4,348)
CO ₂ Product Stream	—	-134 (-127)	—	-134 (-127)
AGR Effluent	—	53 (51)	—	53 (51)
Blowdown Streams and Deaerator Vent	—	3.1 (2.9)	—	3.1 (2.9)
<i>Ambient Losses^B</i>	—	175 (166)	—	175 (166)
Power	—	—	2,746 (2,603)	2,746 (2,603)
TOTAL	2.5 (2.4)	5,164 (4,895)	2,796 (2,650)	7,963 (7,547)
<i>Unaccounted Energy^C</i>	—	62 (59)	—	62 (59)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^CBy difference

4.3.9 Case B12B.90 – Major Equipment List

Major equipment items for the SC PC plant with CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.3.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B12B.90 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	60 tonne (60 ton)	2	1
9	Feeder	Vibratory	220 tonne/hr (250 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	450 tonne/hr (500 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	220 tonne (250 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	450 tonne/hr (500 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	450 tonne/hr (500 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,000 tonne (1,100 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 11 tonne (12 ton) Feeder - 70 kg/hr (140 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 280 tonne (310 ton) Feeder - 1,650 kg/hr (3,640 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	111 tonne/hr (122 tph)	1	0
23	Limestone Conveyor No. 1	Belt	111 tonne/hr (122 tph)	1	0
24	Limestone Reclaim Hopper	N/A	22 tonne (24 ton)	1	0
25	Limestone Reclaim Feeder	Belt	87 tonne/hr (96 tph)	1	0
26	Limestone Conveyor No. 2	Belt	87 tonne/hr (96 tph)	1	0
27	Limestone Day Bin	w/ actuator	348 tonne (384 ton)	2	0

Case B12B.90 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	50 tonne/hr (55 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	50 tonne/hr (55 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	29 tonne/hr (32 tph)	1	1
4	Limestone Ball Mill	Rotary	29 tonne/hr (32 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	114,000 liters (30,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,890 lpm @ 10 m H ₂ O (500 gpm @ 40 ft H ₂ O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5-cyclone bank	470 lpm (130 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	627,000 liters (166,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,310 lpm @ 9 m H ₂ O (350 gpm @ 30 ft H ₂ O)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B12B.90 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	318,000 liters (84,000 gal)	2	0
2	Condensate Pumps	Vertical canned	10,800 lpm @ 200 m H ₂ O (2,860 gpm @ 500 ft H ₂ O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,323,000 kg/hr (2,917,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	22,000 lpm @ 3,500 m H ₂ O (5,900 gpm @ 11,400 ft H ₂ O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	6,600 lpm @ 3,500 m H ₂ O (1,700 gpm @ 11,400 ft H ₂ O)	2	0
6	LP Feedwater Heater 2A/2B	Horizontal U-tube	480,000 kg/hr (1,050,000 lb/hr)	4	0
7	LP Feedwater Heater 3A/3B	Horizontal U-tube	480,000 kg/hr (1,050,000 lb/hr)	4	0
8	LP Feedwater Heater 4A/4B	Horizontal U-tube	480,000 kg/hr (1,050,000 lb/hr)	4	0
9	HP Feedwater Heater 5	Horizontal U-tube	1,320,000 kg/hr (2,910,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	1,320,000 kg/hr (2,910,000 lb/hr)	2	0
11	HP Feedwater Heater 7	Horizontal U-tube	1,320,000 kg/hr (2,910,000 lb/hr)	2	0
12	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
13	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
14	Service Air Compressors	Flooded Screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H ₂ O (5,500 gpm @ 100 ft H ₂ O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	9,400 lpm @ 20 m H ₂ O (2,490 gpm @ 60 ft H ₂ O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	3,770 lpm @ 270 m H ₂ O (1,000 gpm @ 880 ft H ₂ O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	1,200 lpm @ 50 m H ₂ O (310 gpm @ 160 ft H ₂ O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,139,000 liter (301,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,510 m ³ /min (88,600 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 150 lpm (40 gpm) @ 19,990 ppmw Cl ⁻	2	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B12B.90 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, once-through, wall-fired, low NOx burners, overfire air	2,640,000 kg/hr steam @ 24.1 MPa/593°C/593°C (5,820,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	362,000 kg/hr, 4,900 m ³ /min @ 101 cm WG (799,000 lb/hr, 174,600 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,179,000 kg/hr, 16,100 m ³ /min @ 26 cm WG (2,600,000 lb/hr, 568,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,710,000 kg/hr, 34,600 m ³ /min @ 114 cm WG (3,770,000 lb/hr, 1,223,000 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,230,000 kg/hr (7,130,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	120 m ³ /min @ 108 cm WG (4,400 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	137,000 liter (36,100 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	26 lpm @ 90 m H ₂ O (7 gpm @ 300 ft H ₂ O)	2	1

Case B12B.90 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,711,000 kg/hr (3,771,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	58,000 m ³ /min (2,050,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	201,000 lpm @ 65 m H ₂ O (53,200 gpm @ 210 ft H ₂ O)	5	1
4	Bleed Pumps	Horizontal centrifugal	5,570 lpm (1,470 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	950 m ³ /min @ 0.3 MPa (33,630 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,390 lpm (370 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	44 tonne/hr (49 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	850 lpm @ 13 m H ₂ O (220 gpm @ 40 ft H ₂ O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	550,000 lpm (150,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	2,030 lpm @ 21 m H ₂ O (540 gpm @ 70 ft H ₂ O)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
12	Activated Carbon Injectors	---	70 kg/hr (140 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,650 kg/hr (3,640 lb/hr)	1	0
14	CANSOLV	Amine-based CO ₂ capture technology	3,712,000 kg/hr (8,184,000 lb/hr) 19.1 wt % CO ₂ concentration	1	0
15	CANSOLV LP Condensate Pump	Centrifugal	1,331 lpm @ 1 m H ₂ O (352 gpm @ 3 ft H ₂ O)	1	1
16	CANSOLV IP Condensate Pump	Centrifugal	17 lpm @ 4.6 m H ₂ O (5 gpm @ 15 ft H ₂ O)	1	1
17	CO ₂ Dryer	Triethylene glycol	Inlet: 167 m ³ /min @ 2.8 MPa (5,897 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Recovered: 534 kg/hr (1,177 lb/hr)	1	0
18	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	8.0 m ³ /min @ 15.3 MPa, 82°C (297 acfm @ 2,217 psia, 180°F)	2	0
19	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 91 GJ/hr (86 MMBtu/hr)	1	0

Case B12B.90 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.2 m (20 ft) diameter	1	0

Case B12B.90 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	803 MW 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	890 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,150 GJ/hr (2,190 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0

Case B12B.90 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	905,000 lpm @ 30 m (239,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 5,050 GJ/hr (4,780 MMBtu/hr) heat duty	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B12B.90 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	6.0 tonne/hr (6.7 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	24 m ³ /min @ 0.2 MPa (862 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,600 tonne (1,770 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	150 tonne/hr (160 tph)	1	0

Case B12B.90 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 26 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 52 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 18 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B12B.90 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.3.10 Case B12B.90 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 4-89 shows a detailed breakdown of the capital costs; Exhibit 4-90 shows the owner's costs, TOC, and TASC; Exhibit 4-91 shows the initial and annual O&M costs; and Exhibit 4-92 shows the LCOE breakdown.

The estimated TPC of the SC PC boiler with CO₂ capture is \$3,452/kW. Process contingency represents 2.6 percent of the TPC and project contingency represents 13.9 percent. The LCOE, including CO₂ T&S costs of \$8.9/MWh, is \$107.3/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-89. Case B12B.90 total plant cost details

Case:		B12B.90	– SC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1 Coal & Sorbent Handling											
1.1	Coal Receive & Unload	\$1,174	\$0	\$529	\$0	\$1,702	\$298	\$0	\$300	\$2,300	\$4
1.2	Coal Stackout & Reclaim	\$3,853	\$0	\$861	\$0	\$4,714	\$825	\$0	\$830	\$6,369	\$10
1.3	Coal Conveyors	\$35,499	\$0	\$8,443	\$0	\$43,943	\$7,690	\$0	\$7,745	\$59,377	\$91
1.4	Other Coal Handling	\$4,932	\$0	\$1,037	\$0	\$5,969	\$1,045	\$0	\$1,052	\$8,066	\$12
1.5	Sorbent Receive & Unload	\$225	\$0	\$67	\$0	\$293	\$51	\$0	\$52	\$396	\$1
1.6	Sorbent Stackout & Reclaim	\$1,650	\$0	\$298	\$0	\$1,949	\$341	\$0	\$343	\$2,633	\$4
1.7	Sorbent Conveyors	\$2,500	\$544	\$605	\$0	\$3,649	\$639	\$0	\$643	\$4,931	\$8
1.8	Other Sorbent Handling	\$120	\$28	\$62	\$0	\$211	\$37	\$0	\$37	\$285	\$0
1.9	Coal & Sorbent Handling Foundations	\$0	\$1,630	\$2,148	\$0	\$3,778	\$661	\$0	\$666	\$5,105	\$8
	Subtotal	\$49,954	\$2,202	\$14,051	\$0	\$66,207	\$11,586	\$0	\$11,669	\$89,462	\$138
2 Coal & Sorbent Preparation & Feed											
2.1	Coal Crushing & Drying	\$2,522	\$0	\$484	\$0	\$3,006	\$526	\$0	\$530	\$4,062	\$6
2.2	Prepared Coal Storage & Feed	\$8,488	\$0	\$1,828	\$0	\$10,315	\$1,805	\$0	\$1,818	\$13,938	\$21
2.5	Sorbent Preparation Equipment	\$1,110	\$48	\$227	\$0	\$1,386	\$242	\$0	\$244	\$1,872	\$3
2.6	Sorbent Storage & Feed	\$1,861	\$0	\$702	\$0	\$2,563	\$449	\$0	\$452	\$3,463	\$5
2.9	Coal & Sorbent Feed Foundation	\$0	\$737	\$646	\$0	\$1,383	\$242	\$0	\$244	\$1,869	\$3
	Subtotal	\$13,981	\$785	\$3,887	\$0	\$18,653	\$3,264	\$0	\$3,288	\$25,205	\$39
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$3,973	\$6,811	\$3,406	\$0	\$14,190	\$2,483	\$0	\$2,501	\$19,175	\$29
3.2	Water Makeup & Pretreating	\$7,880	\$788	\$4,465	\$0	\$13,133	\$2,298	\$0	\$3,086	\$18,517	\$28
3.3	Other Feedwater Subsystems	\$3,101	\$1,017	\$966	\$0	\$5,084	\$890	\$0	\$896	\$6,870	\$11
3.4	Service Water Systems	\$2,489	\$4,751	\$15,384	\$0	\$22,623	\$3,959	\$0	\$5,316	\$31,898	\$49
3.5	Other Boiler Plant Systems	\$767	\$279	\$698	\$0	\$1,744	\$305	\$0	\$307	\$2,357	\$4
3.6	Natural Gas Pipeline and Start-Up System	\$3,341	\$144	\$108	\$0	\$3,592	\$629	\$0	\$633	\$4,854	\$7
3.7	Waste Water Treatment Equipment	\$12,932	\$0	\$7,926	\$0	\$20,858	\$3,650	\$0	\$4,902	\$29,409	\$45
3.8	Spray Dryer Evaporator	\$16,923	\$0	\$9,798	\$0	\$26,721	\$4,676	\$0	\$6,280	\$37,677	\$58
3.9	Miscellaneous Plant Equipment	\$225	\$30	\$115	\$0	\$370	\$65	\$0	\$87	\$521	\$1
	Subtotal	\$51,632	\$13,819	\$42,864	\$0	\$108,315	\$18,955	\$0	\$24,008	\$151,278	\$233
4 Pulverized Coal Boiler & Accessories											
4.9	Pulverized Coal Boiler & Accessories	\$268,021	\$0	\$152,717	\$0	\$420,738	\$73,629	\$0	\$74,155	\$568,522	\$874
4.10	Selective Catalytic Reduction System	\$30,239	\$0	\$17,267	\$0	\$47,506	\$8,314	\$0	\$8,373	\$64,193	\$99
4.11	Boiler Balance of Plant	\$1,763	\$0	\$1,005	\$0	\$2,768	\$484	\$0	\$488	\$3,740	\$6
4.12	Primary Air System	\$1,692	\$0	\$964	\$0	\$2,657	\$465	\$0	\$468	\$3,590	\$6
4.13	Secondary Air System	\$2,563	\$0	\$1,461	\$0	\$4,024	\$704	\$0	\$709	\$5,437	\$8

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B12B.90	– SC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
4.14	Induced Draft Fans	\$5,530	\$0	\$3,151	\$0	\$8,680	\$1,519	\$0	\$1,530	\$11,729	\$18
4.15	Major Component Rigging	\$93	\$0	\$53	\$0	\$146	\$25	\$0	\$26	\$197	\$0
4.16	Boiler Foundations	\$0	\$398	\$350	\$0	\$748	\$131	\$0	\$132	\$1,011	\$2
	Subtotal	\$309,901	\$398	\$176,967	\$0	\$487,267	\$85,272	\$0	\$85,881	\$658,420	\$1,012
5		Flue Gas Cleanup									
5.1	CANSOLV Carbon Dioxide (CO ₂) Removal System	\$141,501	\$62,150	\$130,515	\$0	\$334,167	\$58,479	\$56,808	\$78,654	\$528,109	\$812
5.2	WFGD Absorber Vessels & Accessories	\$79,280	\$0	\$16,957	\$0	\$96,237	\$16,841	\$0	\$16,962	\$130,040	\$200
5.3	Other FGD	\$1,263	\$0	\$972	\$0	\$2,235	\$391	\$0	\$394	\$3,021	\$5
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$42,506	\$6,376	\$14,212	\$0	\$63,093	\$11,041	\$0	\$14,827	\$88,962	\$137
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$467	\$74	\$200	\$0	\$741	\$130	\$0	\$174	\$1,045	\$2
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$2,661	\$585	\$2,617	\$0	\$5,863	\$1,026	\$0	\$1,033	\$7,923	\$12
5.9	Particulate Removal (Bag House & Accessories) (included with 5.2)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5.12	Gas Cleanup Foundations	\$0	\$197	\$173	\$0	\$370	\$65	\$0	\$65	\$500	\$1
5.13	Gypsum Dewatering System	\$762	\$0	\$128	\$0	\$890	\$156	\$0	\$157	\$1,203	\$2
	Subtotal	\$268,440	\$69,383	\$165,774	\$0	\$503,597	\$88,129	\$56,808	\$112,267	\$760,802	\$1,170
7		Ductwork & Stack									
7.3	Ductwork	\$0	\$746	\$518	\$0	\$1,264	\$221	\$0	\$223	\$1,708	\$3
7.4	Stack	\$8,814	\$0	\$5,122	\$0	\$13,936	\$2,439	\$0	\$2,456	\$18,831	\$29
7.5	Duct & Stack Foundations	\$0	\$210	\$249	\$0	\$459	\$80	\$0	\$108	\$647	\$1
	Subtotal	\$8,814	\$956	\$5,889	\$0	\$15,659	\$2,740	\$0	\$2,787	\$21,186	\$33
8		Steam Turbine & Accessories									
8.1	Steam Turbine Generator & Accessories	\$72,900	\$0	\$8,124	\$0	\$81,024	\$14,179	\$0	\$14,280	\$109,484	\$168
8.2	Steam Turbine Plant Auxiliaries	\$1,654	\$0	\$3,522	\$0	\$5,176	\$906	\$0	\$912	\$6,994	\$11
8.3	Condenser & Auxiliaries	\$11,146	\$0	\$3,782	\$0	\$14,928	\$2,612	\$0	\$2,631	\$20,172	\$31
8.4	Steam Piping	\$43,007	\$0	\$17,430	\$0	\$60,437	\$10,576	\$0	\$10,652	\$81,666	\$126
8.5	Turbine Generator Foundations	\$0	\$258	\$427	\$0	\$685	\$120	\$0	\$161	\$966	\$1
	Subtotal	\$128,707	\$258	\$33,285	\$0	\$162,251	\$28,394	\$0	\$28,637	\$219,281	\$337
9		Cooling Water System									
9.1	Cooling Towers	\$19,149	\$0	\$5,922	\$0	\$25,072	\$4,388	\$0	\$4,419	\$33,878	\$52
9.2	Circulating Water Pumps	\$2,697	\$0	\$198	\$0	\$2,896	\$507	\$0	\$510	\$3,913	\$6
9.3	Circulating Water System Auxiliaries	\$16,029	\$0	\$2,115	\$0	\$18,143	\$3,175	\$0	\$3,198	\$24,516	\$38
9.4	Circulating Water Piping	\$0	\$7,410	\$6,710	\$0	\$14,120	\$2,471	\$0	\$2,489	\$19,079	\$29

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B12B.90	– SC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
9.5	Make-up Water System	\$1,241	\$0	\$1,594	\$0	\$2,834	\$496	\$0	\$500	\$3,830	\$6
9.6	Component Cooling Water System	\$1,155	\$0	\$886	\$0	\$2,040	\$357	\$0	\$360	\$2,757	\$4
9.7	Circulating Water System Foundations	\$0	\$691	\$1,148	\$0	\$1,839	\$322	\$0	\$432	\$2,593	\$4
	Subtotal	\$40,271	\$8,101	\$18,572	\$0	\$66,944	\$11,715	\$0	\$11,907	\$90,566	\$139
10 Ash & Spent Sorbent Handling Systems											
10.6	Ash Storage Silos	\$1,170	\$0	\$3,578	\$0	\$4,747	\$831	\$0	\$837	\$6,415	\$10
10.7	Ash Transport & Feed Equipment	\$3,977	\$0	\$3,943	\$0	\$7,920	\$1,386	\$0	\$1,396	\$10,701	\$16
10.9	Ash/Spent Sorbent Foundation	\$0	\$813	\$1,001	\$0	\$1,814	\$317	\$0	\$426	\$2,558	\$4
	Subtotal	\$5,146	\$813	\$8,521	\$0	\$14,481	\$2,534	\$0	\$2,659	\$19,674	\$30
11 Accessory Electric Plant											
11.1	Generator Equipment	\$2,658	\$0	\$2,005	\$0	\$4,663	\$816	\$0	\$822	\$6,300	\$10
11.2	Station Service Equipment	\$7,505	\$0	\$644	\$0	\$8,148	\$1,426	\$0	\$1,436	\$11,010	\$17
11.3	Switchgear & Motor Control	\$11,650	\$0	\$2,021	\$0	\$13,671	\$2,392	\$0	\$2,410	\$18,473	\$28
11.4	Conduit & Cable Tray	\$0	\$1,514	\$4,364	\$0	\$5,879	\$1,029	\$0	\$1,036	\$7,944	\$12
11.5	Wire & Cable	\$0	\$4,011	\$7,169	\$0	\$11,180	\$1,956	\$0	\$1,970	\$15,107	\$23
11.6	Protective Equipment	\$55	\$0	\$191	\$0	\$246	\$43	\$0	\$43	\$332	\$1
11.7	Standby Equipment	\$823	\$0	\$760	\$0	\$1,583	\$277	\$0	\$279	\$2,139	\$3
11.8	Main Power Transformers	\$6,966	\$0	\$142	\$0	\$7,108	\$1,244	\$0	\$1,253	\$9,605	\$15
11.9	Electrical Foundations	\$0	\$221	\$563	\$0	\$784	\$137	\$0	\$184	\$1,106	\$2
	Subtotal	\$29,657	\$5,747	\$17,859	\$0	\$53,262	\$9,321	\$0	\$9,434	\$72,017	\$111
12 Instrumentation & Control											
12.1	Pulverized Coal Boiler Control Equipment	\$803	\$0	\$143	\$0	\$946	\$166	\$0	\$167	\$1,278	\$2
12.3	Steam Turbine Control Equipment	\$719	\$0	\$80	\$0	\$799	\$140	\$0	\$141	\$1,080	\$2
12.5	Signal Processing Equipment	\$911	\$0	\$162	\$0	\$1,074	\$188	\$0	\$189	\$1,451	\$2
12.6	Control Boards, Panels & Racks	\$279	\$0	\$170	\$0	\$449	\$79	\$22	\$82	\$632	\$1
12.7	Distributed Control System Equipment	\$7,864	\$0	\$1,402	\$0	\$9,266	\$1,622	\$463	\$1,703	\$13,053	\$20
12.8	Instrument Wiring & Tubing	\$551	\$441	\$1,762	\$0	\$2,753	\$482	\$138	\$506	\$3,879	\$6
12.9	Other Instrumentation & Controls Equipment	\$677	\$0	\$1,568	\$0	\$2,245	\$393	\$112	\$412	\$3,162	\$5
	Subtotal	\$11,803	\$441	\$5,288	\$0	\$17,531	\$3,068	\$736	\$3,200	\$24,535	\$38
13 Improvements to Site											
13.1	Site Preparation	\$0	\$462	\$9,804	\$0	\$10,266	\$1,797	\$0	\$2,412	\$14,475	\$22
13.2	Site Improvements	\$0	\$2,283	\$3,017	\$0	\$5,300	\$928	\$0	\$1,246	\$7,474	\$11
13.3	Site Facilities	\$2,609	\$0	\$2,737	\$0	\$5,346	\$935	\$0	\$1,256	\$7,537	\$12
	Subtotal	\$2,609	\$2,745	\$15,558	\$0	\$20,912	\$3,660	\$0	\$4,914	\$29,486	\$45
14 Buildings & Structures											
14.2	Boiler Building	\$0	\$11,598	\$10,193	\$0	\$21,791	\$3,813	\$0	\$3,841	\$29,445	\$45
14.3	Steam Turbine Building	\$0	\$16,121	\$15,014	\$0	\$31,136	\$5,449	\$0	\$5,488	\$42,072	\$65

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B12B.90	– SC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
14.4	Administration Building	\$0	\$1,047	\$1,107	\$0	\$2,154	\$377	\$0	\$380	\$2,911	\$4
14.5	Circulation Water Pump house	\$0	\$184	\$146	\$0	\$330	\$58	\$0	\$58	\$446	\$1
14.6	Water Treatment Buildings	\$0	\$460	\$419	\$0	\$880	\$154	\$0	\$155	\$1,189	\$2
14.7	Machine Shop	\$0	\$553	\$371	\$0	\$923	\$162	\$0	\$163	\$1,247	\$2
14.8	Warehouse	\$0	\$416	\$416	\$0	\$832	\$146	\$0	\$147	\$1,124	\$2
14.9	Other Buildings & Structures	\$0	\$290	\$247	\$0	\$537	\$94	\$0	\$95	\$726	\$1
14.10	Waste Treating Building & Structures	\$0	\$642	\$1,945	\$0	\$2,587	\$453	\$0	\$456	\$3,496	\$5
	Subtotal	\$0	\$31,312	\$29,859	\$0	\$61,170	\$10,705	\$0	\$10,781	\$82,657	\$127
	Total	\$920,915	\$136,959	\$538,376	\$0	\$1,596,250	\$279,344	\$57,544	\$311,431	\$2,244,569	\$3,452

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-90. Case B12B.90 owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$13,454	\$21
1 Month Maintenance Materials	\$2,113	\$3
1 Month Non-Fuel Consumables	\$3,204	\$5
1 Month Waste Disposal	\$941	\$1
25% of 1 Months Fuel Cost at 100% CF	\$2,848	\$4
2% of TPC	\$44,891	\$69
Total	\$67,451	\$104
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	\$28,422	\$44
0.5% of TPC (spare parts)	\$11,223	\$17
Total	\$39,645	\$61
Other Costs		
Initial Cost for Catalyst and Chemicals	\$2,602	\$4
Land	\$900	\$1
Other Owner's Costs	\$336,685	\$518
Financing Costs	\$60,603	\$93
Total Overnight Costs (TOC)	\$2,752,456	\$4,233
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	\$3,177,468	\$4,886

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-91. Case B12B.90 initial and annual operating and maintenance costs

Case:	B12B.90	– SC PC w/ CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):	10,778	Capacity Factor (%):	85	
Operating & Maintenance Labor						
Operating Labor			Operating Labor Requirements per Shift			
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:		2.0
Operating Labor Burden:		30.00	% of base	Operator:		11.3
Labor O-H Charge Rate:		25.00	% of labor	Foreman:		1.0
				Lab Techs, etc.:		2.0
				Total:		16.3
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$7,161,008	\$11.012
Maintenance Labor:					\$14,365,244	\$22.090
Administrative & Support Labor:					\$5,381,563	\$8.276
Property Taxes and Insurance:					\$44,891,388	\$69.032
Total:					\$71,799,203	\$110.409
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$21,547,866	\$4.45008
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	6,698	\$1.90	\$0	\$3,948,020	\$0.81535
Makeup and Waste Water Treatment Chemicals (ton):	0	20.0	\$550.00	\$0	\$3,404,383	\$0.70308
Brominated Activated Carbon (ton):	0	1.58	\$1,600.00	\$0	\$783,027	\$0.16171
Enhanced Hydrated Lime (ton):	0	39.7	\$240.00	\$0	\$2,955,235	\$0.61032
Limestone (ton):	0	697	\$22.00	\$0	\$4,760,201	\$0.98308
Ammonia (19 wt%, ton):	0	68.8	\$300.00	\$0	\$6,403,145	\$1.32238
SCR Catalyst (ft ³):	17,344	15.8	\$150.00	\$2,601,531	\$737,100	\$0.15223
CO ₂ Capture System Chemicals ^A :	Proprietary				\$8,434,609	\$1.74192
Triethylene Glycol (gal):	w/equip.	596	\$6.80	\$0	\$1,258,163	\$0.25984
Subtotal:				\$2,601,531	\$32,683,884	\$6.74989
Waste Disposal						
Fly Ash (ton):	0	654	\$38.00	\$0	\$7,713,755	\$1.59305
Bottom Ash (ton):	0	145	\$38.00	\$0	\$1,713,430	\$0.35386
SCR Catalyst (ft ³):	0	15.8	\$2.50	\$0	\$12,285	\$0.00254
Triethylene Glycol (gal):	0	596	\$0.35	\$0	\$64,758	\$0.01337
Thermal Reclaimer Unit Waste (ton):	0	7.68	\$38.00	\$0	\$90,555	\$0.01870
Subtotal:				\$0	\$9,594,783	\$1.98152
By-Products						
Gypsum (ton):	0	1,060	\$0.00	\$0	\$0	\$0.00000
Subtotal:				\$0	\$0	\$0.00000
Variable Operating Costs Total:				\$2,601,531	\$63,826,533	\$13.18149
Fuel Cost						
Illinois Number 6 (ton):	0	7,210	\$51.96	\$0	\$116,218,729	\$24.00155
Total:				\$0	\$116,218,729	\$24.00155

^ACO₂ Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit 4-92. Case B12B.90 LCOE breakdown

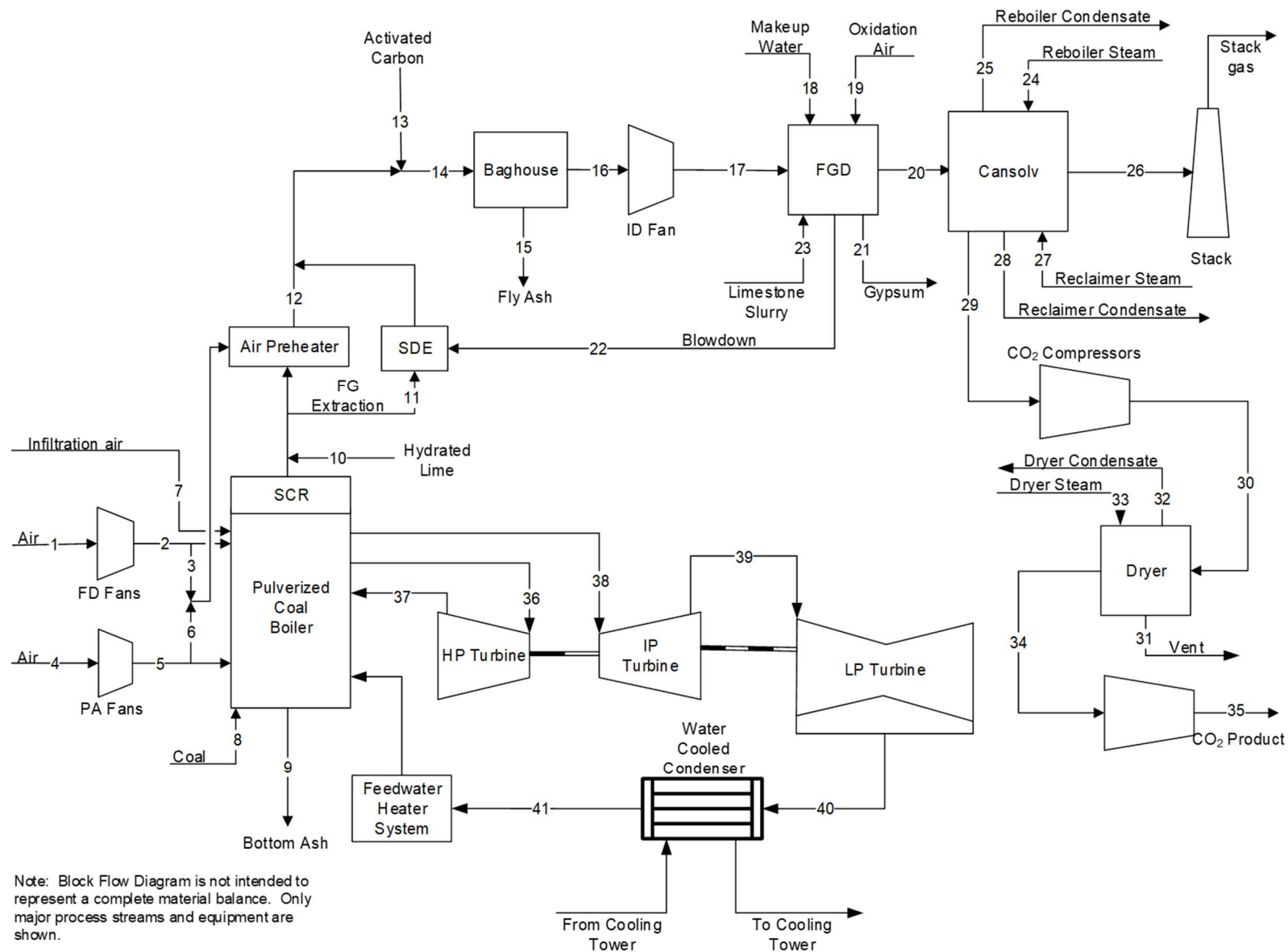
Component	Value, \$/MWh	Percentage
Capital	46.4	43%
Fixed	14.8	14%
Variable	13.2	12%
Fuel	24.0	22%
Total (Excluding T&S)	98.4	N/A
CO ₂ T&S	8.9	8%
Total (Including T&S)	107.3	N/A

4.3.11 Case B12B.95 – SC PC with 95 Percent CO₂ Capture Process Description

The plant configuration and process description for Case B12B.95 are nearly the same as Case B12B.90, with the exception that the capture rate is 95 percent. Since the process descriptions of the plant and CDR facility were provided in Section 4.3.3 and Section 4.1.8, respectively, they are not repeated here.

The BFD for Case B12B.95 is shown in Exhibit 4-93. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 4-94. The modeling assumptions were presented previously in Section 4.3.1.

Exhibit 4-93. Case B12B.95 block flow diagram, SC unit with CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-94. Case B12B.95 stream table, SC unit with capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0087	0.0088	0.0000	0.0087	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379	0.0000	0.1372	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837	0.0000	0.0911	0.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340	0.0000	0.7281	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336	0.0000	0.0329	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020	0.0000	0.0020	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1158
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.8842
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	75,402	75,402	2,233	23,163	23,163	3,188	1,667	0	0	1	4,969	100,794	0	106,605	7
V-L Flowrate (kg/hr)	2,175,880	2,175,880	64,447	668,408	668,408	91,989	48,095	0	0	15	147,779	2,993,021	0	3,156,369	682
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	276,574	5,575	1,507	1,194	22,910	61	24,401	24,418
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143	15	143	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.31	-6.79	-2,453.14	-1,065.93
Density (kg/m ³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8	---	0.8	2,150.2
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694	---	29.608	104.898
V-L Flowrate (lb _{mol} /hr)	166,234	166,234	4,924	51,065	51,065	7,028	3,674	0	0	2	10,954	222,214	0	235,024	14
V-L Flowrate (lb/hr)	4,796,995	4,796,995	142,081	1,473,587	1,473,587	202,801	106,031	0	0	34	325,796	6,598,482	0	6,958,602	1,504
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	609,741	12,291	3,323	2,631	50,508	133	53,795	53,832
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289	59	289	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1	14.7	14.1	14.1
Steam Table Enthalpy (Btu/lb) ^A	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4	-2.9	-1,054.7	-458.3
Density (lb/ft ³)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052	---	0.052	134.232

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-94. Case B12B.95 stream table, SC unit with capture (continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0102	0.0000	0.0000	0.0000	0.0000
CO ₂	0.1372	0.1372	0.0000	0.0003	0.1245	0.0001	0.0000	0.0000	0.0000	0.0000	0.0079	0.0000	0.0000	0.9783	0.9975
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0911	0.0911	0.9999	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000	1.0000	0.0807	1.0000	1.0000	0.0217	0.0025
HCl	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000	0.0000	0.8555	0.0000	0.0000	0.0000	0.0000
O ₂	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000	0.0000	0.0457	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0001	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	106,598	106,598	6,228	4,462	119,168	251	842	3,469	36,090	33,054	94,758	392	392	14,400	14,122
V-L Flowrate (kg/hr)	3,155,670	3,155,670	112,215	128,768	3,424,914	4,521	15,569	62,497	650,164	595,482	2,618,773	7,064	7,064	625,596	620,597
Solids Flowrate (kg/hr)	0	0	0	0	0	40,666	237	26,754	0	0	0	0	0	0	0
Temperature (°C)	143	156	15	15	57	15	57	15	269	105	45	342	214	31	29
Pressure (MPa, abs)	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.48	0.12	0.10	4.90	2.04	0.17	2.81
Steam Table Enthalpy (kJ/kg) ^A	287.58	302.09	-47.80	30.23	297.00	---	---	---	3,000.14	439.34	179.09	3,049.81	913.81	46.68	-3.05
AspenPlus Enthalpy (kJ/kg) ^B	-2,464.17	-2,449.66	-16,015.01	-97.58	-2,939.24	-12,513.34	-15,496.23	-14,994.25	-12,980.15	-15,540.95	-797.41	-12,930.48	-15,066.49	-8,978.62	-8,972.51
Density (kg/m ³)	0.8	0.9	1,003.7	1.2	1.1	878.3	979.4	1,003.7	2.0	954.9	1.1	19.2	848.5	3.0	57.8
V-L Molecular Weight	29.603	29.603	18.019	28.857	28.740	18.021	18.494	18.019	18.015	18.015	27.637	18.015	18.015	43.445	43.945
V-L Flowrate (lb _{mol} /hr)	235,009	235,009	13,730	9,838	262,720	553	1,856	7,647	79,564	72,872	208,905	864	864	31,746	31,134
V-L Flowrate (lb/hr)	6,957,062	6,957,062	247,391	283,886	7,550,643	9,967	34,324	137,783	1,433,366	1,312,812	5,773,406	15,573	15,573	1,379,204	1,368,181
Solids Flowrate (lb/hr)	0	0	0	0	0	89,653	522	58,983	0	0	0	0	0	0	0
Temperature (°F)	289	313	59	59	135	59	135	59	516	221	113	648	416	87	85
Pressure (psia)	13.9	15.3	14.7	14.7	14.8	14.7	14.7	14.7	70.0	17.4	14.8	710.8	296.6	24.7	407.6
Steam Table Enthalpy (Btu/lb) ^A	123.6	129.9	-20.5	13.0	127.7	---	---	---	1,289.8	188.9	77.0	1,311.2	392.9	20.1	-1.3
AspenPlus Enthalpy (Btu/lb) ^B	-1,059.4	-1,053.2	-6,885.2	-42.0	-1,263.6	-5,379.8	-6,662.2	-6,446.4	-5,580.5	-6,681.4	-342.8	-5,559.1	-6,477.4	-3,860.1	-3,857.5
Density (lb/ft ³)	0.051	0.055	62.658	0.076	0.067	54.833	61.145	62.658	0.122	59.612	0.066	1.197	52.968	0.184	3.609

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-94. Case B12B.95 stream table, SC unit with capture (continued)

	31	32	33	34	35	36	37	38	39	40	41
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0500	0.0000	0.0000	0.9995	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	30	18	18	14,092	14,092	135,250	112,678	112,678	97,029	41,067	64,246
V-L Flowrate (kg/hr)	572	330	330	620,024	620,024	2,436,565	2,029,920	2,029,920	1,747,998	739,838	1,157,402
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	29	203	461	29	30	593	342	593	270	38	39
Pressure (MPa, abs)	2.81	1.64	2.14	2.68	15.27	24.23	4.90	4.80	0.52	0.01	1.26
Steam Table Enthalpy (kJ/kg) ^A	137.94	863.65	3,379.61	-3.59	-231.09	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.36
AspenPlus Enthalpy (kJ/kg) ^B	-15,225.22	-15,116.65	-12,600.69	-8,967.15	-9,194.65	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.93
Density (kg/m ³)	351.5	861.8	6.4	54.7	630.1	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	19.315	18.015	18.015	43.997	43.997	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	65	40	40	31,069	31,069	298,175	248,412	248,412	213,911	90,538	141,637
V-L Flowrate (lb/hr)	1,262	728	728	1,366,920	1,366,920	5,371,707	4,475,208	4,475,208	3,853,675	1,631,063	2,551,634
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	85	397	862	85	86	1,100	648	1,100	517	101	101
Pressure (psia)	407.6	237.4	310.1	389.1	2,214.7	3,514.7	710.8	696.6	75.0	1.0	183.1
Steam Table Enthalpy (Btu/lb) ^A	59.3	371.3	1,453.0	-1.5	-99.4	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb) ^B	-6,545.7	-6,499.0	-5,417.3	-3,855.2	-3,953.0	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft ³)	21.943	53.801	0.402	3.416	39.338	4.319	1.197	0.768	0.131	0.003	62.009

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

4.3.12 Case B12B.95 – Performance Results

Overall plant performance is summarized in Exhibit 4-95; Exhibit 4-96 provides a detailed breakdown of the auxiliary power requirements.

The CDR facility, including CO₂ compression, accounts for over half of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for over 11 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility and CO₂ compressors.

Unlike the NGCC cases where gross output was fixed by the available size of the CTs, the PC cases utilize boilers and steam turbines that can be procured at nearly any desired output. By increasing the boiler and turbine/generator size to account for the greater auxiliary load imposed by the CDR facility and CO₂ compressors, a net output of 650 MW is maintained at a reduced net plant efficiency of 31.2 percent (HHV basis).

Exhibit 4-95. Case B12B.95 plant performance summary

Performance Summary	
Total Gross Power, MWe	768
CO ₂ Capture/Removal Auxiliaries, kWe	19,200
CO ₂ Compression, kWe	49,640
Balance of Plant, kWe	49,030
Total Auxiliaries, MWe	118
Net Power, MWe	650
HHV Net Plant Efficiency, %	31.2
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,540 (10,938)
LHV Net Plant Efficiency, %	32.3
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,131 (10,550)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	58.2
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	6,189 (5,866)
Condenser Duty, GJ/hr (MMBtu/hr)	2,064 (1,956)
CO ₂ Capture Rate, %	95
AGR Duty, GJ/hr (MMBtu/hr)	2,177 (2,064)
As-Received Coal Feed, kg/hr (lb/hr)	276,574 (609,741)
Limestone Sorbent Feed, kg/hr (lb/hr)	26,754 (58,983)
HHV Thermal Input, kWt	2,084,684
LHV Thermal Input, kWt	2,010,703
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.055 (14.6)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.041 (10.9)
Excess Air, %	20.3

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-96. Case B12B.95 plant power summary

Power Summary	
Steam Turbine Power, MWe	768
Total Gross Power, MWe	768
Auxiliary Load Summary	
Activated Carbon Injection, kWe	40
Ash Handling, kWe	910
Baghouse, kWe	120
Circulating Water Pumps, kWe	9,230
CO ₂ Capture/Removal Auxiliaries, kWe	19,200
CO ₂ Compression, kWe	49,640
Coal Handling and Conveying, kWe	530
Condensate Pumps, kWe	800
Cooling Tower Fans, kWe	4,770
Dry Sorbent Injection, kWe	80
Flue Gas Desulfurizer, kWe	4,270
Forced Draft Fans, kWe	1,420
Ground Water Pumps, kWe	860
Induced Draft Fans, kWe	13,110
Miscellaneous Balance of Plant ^{A,B} , kWe	2,250
Primary Air Fans, kWe	1,680
Pulverizers, kWe	4,150
SCR, kWe	50
Sorbent Handling & Reagent Preparation, kWe	1,290
Spray Dryer Evaporator, kWe	300
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,670
Total Auxiliaries, MWe	118
Net Power, MWe	650

^ABoiler feed pumps are turbine driven

^BIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

4.3.12.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B12B.95 is presented in Exhibit 4-97. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 4-97. Case B12B.95 air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.033 (0.076)	1,816 (2,002)	0.318 (0.700)
Particulate	0.004 (0.010)	234 (257)	0.041 (0.090)
Hg	1.39E-7 (3.24E-7)	0.008 (0.009)	1.36E-6 (3.00E-6)
CO ₂	4 (10)	244,496 (269,510)	43 (94)
CO ₂ ^C	–	–	50 (111)
mg/Nm ³			
Particulate Concentration ^{D,E}	13.13		

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

^DConcentration of particles in the flue gas after the baghouse

^ENormal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The SO₂ emissions are further reduced to 0.37 ppmv using a NaOH based polishing scrubber in the CDR facility. The remaining low concentration of SO₂ is essentially completely removed in the CDR absorber vessel resulting in very low SO₂ emissions (reported as zero here).

NO_x emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 78.4 percent to 0.03 kg/GJ (0.08 lb/MMBtu).

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and wet FGD) is 97.5 percent.

Ninety-five percent of the CO₂ in the flue gas is removed in CDR facility.

The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD. Carbon leaves the plant mostly as CO₂ product from the CO₂ compression train; however, some CO₂ exits through the stack, the PAC is captured in the fabric filter, unburned carbon remains in the bottom ash, and some leaves as gypsum. The

carbon balance is shown in Exhibit 4-98. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in (minus unburnt carbon in the ash), represented by the following fraction:

$$1 - \frac{\text{Carbon in Stack}}{\text{Total Carbon In} - \text{Unburnt Carbon}} = \left(1 - \left(\frac{19,757}{395,702 - 466} \right) \right) * 100 = 95\%$$

Exhibit 4-98. Case B12B.95 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	176,301 (388,678)	Stack Gas	8,961 (19,757)
Air (CO ₂)	411 (906)	FGD Product	209 (461)
PAC	61 (133)	Baghouse	907 (1,999)
FGD Reagent	2,715 (5,985)	Bottom Ash	212 (466)
		CO ₂ Product	169,180 (372,979)
		CO ₂ Dryer Vent	18 (39)
		CO ₂ Knockout	0.5 (1.1)
Total	179,487 (395,702)	Total	179,487 (395,702)

Exhibit 4-99 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur emitted in the stack gas, and sulfur removed in the polishing scrubber.

Exhibit 4-99. Case B12B.95 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	6,932 (15,283)	FGD Product	6,517 (14,368)
		Stack Gas	0 (0)
		Polishing Scrubber and Solvent Reclaiming	135 (299)
		Baghouse	279 (616)
Total	6,932 (15,283)	Total	6,932 (15,283)

Exhibit 4-100 shows the overall water balance for the plant. The exhibit is presented in an identical manner as for Case B12A. The only notable difference is the FGD makeup water source. In CO₂ capture cases, a significant amount of water is recovered from the initial CDR facility cooling step. This water would otherwise be discharged; however, it is suitable to be used as FGD makeup. The balance of the water from the CDR facility is sent to discharge.

Exhibit 4-100. Case B12B.95 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
FGD Process Makeup	1.9 (495)	1.9 (495)	–	–	–
FGD Slurry Water	1.0 (276)	1.0 (276)	–	–	–
CO ₂ Drying	–	–	–	0.0 (2.5)	0.0 (-2.5)
CO ₂ Capture Recovery	–	–	–	1.0 (266)	-1.0 (-266)
CO ₂ Compression KO	–	–	–	0.1 (22)	-0.1 (-22)
Deaerator Vent	–	–	–	0.1 (22)	-0.1 (-22)
Condenser Makeup	0.1 (22)	–	0.1 (22)	–	0.1 (22)
BFW Makeup	0.1 (22)	–	0.1 (22)	–	0.1 (22)
Cooling Tower	36 (9,494)	–	36 (9,494)	8.1 (2,135)	28 (7,359)
BFW Blowdown	–	–	–	–	–
Total	39 (10,286)	2.9 (770)	36 (9,516)	9.3 (2,447)	27 (7,069)

4.3.12.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for the Case B12B.95 PC boiler, FGD unit, CDR system, and steam cycle in Exhibit 4-101 and Exhibit 4-102. An overall plant energy balance is provided in tabular form in Exhibit 4-103.

The power out is the steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a generator efficiency of 98.5 percent. The cooling tower load includes the condenser, capture process heat rejected to cooling water, the CO₂ compressor intercooler load, and other miscellaneous cooling loads.

This page intentionally left blank

Exhibit 4-101. Case B12B.95 energy and mass balance, SC PC boiler with CO₂ capture

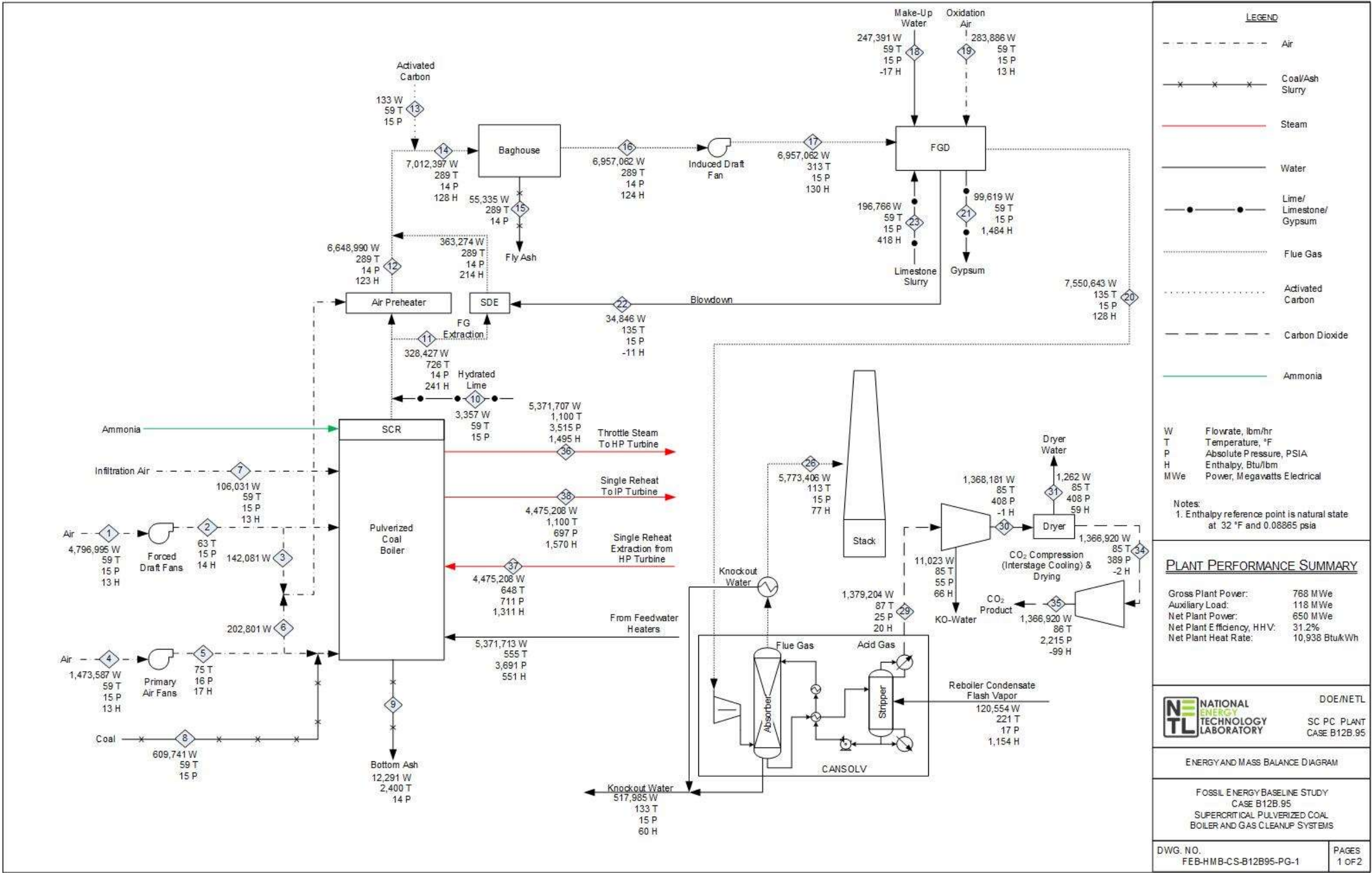


Exhibit 4-102. Case B12B.95 energy and mass balance, SC steam cycle

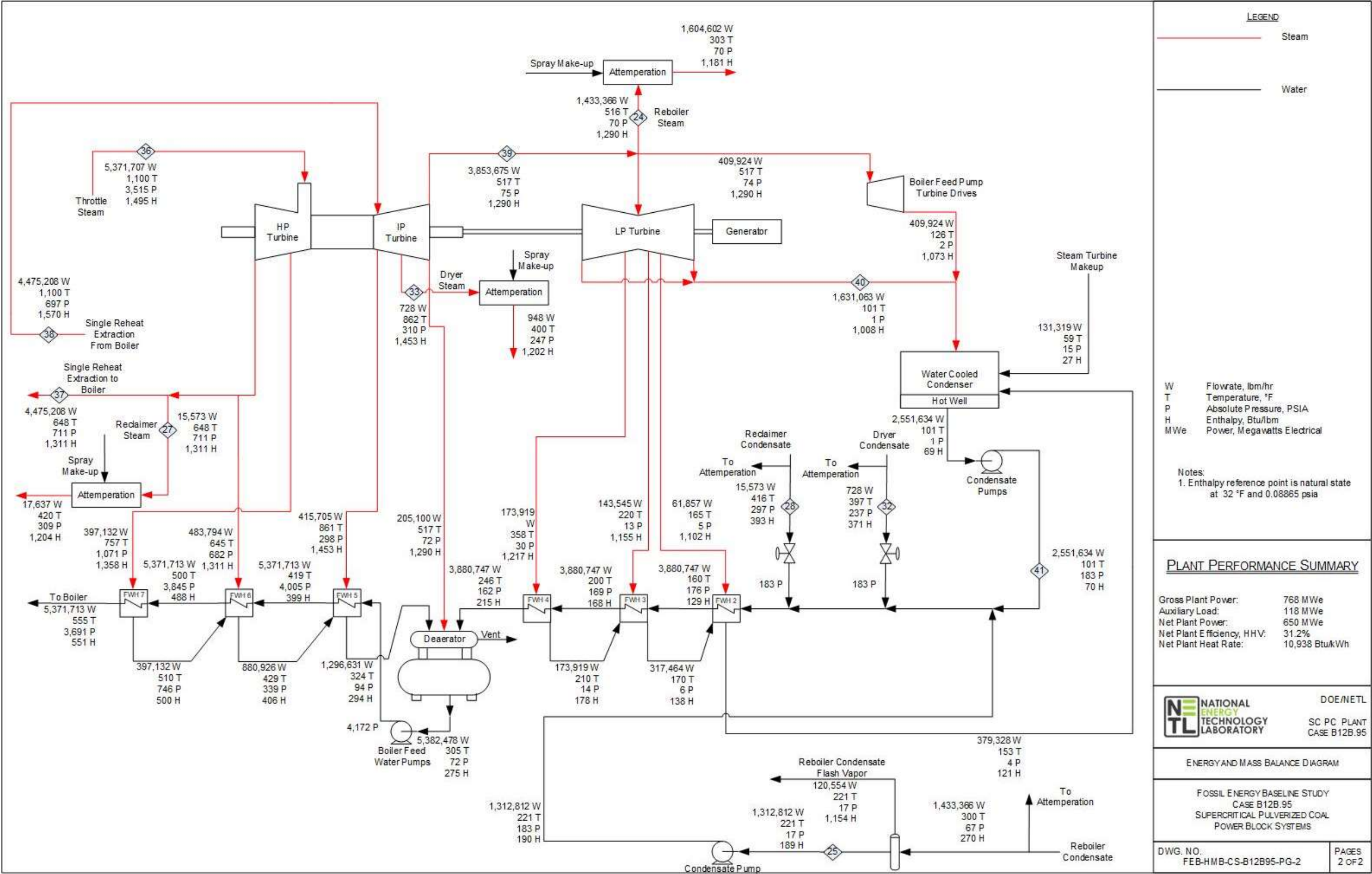


Exhibit 4-103. Case B12B.95 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	7,505 (7,113)	6.3 (5.9)	—	7,511 (7,119)
Air	—	87 (83)	—	87 (83)
Raw Water Makeup	—	135 (128)	—	135 (128)
Limestone	—	0.6 (0.6)	—	0.6 (0.6)
Auxiliary Power	—	—	424 (402)	424 (402)
TOTAL	7,505 (7,113)	230 (218)	424 (402)	8,159 (7,733)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	—	7.1 (6.7)	—	7.1 (6.7)
Fly Ash	—	2.6 (2.4)	—	2.6 (2.4)
Stack Gas	—	469 (445)	—	469 (445)
Sulfur	2.5 (2.4)	0.0 (0.0)	—	2.5 (2.4)
Gypsum	—	2.6 (2.5)	—	2.6 (2.5)
Motor Losses and Design Allowances	—	—	51 (48)	51 (48)
Cooling Tower Load ^A	—	4,693 (4,448)	—	4,693 (4,448)
CO ₂ Product Stream	—	-143 (-136)	—	-143 (-136)
AGR Effluent	—	55 (52)	—	55 (52)
Blowdown Streams and Deaerator Vent	—	3.1 (2.9)	—	3.1 (2.9)
<i>Ambient Losses^B</i>	—	178 (168)	—	178 (168)
Power	—	—	2,766 (2,621)	2,766 (2,621)
TOTAL	2.5 (2.4)	5,267 (4,992)	2,816 (2,669)	8,086 (7,664)
<i>Unaccounted Energy^C</i>	—	73 (70)	—	73 (70)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^CBy difference

4.3.13 Case B12B.95 – Major Equipment List

Major equipment items for the SC PC plant with CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.3.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B12B.95 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	60 tonne (60 ton)	2	1
9	Feeder	Vibratory	230 tonne/hr (250 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	460 tonne/hr (500 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	230 tonne (250 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/trippper	460 tonne/hr (500 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	460 tonne/hr (500 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,010 tonne (1,120 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 11 tonne (12 ton) Feeder - 70 kg/hr (150 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 280 tonne (310 ton) Feeder - 1,670 kg/hr (3,690 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	112 tonne/hr (124 tph)	1	0
23	Limestone Conveyor No. 1	Belt	112 tonne/hr (124 tph)	1	0
24	Limestone Reclaim Hopper	N/A	22 tonne (24 ton)	1	0
25	Limestone Reclaim Feeder	Belt	88 tonne/hr (97 tph)	1	0
26	Limestone Conveyor No. 2	Belt	88 tonne/hr (97 tph)	1	0
27	Limestone Day Bin	w/ actuator	353 tonne (389 ton)	2	0

Case B12B.95 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	51 tonne/hr (56 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	51 tonne/hr (56 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	29 tonne/hr (32 tph)	1	1
4	Limestone Ball Mill	Rotary	29 tonne/hr (32 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	114,000 liters (30,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,890 lpm @ 10 m H ₂ O (500 gpm @ 40 ft H ₂ O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5-cyclone bank	470 lpm (130 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	636,000 liters (168,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,330 lpm @ 9 m H ₂ O (350 gpm @ 30 ft H ₂ O)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B12B.95 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	323,000 liters (85,300 gal)	2	0
2	Condensate Pumps	Vertical canned	10,700 lpm @ 200 m H ₂ O (2,820 gpm @ 500 ft H ₂ O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,343,000 kg/hr (2,960,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	22,000 lpm @ 3,500 m H ₂ O (5,900 gpm @ 11,400 ft H ₂ O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	6,700 lpm @ 3,500 m H ₂ O (1,800 gpm @ 11,400 ft H ₂ O)	2	0
6	LP Feedwater Heater 2A/2B	Horizontal U-tube	480,000 kg/hr (1,070,000 lb/hr)	4	0
7	LP Feedwater Heater 3A/3B	Horizontal U-tube	480,000 kg/hr (1,070,000 lb/hr)	4	0
8	LP Feedwater Heater 4A/4B	Horizontal U-tube	480,000 kg/hr (1,070,000 lb/hr)	4	0
9	HP Feedwater Heater 5	Horizontal U-tube	1,340,000 kg/hr (2,950,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	1,340,000 kg/hr (2,950,000 lb/hr)	2	0
11	HP Feedwater Heater 7	Horizontal U-tube	1,340,000 kg/hr (2,950,000 lb/hr)	2	0
12	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
13	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
14	Service Air Compressors	Flooded Screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H ₂ O (5,500 gpm @ 100 ft H ₂ O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	9,600 lpm @ 20 m H ₂ O (2,540 gpm @ 60 ft H ₂ O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	3,850 lpm @ 270 m H ₂ O (1,020 gpm @ 880 ft H ₂ O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	1,200 lpm @ 50 m H ₂ O (310 gpm @ 160 ft H ₂ O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,139,000 liter (301,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,550 m ³ /min (89,900 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 150 lpm (40 gpm) @ 19,982 ppmw Cl ⁻	2	1

Case B12B.95 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, once-through, wall-fired, low NOx burners, overfire air	2,680,000 kg/hr steam @ 24.1 MPa/593°C/593°C (5,910,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	368,000 kg/hr, 5,000 m ³ /min @ 101 cm WG (810,000 lb/hr, 177,200 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,197,000 kg/hr, 16,300 m ³ /min @ 26 cm WG (2,638,000 lb/hr, 577,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,736,000 kg/hr, 35,200 m ³ /min @ 114 cm WG (3,826,000 lb/hr, 1,242,000 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,280,000 kg/hr (7,240,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	130 m ³ /min @ 108 cm WG (4,500 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	139,000 liter (36,700 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	27 lpm @ 90 m H ₂ O (7 gpm @ 300 ft H ₂ O)	2	1

Case B12B.95 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,736,000 kg/hr (3,827,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	58,800 m ³ /min (2,080,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	204,000 lpm @ 65 m H ₂ O (54,000 gpm @ 210 ft H ₂ O)	5	1
4	Bleed Pumps	Horizontal centrifugal	5,650 lpm (1,490 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	970 m ³ /min @ 0.3 MPa (34,130 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,410 lpm (370 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	45 tonne/hr (49 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	860 lpm @ 13 m H ₂ O (230 gpm @ 40 ft H ₂ O)	1	1
10	Filtrate Water	Vertical, lined	560,000 lpm (150,000 gal)	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
	Return Storage Tank				
11	Process Makeup Water Pumps	Horizontal centrifugal	2,060 lpm @ 21 m H ₂ O (540 gpm @ 70 ft H ₂ O)	1	1
12	Activated Carbon Injectors	---	70 kg/hr (150 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,670 kg/hr (3,690 lb/hr)	1	0
14	CANSOLV	Amine-based CO ₂ capture technology	3,767,000 kg/hr (8,306,000 lb/hr) 19.1 wt % CO ₂ concentration	1	0
15	CANSOLV LP Condensate Pump	Centrifugal	1,426 lpm @ 1 m H ₂ O (377 gpm @ 3 ft H ₂ O)	1	1
16	CANSOLV IP Condensate Pump	Centrifugal	17 lpm @ 4.6 m H ₂ O (5 gpm @ 15 ft H ₂ O)	1	1
17	CO ₂ Dryer	Triethylene glycol	Inlet: 179 m ³ /min @ 2.8 MPa (6,318 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Recovered: 572 kg/hr (1,262 lb/hr)	1	0
18	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	9.0 m ³ /min @ 15.3 MPa, 82°C (319 acfm @ 2,217 psia, 180°F)	2	0
19	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 98 GJ/hr (93 MMBtu/hr)	1	0

Case B12B.95 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.3 m (21 ft) diameter	1	0

Case B12B.95 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	809 MW 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	900 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,140 GJ/hr (2,150 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B12B.95 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	926,000 lpm @ 30 m (245,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 5,160 GJ/hr (4,890 MMBtu/hr) heat duty	1	0

Case B12B.95 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	6.1 tonne/hr (6.8 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	25 m ³ /min @ 0.2 MPa (875 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,630 tonne (1,790 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	150 tonne/hr (170 tph)	1	0

Case B12B.95 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 28 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 54 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 19 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B12B.95 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.3.14 Case B12B.95 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 4-104 shows a detailed breakdown of the capital costs; Exhibit 4-105 shows the owner's costs, TOC, and TASC; Exhibit 4-106 shows the initial and annual O&M costs; and Exhibit 4-107 shows the LCOE breakdown.

The estimated TPC of the SC PC boiler with CO₂ capture is \$3,514/kW. Process contingency represents 2.6 percent of the TPC and project contingency represents 13.9 percent. The LCOE, including CO₂ T&S costs of \$9.5/MWh, is \$109.7/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-104. Case B12B.95 total plant cost details

Case:		B12B.95	– SC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1 Coal & Sorbent Handling											
1.1	Coal Receive & Unload	\$1,184	\$0	\$534	\$0	\$1,718	\$301	\$0	\$303	\$2,321	\$4
1.2	Coal Stackout & Reclaim	\$3,888	\$0	\$869	\$0	\$4,757	\$832	\$0	\$838	\$6,428	\$10
1.3	Coal Conveyors	\$35,826	\$0	\$8,521	\$0	\$44,347	\$7,761	\$0	\$7,816	\$59,924	\$92
1.4	Other Coal Handling	\$4,978	\$0	\$1,046	\$0	\$6,024	\$1,054	\$0	\$1,062	\$8,140	\$13
1.5	Sorbent Receive & Unload	\$228	\$0	\$68	\$0	\$296	\$52	\$0	\$52	\$399	\$1
1.6	Sorbent Stackout & Reclaim	\$1,666	\$0	\$301	\$0	\$1,967	\$344	\$0	\$347	\$2,658	\$4
1.7	Sorbent Conveyors	\$2,525	\$549	\$611	\$0	\$3,685	\$645	\$0	\$649	\$4,979	\$8
1.8	Other Sorbent Handling	\$121	\$29	\$63	\$0	\$213	\$37	\$0	\$37	\$287	\$0
1.9	Coal & Sorbent Handling Foundations	\$0	\$1,645	\$2,168	\$0	\$3,813	\$667	\$0	\$672	\$5,152	\$8
	Subtotal	\$50,416	\$2,222	\$14,181	\$0	\$66,819	\$11,693	\$0	\$11,776	\$90,289	\$139
2 Coal & Sorbent Preparation & Feed											
2.1	Coal Crushing & Drying	\$2,546	\$0	\$489	\$0	\$3,035	\$531	\$0	\$535	\$4,102	\$6
2.2	Prepared Coal Storage & Feed	\$8,571	\$0	\$1,846	\$0	\$10,416	\$1,823	\$0	\$1,836	\$14,075	\$22
2.5	Sorbent Preparation Equipment	\$1,121	\$48	\$230	\$0	\$1,399	\$245	\$0	\$247	\$1,890	\$3
2.6	Sorbent Storage & Feed	\$1,879	\$0	\$709	\$0	\$2,588	\$453	\$0	\$456	\$3,497	\$5
2.9	Coal & Sorbent Feed Foundation	\$0	\$744	\$652	\$0	\$1,396	\$244	\$0	\$246	\$1,887	\$3
	Subtotal	\$14,117	\$792	\$3,925	\$0	\$18,835	\$3,296	\$0	\$3,320	\$25,451	\$39
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$4,014	\$6,881	\$3,441	\$0	\$14,336	\$2,509	\$0	\$2,527	\$19,371	\$30
3.2	Water Makeup & Pretreating	\$8,011	\$801	\$4,540	\$0	\$13,352	\$2,337	\$0	\$3,138	\$18,826	\$29
3.3	Other Feedwater Subsystems	\$3,142	\$1,030	\$979	\$0	\$5,151	\$901	\$0	\$908	\$6,961	\$11
3.4	Service Water Systems	\$2,534	\$4,838	\$15,665	\$0	\$23,037	\$4,031	\$0	\$5,414	\$32,482	\$50
3.5	Other Boiler Plant Systems	\$778	\$283	\$707	\$0	\$1,767	\$309	\$0	\$312	\$2,388	\$4
3.6	Natural Gas Pipeline and Start-Up System	\$3,365	\$145	\$109	\$0	\$3,619	\$633	\$0	\$638	\$4,890	\$8
3.7	Waste Water Treatment Equipment	\$13,202	\$0	\$8,091	\$0	\$21,293	\$3,726	\$0	\$5,004	\$30,023	\$46
3.8	Spray Dryer Evaporator	\$17,112	\$0	\$9,907	\$0	\$27,019	\$4,728	\$0	\$6,350	\$38,097	\$59
3.9	Miscellaneous Plant Equipment	\$226	\$30	\$115	\$0	\$371	\$65	\$0	\$87	\$523	\$1
	Subtotal	\$52,384	\$14,008	\$43,553	\$0	\$109,945	\$19,240	\$0	\$24,376	\$153,561	\$236
4 Pulverized Coal Boiler & Accessories											
4.9	Pulverized Coal Boiler & Accessories	\$271,047	\$0	\$154,441	\$0	\$425,489	\$74,461	\$0	\$74,992	\$574,942	\$884
4.10	Selective Catalytic Reduction System	\$30,550	\$0	\$17,445	\$0	\$47,994	\$8,399	\$0	\$8,459	\$64,852	\$100
4.11	Boiler Balance of Plant	\$1,781	\$0	\$1,015	\$0	\$2,796	\$489	\$0	\$493	\$3,778	\$6
4.12	Primary Air System	\$1,710	\$0	\$974	\$0	\$2,684	\$470	\$0	\$473	\$3,627	\$6
4.13	Secondary Air System	\$2,590	\$0	\$1,476	\$0	\$4,065	\$711	\$0	\$716	\$5,493	\$8

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B12B.95	– SC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
4.14	Induced Draft Fans	\$5,586	\$0	\$3,183	\$0	\$8,769	\$1,535	\$0	\$1,546	\$11,849	\$18
4.15	Major Component Rigging	\$94	\$0	\$53	\$0	\$147	\$26	\$0	\$26	\$199	\$0
4.16	Boiler Foundations	\$0	\$402	\$354	\$0	\$756	\$132	\$0	\$133	\$1,022	\$2
	Subtotal	\$313,357	\$402	\$178,941	\$0	\$492,701	\$86,223	\$0	\$86,839	\$665,762	\$1,024
5 Flue Gas Cleanup											
5.1	CANSOLV Carbon Dioxide (CO ₂) Removal System	\$147,454	\$64,400	\$135,239	\$0	\$347,093	\$60,741	\$59,006	\$81,697	\$548,537	\$843
5.2	WFGD Absorber Vessels & Accessories	\$80,139	\$0	\$17,141	\$0	\$97,280	\$17,024	\$0	\$17,146	\$131,450	\$202
5.3	Other FGD	\$1,278	\$0	\$983	\$0	\$2,261	\$396	\$0	\$399	\$3,055	\$5
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$44,333	\$6,650	\$14,823	\$0	\$65,806	\$11,516	\$0	\$15,464	\$92,786	\$143
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$494	\$78	\$212	\$0	\$785	\$137	\$0	\$184	\$1,106	\$2
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$2,692	\$592	\$2,647	\$0	\$5,931	\$1,038	\$0	\$1,045	\$8,015	\$12
5.9	Particulate Removal (Bag House & Accessories) (included with 5.2)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5.12	Gas Cleanup Foundations	\$0	\$199	\$175	\$0	\$374	\$65	\$0	\$66	\$505	\$1
5.13	Gypsum Dewatering System	\$768	\$0	\$130	\$0	\$898	\$157	\$0	\$158	\$1,213	\$2
	Subtotal	\$277,159	\$71,920	\$171,349	\$0	\$520,429	\$91,075	\$59,006	\$116,160	\$786,669	\$1,210
7 Ductwork & Stack											
7.3	Ductwork	\$0	\$749	\$521	\$0	\$1,270	\$222	\$0	\$224	\$1,716	\$3
7.4	Stack	\$8,817	\$0	\$5,124	\$0	\$13,941	\$2,440	\$0	\$2,457	\$18,838	\$29
7.5	Duct & Stack Foundations	\$0	\$210	\$249	\$0	\$460	\$80	\$0	\$108	\$648	\$1
	Subtotal	\$8,817	\$959	\$5,894	\$0	\$15,670	\$2,742	\$0	\$2,789	\$21,201	\$33
8 Steam Turbine & Accessories											
8.1	Steam Turbine Generator & Accessories	\$73,261	\$0	\$8,164	\$0	\$81,425	\$14,249	\$0	\$14,351	\$110,026	\$169
8.2	Steam Turbine Plant Auxiliaries	\$1,662	\$0	\$3,539	\$0	\$5,202	\$910	\$0	\$917	\$7,029	\$11
8.3	Condenser & Auxiliaries	\$10,948	\$0	\$3,715	\$0	\$14,662	\$2,566	\$0	\$2,584	\$19,813	\$30
8.4	Steam Piping	\$43,454	\$0	\$17,612	\$0	\$61,065	\$10,686	\$0	\$10,763	\$82,515	\$127
8.5	Turbine Generator Foundations	\$0	\$260	\$429	\$0	\$689	\$121	\$0	\$162	\$971	\$1
	Subtotal	\$129,325	\$260	\$33,459	\$0	\$163,043	\$28,533	\$0	\$28,777	\$220,353	\$339
9 Cooling Water System											
9.1	Cooling Towers	\$19,487	\$0	\$6,027	\$0	\$25,514	\$4,465	\$0	\$4,497	\$34,475	\$53
9.2	Circulating Water Pumps	\$2,751	\$0	\$202	\$0	\$2,953	\$517	\$0	\$520	\$3,990	\$6
9.3	Circulating Water System Auxiliaries	\$16,259	\$0	\$2,145	\$0	\$18,405	\$3,221	\$0	\$3,244	\$24,869	\$38
9.4	Circulating Water Piping	\$0	\$7,516	\$6,807	\$0	\$14,323	\$2,507	\$0	\$2,524	\$19,354	\$30

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B12B.95	– SC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
9.5	Make-up Water System	\$1,254	\$0	\$1,611	\$0	\$2,866	\$502	\$0	\$505	\$3,873	\$6
9.6	Component Cooling Water System	\$1,171	\$0	\$898	\$0	\$2,070	\$362	\$0	\$365	\$2,797	\$4
9.7	Circulating Water System Foundations	\$0	\$700	\$1,163	\$0	\$1,863	\$326	\$0	\$438	\$2,627	\$4
	Subtotal	\$40,923	\$8,217	\$18,854	\$0	\$67,993	\$11,899	\$0	\$12,093	\$91,986	\$141
10 Ash & Spent Sorbent Handling Systems											
10.6	Ash Storage Silos	\$1,179	\$0	\$3,607	\$0	\$4,787	\$838	\$0	\$844	\$6,468	\$10
10.7	Ash Transport & Feed Equipment	\$4,010	\$0	\$3,976	\$0	\$7,985	\$1,397	\$0	\$1,407	\$10,790	\$17
10.9	Ash/Spent Sorbent Foundation	\$0	\$820	\$1,009	\$0	\$1,829	\$320	\$0	\$430	\$2,579	\$4
	Subtotal	\$5,189	\$820	\$8,592	\$0	\$14,601	\$2,555	\$0	\$2,681	\$19,837	\$31
11 Accessory Electric Plant											
11.1	Generator Equipment	\$2,668	\$0	\$2,013	\$0	\$4,681	\$819	\$0	\$825	\$6,326	\$10
11.2	Station Service Equipment	\$7,657	\$0	\$657	\$0	\$8,313	\$1,455	\$0	\$1,465	\$11,233	\$17
11.3	Switchgear & Motor Control	\$11,886	\$0	\$2,062	\$0	\$13,948	\$2,441	\$0	\$2,458	\$18,847	\$29
11.4	Conduit & Cable Tray	\$0	\$1,545	\$4,453	\$0	\$5,998	\$1,050	\$0	\$1,057	\$8,105	\$12
11.5	Wire & Cable	\$0	\$4,092	\$7,314	\$0	\$11,406	\$1,996	\$0	\$2,010	\$15,413	\$24
11.6	Protective Equipment	\$55	\$0	\$191	\$0	\$246	\$43	\$0	\$43	\$332	\$1
11.7	Standby Equipment	\$826	\$0	\$762	\$0	\$1,588	\$278	\$0	\$280	\$2,146	\$3
11.8	Main Power Transformers	\$7,001	\$0	\$143	\$0	\$7,144	\$1,250	\$0	\$1,259	\$9,653	\$15
11.9	Electrical Foundations	\$0	\$222	\$566	\$0	\$788	\$138	\$0	\$185	\$1,111	\$2
	Subtotal	\$30,092	\$5,860	\$18,161	\$0	\$54,112	\$9,470	\$0	\$9,584	\$73,166	\$113
12 Instrumentation & Control											
12.1	Pulverized Coal Boiler Control Equipment	\$808	\$0	\$144	\$0	\$952	\$167	\$0	\$168	\$1,286	\$2
12.3	Steam Turbine Control Equipment	\$723	\$0	\$81	\$0	\$804	\$141	\$0	\$142	\$1,087	\$2
12.5	Signal Processing Equipment	\$917	\$0	\$163	\$0	\$1,080	\$189	\$0	\$190	\$1,460	\$2
12.6	Control Boards, Panels & Racks	\$280	\$0	\$171	\$0	\$452	\$79	\$23	\$83	\$636	\$1
12.7	Distributed Control System Equipment	\$7,912	\$0	\$1,411	\$0	\$9,322	\$1,631	\$466	\$1,713	\$13,133	\$20
12.8	Instrument Wiring & Tubing	\$554	\$443	\$1,773	\$0	\$2,770	\$485	\$138	\$509	\$3,902	\$6
12.9	Other Instrumentation & Controls Equipment	\$681	\$0	\$1,577	\$0	\$2,258	\$395	\$113	\$415	\$3,181	\$5
	Subtotal	\$11,875	\$443	\$5,320	\$0	\$17,638	\$3,087	\$740	\$3,220	\$24,684	\$38
13 Improvements to Site											
13.1	Site Preparation	\$0	\$464	\$9,840	\$0	\$10,303	\$1,803	\$0	\$2,421	\$14,527	\$22
13.2	Site Improvements	\$0	\$2,291	\$3,028	\$0	\$5,320	\$931	\$0	\$1,250	\$7,501	\$12
13.3	Site Facilities	\$2,618	\$0	\$2,747	\$0	\$5,365	\$939	\$0	\$1,261	\$7,565	\$12
	Subtotal	\$2,618	\$2,755	\$15,614	\$0	\$20,988	\$3,673	\$0	\$4,932	\$29,593	\$46
14 Buildings & Structures											
14.2	Boiler Building	\$0	\$11,598	\$10,193	\$0	\$21,791	\$3,813	\$0	\$3,841	\$29,445	\$45
14.3	Steam Turbine Building	\$0	\$16,121	\$15,014	\$0	\$31,136	\$5,449	\$0	\$5,488	\$42,072	\$65

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B12B.95	– SC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
14.4	Administration Building	\$0	\$1,047	\$1,107	\$0	\$2,154	\$377	\$0	\$380	\$2,911	\$4
14.5	Circulation Water Pumphouse	\$0	\$187	\$148	\$0	\$335	\$59	\$0	\$59	\$452	\$1
14.6	Water Treatment Buildings	\$0	\$466	\$424	\$0	\$890	\$156	\$0	\$157	\$1,202	\$2
14.7	Machine Shop	\$0	\$553	\$371	\$0	\$923	\$162	\$0	\$163	\$1,247	\$2
14.8	Warehouse	\$0	\$416	\$416	\$0	\$832	\$146	\$0	\$147	\$1,124	\$2
14.9	Other Buildings & Structures	\$0	\$290	\$247	\$0	\$537	\$94	\$0	\$95	\$726	\$1
14.10	Waste Treating Building & Structures	\$0	\$643	\$1,947	\$0	\$2,590	\$453	\$0	\$456	\$3,500	\$5
	Subtotal	\$0	\$31,320	\$29,868	\$0	\$61,188	\$10,708	\$0	\$10,784	\$82,680	\$127
	Total	\$936,275	\$139,978	\$547,710	\$0	\$1,623,963	\$284,193	\$59,746	\$317,330	\$2,285,232	\$3,514

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-105. Case B12B.95 owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$13,617	\$21
1 Month Maintenance Materials	\$2,151	\$3
1 Month Non-Fuel Consumables	\$3,281	\$5
1 Month Waste Disposal	\$955	\$1
25% of 1 Months Fuel Cost at 100% CF	\$2,891	\$4
2% of TPC	\$45,705	\$70
Total	\$68,599	\$105
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	\$28,896	\$44
0.5% of TPC (spare parts)	\$11,426	\$18
Total	\$40,323	\$62
Other Costs		
Initial Cost for Catalyst and Chemicals	\$2,640	\$4
Land	\$900	\$1
Other Owner's Costs	\$342,785	\$527
Financing Costs	\$61,701	\$95
Total Overnight Costs (TOC)	\$2,802,179	\$4,309
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	\$3,234,869	\$4,974

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-106. Case B12B.95 initial and annual operating and maintenance costs

Case:	B12B.95	– SC PC w/ CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):	10,938	Capacity Factor (%):	85	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	% of base	Operator:	11.3	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	2.0	
				Total:	16.3	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$7,161,008	\$11.011
Maintenance Labor:					\$14,625,483	\$22.489
Administrative & Support Labor:					\$5,446,623	\$8.375
Property Taxes and Insurance:					\$45,704,636	\$70.279
Total:					\$72,937,750	\$112.155
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$21,938,225	\$4.53048
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	6,851	\$1.90	\$0	\$4,038,594	\$0.83401
Makeup and Waste Water Treatment Chemicals (ton):	0	20.4	\$550.00	\$0	\$3,482,485	\$0.71917
Brominated Activated Carbon (ton):	0	1.60	\$1,600.00	\$0	\$794,679	\$0.16411
Enhanced Hydrated Lime (ton):	0	40.3	\$240.00	\$0	\$2,999,210	\$0.61937
Limestone (ton):	0	708	\$22.00	\$0	\$4,831,035	\$0.99766
Ammonia (19 wt%, ton):	0	70.0	\$300.00	\$0	\$6,512,325	\$1.34487
SCR Catalyst (ft ³):	17,602	16.1	\$150.00	\$2,640,243	\$748,069	\$0.15448
CO ₂ Capture System Chemicals ^A :			Proprietary		\$8,707,451	\$1.79818
Triethylene Glycol (gal):	w/equip.	639	\$6.80	\$0	\$1,347,996	\$0.27838
Subtotal:				\$2,640,243	\$33,461,844	\$6.91024
Waste Disposal						
Fly Ash (ton):	0	664	\$38.00	\$0	\$7,828,493	\$1.61667
Bottom Ash (ton):	0	147	\$38.00	\$0	\$1,738,927	\$0.35911
SCR Catalyst (ft ³):	0	16.1	\$2.50	\$0	\$12,468	\$0.00257
Triethylene Glycol (gal):	0	639	\$0.35	\$0	\$69,382	\$0.01433
Thermal Reclaimer Unit Waste (ton):	0	7.94	\$38.00	\$0	\$93,642	\$0.01934
Subtotal:				\$0	\$9,742,912	\$2.01202
By-Products						
Gypsum (ton):	0	1,076	\$0.00	\$0	\$0	\$0.00000
Subtotal:				\$0	\$0	\$0.00000
Variable Operating Costs Total:				\$2,640,243	\$65,142,981	\$13.45274
Fuel Cost						
Illinois Number 6 (ton):	0	7,317	\$51.96	\$0	\$117,948,116	\$24.35758
Total:				\$0	\$117,948,116	\$24.35758

^ACO₂ Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit 4-107. Case B12B.95 LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	47.3	43%
Fixed	15.1	14%
Variable	13.5	12%
Fuel	24.4	22%
Total (Excluding T&S)	100.1	N/A
CO ₂ T&S	9.5	9%
Total (Including T&S)	109.7	N/A

4.4 PC CASE SUMMARY

The performance and cost results of the six PC plant configurations are summarized in Exhibit 4-108.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-108. Estimated performance and cost results for PC cases

Pulverized Coal Boiler						
	SubC PC			SC PC		
Case	B11A	B11B.90	B11B.95	B12A	B12B.90	B12B.95
PERFORMANCE						
CO ₂ Capture Rate (%)	0	90	95	0	90	95
Capacity Factor (%)	85	85	85	85	85	85
Gross Power Output (MWe)	688	769	774	686	763	768
Auxiliary Power Requirement (MWe)	38	118	124	36	113	118
Net Power Output (MWe)	650	650	650	650	650	650
Coal Flow Rate (lb/hr)	493,115	630,940	640,819	473,055	600,801	609,741
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A
HHV Thermal Input (kW _t)	1,685,945	2,157,162	2,190,938	1,617,359	2,054,118	2,084,684
Net Plant HHV Efficiency (%)	38.6	30.2	29.7	40.2	31.7	31.2
Net Plant HHV Heat Rate (Btu/kWh)	8,849	11,317	11,495	8,490	10,778	10,938
Raw Water Withdrawal (gpm/MWnet)	10.0	15.3	15.7	9.3	14.3	14.6
Process Water Discharge (gpm/MWnet)	2.1	3.9	4.0	1.9	3.7	3.8
Raw Water Consumption (gpm/MWnet)	8.0	11.4	11.7	7.4	10.6	10.9
CO ₂ Emissions (lb/MMBtu)	202	20	10	202	20	10
CO ₂ Emissions (lb/MWh-gross)	1,693	195	98	1,628	187	94
CO ₂ Emissions (lb/MWh-net)	1,790	230	117	1,718	219	111
SO ₂ Emissions (lb/MMBtu)	0.081	0.000	0.000	0.081	0.000	0.000
SO ₂ Emissions (lb/MWh-gross)	0.675	0.000	0.000	0.649	0.000	0.000
NO _x Emissions (lb/MMBtu)	0.084	0.073	0.072	0.087	0.076	0.076
NO _x Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.700	0.700
PM Emissions (lb/MMBtu)	0.011	0.009	0.009	0.011	0.010	0.010
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.090	0.090
Hg Emissions (lb/TBtu)	0.359	0.313	0.311	0.373	0.326	0.324

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Pulverized Coal Boiler						
	SubC PC			SC PC		
Case	B11A	B11B.90	B11B.95	B12A	B12B.90	B12B.95
Hg Emissions (lb/MWh-gross)	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06
COST						
Total Plant Cost (2018\$/kW)	2,015	3,393	3,458	2,103	3,452	3,514
<i>Bare Erected Cost</i>	1,486	2,408	2,453	1,551	2,455	2,497
<i>Home Office Expenses</i>	260	421	429	271	430	437
<i>Project Contingency</i>	270	472	482	281	479	488
<i>Process Contingency</i>	0	91	95	0	88	92
Total Overnight Cost (2018\$/MM)	1,615	2,709	2,761	1,683	2,752	2,802
Total Overnight Cost (2018\$/kW)	2,484	4,165	4,245	2,588	4,233	4,309
<i>Owner's Costs</i>	468	772	787	485	781	795
Total As-Spent Cost (2018\$/kW)	2,867	4,808	4,900	2,988	4,886	4,974
LCOE (\$/MWh) (excluding T&S) ^A	64.0	99.1	100.9	64.5	98.4	100.1
<i>Capital Costs</i>	27.2	45.7	46.6	28.4	46.4	47.3
<i>Fixed Costs</i>	9.2	14.6	14.9	9.5	14.8	15.1
<i>Variable Costs</i>	7.9	13.6	13.9	7.7	13.2	13.5
<i>Fuel Costs</i>	19.7	25.2	25.6	18.9	24.0	24.4
LCOE (\$/MWh) (including T&S) ^A	64.0	108.4	110.9	64.5	107.3	109.7
<i>CO₂ T&S Costs</i>	N/A	9.3	10.0	N/A	8.9	9.5
Cost of CO ₂ Captured (ex. T&S), \$/tonne ^B	N/A	37.0	36.3	N/A	38.1	37.3
Cost of CO ₂ Avoided (incl. T&S), \$/tonne ^B	N/A	65.0	63.9	N/A	63.0	61.9

^AVarying incentives, such as tax credits, could impact the economics of the system

^BBoth the cost of CO₂ captured and cost of CO₂ avoided were calculated based on the non-capture SC PC Case B12A for all coal cases

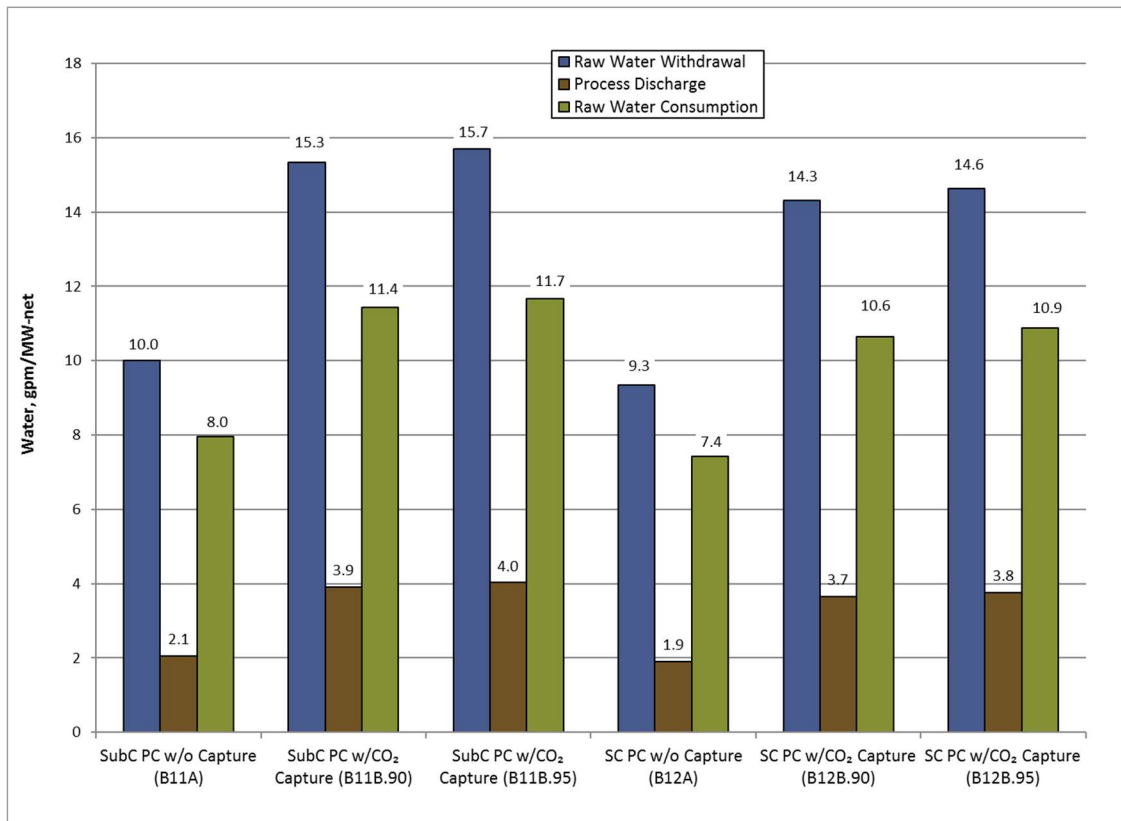
The following observations can be made regarding plant performance:

- The addition of CO₂ capture and compression, comparing cases B11A and B11B.90, results in an HHV efficiency penalty of 8.4 percentage points (21.8 percent relative to non-capture) in the SubC PC case. For the SC PC cases, the addition of 90 percent capture results in an HHV efficiency penalty of 8.5 percentage points (21.2 percent relative to non-capture). The efficiency is negatively impacted by the large auxiliary loads of the capture process and CO₂ compression, as well as the large increase in cooling water requirement, which increases the CWP and cooling tower fan auxiliary loads. The auxiliary load increases by 81 MW in the SubC PC case and by 77 MW in the SC PC case. In addition to the negative impact of the auxiliary load increase, steam is extracted prior to the LP section of the steam cycle for CO₂ capture solvent regeneration. The use of this steam in the reboiler, rather than passing through the LP steam turbine section and generating power, also contributes to the efficiency penalty.
- The addition of higher CO₂ capture rates, comparing B11B.90 and B11B.95, results in an HHV efficiency penalty of 0.5 percentage points (1.6 percent relative to B11B.90). For the SC PC cases, between B12B.90 and B12B.95 cases results in an HHV efficiency penalty of 0.5 percentage points (1.5 percent relative to B12B.90). The auxiliary load increases by 6 MW between cases B11B.90 and B11B.95 and by 5 MW between cases B12B.90 and B12B.95.
- Since the PC cases utilize a wet FGD system, SO₂ emissions could be used as a surrogate for HCl. [33] Provided the SO₂ emissions limit is not exceeded, it can be assumed per the MATS regulation that the HCl emissions limit is also satisfied.
- The SO₂ emissions for non-capture cases are nearly identical, with the SubC PC emissions being higher than SC when normalized by gross output because of the lower HHV efficiency. The CO₂ capture process polishing scrubber and absorber vessel result in negligible SO₂ emissions in CO₂ capture cases.
- Uncontrolled CO₂ emissions on a mass basis normalized by gross output are greater for SubC PC compared to SC because of the lower HHV efficiency.

For the PC cases in this study, the FGD wastewater blowdown flow rate range to be treated by the SDE spans 55–75 gpm. The approximate performance impact of implementing the SDE across the six PC cases is a 0.25–0.27 percentage point (absolute) decrease in the HHV net plant efficiency. This is due primarily to the diversion of warm flue gas away from the air preheater and to the evaporator, with an additional minor impact resulting from the small auxiliary load required by the SDE.

The normalized water withdrawal, process discharge and raw water consumption are shown in Exhibit 4-109 for each of the PC cases.

Exhibit 4-109. Raw water withdrawal and consumption in PC cases



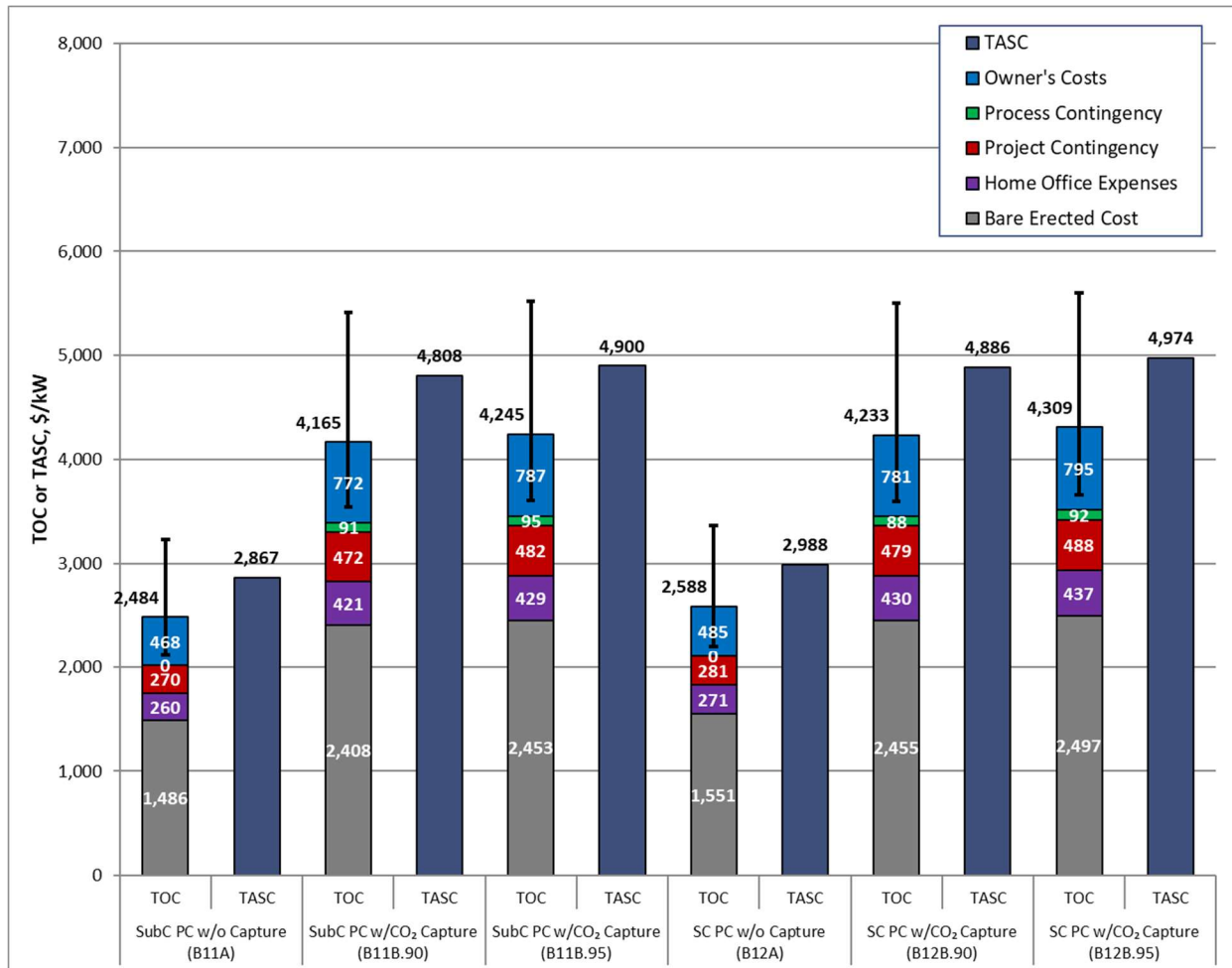
Raw water consumption for all cases is dominated by cooling tower makeup requirements, which accounts for about 86–88 percent of raw water in non-capture cases and 99 percent in CO₂ capture cases. The amount of raw water consumption in the CO₂ capture cases is greatly increased by the cooling water requirements of the capture process. Cooling water is required to:

- Reduce the flue gas temperature from 57°C (135°F) (FGD exit temperature) to 31°C (87°F) (CO₂ absorber operating temperature), which also requires condensing water from the flue gas that comes saturated from the FGD unit
- Remove the heat input by the stripping steam to cool the solvent
- Remove heat of CO₂ absorption through absorber tower intercoolers
- Remove the heat input from the auxiliary electric loads
- Remove heat in the CO₂ compressor intercoolers
- Cool the CO₂ product stream exiting the CO₂ compressor to the target specification of 30°C (86°F)

In the CO₂ capture cases, additional water is recovered from the flue gas as it is cooled to the absorber temperature. A portion of this water is used as FGD makeup, and the remainder is discharged.

The components of TOC and TASC are shown for each PC case in Exhibit 4-110.

Exhibit 4-110. Plant capital cost for PC cases



The PC capital cost estimate accuracy provides an AACE Class 4 range of -15 percent/+30 percent. The error bars included in Exhibit 4-110 represent the potential TOC range relative to the maximum and minimum of the capital cost uncertainty range.

The following observations about normalized TOC (\$/kW) can be made:

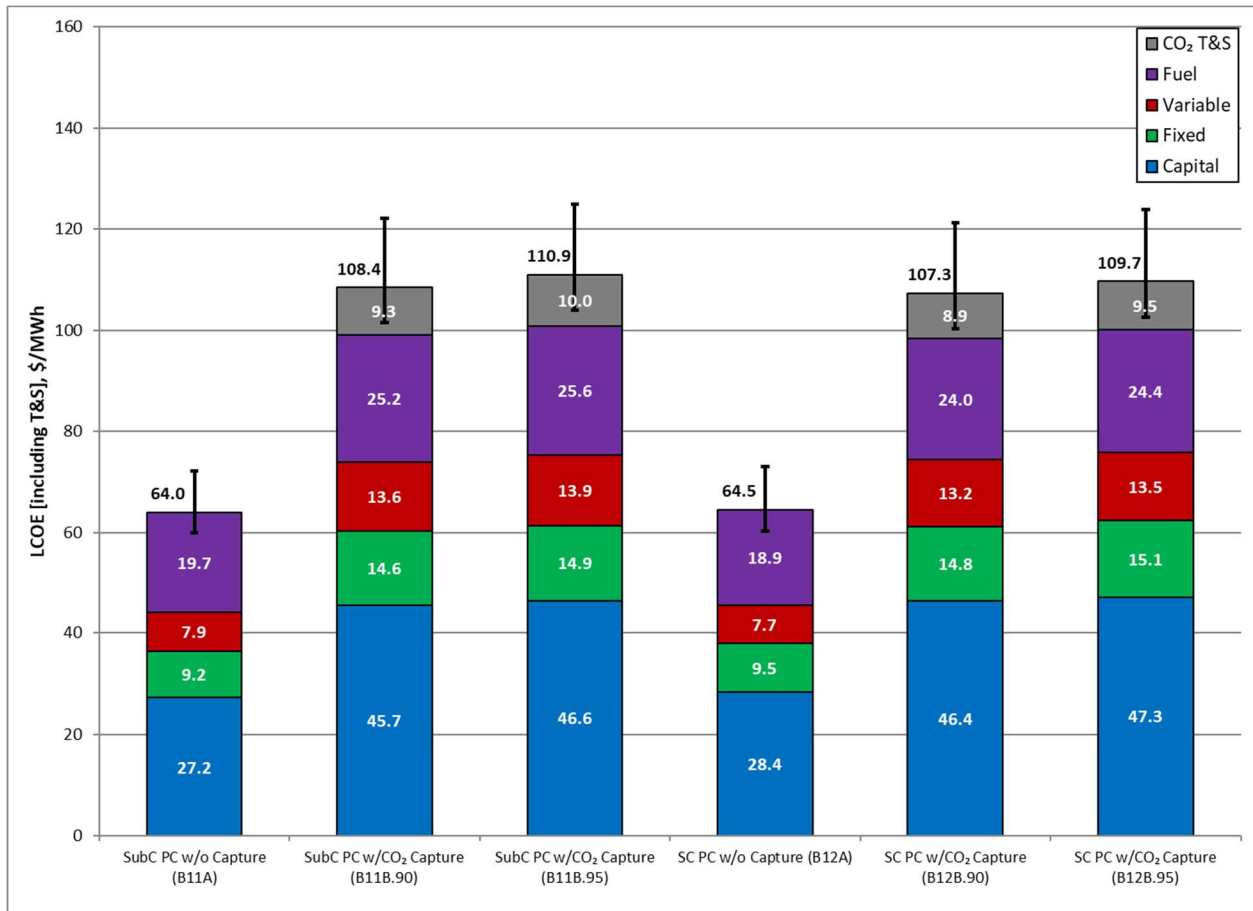
- The TOC of the non-capture SC PC case is approximately 4.2 percent greater than non-capture SubC PC. The TOC of SC PC with 90 percent CO₂ capture is approximately 1.6 percent greater than SubC PC with CO₂ capture. The TOC of SC PC with 95 percent CO₂ capture is approximately 1.5 percent greater than SubC PC with CO₂ capture.
- The TOC penalty for adding 90 percent CO₂ capture in the SubC case is 68 percent and is 64 percent in the SC case. The TOC penalty for adding 95 percent CO₂ capture in the SubC case is 71 percent and is 66 percent in the SC case. In addition to the high cost of the capture process, there is a significant increase in the cost of the cooling towers and CWPs in the CO₂ capture cases because of the larger cooling water demand discussed

previously. Also, the gross output of the PC plants increases by 81 MW (SubC) and 77 MW (SC) with the addition of 90 percent CO₂ capture to maintain the net output at 650 MW. For 95 percent capture, the gross power increases by 87 MW (SubC) and 82 MW (SC). The increased gross output results in higher coal flow rate and consequently higher costs for all cost accounts in the estimate.

- Comparing the 90 percent capture cases from Revision 4a to Revision 4, the TOC decreased 9.5 percent for case B11B.90. For case B12B.90, the TOC decreased by 9.0 percent. This decrease in TOC is largely due to the significant reduction in cost of the capture system from the revised 2021 quote.
 - In addition, due to this significant cost reduction, the TOC for the Revision 4a 95 percent SubPC capture case is 7.8 percent less than the TOC for the Revision 4 90 percent SubPC capture case. The TOC for the Revision 4a 95 percent SCPC capture case is 7.4 percent less than the TOC for the Revision 4 90 percent SCPC capture case.

The LCOE is shown for the six PC cases in Exhibit 4-111 (including T&S in the capture cases).

Exhibit 4-111. LCOE for PC cases



Note: Financial assumptions are presented in NETL's "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance" [4]

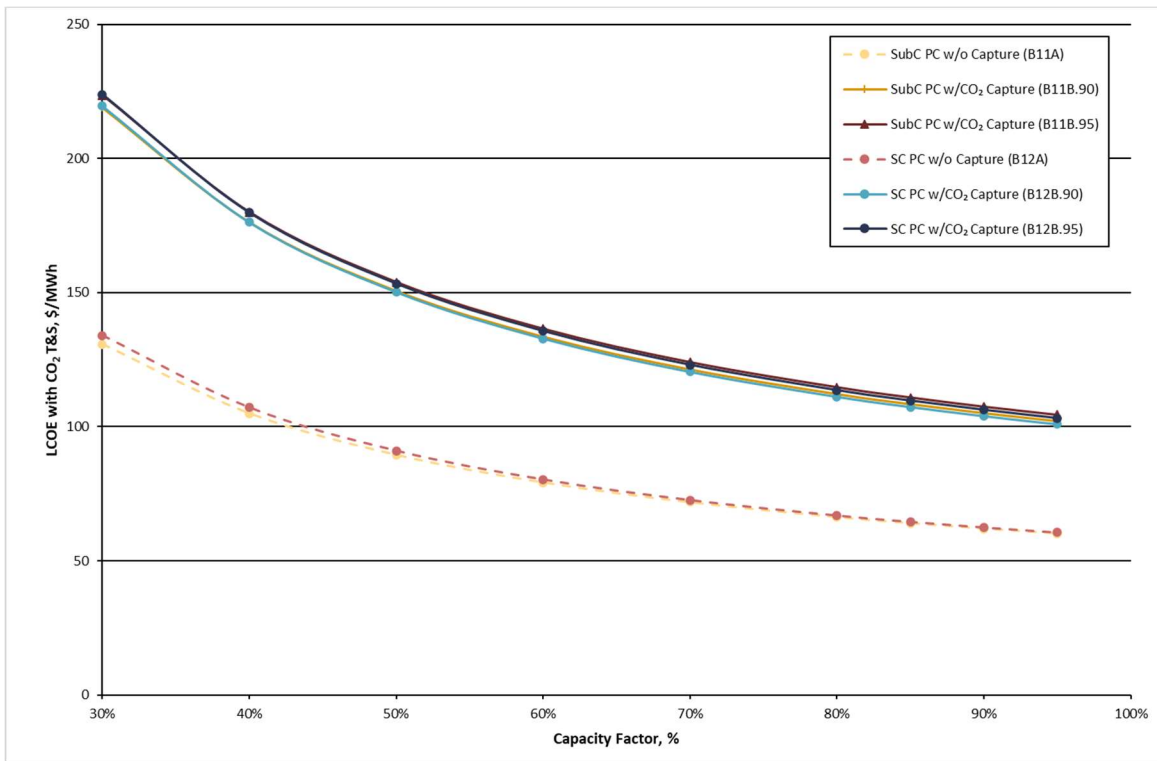
Similar to Exhibit 4-110, the error bars included in Exhibit 4-111 represent the potential LCOE range relative to the maximum and minimum capital cost uncertainty ranges. The LCOE ranges presented are not reflective of other changes, such as variation in fuel price, labor price, CF, or other factors. As an example, if Case B11B.90's capital costs were determined to be at the high end of the uncertainty range (+30 percent), then the LCOE result would be \$122.1/MWh. Conversely, if at the low end of the uncertainty range (-15 percent), the LCOE result would be \$101.6/MWh.

The following observations can be made:

- Capital costs represent the largest fraction of LCOE in all cases. Fuel cost is the second largest component of LCOE, and capital charges and fuel costs combined represent 65 to 73 percent of the total, including CO₂ T&S, in all cases.
- In the non-capture cases, the slight increase in capital cost in the SC case is almost offset by the efficiency gain so that the LCOE for SC PC is only approximately 0.8 percent more than SubC despite having more than a 4 percent greater TOC.
- The delta between the LCOE of the non-capture SubC PC case and the non-capture SC PC case is well within the limits of the study accuracy. The same is true of the two CO₂ capture cases.
- The addition of higher CO₂ capture rates to the SubC PC cases results in an LCOE penalty of \$2.5/MWh (2.3 percent) in Case B11B.95, compared to Case B11B.90. For the SCPC cases, the addition of higher CO₂ capture rates results in an LCOE penalty of \$2.3/MWh (2.2 percent) in Case B12B.95, compared to Case B12B.90.
- Due to the cost reductions from the revised 2021 quote, when comparing the 90 percent capture cases from Revision 4a to Revision 4, the LCOE decreased 6.3 percent for case B11B.90. For case B12B.90, the LCOE decreased by 6.1 percent.
 - In addition, the LCOE for the Revision 4a 95 percent SubC PC capture case is 4.2 percent less than the LCOE for the Revision 4 90 percent SubC PC capture case. The LCOE for the Revision 4a 95 percent SC PC capture case is 4.0 percent less than the LCOE for the Revision 4 90 percent SC PC capture case.

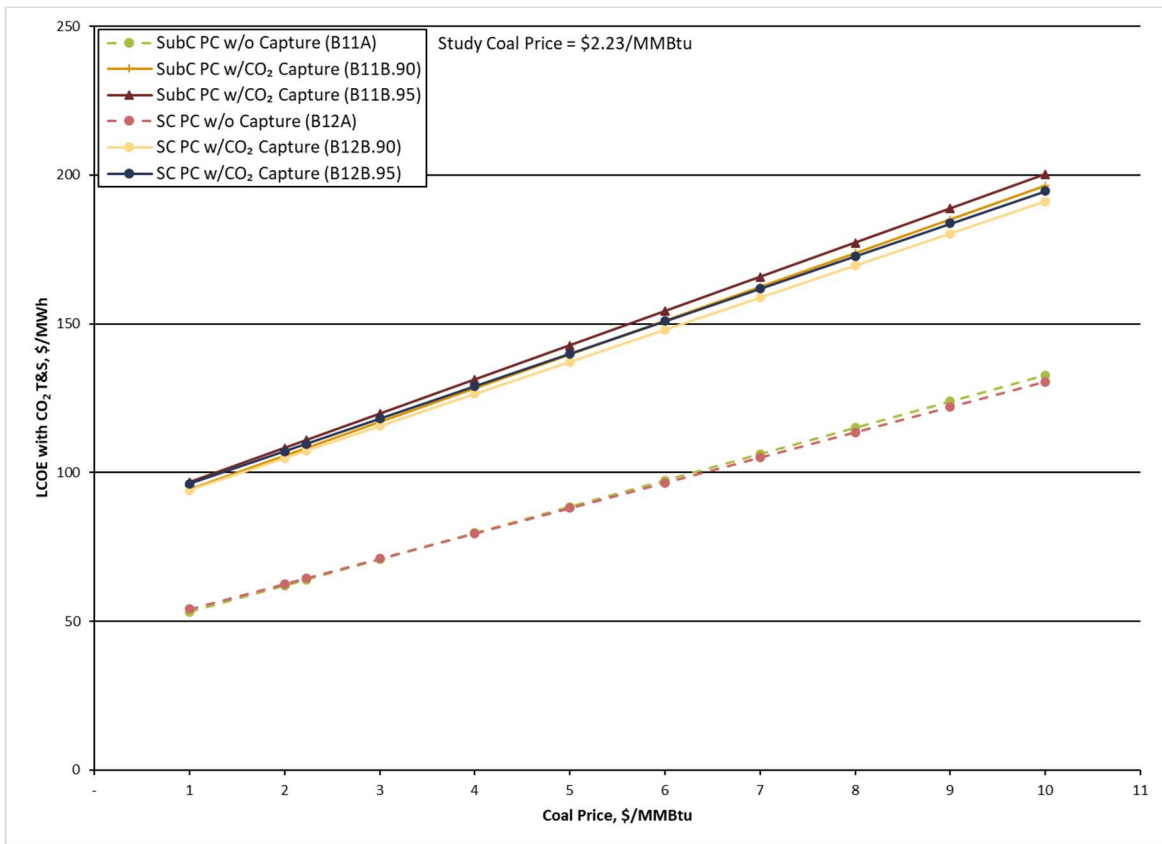
The sensitivity of LCOE to CF is shown in Exhibit 4-112. Implicit in the curves is the assumption that a CF of greater than 85 percent can be achieved without the expenditure of additional capital and capacity factors less than 85 percent don't result in lower capital or operating costs. The SubC and SC cases are nearly identical making it difficult to distinguish between the two lines. The LCOE increases slightly more rapidly at low CF because the relatively high capital component is spread over fewer kWh of generation.

Exhibit 4-112. Sensitivity of LCOE to capacity factor for PC cases



The sensitivity of LCOE to fuel costs for the PC cases is shown in Exhibit 4-113. A tripling of coal price from \$2.11/GJ to \$6.34/GJ (\$2.23/MMBtu to \$6.69/MMBtu) results in an approximate LCOE increase of about 59-62 percent in the non-capture cases and 45-47 percent in the CO₂ capture cases.

Exhibit 4-113. Sensitivity of LCOE to coal price for PC cases



As presented in Section 2.7.4, the cost of CO₂ captured and cost of CO₂ avoided were calculated and the results for the PC CO₂ capture cases—using SC PC as the non-capture reference case (Case B12A)—are shown in Exhibit 4-114 and Exhibit 4-115. The costs are nearly identical for the SubC and SC PC cases.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-114. Breakdown of Cost of CO₂ Captured in PC cases

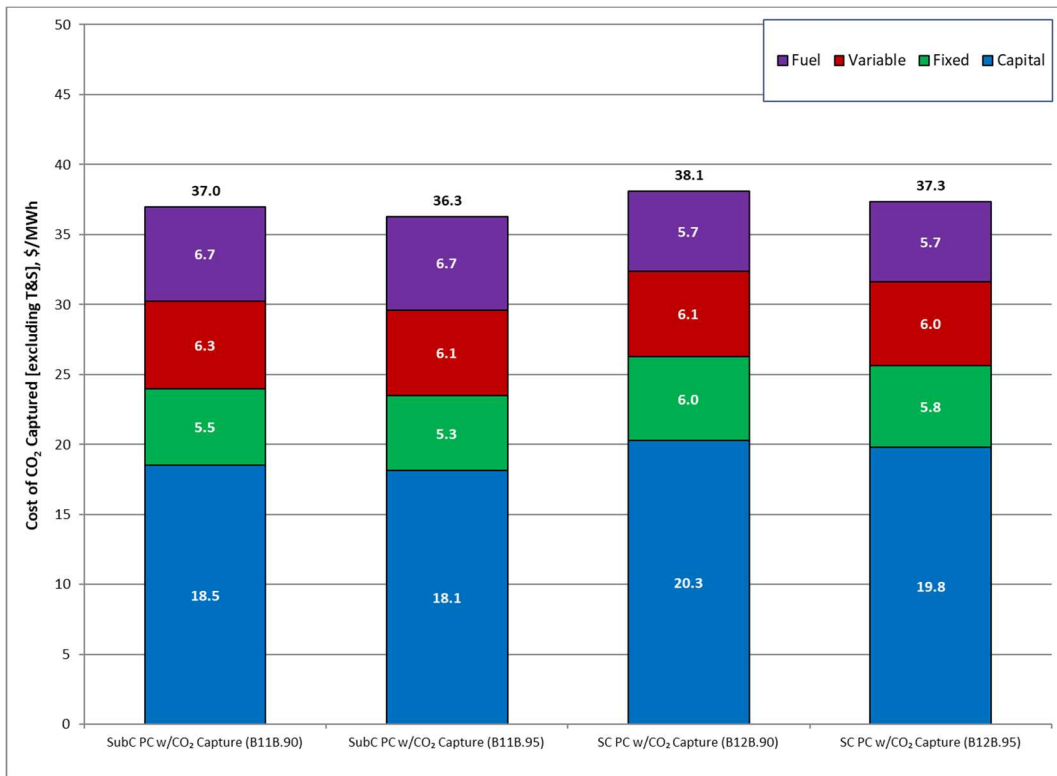
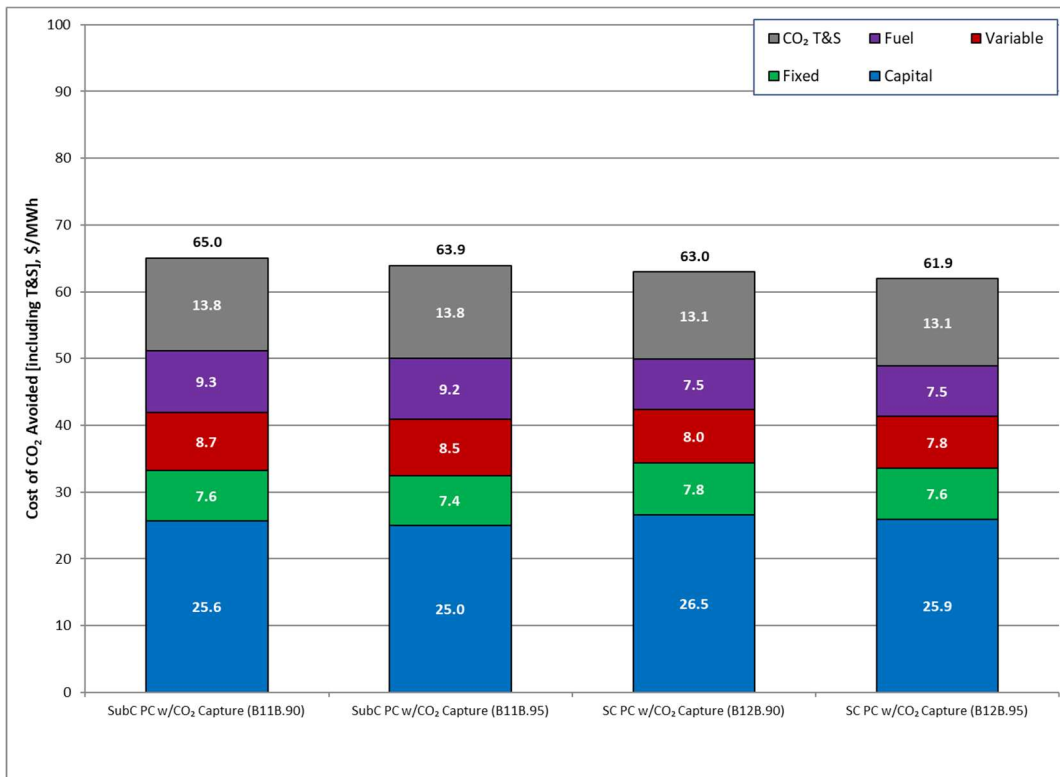


Exhibit 4-115. Breakdown of Cost of CO₂ Avoided in PC cases



The following observations can be made:

- Comparing the 90 percent capture cases from Revision 4a to Revision 4, the cost of CO₂ captured decreased 17 percent for case B11B.90. For case B12B.90, the cost of CO₂ captured decreased by 17 percent. The cost of CO₂ avoided decreased 15 percent for case B11B.90. For case B12B.90, the cost of CO₂ avoided decreased by 14 percent.

NATURAL GAS COMBINED CYCLE PLANTS

5 NATURAL GAS COMBINED CYCLE PLANTS

Six NGCC power plant configurations were evaluated and are presented in this section. Each design is based on a market-ready technology that is assumed to be commercially available at the time the project commences. Each design consists of two state-of-the-art (either 2017 F-class or H-class) CTGs, two HRSGs, and one STG in a multi-shaft 2x2x1 configuration.

The NGCC cases are evaluated with and without CO₂ capture on a common thermal input basis. The NGCC designs that include CDR have a smaller plant net output resulting from the additional CDR facility and CO₂ compressors auxiliary loads. The gross output of the NGCC cases was largely governed by the characteristic output of the commercially available CT. Hence, evaluation of the NGCC designs on a common net output basis for capture and non-capture cases was not practicable.

The Rankine cycle portion of uses a single reheat 16.5 MPa/585°C/584°C (2,393 psia/1,085°F/1,084°F) SubC steam cycle for F-class cases and 18.5 MPa/585°C/562°C (2,683 psia/1,085°F/1,044°F) SubC steam cycle for H-class cases. A more aggressive steam cycle was considered but not chosen because there are very few HRSGs in operation that would support such conditions and doing so would have limited the applicability of the NGCC plant cases in the marketplace. [113]

5.1 NGCC PROCESS AREAS

The six NGCC cases are nearly identical in configuration with the exception that Case B31A and B32A do not include CO₂ capture whereas the remainder do. The process areas that are common to the two plant configurations are presented in this section.

5.1.1 Natural Gas Supply System

It was assumed that a natural gas main with adequate capacity is near to the site fence line (within 16 km [10 mi]) and that a suitable right-of-way is available to install a branch line to the site. For the purposes of this report, it was also assumed that the gas will be delivered to the plant custody transfer point at sufficient pressure such that natural gas is available at the turbine inlet at either 2.9 MPa (415 psig) and 27°C (80°F), which matches the state-of-the-art 2017 F-class fuel system requirements or 3.8 MPa (550 psig) and 27°C (80°F), which matches the state-of-the-art 2018 H-class fuel system requirements. Hence, neither a pressure reducing station, nor a fuel booster compressor is required. It is further assumed that the cost of the natural gas remains constant at either pressure to help maintain consistency across cases. In reality one may require a pressure let down or booster, impacting the price of natural gas at the turbine inlet. A sensitivity to natural gas price is included later which covers both fluctuations in natural gas price and the deviation described above.

As discussed in Section 2.3, it was assumed that the natural gas has an added mercaptan composition of 5.75×10^{-6} mol%. [23]

A new gas metering station is assumed to be added on the site, adjacent to the new CT. The meter may be of the rate-of-flow type, with input to the plant computer for summing and recording or may be of the positive displacement type. In either case, a complete timeline record of gas consumption rates and cumulative consumption is provided.

5.1.2 Combustion Turbine

The combined cycle plant is based on two CTGs. The CTGs are representative of state-of-the-art 2017 F-class and 2017 H-class turbines with ISO base ratings of 238 MW and 343 MW, respectively, when firing natural gas. [34] These machines are an axial flow, single spool, constant speed unit, with variable IGVs, and dry low NOx combustion system.

Each CTG is provided with inlet air filtration systems, inlet silencers, lube and control oil systems including cooling, electric motor starting systems, acoustical enclosures including heating and ventilation, control systems including supervisory, fire protection, and fuel systems. No back up fuel was envisioned for these cases.

The CTG is typically supplied in several fully shop-fabricated modules, complete with all mechanical, electrical, and control systems required for CTG operation. Site CTG installation involves module interconnection and linking CTG modules to the plant systems. The CTG package scope of supply for combined cycle application, while project specific, does not vary much from project-to-project. A typical scope of supply is presented in Exhibit 5-1.

Exhibit 5-1. Combustion turbine typical scope of supply

System	System Scope
ENGINE ASSEMBLY	Coupling to Generator, Water Mist Fire Protection System, Insulation Blankets, Platforms, Stairs and Ladders
ENGINE ASSEMBLY WITH BEDPLATE	Variable Inlet Guide Vane System, Compressor, Bleed System, Purge Air System, Bearing Seal Air System, Combustors, Turbine Rotor Cooler
WALK-IN ACOUSTICAL ENCLOSURE	HVAC, Lighting, and Water Mist Fire Protection System
MECHANICAL PACKAGE	HVAC, Lighting, Air Compressor for Pneumatic System, Fire Protection Systems
LUBRICATING OIL SYSTEM AND CONTROL OIL SYSTEM	Lube Oil Reservoir, Accumulators, 2x100% AC Driven Oil Pumps, DC Emergency Oil Pump with Starter, 2x100% Oil Coolers, Duplex Oil Filter, Oil Temperature and Pressure Control Valves, Oil Vapor Exhaust Fans and Demister, Oil Heaters, Oil Interconnect Piping (SS and CS), Oil System Instrumentation
ELECTRICAL PACKAGE	HVAC, Lighting, AC and DC Motor Control Centers, Generator Voltage Regulating Cabinet, Generator Protective Relay Cabinet, DC Distribution Panel, Battery Charger, Digital Control System with Local Control Panel (all control and monitoring functions as well as data logger and sequence of events recorder), Control System Valves and Instrumentation Communication link for interface with plant DCS Supervisory System, Bentley Nevada Vibration Monitoring System, FM-200 Fire Protection System, Cable Tray and Conduit, Provisions for Performance Testing including Test Ports, Thermowells, Instrumentation and DCS interface cards

System	System Scope
INLET AND EXHAUST SYSTEMS	Inlet Duct Trash Screens, Inlet Duct and Silencers, Self-Cleaning Filters, Hoist System for Filter Maintenance, Evaporative Cooler System, Exhaust Duct Expansion Joint, Inlet Silencer and Exhaust Acoustic Treatment, Pressure and Temperature Ports and Instrumentation
NG FUEL SYSTEM	Gas Valves Including Vent, Throttle and Trip Valves, Gas Filter/Separator, Gas Supply Instruments and Instrument Panel
STARTING SYSTEM	Enclosure, Static Start System, Turning Gear, and Clutch Assembly
GENERATOR	Static Exciter and Excitation Transformer, Line Termination Enclosure with CTs, VTs, Surge Arrestors, and Surge Capacitors, Neutral Cubicle with CT, Neutral Tie Bus, Grounding Transformer and Secondary Resistor, Generator Gas Dryer, Seal Oil System (including Defoaming Tank, Reservoir, Seal Oil Pump, Emergency Seal Oil Pump, Vapor Extractor, and Oil Mist Eliminator), Generator Auxiliaries Control Enclosure, Grounding System Connectors
GENERATOR COOLING	Hydrogen Cooling System (including H ₂ to Glycol and Glycol to Air Heat Exchangers, Liquid Level Detector Circulation System, Interconnecting Piping and Controls)
MISCELLANEOUS	Interconnecting Pipe, Wire, Tubing and Cable Instrument Air System Including Air Dryer On Line and Off Line Water Wash System LP CO ₂ Storage Tank Drain System Drain Tanks Coupling, Coupling Cover, and Associated Hardware

Electrical generators are provided with the CT package. The generators are assumed to be 18 kV, 3-phase, 60 Hz, constructed to meet American National Standards Institute (ANSI) and National Electrical Manufacturers Association (NEMA) standards for turbine-driven synchronous generators. The generator is H₂ cooled, complete with excitation system, cooling, and protective relaying.

5.1.2.1 Combustion Turbine Frame Comparison from Literature

The current combustion turbine market for natural gas applications offers multiple frame size options, supplied by several different OEMs. In general, the frame class (e.g., F-class) is delineated by combustion turbine output. Advanced-class combustion turbines, such as the H- or J-class will have higher outputs, and higher efficiencies, than the F-class. Exhibit 5-2 below compares parameter values for currently-offered F- and H-class combustion turbines, both for simple cycle and 2x1 combined cycle configurations. [131] [132] [133]

Exhibit 5-2. F- versus H-class combustion turbines

Parameter	F-Class	H-Class
Simple Cycle		
Combustion Turbine Net Output (Nominal), MW	243	384
Combustion Turbine Net Efficiency (LHV), %	39.8	42.6
Turbine Inlet Temperature, °F	2,300-2,600	>2,600
2x1 Combined Cycle Configuration		
Combined Cycle Net Output, MW	756	1,148
Combined Cycle Net Efficiency (LHV), %	60.4	63.6
Plant Turndown – Minimum Load, %	22.0	15.0

Parameter	F-Class	H-Class
Simple Cycle		
Ramp Rate, MW/min	80	120
Startup Time (RR Hot), min	25	<30

The H-class nominal net output, in a 2x1 combined cycle configuration, can offer approximately an additional 400 MW in net output, while also providing three or more additional net plant efficiency percentage points (absolute, LHV) as compared to the F-class. Flexible operation capabilities can also be enhanced for advanced class options.

As is stated throughout this report, the objective of the cases presented is to provide a consistent and transparent analysis methodology that is robust enough to allow for technology comparison on an equivalent basis. One of the mechanisms to facilitate comparison is to consider plants on a comparable net electrical output basis. The PC cases presented in Section 4 consider a fixed 650 MW net output. This was selected to maintain comparability with both NGCC cases (specifically F-frame NGCC with CO₂ capture), as well as IGCC cases. As discussed in Section 3.1.9.1 previously, there has been little development in syngas-capable combustion turbines; therefore, there is currently no offering that could increase IGCC net electrical output to meet the significantly higher output of the H-frame combustion turbine. Alternate configurations were considered (e.g., 1x1 combined cycle for NGCC; 3x1 combined cycle for IGCC), but it was determined that maintaining system configuration across report revisions provided an additional layer of consistency for technology comparison. Given the net electrical output comparison point, the F-frame was selected for inclusion in NGCC cases in FEBR4. As acknowledged in FEBR4, larger output, higher efficiency machines are deployed and currently operating in the market today, thus H-frame was also selected for inclusion in the NGCC cases. Future power projects may pursue additional larger/smaller/modular/flexible advanced combustion turbine technologies.

5.1.3 Heat Recovery Steam Generator

The HRSG is configured with HP, IP, and LP steam drums, and superheater, reheater, evaporator, and economizer sections. The HP drum is supplied with FW by the HP boiler feed pump to generate HP steam, which passes to the superheater section for heating to 585°C (1,085°F) in both F-frame and H-frame cases. The IP drum is supplied with FW by an interstage bleed from the HP boiler feed pump. The IP steam is mixed with the HP turbine exhaust before being reheated to 584°C (1,084°F) in F-frame cases and 562°C (1,044°F) in H-frame cases. The combined flows are admitted into the IP section of the steam turbine. The LP drum provides steam to the LP turbine.

The HRSG tubes typically comprise finned tubing. The high-temperature portions are type P91, P92, or P22 ferritic alloy material; the low-temperature portions (less than 399°C [750°F]) are CS. Each HRSG exhausts directly to the stack, which is fabricated from CS plate materials and epoxy coated. The stack for the NGCC cases is assumed to be 46 m (150 ft) high, and the cost is included in the HRSG account.

5.1.4 NO_x Control System

Two measures are taken to reduce the NO_x. The first is a DLN burner in the CTG. The DLN burners reduce the emissions to about 9 ppmvd [34] (assumed to be 100 percent NO and referenced to 15 percent O₂).

While state-of-the-art 2017 F-class and 2017 H-class CTs alone produce NO_x emissions below the limits described in Section 2.4.3.3, an SCR was included as a second measure to ensure the plant met EPA's PSD program by installing the BACT. The SCR unit cost accounts for less than 1 percent of the overall TPC for both capture and non-capture cases.

An SCR reactor uses NH₃ and a catalyst to reduce NO_x to N₂ and H₂O. The SCR system consists of a reactor, and NH₃ supply and storage system. The SCR system is designed for 90 percent reduction while firing natural gas. [35]

Operation Description – The SCR reactor is in the flue gas path inside the HRSG between the HP and IP sections. The SCR reactor is equipped with one catalyst layer consisting of catalyst modules stacked in line on a supporting structural frame. The SCR reactor has space for installation of an additional layer. NH₃ is injected into the gas immediately prior to it entering the SCR reactor. The NH₃ injection grid is arranged into several sections and consists of multiple pipes with nozzles. The NH₃ flow rate into each injection grid section is controlled considering imbalances in the flue gas flow distribution across the HRSG. The catalyst contained in the reactor greatly accelerates the reaction between the NH₃ and the NO_x in the gas. The catalyst consists of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. The optimum inlet flue gas temperature range for the catalyst is 260°C (500°F) to 371°C (700°F).

The NH₃ storage and injection system consists of unloading facilities, bulk storage tank, vaporizers, and dilution air skid.

5.1.5 Carbon Dioxide Recovery Facility

A CDR facility is used to remove CO₂ in the flue gas exiting the HRSG, purify it, and compress it to a SC condition. 90 percent of the CO₂ is removed in cases B31B.90 and B32B.90. 95 percent of the CO₂ is removed in Cases B31B.95 and B32B.95. It is assumed that all the carbon in the natural gas is converted to CO₂. The CDR facility comprises flue gas supply, direct contact cooler, CO₂ absorption, solvent stripping and reclaiming, and CO₂ compression and drying.

The CO₂ absorption/stripping/solvent reclamation process designed for NGCC cases, such as Case B31B.90, is based on the CANSOLV system, previously described in Section 4.1.8 for the PC-specific application, but with the following differences:

- No SO₂ polishing step is required in the NGCC case, as the pipeline natural gas sulfur content produces a flue gas with an SO₂ content below the concentration in the outlet of the pre-scrubber used in the PC cases.

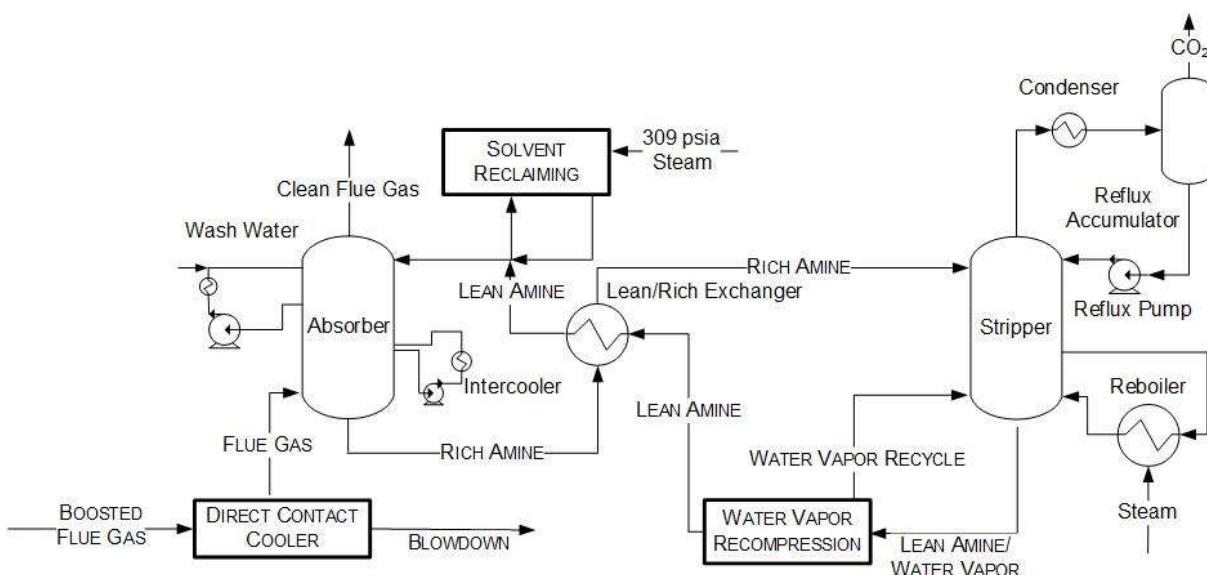
- For the steady-state case described here, the low-pressure steam requirement for the reboiler only is calculated as approximately 2.4 MJ/kg (1,050 Btu/lb) CO₂ for the CANSOLV process.

The design of the SC&T CANSOLV system used in the NGCC cases is based on revised data received in 2021. Changes from the SC&T CANSOLV system used in FEBR4 include:

- NGCC cases use the same solvent and process configuration as the PC cases.
- The NGCC cases no longer requires an ion exchanger reclaiming and now includes mechanical vapor recompression.

A diagram of the CANSOLV CO₂ capture process for the NGCC application is provided in Exhibit 5-3.

Exhibit 5-3. CANSOLV CO₂ capture process typical flow diagram for NGCC



Due to the larger volumetric flow rate in the quoted NGCC case compared to the PC cases (4.2 million m³/hr [148 million ft³/hr] in Case B31B.90 and 3.2 million m³/hr [112 million ft³/hr] in Case B12B.90) and the low CO₂ concentration (4.1 mol% in Case B31B.90 and 12.5 mol% in Case B12B.90), the natural gas case requires a CO₂ absorber approximately 2 times the volume of the coal cases. However, as a result of the lower CO₂ content, the CO₂ stripper used in Case B31B.90 is only 38 percent of the volume of the stripper used in Case B12B.90.

For H-class cases it was assumed that a single capture train would be possible, even given the larger volumetric flow rate at the absorber inlet (5.7 million m³/hr [200 million ft³/hr]).

The CANSOLV system in the NGCC case discharges CO₂ at the same temperature and pressure as that in the PC cases; as such, the enthalpy versus pressure operating profile presented for PC cases in Exhibit 4-12 in Section 4.1.9 is also representative of the CO₂ compressor for the NGCC case with capture.

5.1.6 Steam Turbine

The steam turbine consists of an HP section, an IP section, and a double-flow LP section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single span, opposed-flow casing, with the double-flow LP section in a separate casing.

Main steam from the boiler passes through the stop valves and control valves and enters the turbine at the conditions provided in Exhibit 5-4.

Exhibit 5-4. NGCC steam conditions

Steam Conditions		
Steam Parameter	F-frame	H-frame
Main Pressure, MPa (psig)	16.4 (2,378)	18.4 (2,668)
Main Temperature, °C (°F)	585 (1,085)	585 (1,085)
Reheat Pressure, MPa (psig)	3.4 (494)	3.2 (465)
Reheat Temperature, °C (°F)	584 (1,084)	562 (1,044)

The steam initially enters the turbine near the middle of the HP span, flows through the turbine, and is combined with steam from the IP superheater before being returned to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at the conditions provided in Exhibit 5-4. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the LP section. A branch line equipped with combined stop/intercept valves conveys LP steam from the HRSG LP drum to a tie-in at the crossover line. The steam divides into two paths and flows through the LP sections exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system. Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a LP steam seal system. The open-air-cooled generator produces power at 18 kV. A static, transformer type exciter is provided. The STG is controlled by a triple-redundant microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color monitor/operator interfacing, and datalink interfaces to the balance-of-plant DCS and incorporates on-line repair capability.

5.1.7 Water and Steam Systems

5.1.7.1 Condensate

The function of the condensate system is to pump condensate from the condenser's deaerating hotwell through the gland steam condenser and the low-temperature economizer section in the HRSG.

The system consists of one main condenser; two 100 percent capacity, motor-driven vertical multistage condensate pumps (total of two pumps for the plant), one gland steam condenser, condenser air removal vacuum pumps, condensate polisher, and a low-temperature tube bundle in the HRSG.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Deaerating condenser losses are assumed to be 0.2 percent of the total flowrate. To account for these losses, makeup water is supplied to the condenser. The makeup water provides high-quality demineralized water for makeup to the HRSG cycle. The demineralizer is sized based on the requirements of the startup boiler.

5.1.7.2 Feedwater

The function of the FW system is to pump the various FW streams from the LP evaporator to the respective steam drums. Two 100 percent capacity motor-driven feed pumps are provided per each HRSG (total of four pumps for the plant). The FW pumps are equipped with an interstage takeoff to provide IP FW. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the LP drum. The recirculation flow is controlled by automatic or pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with strainers.

5.1.7.3 Steam System

Main, intermediate, and low-pressure steam exits the HRSG superheater section through motor-operated stop/check valves and motor-operated gate valves. The main steam is routed to the HP turbine stop valve. The intermediate steam is combined with the HP turbine exhaust and is conveyed through a motor-operated isolation gate valve to the HRSG reheater and from the HRSG reheater outlet through a motor-operated gate valve to the IP turbines. The LP steam is combined with the IP turbine exhaust and is conveyed through a motor-operated isolation gate valve to the LP turbines.

5.1.7.4 Circulating Water System

The function of the CWS is to supply cooling water to condense the main turbine exhaust steam, for the auxiliary cooling system, and for the CDR facility in capture cases. The system consists of two 50 percent capacity vertical CWP (total of two pumps for the plant), a mechanical draft evaporative cooling tower, and interconnecting piping. The condenser is a two pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

The auxiliary cooling system is a CL system. Plate and frame HXs with circulating water as the cooling medium are provided. The system provides cooling water to the following systems:

1. CTG lube oil coolers
2. CTG air coolers
3. STG lube oil coolers
4. STG H₂ coolers
5. BFW pumps
6. Air compressors
7. Generator seal oil coolers (as applicable)
8. Sample room chillers
9. Blowdown coolers
10. Condensate extraction pump-motor coolers

The CDR system in capture cases requires a substantial amount of cooling water that is provided by the NGCC plant CWS. The additional cooling load imposed by the CDR is reflected in the significantly larger CWP's and cooling tower in that case.

5.1.7.5 Buildings and Structures

Structures assumed for NGCC cases can be summarized as follows:

1. Generation Building housing the STG
2. CWP House
3. Administration/Office/Control Room/Maintenance Building
4. Water Treatment Building
5. Fire Water Pump House

5.1.8 Accessory Electric Plant

The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, wire, and cable. It also includes the main transformer, required foundations, and standby equipment.

5.1.9 Waste Treatment/Miscellaneous Systems

An onsite water treatment facility treats all runoff, cleaning wastes, blowdown, and backwash. It is anticipated that the treated water will be suitable for discharge into existing systems and be within EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals.

The waste treatment system is minimal and consists, primarily, of neutralization and oil/water separators (along with the associated pumps, piping, etc.).

Miscellaneous systems consisting of service air, instrument air, and service water are provided. All truck roadways and unloading stations inside the fence area are provided.

5.1.10 Instrumentation and Control

An integrated plant-wide DCS is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of video monitors and keyboard units. The monitor/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability.

The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual procedures, with operator selection of modular automation routines available.

5.1.11 Performance Summary Metrics

This section details the methods used to calculate several metrics reported in the performance summaries of the NGCC cases.

5.1.11.1 Combustion Turbine Efficiency

The combustion turbine efficiency is calculated by taking the CT power produced and dividing it by the thermal input to the turbines. This calculation is represented by the equation:

$$CTE = \frac{CTP}{TI}$$

Where:

CTE – combustion turbine efficiency, percent

CTP – combustion turbine power, after generator losses, kWh

TI – thermal input to turbines, kWh

The thermal input is calculated by taking the natural gas feed rate and multiplying it by the heating value of the natural gas and converting the units to kW.

5.1.11.2 Steam Turbine Efficiency

The steam turbine efficiency is calculated by taking the steam turbine power produced and dividing it by the difference between the thermal input and thermal consumption. This calculation is represented by the equation:

$$STE = \frac{STP}{(TI - TC)}$$

Where:

STE – steam turbine efficiency, percent

STP – steam turbine power, after generator losses, kWh

TI – thermal input, kWh

TC – thermal consumption, kWh

The thermal input is calculated by taking the enthalpy of the flue gas to the HRSG and subtracting the enthalpy of the flue gas exiting the HRSG.

Thermal consumption is only present in the capture cases. It is the enthalpy difference between the streams extracted for the capture and CO₂ dryer systems and the condensate returned to the condenser (steam extraction – condensate return).

5.1.11.3 Steam Turbine Heat Rate

The steam turbine heat rate is calculated by taking the inverse of the steam turbine efficiency. This calculation is represented by the equation:

$$STHR = \frac{1}{STE} * 3,412$$

Where:

STHR – steam turbine heat rate, Btu/kWh

STE – steam turbine efficiency, fraction

5.2 F-FRAME NGCC CASES

This section contains an evaluation of plant designs for cases B31A, B31B.90, and B31B.95. The balance of this section is organized as follows:

- Key System Assumptions is a summary of study and modeling assumptions relevant to cases B31A, B31B.90, and B31B.95.
- Sparing Philosophy is provided for cases B31A, B31B.90, and B31B.95.
- Process and System Description provides an overview of the technology operation as applied to cases B31A, B31B.90, and B31B.95. The systems that are common to all NGCC cases were covered in Section 5.1 and only features that are unique to F-frame cases are discussed further in this section.
- Performance Results provides the main modeling results from cases B31A, B31B.90, and B31B.95, including the performance summary, environmental performance, carbon balance, water balance, mass and energy balance diagrams, and energy balance table.
- Equipment List provides an itemized list of major equipment for cases B31A, B31B.90, and B31B.95 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs for cases B31A, B31B.90, and B31B.95.

5.2.1 Key System Assumptions

System assumptions for cases B31A, B31B.90, and B31B.95 are compiled in Exhibit 5-5.

Exhibit 5-5. NGCC F-frame plant study configuration matrix

	Case B31A w/o CO ₂ Capture	Case B31B.90 w/CO ₂ Capture	Case B31B.95 w/CO ₂ Capture
Steam Cycle, MPa/°C/°C (psia/°F/°F)	16.5/585/584 (2,393/1,085/1,084)		
Fuel	Natural Gas		
Fuel Pressure at Plant Battery Limit MPa (psia)	3.0 (430)		
Condenser Pressure, mm Hg (in. Hg)	50.8 (2)		
Cooling Water to Condenser, °C (°F)	16 (60)		
Cooling Water from Condenser, °C (°F)	27 (80)		
Stack Temperature, °C (°F)	82 (181)	38 (100)	38 (100)
SO ₂ Control	Low Sulfur Fuel		
NO _x Control	LNB and SCR		
SCR Efficiency, % ^A	85.4	86.5	86.5
Ammonia Slip (End of Catalyst Life), ppmv	10		
Particulate Control	N/A		
Mercury Control	N/A		
CO ₂ Control	N/A	CANSOLV	
Overall Carbon Capture, % ^A	N/A	90	95
CO ₂ Sequestration	N/A	Off-site Saline Formation	

^ARemoval efficiencies are based on the flue gas content

5.2.1.1 Balance of Plant – Case B31A, Case B31B.90, and Case B31B.95

The balance of plant assumptions are common to all F-frame NGCC cases and are presented in Exhibit 5-6.

Exhibit 5-6. F-frame NGCC balance of plant assumptions

Parameter	Value
Cooling System	Recirculating Wet Cooling Tower
Fuel and Other Storage	
Natural Gas	Pipeline supply at 3.0 MPa (430 psia) and 27°C (80°F)
Plant Distribution Voltage	
Motors below 1 hp	110/220 V
Motors between 1 hp and 250 hp	480 V
Motors between 250 hp and 5,000 hp	4,160 V
Motors above 5,000 hp	13,800 V

Parameter	Value
Steam and CT generators	18,000 V
Grid Interconnection voltage	345 kV
<u>Water and Wastewater</u>	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and DI water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 m ³ /d (1,500 gpd)
Water Discharge	Blowdown is treated for chloride and metals and discharged.

5.2.2 Sparing Philosophy

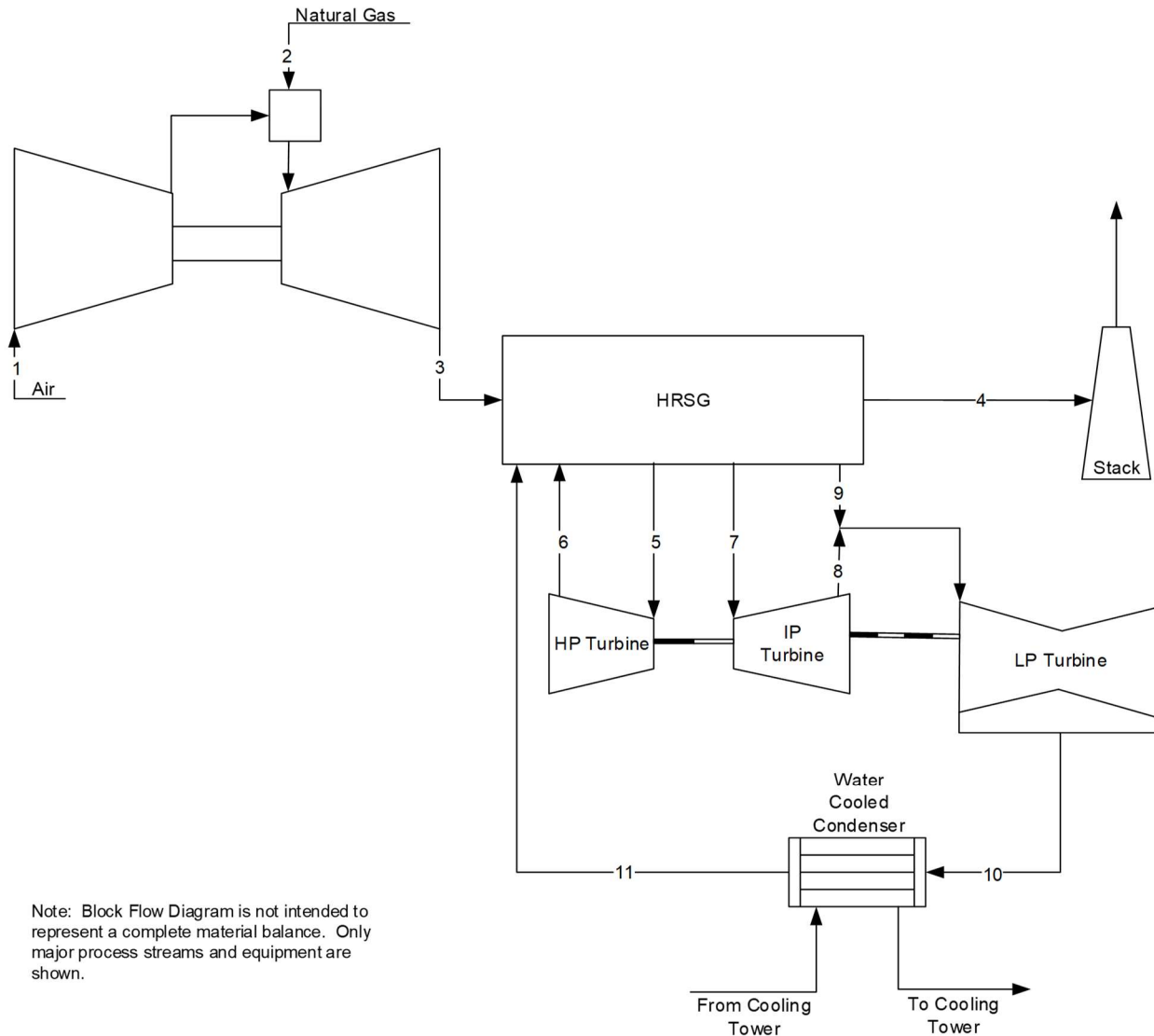
Dual trains are used to accommodate the size of commercial CTs. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- Two state-of-the-art 2017 F-Class CTGs (2 x 50 percent)
- Two 3-pressure reheat HRSGs with self-supporting stacks and SCR systems (2 x 50 percent)
- One 3-pressure reheat, triple-admission STG (1 x 100 percent)
- For Cases B31B.90 and B31B.95, one CO₂ absorption system, consisting of an absorber, stripper, and ancillary equipment (1 x 100 percent) and two CO₂ compression systems (2 x 50 percent)

5.2.3 Case B31A – NGCC without CO₂ Capture Process Description

In this section, the F-class NGCC process without CO₂ capture is described. The system description follows the BFD in Exhibit 5-7 and stream numbers reference the same exhibit. Exhibit 5-8 provides process data for the numbered streams in the BFD. The BFD shows only one of the two CT/HRSG trains, but the flow rates in the stream table are the total for two systems.

Exhibit 5-7. Case B31A block flow diagram, NGCC without CO₂ capture



For case B31A, ambient air (stream 1) is supplied to an inlet filter and compressed before being combined with natural gas (stream 2) in the dry LNB, which is operated to control the rotor inlet temperature at 1,423°C (2,594°F). The flue gas exits the turbine at 624°C (1,156°F) (stream 3) and passes into the HRSG. The HRSG generates both the main steam and reheat steam for the steam turbine. Flue gas exits the HRSG at 83°C (181°F) (stream 4) and passes to the plant stack.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-8. Case B31A stream table, NGCC without capture

	1	2	3	4	5	6	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₂ H ₆	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0100	0.0408	0.0408	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0000	0.0875	0.0875	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N ₂	0.7732	0.0160	0.7428	0.7428	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.2074	0.0000	0.1200	0.1200	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	132,867	5,383	138,406	138,406	26,969	26,969	31,151	31,151	4,030	35,181	35,225
V-L Flowrate (kg/hr)	3,834,126	93,272	3,927,398	3,927,398	485,855	485,855	561,194	561,194	72,598	633,792	634,582
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	625	83	585	356	584	308	281	38	38
Pressure (MPa, abs)	0.10	2.96	0.11	0.10	16.50	3.74	3.51	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg) ^A	30.23	22.04	832.68	225.49	3,528.08	3,112.11	3,642.68	3,080.22	3,024.62	2,378.69	160.78
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-4,487.18	-644.44	-1,251.63	-12,452.22	-12,868.18	-12,337.62	-12,900.07	-12,955.67	-13,601.61	-15,819.51
Density (kg/m ³)	1.2	22.1	0.4	1.0	45.6	13.8	9.0	2.0	2.0	0.1	992.8
V-L Molecular Weight	28.857	17.328	28.376	28.376	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	292,921	11,867	305,132	305,132	59,457	59,457	68,676	68,676	8,884	77,560	77,657
V-L Flowrate (lb/hr)	8,452,800	205,630	8,658,430	8,658,430	1,071,128	1,071,128	1,237,221	1,237,221	160,051	1,397,272	1,399,015
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,156	181	1,085	672	1,084	587	538	101	101
Pressure (psia)	14.7	430.0	15.5	14.8	2,393.1	542.3	508.6	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb) ^A	13.0	9.5	358.0	96.9	1,516.8	1,338.0	1,566.1	1,324.3	1,300.4	1,022.7	69.1
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-1,929.1	-277.1	-538.1	-5,353.5	-5,532.3	-5,304.2	-5,546.0	-5,569.9	-5,847.6	-6,801.2
Density (lb/ft ³)	0.076	1.380	0.025	0.061	2.849	0.863	0.563	0.122	0.125	0.003	61.977

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

5.2.4 Case B31A – Performance Results

The plant produces a net output of 727 MW at a net plant efficiency of 53.6 percent (HHV basis).

Overall plant performance is summarized in Exhibit 5-9; Exhibit 5-10 provides a detailed breakdown of the auxiliary power requirements.

Exhibit 5-9. Case B31A plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	477
Steam Turbine Power, MWe	263
Total Gross Power, MWe	740
CO ₂ Capture/Removal Auxiliaries, kWe	–
CO ₂ Compression, kWe	–
Balance of Plant, kWe	13,562
Total Auxiliaries, MWe	14
Net Power, MWe	727
HHV Net Plant Efficiency, %	53.6
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,714 (6,363)
HHV Combustion Turbine Efficiency, %	35.2
LHV Net Plant Efficiency, %	59.4
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,060 (5,743)
LHV Combustion Turbine Efficiency, %	39.0
Steam Turbine Cycle Efficiency, %	39.7
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	9,074 (8,601)
CO ₂ Capture Rate, %	0
Condenser Duty, GJ/hr (MMBtu/hr)	1,406 (1,332)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	–
Natural Gas Feed Flow, kg/hr (lb/hr)	93,272 (205,630)
HHV Thermal Input, kWt	1,354,905
LHV Thermal Input, kWt	1,222,936
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.015 (4.0)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.012 (3.1)

Exhibit 5-10. Case B31A plant power summary

Power Summary	
Combustion Turbine Power, MWe	477
Steam Turbine Power, MWe	263
Total Gross Power, MWe	740
Auxiliary Load Summary	
Circulating Water Pumps, kWe	2,820
Combustion Turbine Auxiliaries, kWe	1,020
Condensate Pumps, kWe	150
Cooling Tower Fans, kWe	1,460
CO ₂ Capture/Removal Auxiliaries, kWe	–
CO ₂ Compression, kWe	–
Feedwater Pumps, kWe	4,830
Ground Water Pumps, kWe	260
Miscellaneous Balance of Plant ^A , kWe	570
SCR, kWe	2
Steam Turbine Auxiliaries, kWe	200
Transformer Losses, kWe	2,250
Total Auxiliaries, MWe	14
Net Power, MWe	727

^AIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

5.2.4.1 Environmental Performance

The environmental targets for emissions of NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B31A is presented in Exhibit 5-11.

Exhibit 5-11. Case B31A air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.001)	15 (16)	0.003 (0.006)
NO _x	0.002 (0.004)	56 (61)	0.010 (0.022)
Particulate	0.001 (0.002)	29 (32)	0.005 (0.012)
Hg	0.00E+0 (0.00E+0)	0.000 (0.000)	0.00E+0 (0.00E+0)
CO	0.001 (0.002)	29 (32)	0.005 (0.012)
CO ₂	51 (119)	1,852,253 (2,041,760)	336 (741)
CO ₂ ^C	–	–	342 (755)

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

For the purpose of this report, the natural gas was assumed to contain the domestic average value of total sulfur of 0.34 gr/100 scf (4.71×10^{-4} lb-S/MMBtu). [23] It was also assumed that the added CH₄S was the sole contributor of sulfur to the natural gas. No sulfur capture systems were required.

The NGCC cases were designed to achieve approximately 1.8 ppmvd NO_x emissions (at 15 percent O₂) using a DLN burner in the CTG—the DLN burners reduce the emissions to about 9 ppmvd (at 15 percent O₂) [34]—and an SCR—the SCR system is designed for 85.4 percent NO_x reduction. [35]

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2017 F-Class gas turbine achieves approximately 1.0 ppmv CO and 1.0 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not produced or emitted in any significant amount.

CO₂ emissions are reduced relative to those produced by burning coal given the same power output because of the higher heat content of natural gas, the lower carbon intensity of gas relative to coal, and the higher overall efficiency of the NGCC plant relative to a coal-fired plant.

The carbon balance for the plant is shown in Exhibit 5-12. The carbon input to the plant consists of carbon in the natural gas and carbon as CO₂ in the CT air. Carbon leaves the plant as CO₂ through the stack.

Exhibit 5-12. Case B31A carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	67,369 (148,523)	Stack Gas	67,890 (149,672)
Air (CO ₂)	521 (1,150)	CO ₂ Product	—
		CO ₂ Dryer Vent	—
		CO ₂ Knockout	—
Total	67,890 (149,672)	Total	67,890 (149,672)

As shown in Exhibit 5-13, the sulfur content of the natural gas is insignificant. All sulfur in the natural gas is emitted in the stack gas.

Exhibit 5-13. Case B31A sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.0 (2.2)	Stack Gas	1.0 (2.2)
		Solvent Reclaiming	—
Total	1.0 (2.2)	Total	1.0 (2.2)

Exhibit 5-14 shows the water balance for Case B31A.

Exhibit 5-14. Case B31A water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
CO ₂ Drying	–	–	–	–	–
CO ₂ Capture System Makeup	–	–	–	–	–
CO ₂ Capture Recovery	–	–	–	–	–
CO ₂ Compression Recovery	–	–	–	–	–
Deaerator Vent	–	–	–	0.0 (5.6)	0.0 (-5.6)
Condenser Makeup	0.0 (5.6)	–	0.0 (5.6)	–	0.0 (5.6)
BFW Makeup	0.0 (5.6)	–	0.0 (5.6)	–	0.0 (5.6)
Cooling Tower	11 (2,897)	–	11 (2,897)	2.5 (651)	8.5 (2,245)
Total	11 (2,902)	–	11 (2,902)	2.5 (657)	8.5 (2,245)

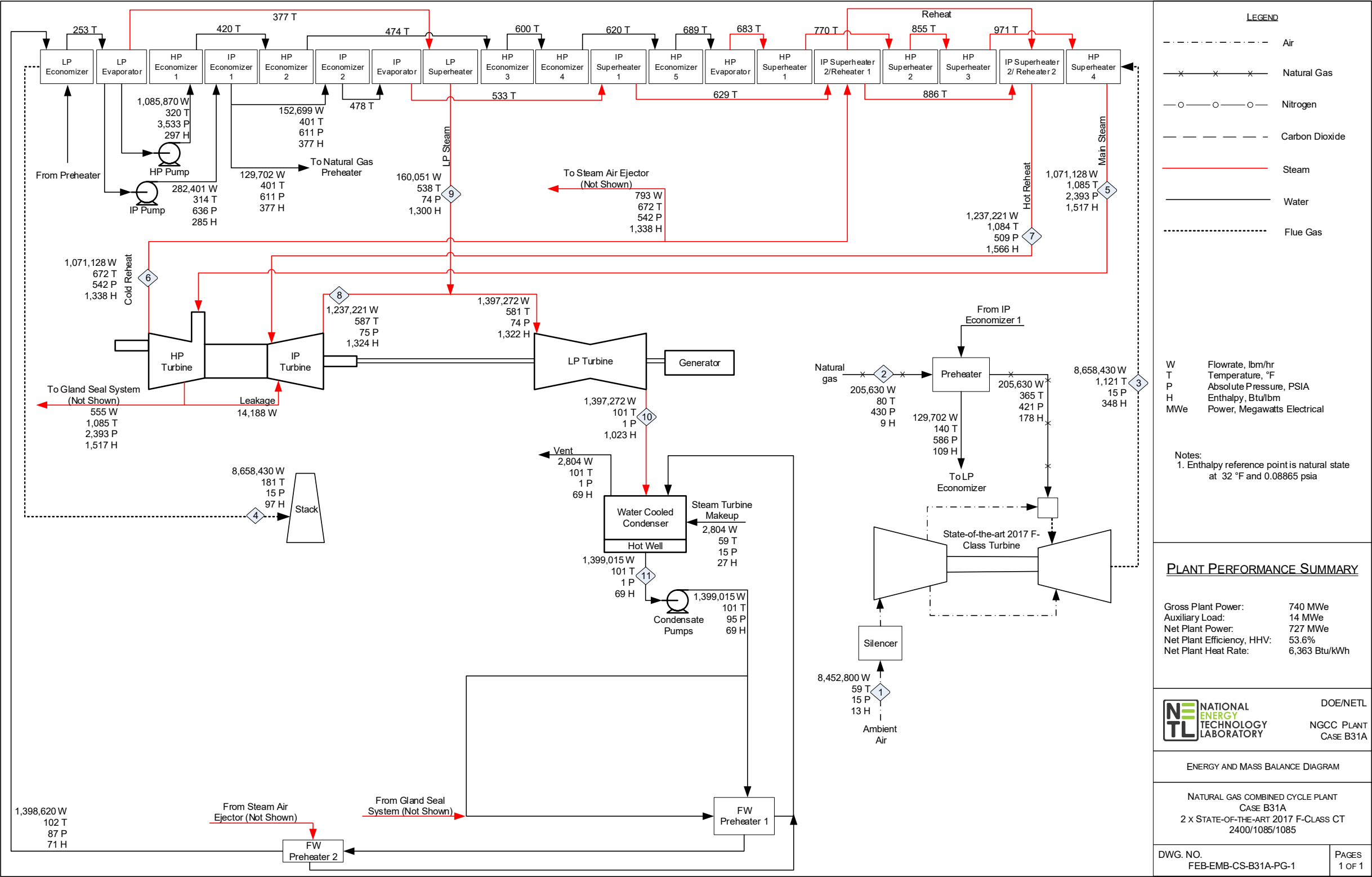
Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a surface-water source for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from groundwater. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for all purposes, such as condenser and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

5.2.4.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram for B31A is shown in Exhibit 5-15. An overall plant energy balance is provided in tabular form in Exhibit 5-16. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT, and 98.7 percent for the steam turbine.

This page intentionally left blank

Exhibit 5-15. Case B31A energy and mass balance, NGCC without CO₂ capture



This page intentionally left blank

Exhibit 5-16. Case B31A overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	4,878 (4,623)	3.3 (3.1)	–	4,881 (4,626)
Air	–	116 (110)	–	116 (110)
Raw Water Makeup	–	41 (39)	–	41 (39)
Auxiliary Power	–	–	49 (46)	49 (46)
TOTAL	4,878 (4,623)	160 (152)	49 (46)	5,087 (4,821)
Heat Out GJ/hr (MMBtu/hr)				
Stack Gas	–	886 (839)	–	886 (839)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	58 (55)	58 (55)
Cooling Tower Load ^A	–	1,432 (1,357)	–	1,432 (1,357)
CO ₂ Product Stream	–	–	–	–
Deaerator Vent	–	0.2 (0.2)	–	0.2 (0.2)
<i>Ambient Losses^B</i>	–	33 (31)	–	33 (31)
Power	–	–	2,664 (2,525)	2,664 (2,525)
TOTAL	–	2,351 (2,228)	2,722 (2,580)	5,073 (4,808)
<i>Unaccounted Energy^C</i>	–	14 (13)	–	14 (13)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers

^CBy difference

5.2.5 Case B31A – Major Equipment List

Major equipment items for the NGCC plant with no CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 5.2.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

Case B31A – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	84,000 liters (22,000 gal)	2	0
2	Condensate Pumps	Vertical canned	11,710 lpm @ 80 m H ₂ O (3,090 gpm @ 260 ft H ₂ O)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 4,550 lpm @ 2,940 m H ₂ O (1,200 gpm @ 9,640 ft H ₂ O) IP water: 2,360 lpm @ 470 m H ₂ O (620 gpm @ 1,550 ft H ₂ O)	2	2
4	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m ³ /min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m ³ /min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 GJ/hr (13 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,200 lpm @ 20 m H ₂ O (1,400 gpm @ 70 ft H ₂ O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	6,200 lpm @ 20 m H ₂ O (1,600 gpm @ 60 ft H ₂ O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H ₂ O (40 gpm @ 160 ft H ₂ O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
15	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
16	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	77 m ³ /min @ 3.0 MPa (2,732 acfm @ 430 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
17	Gas Metering Station	–	77 m ³ /min (2,732 acfm)	1	0

Case B31A – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	Advanced F class w/ dry low-NOx burner	240 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	270 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	2	0

Case B31A – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 5.7 m (19 ft) diameter	2	0
2	Heat Recovery Steam Generator		Main steam - 267,221 kg/hr, 16.4 MPa/585°C	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
		Drum, multi-pressure with economizer section	(589,120 lb/hr, 2,378 psig/1,085°F)		
			Reheat steam - 308,657 kg/hr, 3.4 MPa/584°C (680,472 lb/hr, 494 psig/1,084°F)		
3	SCR Reactor	–	2,160,000 kg/hr (4,760,000 lb/hr)	2	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	10 m ³ /min @ 108 cm WG (220 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	1.3 lpm @ 90 m H ₂ O (0.3 gpm @ 300 ft H ₂ O)	2	1
7	Ammonia Storage Tank	Horizontal tank	38,000 liter (10,000 gal)	1	0

Case B31A – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	277 MW 16.4 MPa/585°C/584°C (2,378 psig/1,085°F/1,084°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	310 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	1,550 GJ/hr (1,470 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

Case B31A – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	283,000 lpm @ 30 m (75,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 1,580 GJ/hr (1,490 MMBtu/hr) heat duty	1	0

Case B31A – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 270 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 290 MVA, 3-ph, 60 Hz	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 11 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 2 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B31A – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

5.2.6 Case B31A – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 5-17 shows a detailed breakdown of the capital costs; Exhibit 5-18 shows the owner's costs, TOC, and TASC; Exhibit 5-19 shows the initial and annual O&M costs; and Exhibit 5-20 shows the LCOE breakdown.

The estimated TPC of the NGCC with no CO₂ capture is \$780/kW. No process contingency was included in this case because all elements of the technology are commercially proven. The project contingency is 13.7 percent of TPC. The LCOE is \$43.3/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-17. Case B31A total plant cost details

Case:		B31A	– 2x1 CT NGCC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		727					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$1,697	\$2,908	\$1,454	\$0	\$6,059	\$1,212	\$0	\$1,091	\$8,362	\$12
3.2	Water Makeup & Pretreating	\$3,756	\$376	\$2,129	\$0	\$6,260	\$1,252	\$0	\$1,502	\$9,015	\$12
3.3	Other Feedwater Subsystems	\$965	\$316	\$301	\$0	\$1,582	\$316	\$0	\$285	\$2,183	\$3
3.4	Service Water Systems	\$1,140	\$2,176	\$7,046	\$0	\$10,362	\$2,072	\$0	\$2,487	\$14,922	\$21
3.5	Other Boiler Plant Systems	\$230	\$84	\$209	\$0	\$523	\$105	\$0	\$94	\$721	\$1
3.6	Natural Gas Pipeline and Start-Up System	\$9,304	\$400	\$300	\$0	\$10,005	\$2,001	\$0	\$1,801	\$13,807	\$19
3.7	Waste Water Treatment Equipment	\$4,998	\$0	\$3,063	\$0	\$8,062	\$1,612	\$0	\$1,935	\$11,609	\$16
3.9	Miscellaneous Plant Equipment	\$14,217	\$1,865	\$7,225	\$0	\$23,306	\$4,661	\$0	\$5,594	\$33,561	\$46
	Subtotal	\$36,307	\$8,125	\$21,727	\$0	\$66,159	\$13,232	\$0	\$14,788	\$94,179	\$130
6 Combustion Turbine & Accessories											
6.1	Combustion Turbine Generator	\$72,224	\$0	\$4,395	\$0	\$76,619	\$15,324	\$0	\$13,791	\$105,735	\$146
6.3	Combustion Turbine Accessories	\$2,626	\$0	\$160	\$0	\$2,786	\$557	\$0	\$501	\$3,845	\$5
6.4	Compressed Air Piping	\$0	\$867	\$196	\$0	\$1,063	\$213	\$0	\$191	\$1,467	\$2
6.5	Combustion Turbine Foundations	\$0	\$906	\$979	\$0	\$1,885	\$377	\$0	\$452	\$2,714	\$4
	Subtotal	\$74,850	\$1,773	\$5,730	\$0	\$82,353	\$16,471	\$0	\$14,937	\$113,760	\$157
7 HRSG, Ductwork, & Stack											
7.1	Heat Recovery Steam Generator	\$38,294	\$0	\$9,573	\$0	\$47,867	\$9,573	\$0	\$8,616	\$66,057	\$91
7.2	Heat Recovery Steam Generator Accessories	\$15,128	\$0	\$2,800	\$0	\$17,928	\$3,586	\$0	\$3,227	\$24,740	\$34
7.3	Ductwork	\$0	\$1,019	\$708	\$0	\$1,727	\$345	\$0	\$311	\$2,383	\$3
7.4	Stack	\$9,744	\$0	\$1,803	\$0	\$11,547	\$2,309	\$0	\$2,079	\$15,936	\$22
7.5	Heat Recovery Steam Generator, Ductwork & Stack Foundations	\$0	\$760	\$713	\$0	\$1,472	\$294	\$0	\$353	\$2,120	\$3
7.6	Selective Catalytic Reduction System	\$1,465	\$616	\$859	\$0	\$2,940	\$588	\$0	\$529	\$4,057	\$6
	Subtotal	\$64,632	\$2,394	\$16,456	\$0	\$83,482	\$16,696	\$0	\$15,115	\$115,293	\$159
8 Steam Turbine & Accessories											
8.1	Steam Turbine Generator & Accessories	\$37,060	\$0	\$5,427	\$0	\$42,487	\$8,497	\$0	\$7,648	\$58,632	\$81
8.2	Steam Turbine Plant Auxiliaries	\$146	\$0	\$333	\$0	\$478	\$96	\$0	\$86	\$660	\$1
8.3	Condenser & Auxiliaries	\$6,988	\$0	\$3,353	\$0	\$10,341	\$2,068	\$0	\$1,861	\$14,271	\$20
8.4	Steam Piping	\$9,400	\$0	\$3,809	\$0	\$13,210	\$2,642	\$0	\$2,378	\$18,230	\$25
8.5	Turbine Generator Foundations	\$0	\$1,252	\$2,068	\$0	\$3,320	\$664	\$0	\$797	\$4,781	\$7
	Subtotal	\$53,594	\$1,252	\$14,990	\$0	\$69,836	\$13,967	\$0	\$12,770	\$96,573	\$133
9 Cooling Water System											

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B31A	– 2x1 CT NGCC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		727					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
9.1	Cooling Towers	\$8,179	\$0	\$2,495	\$0	\$10,675	\$2,135	\$0	\$1,921	\$14,731	\$20
9.2	Circulating Water Pumps	\$1,076	\$0	\$63	\$0	\$1,140	\$228	\$0	\$205	\$1,573	\$2
9.3	Circulating Water System Auxiliaries	\$8,189	\$0	\$1,080	\$0	\$9,269	\$1,854	\$0	\$1,668	\$12,791	\$18
9.4	Circulating Water Piping	\$0	\$2,312	\$2,094	\$0	\$4,406	\$881	\$0	\$793	\$6,081	\$8
9.5	Make-up Water System	\$303	\$0	\$389	\$0	\$692	\$138	\$0	\$125	\$955	\$1
9.6	Component Cooling Water System	\$341	\$0	\$262	\$0	\$602	\$120	\$0	\$108	\$831	\$1
9.7	Circulating Water System Foundations	\$0	\$535	\$888	\$0	\$1,423	\$285	\$0	\$342	\$2,049	\$3
	Subtotal	\$18,088	\$2,847	\$7,272	\$0	\$28,207	\$5,641	\$0	\$5,163	\$39,011	\$54
11 Accessory Electric Plant											
11.1	Generator Equipment	\$2,579	\$0	\$1,945	\$0	\$4,524	\$905	\$0	\$814	\$6,243	\$9
11.2	Station Service Equipment	\$2,944	\$0	\$253	\$0	\$3,196	\$639	\$0	\$575	\$4,411	\$6
11.3	Switchgear & Motor Control	\$4,203	\$0	\$729	\$0	\$4,932	\$986	\$0	\$888	\$6,806	\$9
11.4	Conduit & Cable Tray	\$0	\$1,016	\$2,927	\$0	\$3,943	\$789	\$0	\$710	\$5,441	\$7
11.5	Wire & Cable	\$0	\$1,516	\$2,710	\$0	\$4,226	\$845	\$0	\$761	\$5,833	\$8
11.6	Protective Equipment	\$104	\$0	\$360	\$0	\$464	\$93	\$0	\$84	\$641	\$1
11.7	Standby Equipment	\$652	\$0	\$602	\$0	\$1,253	\$251	\$0	\$226	\$1,730	\$2
11.8	Main Power Transformers	\$6,933	\$0	\$141	\$0	\$7,075	\$1,415	\$0	\$1,273	\$9,763	\$13
11.9	Electrical Foundations	\$0	\$94	\$238	\$0	\$332	\$66	\$0	\$80	\$478	\$1
	Subtotal	\$17,414	\$2,626	\$9,906	\$0	\$29,946	\$5,989	\$0	\$5,410	\$41,345	\$57
12 Instrumentation & Control											
12.1	Natural Gas Combined Cycle Control Equipment	\$206	\$0	\$131	\$0	\$337	\$67	\$0	\$61	\$465	\$1
12.2	Combustion Turbine Control Equipment	\$395	\$0	\$251	\$0	\$646	\$129	\$0	\$116	\$892	\$1
12.3	Steam Turbine Control Equipment	\$330	\$0	\$210	\$0	\$540	\$108	\$0	\$97	\$745	\$1
12.4	Other Major Component Control Equipment	\$553	\$0	\$352	\$0	\$906	\$181	\$0	\$163	\$1,250	\$2
12.5	Signal Processing Equipment	\$461	\$0	\$14	\$0	\$475	\$95	\$0	\$86	\$656	\$1
12.6	Control Boards, Panels & Racks	\$122	\$0	\$74	\$0	\$197	\$39	\$0	\$35	\$271	\$0
12.7	Distributed Control System Equipment	\$6,779	\$0	\$206	\$0	\$6,986	\$1,397	\$0	\$1,257	\$9,640	\$13
12.8	Instrument Wiring & Tubing	\$560	\$448	\$1,791	\$0	\$2,798	\$560	\$0	\$504	\$3,862	\$5
12.9	Other Instrumentation & Controls Equipment	\$388	\$0	\$898	\$0	\$1,285	\$257	\$0	\$231	\$1,774	\$2
	Subtotal	\$9,794	\$448	\$3,928	\$0	\$14,169	\$2,834	\$0	\$2,550	\$19,554	\$27
13 Improvements to Site											
13.1	Site Preparation	\$0	\$537	\$11,394	\$0	\$11,930	\$2,386	\$0	\$2,863	\$17,180	\$24
13.2	Site Improvements	\$0	\$1,727	\$2,280	\$0	\$4,007	\$801	\$0	\$962	\$5,770	\$8
13.3	Site Facilities	\$1,657	\$0	\$1,738	\$0	\$3,394	\$679	\$0	\$815	\$4,888	\$7
	Subtotal	\$1,657	\$2,263	\$15,412	\$0	\$19,332	\$3,866	\$0	\$4,640	\$27,837	\$38
14 Buildings & Structures											

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO
ELECTRICITY

Case:		B31A	– 2x1 CT NGCC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		727					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
14.1	Combustion Turbine Area	\$0	\$346	\$183	\$0	\$528	\$106	\$0	\$95	\$729	\$1
14.3	Steam Turbine Building	\$0	\$3,486	\$4,637	\$0	\$8,122	\$1,624	\$0	\$1,462	\$11,209	\$15
14.4	Administration Building	\$0	\$368	\$249	\$0	\$617	\$123	\$0	\$111	\$852	\$1
14.5	Circulation Water Pumphouse	\$0	\$56	\$28	\$0	\$83	\$17	\$0	\$15	\$115	\$0
14.6	Water Treatment Buildings	\$0	\$312	\$285	\$0	\$597	\$119	\$0	\$107	\$824	\$1
14.7	Machine Shop	\$0	\$551	\$352	\$0	\$903	\$181	\$0	\$162	\$1,246	\$2
14.8	Warehouse	\$0	\$428	\$258	\$0	\$687	\$137	\$0	\$124	\$947	\$1
14.9	Other Buildings & Structures	\$0	\$313	\$227	\$0	\$540	\$108	\$0	\$97	\$746	\$1
14.10	Waste Treating Building & Structures	\$0	\$722	\$1,287	\$0	\$2,010	\$402	\$0	\$362	\$2,773	\$4
	Subtotal	\$0	\$6,581	\$7,506	\$0	\$14,087	\$2,817	\$0	\$2,536	\$19,441	\$27
	Total	\$276,336	\$28,309	\$102,927	\$0	\$407,571	\$81,514	\$0	\$77,908	\$566,994	\$780

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-18. Case B31A owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$4,063	\$6
1 Month Maintenance Materials	\$634	\$1
1 Month Non-fuel Consumables	\$271	\$0
1 Month Waste Disposal	\$0	\$0
25% of 1 Months Fuel Cost at 100% CF	\$3,729	\$5
2% of TPC	\$11,340	\$16
Total	\$20,037	\$28
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	\$300	\$0
0.5% of TPC (spare parts)	\$2,835	\$4
Total	\$3,135	\$4
Other Costs		
Initial Cost for Catalyst and Chemicals	\$847	\$1
Land	\$300	\$0
Other Owner's Costs	\$85,049	\$117
Financing Costs	\$15,309	\$21
Total Overnight Costs (TOC)	\$691,670	\$952
TASC Multiplier (IOU, 33 year)	1.093	
Total As-Spent Cost (TASC)	\$755,751	\$1,040

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-19. Case B31A initial and annual operating and maintenance costs

Case:	B31A	– 2x1 CT NGCC w/o CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	727	Heat Rate-net (Btu/kWh):	6,363	Capacity Factor (%):	85	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:		1.0
Operating Labor Burden:		30.00	% of base	Operator:		2.0
Labor O-H Charge Rate:		25.00	% of labor	Foreman:		1.0
				Lab Techs, etc.:		1.0
				Total:		5.0
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$2,192,190	\$3.017
Maintenance Labor:					\$4,309,151	\$5.931
Administrative & Support Labor:					\$1,625,335	\$2.237
Property Taxes and Insurance:					\$11,339,872	\$15.608
Total:					\$19,466,549	\$26.794
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$6,463,727	\$1.19482
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	2,090	\$1.90	\$0	\$1,231,872	\$0.22771
Makeup and Waste Water Treatment Chemicals (ton):	0	6.23	\$550	\$0	\$1,062,245	\$0.19636
Ammonia (19 wt%, ton):	0	3.45	\$300	\$0	\$321,503	\$0.05943
SCR Catalyst (ft ³):	5,649	3.10	\$150	\$847,299	\$144,041	\$0.02663
Subtotal:				\$847,299	\$2,759,662	\$0.51012
Waste Disposal						
SCR Catalyst (ft ³):	0	3.10	\$2.50	\$0	\$2,401	\$0.00044
Subtotal:				\$0	\$2,401	\$0.00044
Variable Operating Costs Total:				\$847,299	\$9,225,789	\$1.70538
Fuel Cost						
Natural Gas (MMBtu):	0	110,955	\$4.42	\$0	\$152,160,133	\$28.12675
Total:				\$0	\$152,160,133	\$28.12675

Exhibit 5-20. Case B31A LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	9.9	23%
Fixed	3.6	8%
Variable	1.7	4%
Fuel	28.1	65%
Total (Excluding T&S)	43.3	N/A
CO ₂ T&S	–	–
Total (Including T&S)	43.3	N/A

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-22. Case B31B.90 stream table, NGCC with capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000	0.0000	0.0096	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₂ H ₆	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0100	0.0408	0.0408	0.0000	0.0000	0.9778	0.0044	0.0000	0.0000	0.9957	0.0000
H ₂ O	0.0099	0.0000	0.0875	0.0875	1.0000	1.0000	0.0222	0.0550	1.0000	1.0000	0.0043	1.0000
N ₂	0.7732	0.0160	0.7428	0.7428	0.0000	0.0000	0.0000	0.8016	0.0000	0.0000	0.0000	0.0000
O ₂	0.2074	0.0000	0.1200	0.1200	0.0000	0.0000	0.0000	0.1294	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	132,867	5,383	138,406	138,406	13,658	12,509	5,202	128,263	129	129	5,109	7
V-L Flowrate (kg/hr)	3,834,126	93,272	3,927,398	3,927,398	246,047	225,353	225,961	3,612,442	2,330	2,330	224,278	133
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	625	99	308	105	31	38	214	356	29	356
Pressure (MPa, abs)	0.10	2.96	0.11	0.10	0.51	0.12	0.17	0.10	2.04	3.74	2.82	3.74
Steam Table Enthalpy (kJ/kg) ^A	30.23	22.04	832.68	243.03	3,080.22	439.34	49.44	127.14	913.81	3,112.11	-1.25	3,112.11
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-4,487.18	-644.44	-1,234.09	-12,900.08	-15,540.95	-8,979.10	-520.69	-15,066.49	-12,868.18	-8,976.09	-12,868.18
Density (kg/m ³)	1.2	22.1	0.4	0.9	1.9	954.9	3.0	1.1	848.5	13.8	58.0	13.8
V-L Molecular Weight	28.857	17.328	28.376	28.376	18.015	18.015	43.433	28.164	18.015	18.015	43.898	18.015
V-L Flowrate (lb _{mol} /hr)	292,921	11,867	305,132	305,132	30,110	27,578	11,470	282,772	285	285	11,264	16
V-L Flowrate (lb/hr)	8,452,800	205,630	8,658,430	8,658,430	542,441	496,819	498,159	7,964,071	5,137	5,137	494,449	294
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,156	210	586	221	88	100	416	672	85	672
Pressure (psia)	14.7	430.0	15.5	14.8	73.5	17.4	24.8	14.8	296.6	542.3	409.1	542.3
Steam Table Enthalpy (Btu/lb) ^A	13.0	9.5	358.0	104.5	1,324.3	188.9	21.3	54.7	392.9	1,338.0	-0.5	1,338.0
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-1,929.1	-277.1	-530.6	-5,546.0	-6,681.4	-3,860.3	-223.9	-6,477.4	-5,532.3	-3,859.0	-5,532.3
Density (lb/ft ³)	0.076	1.380	0.025	0.058	0.119	59.612	0.185	0.069	52.968	0.863	3.622	0.863

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-22. Case B31B.90 stream table, NGCC with capture (continued)

	13	14	15	16	17	18	19	20	21	22	23
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₂ H ₆	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0000	0.9995	0.0500	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	1.0000	0.0005	0.9500	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	7	5,089	20	5,089	26,993	26,993	31,039	31,039	4,030	21,411	34,100
V-L Flowrate (kg/hr)	133	223,883	395	223,883	486,295	486,295	559,173	559,173	72,598	385,723	614,325
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	203	29	29	30	585	356	584	308	281	38	38
Pressure (MPa, abs)	1.64	2.69	2.82	15.27	16.50	3.74	3.51	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg) ^A	863.65	-3.70	137.93	-231.09	3,528.08	3,112.11	3,642.67	3,080.22	3,024.62	2,376.32	160.78
AspenPlus Enthalpy (kJ/kg) ^B	-15,116.65	-8,967.26	-15,225.22	-9,194.65	-12,452.22	-12,868.18	-12,337.62	-12,900.08	-12,955.67	-13,603.98	-15,819.51
Density (kg/m ³)	861.8	54.9	352.5	630.1	45.6	13.8	9.0	2.0	2.0	0.1	992.8
V-L Molecular Weight	18.015	43.997	19.315	43.997	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	16	11,218	45	11,218	59,510	59,510	68,429	68,429	8,884	47,203	75,178
V-L Flowrate (lb/hr)	294	493,577	872	493,577	1,072,097	1,072,097	1,232,765	1,232,765	160,051	850,375	1,354,355
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	397	85	85	86	1,085	672	1,084	587	538	101	101
Pressure (psia)	237.4	390.4	409.1	2,214.7	2,393.1	542.3	508.6	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb) ^A	371.3	-1.6	59.3	-99.4	1,516.8	1,338.0	1,566.1	1,324.3	1,300.4	1,021.6	69.1
AspenPlus Enthalpy (Btu/lb) ^B	-6,499.0	-3,855.2	-6,545.7	-3,953.0	-5,353.5	-5,532.3	-5,304.2	-5,546.0	-5,569.9	-5,848.7	-6,801.2
Density (lb/ft ³)	53.801	3.430	22.007	39.338	2.849	0.863	0.563	0.122	0.125	0.003	61.977

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

5.2.8 Case B31B.90 – Performance Results

The Case B31B.90 modeling assumptions were presented previously in Section 5.1.

The plant produces a net output of 645 MW at a net plant efficiency of 47.6 percent (HHV basis). Overall plant performance is summarized in Exhibit 5-23. Exhibit 5-24 provides a detailed breakdown of the auxiliary power requirements. The CDR facility, including CO₂ compression, accounts for over 66 percent of the auxiliary plant load. The CWS (CWP and cooling tower fan) accounts for nearly 14 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility.

Exhibit 5-23. Case B31B.90 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	477
Steam Turbine Power, MWe	215
Total Gross Power, MWe	692
CO ₂ Capture/Removal Auxiliaries, kWe	13,600
CO ₂ Compression, kWe	17,900
Balance of Plant, kWe	15,992
Total Auxiliaries, MWe	47
Net Power, MWe	645
HHV Net Plant Efficiency, %	47.6
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,563 (7,169)
HHV Combustion Turbine Efficiency, %	35.2
LHV Net Plant Efficiency, %	52.7
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,827 (6,470)
LHV Combustion Turbine Efficiency, %	39.0
Steam Turbine Cycle Efficiency, %	46.9
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,678 (7,277)
CO ₂ Capture Rate, %	90
Condenser Duty, GJ/hr (MMBtu/hr)	860 (815)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	1,194 (1,132)
Natural Gas Feed Flow, kg/hr (lb/hr)	93,272 (205,630)
HHV Thermal Input, kWt	1,354,905
LHV Thermal Input, kWt	1,222,936
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.026 (6.9)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.017 (4.6)

Exhibit 5-24. Case B31B.90 plant power summary

Power Summary	
Combustion Turbine Power, MWe	477
Steam Turbine Power, MWe	215
Total Gross Power, MWe	692
Auxiliary Load Summary	
Circulating Water Pumps, kWe	4,340
Combustion Turbine Auxiliaries, kWe	1,020
Condensate Pumps, kWe	170
Cooling Tower Fans, kWe	2,240
CO ₂ Capture/Removal Auxiliaries, kWe	13,600
CO ₂ Compression, kWe	17,900
Feedwater Pumps, kWe	4,830
Ground Water Pumps, kWe	400
Miscellaneous Balance of Plant ^A , kWe	570
SCR, kWe	2
Steam Turbine Auxiliaries, kWe	200
Transformer Losses, kWe	2,220
Total Auxiliaries, MWe	47
Net Power, MWe	645

^AIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

5.2.8.1 Environmental Performance

The environmental targets for emissions of NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B31B.90 is presented in Exhibit 5-25.

Exhibit 5-25. Case B31B.90 air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.001 (0.003)	52 (57)	0.010 (0.022)
Particulate	0.000 (0.000)	0 (0)	0.000 (0.000)
Hg	0.00E+0 (0.00E+0)	0.000 (0.000)	0.00E+0 (0.00E+0)
CO	0.000 (0.000)	0 (0)	0.000 (0.000)
CO ₂	5 (12)	185,225 (204,176)	36 (79)
CO ₂ ^C	—	—	39 (85)

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

For the purpose of this report, the natural gas was assumed to contain the domestic average value of total sulfur of 0.34 gr/100 scf (4.71×10^{-4} lb-S/MMBtu). [23] It was also assumed that the added CH₄S was the sole contributor of sulfur to the natural gas. No sulfur capture systems were required.

The NGCC cases were designed to achieve approximately 1.8 ppmvd NO_x emissions (at 15 percent O₂) using a DLN burner in the CTG—the DLN burners reduce the emissions to about 9 ppmvd (at 15 percent O₂) [34]—and an SCR—the SCR system is designed for 86.7 percent NO_x reduction. [35]

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2017 F-Class gas turbine achieves approximately 1.0 ppmv CO and 1.0 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not present in any significant amount. Any CO or PM present in the flue gas is assumed to interact with, and be removed by, the CDR system solvent.

CO₂ emissions are reduced relative to those produced by burning coal given the same power output because of the higher heat content of natural gas, the lower carbon intensity of gas relative to coal, and the higher overall efficiency of the NGCC plant relative to a coal-fired plant.

The CDR facility removes 90 percent of the CO₂ in the flue gas.

The carbon balance for the plant is shown in Exhibit 5-26. The carbon input to the plant consists of carbon in the natural gas in addition to carbon in the CT air. Carbon leaves the plant as CO₂ in the stack gas, the CO₂ dryer's vent, and the captured CO₂ product. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in, represented by the following fraction:

$$1 - \frac{\text{Carbon in Stack}}{\text{Total Carbon In}} = \left(1 - \left(\frac{14,967}{149,672} \right) \right) * 100 = 90\%$$

Exhibit 5-26. Case B31B.90 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	67,369 (148,523)	Stack Gas	6,789 (14,967)
Air (CO ₂)	521 (1,150)	CO ₂ Product	61,089 (134,678)
		CO ₂ Dryer Vent	12 (27)
		CO ₂ Knockout	0.1 (0.3)
Total	67,890 (149,672)	Total	67,890 (149,672)

As shown in Exhibit 5-27, the sulfur content of the natural gas is insignificant, comprised entirely of CH₄S (used as an odorant). [23] All sulfur in the natural gas is assumed to react with the CDR system solvent and is removed from the solvent during solvent reclaiming as a waste stream.

Exhibit 5-27. Case B31B.90 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.0 (2.2)	Stack Gas	0.0 (0.0)
		Solvent Reclaiming	1.0 (2.2)
Total	1.0 (2.2)	Total	1.0 (2.2)

Exhibit 5-28 shows the overall water balance for the plant.

Exhibit 5-28. Case B31B.90 water balance

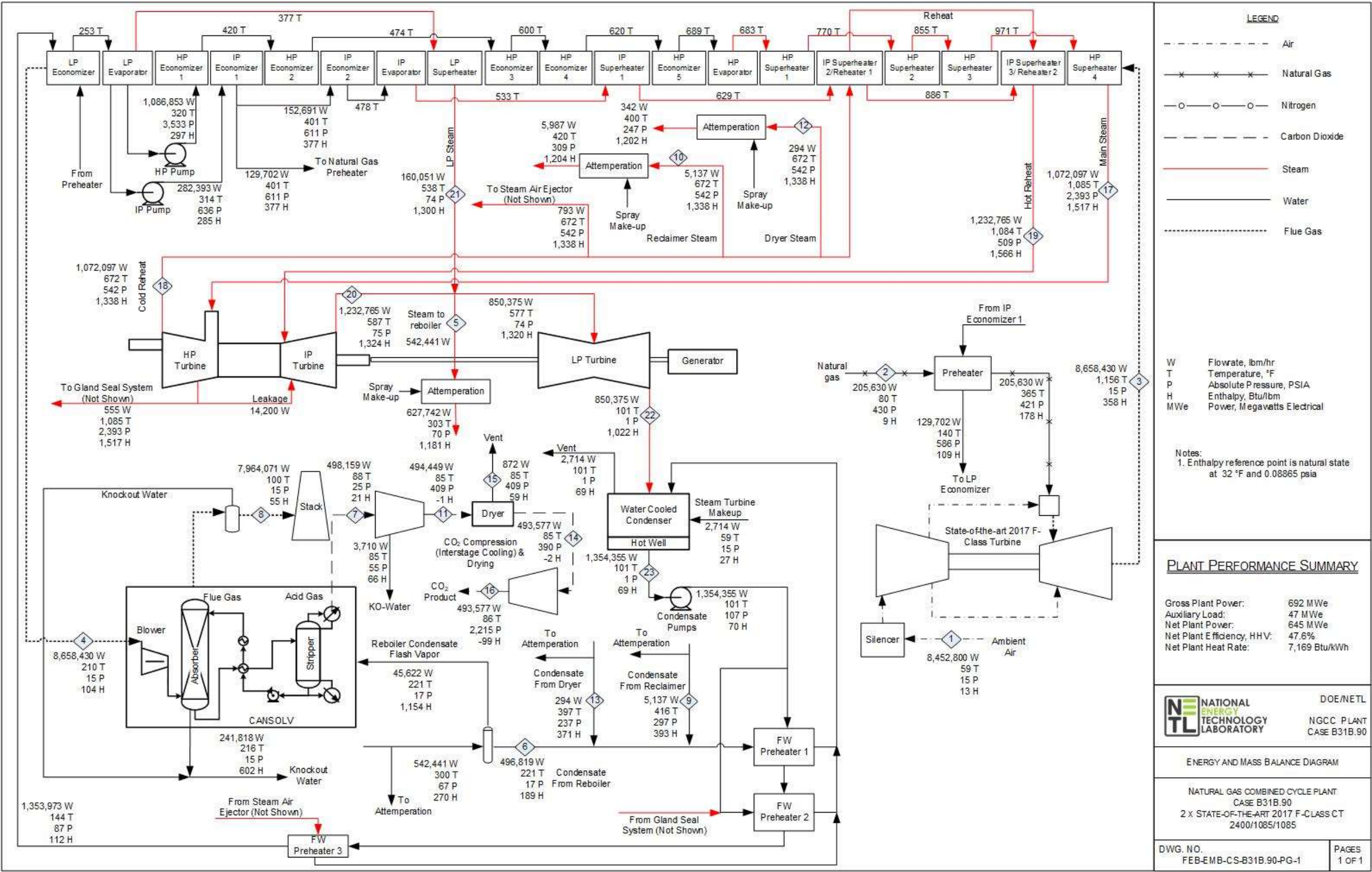
Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
CO ₂ Drying	–	–	–	0.0 (1.7)	0.0 (-1.7)
CO ₂ Capture System Makeup	–	–	–	–	–
CO ₂ Capture Recovery	–	–	–	1.8 (484)	-1.8 (-484)
CO ₂ Compression Recovery	–	–	–	0.0 (7.4)	0.0 (-7.4)
Deaerator Vent	–	–	–	0.0 (5.4)	0.0 (-5.4)
Condenser Makeup	0.0 (5.4)	–	0.0 (5.4)	–	0.0 (5.4)
BFW Makeup	0.0 (5.4)	–	0.0 (5.4)	–	0.0 (5.4)
Cooling Tower	17 (4,461)	–	17 (4,461)	3.8 (1,003)	13 (3,458)
Total	17 (4,467)	–	17 (4,467)	5.7 (1,502)	11 (2,965)

5.2.8.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram for B31B.90 is shown in Exhibit 5-29. An overall plant energy balance is provided in tabular form in Exhibit 5-30.

The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT, and 98.7 percent for the steam turbine. The cooling tower load includes the condenser, capture process heat rejected to cooling water, the CO₂ compressor intercooler load, and other miscellaneous cooling loads.

Exhibit 5-29. Case B31B.90 energy and mass balance, NGCC with CO₂ capture



This page intentionally left blank

Exhibit 5-30. Case B31B.90 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	4,878 (4,623)	3.3 (3.1)	–	4,881 (4,626)
Air	–	116 (110)	–	116 (110)
Raw Water Makeup	–	64 (60)	–	64 (60)
Auxiliary Power	–	–	171 (162)	171 (162)
TOTAL	4,878 (4,623)	183 (173)	171 (162)	5,231 (4,958)
Heat Out GJ/hr (MMBtu/hr)				
Stack Gas	–	459 (435)	–	459 (435)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	58 (55)	58 (55)
Cooling Tower Load ^A	–	2,205 (2,090)	–	2,205 (2,090)
CO ₂ Product Stream	–	-52 (-49)	–	-52 (-49)
AGR Effluent	–	47 (44)	–	47 (44)
Deaerator Vent	–	0.2 (0.2)	–	0.2 (0.2)
<i>Ambient Losses^B</i>	–	36 (34)	–	36 (34)
Power	–	–	2,493 (2,363)	2,493 (2,363)
TOTAL	–	2,696 (2,555)	2,551 (2,417)	5,246 (4,973)
<i>Unaccounted Energy^C</i>	–	-15 (-14)	–	-15 (-14)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers

^CBy difference

5.2.9 Case B31B.90 – Major Equipment List

Major equipment items for the NGCC plant with CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 5.2.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

Case B31B.90 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	81,000 liters (21,000 gal)	2	0
2	Condensate Pumps	Vertical canned	11,340 lpm @ 90 m H ₂ O (3,000 gpm @ 300 ft H ₂ O)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 4,550 lpm @ 2,940 m H ₂ O (1,200 gpm @ 9,640 ft H ₂ O) IP water: 2,360 lpm @ 470 m H ₂ O (620 gpm @ 1,550 ft H ₂ O)	2	2
4	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m ³ /min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m ³ /min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 GJ/hr (13 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,200 lpm @ 20 m H ₂ O (1,400 gpm @ 70 ft H ₂ O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	8,600 lpm @ 20 m H ₂ O (2,300 gpm @ 60 ft H ₂ O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H ₂ O (40 gpm @ 160 ft H ₂ O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
15	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
16	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	77 m ³ /min @ 3.0 MPa (2,732 acfm @ 430 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
17	Gas Metering Station	–	77 m ³ /min (2,732 acfm)	1	0

Case B31B.90 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CANSOLV	Amine-based CO ₂ capture technology	4,320,000 kg/hr (9,524,000 lb/hr) 6.3 wt % CO ₂ concentration	1	0
2	CANSOLV LP Condensate Pump	Centrifugal	719 lpm @ 1 m H ₂ O (190 gpm @ 3 ft H ₂ O)	1	1
3	CANSOLV HP Condensate Pump	Centrifugal	7 lpm @ 5 m H ₂ O (2 gpm @ 15 ft H ₂ O)	1	1
4	CO ₂ Dryer	Triethylene glycol	Inlet: 64 m ³ /min @ 2.8 MPa (2,275 acfm @ 409 psia) Outlet: 2.7 MPa (390 psia) Water Recovered: 395 kg/hr (872 lb/hr)	1	0
5	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	3.0 m ³ /min @ 15.3 MPa, 82°C (115 acfm @ 2,217 psia, 180°F)	2	0
6	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 35 GJ/hr (33 MMBtu/hr)	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B31B.90 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	Advanced F class w/ dry low-NOx burner	240 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	270 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	2	0

Case B31B.90 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 5.1 m (17 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main steam - 267,463 kg/hr, 16.4 MPa/585°C (589,654 lb/hr, 2,378 psig/1,085°F) Reheat steam - 307,545 kg/hr, 3.4 MPa/584°C (678,021 lb/hr, 494 psig/1,084°F)	2	0
3	SCR Reactor	—	2,160,000 kg/hr (4,760,000 lb/hr)	2	0
4	SCR Catalyst	—	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	10 m ³ /min @ 108 cm WG (220 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	1.3 lpm @ 90 m H ₂ O (0.4 gpm @ 300 ft H ₂ O)	2	1
7	Ammonia Storage Tank	Horizontal tank	38,000 liter (10,000 gal)	1	0

Case B31B.90 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	226 MW 16.4 MPa/585°C/584°C (2,378 psig/1,085°F/1,084°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	250 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	950 GJ/hr (900 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

Case B31B.90 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	435,000 lpm @ 30 m (115,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/ 16°C (60°F) CWT/ 27°C (80°F) HWT/ 2,430 GJ/hr (2,300 MMBtu/hr) heat duty	1	0

Case B31B.90 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 270 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 200 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 10 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 23 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 8 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B31B.90 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

5.2.10 Case B31B.90 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 5-31 shows a detailed breakdown of the capital costs; Exhibit 5-32 shows the owner's costs, TOC, and TASC; Exhibit 5-33 shows the initial and annual O&M costs; and Exhibit 5-34 shows the LCOE breakdown.

The estimated TPC of the NGCC with CO₂ capture is \$1,686/kW. Process contingency represents 4.2 percent of the TPC and project contingency represents 15.1 percent. The LCOE, including CO₂ T&S costs of \$3.5/MWh, is \$67.9/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO
ELECTRICITY

Exhibit 5-31. Case B31B.90 total plant cost details

Case:		B31B.90	– 2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		645					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$1,698	\$2,910	\$1,455	\$0	\$6,063	\$1,213	\$0	\$1,091	\$8,367	\$13
3.2	Water Makeup & Pretreating	\$5,095	\$509	\$2,887	\$0	\$8,491	\$1,698	\$0	\$2,038	\$12,227	\$19
3.3	Other Feedwater Subsystems	\$966	\$317	\$301	\$0	\$1,583	\$317	\$0	\$285	\$2,185	\$3
3.4	Service Water Systems	\$1,546	\$2,952	\$9,557	\$0	\$14,055	\$2,811	\$0	\$3,373	\$20,239	\$31
3.5	Other Boiler Plant Systems	\$230	\$84	\$209	\$0	\$523	\$105	\$0	\$94	\$722	\$1
3.6	Natural Gas Pipeline and Start-Up System	\$9,304	\$400	\$300	\$0	\$10,005	\$2,001	\$0	\$1,801	\$13,807	\$21
3.7	Waste Water Treatment Equipment	\$8,988	\$0	\$5,509	\$0	\$14,497	\$2,899	\$0	\$3,479	\$20,875	\$32
3.9	Miscellaneous Plant Equipment	\$14,217	\$1,865	\$7,225	\$0	\$23,306	\$4,661	\$0	\$5,594	\$33,561	\$52
	Subtotal	\$42,044	\$9,036	\$27,443	\$0	\$78,523	\$15,705	\$0	\$17,755	\$111,983	\$174
5 Flue Gas Cleanup											
5.1	CANSOLV Carbon Dioxide (CO ₂) Removal System	\$101,663	\$48,103	\$101,017	\$0	\$250,783	\$50,157	\$45,141	\$69,216	\$415,297	\$644
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$26,989	\$4,049	\$11,197	\$0	\$42,234	\$8,447	\$0	\$10,136	\$60,817	\$94
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$224	\$36	\$96	\$0	\$356	\$71	\$0	\$85	\$513	\$1
5.12	Gas Cleanup Foundations	\$0	\$382	\$413	\$0	\$795	\$159	\$0	\$191	\$1,145	\$2
	Subtotal	\$128,877	\$52,570	\$112,723	\$0	\$294,169	\$58,834	\$45,141	\$79,629	\$477,772	\$741
6 Combustion Turbine & Accessories											
6.1	Combustion Turbine Generator	\$72,224	\$0	\$4,395	\$0	\$76,619	\$15,324	\$0	\$13,791	\$105,735	\$164
6.3	Combustion Turbine Accessories	\$2,626	\$0	\$160	\$0	\$2,786	\$557	\$0	\$501	\$3,845	\$6
6.4	Compressed Air Piping	\$0	\$867	\$196	\$0	\$1,063	\$213	\$0	\$191	\$1,467	\$2
6.5	Combustion Turbine Foundations	\$0	\$906	\$979	\$0	\$1,885	\$377	\$0	\$452	\$2,714	\$4
	Subtotal	\$74,850	\$1,773	\$5,730	\$0	\$82,353	\$16,471	\$0	\$14,937	\$113,760	\$176
7 HRSG, Ductwork, & Stack											
7.1	Heat Recovery Steam Generator	\$37,516	\$0	\$9,379	\$0	\$46,895	\$9,379	\$0	\$8,441	\$64,715	\$100
7.2	Heat Recovery Steam Generator Accessories	\$14,515	\$0	\$2,693	\$0	\$17,207	\$3,441	\$0	\$3,097	\$23,746	\$37
7.3	Ductwork	\$0	\$879	\$611	\$0	\$1,490	\$298	\$0	\$268	\$2,057	\$3
7.4	Stack	\$8,407	\$0	\$1,559	\$0	\$9,966	\$1,993	\$0	\$1,794	\$13,753	\$21
7.5	Heat Recovery Steam Generator, Ductwork & Stack Foundations	\$0	\$655	\$615	\$0	\$1,271	\$254	\$0	\$305	\$1,830	\$3
7.6	Selective Catalytic Reduction System	\$1,465	\$616	\$859	\$0	\$2,940	\$588	\$0	\$529	\$4,057	\$6
	Subtotal	\$61,903	\$2,150	\$15,716	\$0	\$79,769	\$15,954	\$0	\$14,435	\$110,158	\$171
8 Steam Turbine & Accessories											

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B31B.90	– 2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		645					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
8.1	Steam Turbine Generator & Accessories	\$31,573	\$0	\$4,624	\$0	\$36,196	\$7,239	\$0	\$6,515	\$49,951	\$77
8.2	Steam Turbine Plant Auxiliaries	\$128	\$0	\$285	\$0	\$413	\$83	\$0	\$74	\$570	\$1
8.3	Condenser & Auxiliaries	\$4,545	\$0	\$2,434	\$0	\$6,979	\$1,396	\$0	\$1,256	\$9,631	\$15
8.4	Steam Piping	\$9,400	\$0	\$3,810	\$0	\$13,210	\$2,642	\$0	\$2,378	\$18,230	\$28
8.5	Turbine Generator Foundations	\$0	\$1,082	\$1,786	\$0	\$2,868	\$574	\$0	\$688	\$4,130	\$6
	Subtotal	\$45,647	\$1,082	\$12,938	\$0	\$59,667	\$11,933	\$0	\$10,912	\$82,513	\$128
9 Cooling Water System											
9.1	Cooling Towers	\$11,121	\$0	\$3,368	\$0	\$14,489	\$2,898	\$0	\$2,608	\$19,995	\$31
9.2	Circulating Water Pumps	\$1,465	\$0	\$90	\$0	\$1,555	\$311	\$0	\$280	\$2,146	\$3
9.3	Circulating Water System Auxiliaries	\$10,109	\$0	\$1,334	\$0	\$11,442	\$2,288	\$0	\$2,060	\$15,790	\$24
9.4	Circulating Water Piping	\$0	\$2,996	\$2,713	\$0	\$5,709	\$1,142	\$0	\$1,028	\$7,879	\$12
9.5	Make-up Water System	\$358	\$0	\$460	\$0	\$818	\$164	\$0	\$147	\$1,129	\$2
9.6	Component Cooling Water System	\$442	\$0	\$339	\$0	\$781	\$156	\$0	\$141	\$1,077	\$2
9.7	Circulating Water System Foundations	\$0	\$693	\$1,151	\$0	\$1,844	\$369	\$0	\$443	\$2,656	\$4
	Subtotal	\$23,495	\$3,689	\$9,455	\$0	\$36,639	\$7,328	\$0	\$6,706	\$50,672	\$79
11 Accessory Electric Plant											
11.1	Generator Equipment	\$2,479	\$0	\$1,870	\$0	\$4,349	\$870	\$0	\$783	\$6,002	\$9
11.2	Station Service Equipment	\$6,565	\$0	\$563	\$0	\$7,128	\$1,426	\$0	\$1,283	\$9,837	\$15
11.3	Switchgear & Motor Control	\$9,373	\$0	\$1,626	\$0	\$11,000	\$2,200	\$0	\$1,980	\$15,180	\$24
11.4	Conduit & Cable Tray	\$0	\$2,265	\$6,528	\$0	\$8,793	\$1,759	\$0	\$1,583	\$12,134	\$19
11.5	Wire & Cable	\$0	\$3,382	\$6,044	\$0	\$9,426	\$1,885	\$0	\$1,697	\$13,008	\$20
11.6	Protective Equipment	\$412	\$0	\$1,431	\$0	\$1,843	\$369	\$0	\$332	\$2,543	\$4
11.7	Standby Equipment	\$631	\$0	\$583	\$0	\$1,214	\$243	\$0	\$218	\$1,675	\$3
11.8	Main Power Transformers	\$6,022	\$0	\$123	\$0	\$6,145	\$1,229	\$0	\$1,106	\$8,480	\$13
11.9	Electrical Foundations	\$0	\$90	\$228	\$0	\$317	\$63	\$0	\$76	\$457	\$1
	Subtotal	\$25,483	\$5,736	\$18,996	\$0	\$50,215	\$10,043	\$0	\$9,058	\$69,316	\$107
12 Instrumentation & Control											
12.1	Natural Gas Combined Cycle Control Equipment	\$242	\$0	\$154	\$0	\$396	\$79	\$0	\$71	\$547	\$1
12.2	Combustion Turbine Control Equipment	\$395	\$0	\$252	\$0	\$646	\$129	\$0	\$116	\$892	\$1
12.3	Steam Turbine Control Equipment	\$388	\$0	\$247	\$0	\$635	\$127	\$0	\$114	\$877	\$1
12.4	Other Major Component Control Equipment	\$652	\$0	\$416	\$0	\$1,068	\$214	\$53	\$200	\$1,535	\$2
12.5	Signal Processing Equipment	\$543	\$0	\$17	\$0	\$559	\$112	\$0	\$101	\$772	\$1
12.6	Control Boards, Panels & Racks	\$144	\$0	\$88	\$0	\$232	\$46	\$12	\$43	\$333	\$1
12.7	Distributed Control System Equipment	\$7,996	\$0	\$244	\$0	\$8,240	\$1,648	\$412	\$1,545	\$11,845	\$18
12.8	Instrument Wiring & Tubing	\$660	\$528	\$2,112	\$0	\$3,301	\$660	\$165	\$619	\$4,745	\$7

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO
ELECTRICITY

Case:		B31B.90	– 2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:		Conceptual		
Plant Size (MW, net):		645					Cost Base:		Dec 2018		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
12.9	Other Instrumentation & Controls Equipment	\$457	\$0	\$1,059	\$0	\$1,516	\$303	\$76	\$284	\$2,179	\$3
	Subtotal	\$11,477	\$528	\$4,589	\$0	\$16,594	\$3,319	\$718	\$3,095	\$23,725	\$37
13 Improvements to Site											
13.1	Site Preparation	\$0	\$555	\$11,792	\$0	\$12,348	\$2,470	\$0	\$2,963	\$17,781	\$28
13.2	Site Improvements	\$0	\$1,786	\$2,361	\$0	\$4,147	\$829	\$0	\$995	\$5,971	\$9
13.3	Site Facilities	\$1,714	\$0	\$1,799	\$0	\$3,513	\$703	\$0	\$843	\$5,059	\$8
	Subtotal	\$1,714	\$2,342	\$15,952	\$0	\$20,008	\$4,002	\$0	\$4,802	\$28,811	\$45
14 Buildings & Structures											
14.1	Combustion Turbine Area	\$0	\$346	\$183	\$0	\$528	\$106	\$0	\$95	\$729	\$1
14.3	Steam Turbine Building	\$0	\$3,090	\$4,112	\$0	\$7,203	\$1,441	\$0	\$1,296	\$9,940	\$15
14.4	Administration Building	\$0	\$360	\$243	\$0	\$603	\$121	\$0	\$109	\$832	\$1
14.5	Circulation Water Pump House	\$0	\$79	\$39	\$0	\$119	\$24	\$0	\$21	\$164	\$0
14.6	Water Treatment Buildings	\$0	\$412	\$375	\$0	\$788	\$158	\$0	\$142	\$1,087	\$2
14.7	Machine Shop	\$0	\$537	\$344	\$0	\$881	\$176	\$0	\$159	\$1,216	\$2
14.8	Warehouse	\$0	\$419	\$252	\$0	\$671	\$134	\$0	\$121	\$926	\$1
14.9	Other Buildings & Structures	\$0	\$308	\$223	\$0	\$531	\$106	\$0	\$96	\$733	\$1
14.10	Waste Treating Building & Structures	\$0	\$705	\$1,259	\$0	\$1,965	\$393	\$0	\$354	\$2,711	\$4
	Subtotal	\$0	\$6,257	\$7,032	\$0	\$13,289	\$2,658	\$0	\$2,392	\$18,338	\$28
	Total	\$415,488	\$85,163	\$230,574	\$0	\$731,225	\$146,245	\$45,859	\$163,719	\$1,087,048	\$1,686

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-32. Case B31B.90 owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$6,899	\$11
1 Month Maintenance Materials	\$1,215	\$2
1 Month Non-fuel Consumables	\$677	\$1
1 Month Waste Disposal	\$7	\$0
25% of 1 Months Fuel Cost at 100% CF	\$3,729	\$6
2% of TPC	\$21,741	\$34
Total	\$34,268	\$53
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	\$981	\$2
0.5% of TPC (spare parts)	\$5,435	\$8
Total	\$6,417	\$10
Other Costs		
Initial Cost for Catalyst and Chemicals	\$847	\$1
Land	\$300	\$0
Other Owner's Costs	\$163,057	\$253
Financing Costs	\$29,350	\$46
Total Overnight Costs (TOC)	\$1,321,288	\$2,049
TASC Multiplier (IOU, 33 year)	1.093	
Total As-Spent Cost (TASC)	\$1,443,701	\$2,239

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-33. Case B31B.90 initial and annual operating and maintenance costs

Case:	B31B.90	– 2x1 CT NGCC w/ CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	645	Heat Rate-net (Btu/kWh):	7,169	Capacity Factor (%):	85	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	1.0	
Operating Labor Burden:		30.00	% of base	Operator:	3.3	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	6.3	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$2,776,628	\$4.305
Maintenance Labor:					\$8,261,567	\$12.810
Administrative & Support Labor:					\$2,759,549	\$4.279
Property Taxes and Insurance:					\$21,740,967	\$33.712
Total:					\$35,538,711	\$55.107
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$12,392,351	\$2.58067
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	3,216	\$1.90	\$0	\$1,895,852	\$0.39481
Makeup and Waste Water Treatment Chemicals (ton):	0	9.6	\$550	\$0	\$1,634,796	\$0.34044
Ammonia (19 wt%, ton):	0	3.50	\$300	\$0	\$325,533	\$0.06779
SCR Catalyst (ft³):	5,649	3.10	\$150	\$847,299	\$144,041	\$0.03000
CO ₂ Capture System Chemicals ^A :	Proprietary				\$1,969,571	\$0.41016
Triethylene Glycol (gal):	w/equip.	442	\$6.80	\$0	\$931,690	\$0.19402
Subtotal:				\$847,299	\$6,901,483	\$1.43721
Waste Disposal						
SCR Catalyst (ft³):	0	3.10	\$2.50	\$0	\$2,401	\$0.00050
Triethylene Glycol (gal):	0	442	\$0.35	\$0	\$47,955	\$0.00999
Thermal Reclaimer Unit Waste (ton):	0	1.751	\$38.0	\$0	\$20,643	\$0.00430
Subtotal:				\$0	\$70,998	\$0.01479
Variable Operating Costs Total:				\$847,299	\$19,364,832	\$4.03267
Fuel Cost						
Natural Gas (MMBtu):	0	110,955	\$4.42	\$0	\$152,160,133	\$31.68692
Total:				\$0	\$152,160,133	\$31.68692

^ACO₂ Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit 5-34. Case B31B.90 LCOE breakdown

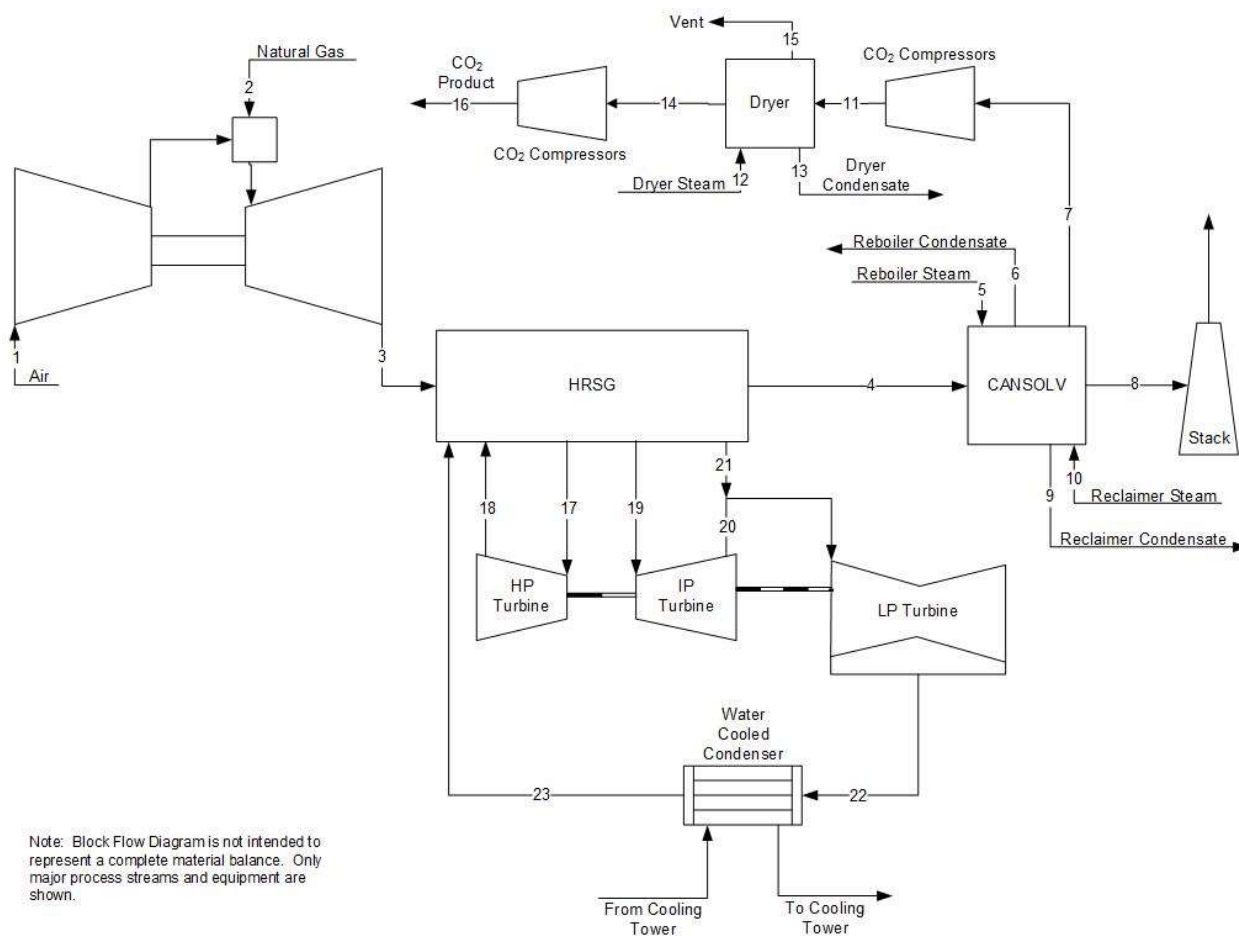
Component	Value, \$/MWh	Percentage
Capital	21.3	31%
Fixed	7.4	11%
Variable	4.0	6%
Fuel	31.7	47%
Total (Excluding T&S)	64.4	N/A
CO ₂ T&S	3.5	5%
Total (Including T&S)	67.9	N/A

5.2.11 Case B31B.95 – NGCC with 95 Percent CO₂ Capture Process Description

The plant configuration for Case B31B.95 is the same as Case B31B.90 with the exception that the CDR technology captures 95, rather than 90, percent of the CO₂ in the flue gas. The nominal net output decreases to 640 MW.

The process description for Case B31B.95 is the same as Case B31B.90. A BFD and stream tables for Case B31B.95 are shown in Exhibit 5-35 and Exhibit 5-36, respectively. Since the CDR facility process description was provided in Section 5.1.5, it is not repeated here.

Exhibit 5-35. Case B31B.95 block flow diagram, NGCC with CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-36. Case B31B.95 stream table, NGCC with capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000	0.0000	0.0096	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₂ H ₆	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0100	0.0408	0.0408	0.0000	0.0000	0.9778	0.0022	0.0000	0.0000	0.9957	0.0000
H ₂ O	0.0099	0.0000	0.0875	0.0875	1.0000	1.0000	0.0222	0.0550	1.0000	1.0000	0.0043	1.0000
N ₂	0.7732	0.0160	0.7428	0.7428	0.0000	0.0000	0.0000	0.8034	0.0000	0.0000	0.0000	0.0000
O ₂	0.2074	0.0000	0.1200	0.1200	0.0000	0.0000	0.0000	0.1297	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	132,867	5,383	138,406	138,406	14,415	13,203	5,492	127,964	129	129	5,393	8
V-L Flowrate (kg/hr)	3,834,126	93,272	3,927,398	3,927,398	259,697	237,855	238,514	3,599,707	2,330	2,330	236,738	141
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	625	100	308	105	31	38	214	356	29	356
Pressure (MPa, abs)	0.10	2.96	0.11	0.10	0.51	0.12	0.17	0.10	2.04	3.74	2.82	3.74
Steam Table Enthalpy (kJ/kg) ^A	30.23	22.04	832.68	243.99	3,080.22	439.34	49.44	127.27	913.81	3,112.11	-1.25	3,112.11
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-4,487.18	-644.44	-1,233.14	-12,900.08	-15,540.95	-8,979.10	-490.56	-15,066.49	-12,868.18	-8,976.09	-12,868.18
Density (kg/m ³)	1.2	22.1	0.4	0.9	1.9	954.9	3.0	1.1	848.5	13.8	58.0	13.8
V-L Molecular Weight	28.857	17.328	28.376	28.376	18.015	18.015	43.433	28.131	18.015	18.015	43.898	18.015
V-L Flowrate (lb _{mol} /hr)	292,921	11,867	305,132	305,132	31,781	29,108	12,107	282,112	285	285	11,889	17
V-L Flowrate (lb/hr)	8,452,800	205,630	8,658,430	8,658,430	572,535	524,382	525,834	7,935,995	5,137	5,137	521,918	310
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,156	212	586	221	88	100	416	672	85	672
Pressure (psia)	14.7	430.0	15.5	14.8	73.5	17.4	24.8	14.8	296.6	542.3	409.1	542.3
Steam Table Enthalpy (Btu/lb) ^A	13.0	9.5	358.0	104.9	1,324.3	188.9	21.3	54.7	392.9	1,338.0	-0.5	1,338.0
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-1,929.1	-277.1	-530.2	-5,546.0	-6,681.4	-3,860.3	-210.9	-6,477.4	-5,532.3	-3,859.0	-5,532.3
Density (lb/ft ³)	0.076	1.380	0.025	0.058	0.119	59.612	0.185	0.069	52.968	0.863	3.622	0.863

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-36. Case B31B.95 stream table, NGCC with capture (continued)

	13	14	15	16	17	18	19	20	21	22	23
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₂ H ₆	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0000	0.9995	0.0500	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	1.0000	0.0005	0.9500	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	8	5,371	22	5,371	26,993	26,993	31,038	31,038	4,030	20,653	34,036
V-L Flowrate (kg/hr)	141	236,321	417	236,321	486,293	486,293	559,163	559,163	72,598	372,064	613,175
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	203	29	29	30	585	356	584	308	281	38	38
Pressure (MPa, abs)	1.64	2.69	2.82	15.27	16.50	3.74	3.51	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg) ^A	863.65	-3.70	137.93	-231.09	3,528.08	3,112.11	3,642.67	3,080.22	3,024.62	2,376.10	160.78
AspenPlus Enthalpy (kJ/kg) ^B	-15,116.65	-8,967.26	-15,225.22	-9,194.65	-12,452.22	-12,868.18	-12,337.62	-12,900.08	-12,955.67	-13,604.20	-15,819.51
Density (kg/m ³)	861.8	54.9	352.5	630.1	45.6	13.8	9.0	2.0	2.0	0.1	992.8
V-L Molecular Weight	18.015	43.997	19.315	43.997	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	17	11,842	48	11,842	59,510	59,510	68,428	68,428	8,884	45,531	75,037
V-L Flowrate (lb/hr)	310	520,998	920	520,998	1,072,093	1,072,093	1,232,744	1,232,744	160,051	820,260	1,351,819
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	397	85	85	86	1,085	672	1,084	587	538	101	101
Pressure (psia)	237.4	390.4	409.1	2,214.7	2,393.1	542.3	508.6	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb) ^A	371.3	-1.6	59.3	-99.4	1,516.8	1,338.0	1,566.1	1,324.3	1,300.4	1,021.5	69.1
AspenPlus Enthalpy (Btu/lb) ^B	-6,499.0	-3,855.2	-6,545.7	-3,953.0	-5,353.5	-5,532.3	-5,304.2	-5,546.0	-5,569.9	-5,848.8	-6,801.2
Density (lb/ft ³)	53.801	3.430	22.007	39.338	2.849	0.863	0.563	0.122	0.125	0.003	61.977

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

5.2.12 Case B31B.95 – Performance Results

The Case B31B.95 modeling assumptions were presented previously in Section 5.1.

The plant produces a net output of 640 MW at a net plant efficiency of 47.3 percent (HHV basis). Overall plant performance is summarized in Exhibit 5-37. Exhibit 5-38 provides a detailed breakdown of the auxiliary power requirements. The CDR facility, including CO₂ compression, accounts for over 67 percent of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for over 13 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility.

Exhibit 5-37. Case B31B.95 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	477
Steam Turbine Power, MWe	212
Total Gross Power, MWe	690
CO ₂ Capture/Removal Auxiliaries, kWe	14,400
CO ₂ Compression, kWe	18,900
Balance of Plant, kWe	16,042
Total Auxiliaries, MWe	49
Net Power, MWe	640
HHV Net Plant Efficiency, %	47.3
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,617 (7,220)
HHV Combustion Turbine Efficiency, %	35.2
LHV Net Plant Efficiency, %	52.4
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,875 (6,516)
LHV Combustion Turbine Efficiency, %	39.0
Steam Turbine Cycle Efficiency, %	47.5
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,586 (7,190)
CO ₂ Capture Rate, %	95
Condenser Duty, GJ/hr (MMBtu/hr)	830 (787)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	1,232 (1,167)
Natural Gas Feed Flow, kg/hr (lb/hr)	93,272 (205,630)
HHV Thermal Input, kWt	1,354,905
LHV Thermal Input, kWt	1,222,936
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.027 (7.0)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.018 (4.7)

Exhibit 5-38. Case B31B.95 plant power summary

Power Summary	
Combustion Turbine Power, MWe	477
Steam Turbine Power, MWe	212
Total Gross Power, MWe	690
Auxiliary Load Summary	
Circulating Water Pumps, kWe	4,360
Combustion Turbine Auxiliaries, kWe	1,020
Condensate Pumps, kWe	170
Cooling Tower Fans, kWe	2,260
CO ₂ Capture/Removal Auxiliaries, kWe	14,400
CO ₂ Compression, kWe	18,900
Feedwater Pumps, kWe	4,830
Ground Water Pumps, kWe	410
Miscellaneous Balance of Plant ^A , kWe	570
SCR, kWe	2
Steam Turbine Auxiliaries, kWe	200
Transformer Losses, kWe	2,220
Total Auxiliaries, MWe	49
Net Power, MWe	640

^AIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

5.2.12.1 Environmental Performance

The environmental targets for emissions of NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B31B.95 is presented in Exhibit 5-39.

Exhibit 5-39. Case B31B.95 air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.001 (0.003)	51 (57)	0.010 (0.022)
Particulate	0.000 (0.000)	0 (0)	0.000 (0.000)
Hg	0.00E+0 (0.00E+0)	0.000 (0.000)	0.00E+0 (0.00E+0)
CO	0.000 (0.000)	0 (0)	0.000 (0.000)
CO ₂	3 (6)	92,613 (102,088)	18 (40)
CO ₂ ^C	—	—	19 (43)

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^cCO₂ emissions based on net power instead of gross power

For the purpose of this report, the natural gas was assumed to contain the domestic average value of total sulfur of 0.34 gr/100 scf (4.71x10⁻⁴ lb-S/MMBtu). [23] It was also assumed that the added CH₄S was the sole contributor of sulfur to the natural gas. No sulfur capture systems were required.

The NGCC cases were designed to achieve approximately 1.8 ppmvd NO_x emissions (at 15 percent O₂) using a DLN burner in the CTG—the DLN burners reduce the emissions to about 9 ppmvd (at 15 percent O₂) [34]—and an SCR—the SCR system is designed for 86.7 percent NO_x reduction. [35]

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2017 F-Class gas turbine achieves approximately 1.0 ppmv CO and 1.0 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not present in any significant amount. Any CO or PM present in the flue gas is assumed to interact with, and be removed by, the CDR system solvent.

CO₂ emissions are reduced relative to those produced by burning coal given the same power output because of the higher heat content of natural gas, the lower carbon intensity of gas relative to coal, and the higher overall efficiency of the NGCC plant relative to a coal-fired plant.

The CDR facility removes 95 percent of the CO₂ in the flue gas.

The carbon balance for the plant is shown in Exhibit 5-40. The carbon input to the plant consists of carbon in the natural gas in addition to carbon in the CT air. Carbon leaves the plant as CO₂ in the stack gas, the CO₂ dryer's vent, and the captured CO₂ product. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in, represented by the following fraction:

$$1 - \frac{\text{Carbon in Stack}}{\text{Total Carbon In}} = \left(1 - \left(\frac{7,484}{149,672} \right) \right) * 100 = 95\%$$

Exhibit 5-40. Case B31B.95 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	67,369 (148,523)	Stack Gas	3,395 (7,484)
Air (CO ₂)	521 (1,150)	CO ₂ Product	64,483 (142,160)
		CO ₂ Dryer Vent	13 (29)
		CO ₂ Knockout	0.1 (0.3)
Total	67,890 (149,672)	Total	67,890 (149,672)

As shown in Exhibit 5-41, the sulfur content of the natural gas is insignificant, comprised entirely of CH₄S (used as an odorant). [23] All sulfur in the natural gas is assumed to react with the CDR system solvent and is removed from the solvent during solvent reclaiming as a waste stream.

Exhibit 5-41. Case B31B.95 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.0 (2.2)	Stack Gas	0.0 (0.0)
		Solvent Reclaiming	1.0 (2.2)
Total	1.0 (2.2)	Total	1.0 (2.2)

Exhibit 5-42 shows the overall water balance for the plant.

Exhibit 5-42. Case B31B.95 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
CO ₂ Drying	—	—	—	0.0 (1.8)	0.0 (-1.8)
CO ₂ Capture System Makeup	—	—	—	—	—
CO ₂ Capture Recovery	—	—	—	1.9 (490)	-1.9 (-490)
CO ₂ Compression Recovery	—	—	—	0.0 (7.8)	0.0 (-7.8)
Deaerator Vent	—	—	—	0.0 (5.4)	0.0 (-5.4)
Condenser Makeup	0.0 (5.4)	—	0.0 (5.4)	—	0.0 (5.4)
BFW Makeup	0.0 (5.4)	—	0.0 (5.4)	—	0.0 (5.4)
Cooling Tower	17 (4,491)	—	17 (4,491)	3.8 (1,010)	13 (3,481)
Total	17 (4,497)	—	17 (4,497)	5.7 (1,515)	11 (2,982)

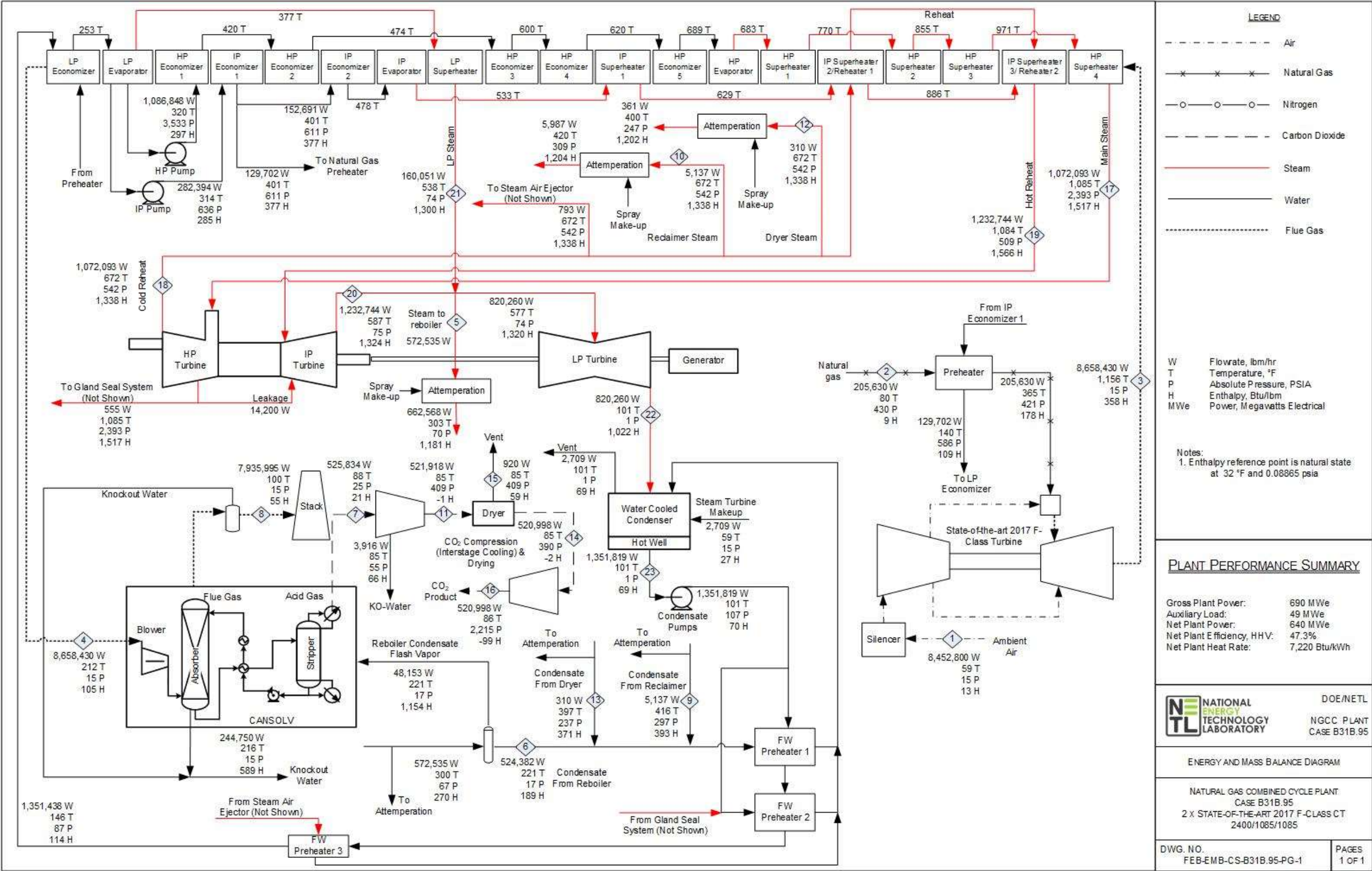
5.2.12.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram for B31B.95 is shown in Exhibit 5-43. An overall plant energy balance is provided in tabular form in Exhibit 5-44.

The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT, and 98.7 percent for the steam turbine. The cooling tower load includes the condenser, capture process heat rejected to cooling water, the CO₂ compressor intercooler load, and other miscellaneous cooling loads.

This page intentionally left blank

Exhibit 5-43. Case B31B.95 energy and mass balance, NGCC with CO₂ capture



This page intentionally left blank

Exhibit 5-44. Case B31B.95 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	4,878 (4,623)	3.3 (3.1)	–	4,881 (4,626)
Air	–	116 (110)	–	116 (110)
Raw Water Makeup	–	64 (61)	–	64 (61)
Auxiliary Power	–	–	178 (168)	178 (168)
TOTAL	4,878 (4,623)	183 (174)	178 (168)	5,238 (4,965)
Heat Out GJ/hr (MMBtu/hr)				
Stack Gas	–	458 (434)	–	458 (434)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	58 (55)	58 (55)
Cooling Tower Load ^A	–	2,220 (2,104)	–	2,220 (2,104)
CO ₂ Product Stream	–	-55 (-52)	–	-55 (-52)
AGR Effluent	–	47 (45)	–	47 (45)
Deaerator Vent	–	0.2 (0.2)	–	0.2 (0.2)
<i>Ambient Losses^B</i>	–	36 (34)	–	36 (34)
Power	–	–	2,483 (2,353)	2,483 (2,353)
TOTAL	–	2,707 (2,566)	2,541 (2,408)	5,248 (4,974)
<i>Unaccounted Energy^C</i>	–	-9.5 (-9.0)	–	-9.5 (-9.0)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers

^CBy difference

5.2.13 Case B31B.95 – Major Equipment List

Major equipment items for the NGCC plant with 95 percent CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 5.2.14. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

Case B31B.95 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	81,000 liters (21,000 gal)	2	0

**COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY**

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
2	Condensate Pumps	Vertical canned	11,320 lpm @ 90 m H ₂ O (2,990 gpm @ 300 ft H ₂ O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 4,550 lpm @ 2,940 m H ₂ O (1,200 gpm @ 9,640 ft H ₂ O) IP water: 2,360 lpm @ 470 m H ₂ O (620 gpm @ 1,550 ft H ₂ O)	2	2
4	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m ³ /min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m ³ /min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 GJ/hr (13 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,200 lpm @ 20 m H ₂ O (1,400 gpm @ 70 ft H ₂ O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	8,700 lpm @ 20 m H ₂ O (2,300 gpm @ 60 ft H ₂ O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H ₂ O (40 gpm @ 160 ft H ₂ O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
15	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
16	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	77 m ³ /min @ 3.0 MPa (2,732 acfm @ 430 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
17	Gas Metering Station	–	77 m ³ /min (2,732 acfm)	1	0

Case B31B.95 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CANSOLV	Amine-based CO ₂ capture technology	4,320,000 kg/hr (9,524,000 lb/hr) 6.3 wt % CO ₂ concentration	1	0
2	CANSOLV LP Condensate Pump	Centrifugal	757 lpm @ 1 m H ₂ O (200 gpm @ 3 ft H ₂ O)	1	1
3	CANSOLV HP Condensate Pump	Centrifugal	7 lpm @ 5 m H ₂ O (2 gpm @ 15 ft H ₂ O)	1	1
4	CO ₂ Dryer	Triethylene glycol	Inlet: 68 m ³ /min @ 2.8 MPa (2,401 acfm @ 409 psia) Outlet: 2.7 MPa (390 psia) Water Recovered: 417 kg/hr (920 lb/hr)	1	0
5	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	3.0 m ³ /min @ 15.3 MPa, 82°C (121 acfm @ 2,217 psia, 180°F)	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
6	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 37 GJ/hr (35 MMBtu/hr)	2	0

Case B31B.95 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	Advanced F class w/ dry low-NOx burner	240 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	270 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	2	0

Case B31B.95 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 5.1 m (17 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main steam - 267,462 kg/hr, 16.4 MPa/585°C (589,651 lb/hr, 2,378 psig/1,085°F) Reheat steam - 307,540 kg/hr, 3.4 MPa/584°C (678,009 lb/hr, 494 psig/1,084°F)	2	0
3	SCR Reactor	—	2,160,000 kg/hr (4,760,000 lb/hr)	2	0
4	SCR Catalyst	—	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	10 m ³ /min @ 108 cm WG (220 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	1.3 lpm @ 90 m H ₂ O (0.4 gpm @ 300 ft H ₂ O)	2	1
7	Ammonia Storage Tank	Horizontal tank	38,000 liter (10,000 gal)	1	0

Case B31B.95 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	224 MW 16.4 MPa/585°C/584°C (2,378 psig/1,085°F/1,084°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	250 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	910 GJ/hr (870 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

Case B31B.95 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	438,000 lpm @ 30 m (116,000 gpm @ 100 ft)	2	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 2,440 GJ/hr (2,310 MMBtu/hr) heat duty	1	0

Case B31B.95 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 270 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 190 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 11 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 24 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 8 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B31B.95 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

5.2.14 Case B31B.95 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 5-45 shows a detailed breakdown of the capital costs; Exhibit 5-46 shows the owner's costs, TOC, and TASC; Exhibit 5-47 shows the initial and annual O&M costs; and Exhibit 5-48 shows the LCOE breakdown.

The estimated TPC of the NGCC with CO₂ capture is \$1,727/kW. Process contingency represents 4.3 percent of the TPC and project contingency represents 15.1 percent. The LCOE, including CO₂ T&S costs of \$3.7/MWh, is \$69.1/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO
ELECTRICITY

Exhibit 5-45. Case B31B.95 total plant cost details

Case:		B31B.95	– 2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		640					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$1,698	\$2,910	\$1,455	\$0	\$6,063	\$1,213	\$0	\$1,091	\$8,367	\$13
3.2	Water Makeup & Pretreating	\$5,119	\$512	\$2,901	\$0	\$8,532	\$1,706	\$0	\$2,048	\$12,287	\$19
3.3	Other Feedwater Subsystems	\$966	\$317	\$301	\$0	\$1,583	\$317	\$0	\$285	\$2,185	\$3
3.4	Service Water Systems	\$1,554	\$2,966	\$9,604	\$0	\$14,123	\$2,825	\$0	\$3,390	\$20,337	\$32
3.5	Other Boiler Plant Systems	\$230	\$84	\$209	\$0	\$523	\$105	\$0	\$94	\$722	\$1
3.6	Natural Gas Pipeline and Start-Up System	\$9,304	\$400	\$300	\$0	\$10,005	\$2,001	\$0	\$1,801	\$13,807	\$22
3.7	Waste Water Treatment Equipment	\$9,043	\$0	\$5,543	\$0	\$14,586	\$2,917	\$0	\$3,501	\$21,003	\$33
3.9	Miscellaneous Plant Equipment	\$14,217	\$1,865	\$7,225	\$0	\$23,306	\$4,661	\$0	\$5,594	\$33,561	\$52
	Subtotal	\$42,131	\$9,053	\$27,538	\$0	\$78,722	\$15,744	\$0	\$17,803	\$112,269	\$175
5 Flue Gas Cleanup											
5.1	CANSOLV Carbon Dioxide (CO ₂) Removal System	\$106,145	\$49,875	\$104,737	\$0	\$260,757	\$52,151	\$46,936	\$71,969	\$431,813	\$674
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$27,597	\$4,140	\$11,449	\$0	\$43,186	\$8,637	\$0	\$10,365	\$62,188	\$97
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$235	\$37	\$101	\$0	\$372	\$74	\$0	\$89	\$536	\$1
5.12	Gas Cleanup Foundations	\$0	\$399	\$431	\$0	\$830	\$166	\$0	\$199	\$1,195	\$2
	Subtotal	\$133,977	\$54,451	\$116,717	\$0	\$305,145	\$61,029	\$46,936	\$82,622	\$495,733	\$774
6 Combustion Turbine & Accessories											
6.1	Combustion Turbine Generator	\$72,224	\$0	\$4,395	\$0	\$76,619	\$15,324	\$0	\$13,791	\$105,735	\$165
6.3	Combustion Turbine Accessories	\$2,626	\$0	\$160	\$0	\$2,786	\$557	\$0	\$501	\$3,845	\$6
6.4	Compressed Air Piping	\$0	\$867	\$196	\$0	\$1,063	\$213	\$0	\$191	\$1,467	\$2
6.5	Combustion Turbine Foundations	\$0	\$906	\$979	\$0	\$1,885	\$377	\$0	\$452	\$2,714	\$4
	Subtotal	\$74,850	\$1,773	\$5,730	\$0	\$82,353	\$16,471	\$0	\$14,937	\$113,760	\$178
7 HRSG, Ductwork, & Stack											
7.1	Heat Recovery Steam Generator	\$37,474	\$0	\$9,368	\$0	\$46,842	\$9,368	\$0	\$8,432	\$64,642	\$101
7.2	Heat Recovery Steam Generator Accessories	\$14,482	\$0	\$2,686	\$0	\$17,168	\$3,434	\$0	\$3,090	\$23,692	\$37
7.3	Ductwork	\$0	\$878	\$610	\$0	\$1,488	\$298	\$0	\$268	\$2,053	\$3
7.4	Stack	\$8,393	\$0	\$1,557	\$0	\$9,950	\$1,990	\$0	\$1,791	\$13,731	\$21
7.5	Heat Recovery Steam Generator, Ductwork & Stack Foundations	\$0	\$654	\$614	\$0	\$1,269	\$254	\$0	\$304	\$1,827	\$3
7.6	Selective Catalytic Reduction System	\$1,465	\$616	\$859	\$0	\$2,940	\$588	\$0	\$529	\$4,057	\$6
	Subtotal	\$61,813	\$2,148	\$15,695	\$0	\$79,656	\$15,931	\$0	\$14,414	\$110,001	\$172
8 Steam Turbine & Accessories											

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B31B.95	– 2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		640					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
8.1	Steam Turbine Generator & Accessories	\$31,256	\$0	\$4,577	\$0	\$35,833	\$7,167	\$0	\$6,450	\$49,449	\$77
8.2	Steam Turbine Plant Auxiliaries	\$127	\$0	\$283	\$0	\$410	\$82	\$0	\$74	\$565	\$1
8.3	Condenser & Auxiliaries	\$4,418	\$0	\$2,365	\$0	\$6,783	\$1,357	\$0	\$1,221	\$9,361	\$15
8.4	Steam Piping	\$9,400	\$0	\$3,810	\$0	\$13,210	\$2,642	\$0	\$2,378	\$18,230	\$28
8.5	Turbine Generator Foundations	\$0	\$1,072	\$1,770	\$0	\$2,842	\$568	\$0	\$682	\$4,092	\$6
	Subtotal	\$45,201	\$1,072	\$12,805	\$0	\$59,077	\$11,815	\$0	\$10,804	\$81,697	\$128
	9Cooling Water System										
9.1	Cooling Towers	\$11,175	\$0	\$3,384	\$0	\$14,559	\$2,912	\$0	\$2,621	\$20,092	\$31
9.2	Circulating Water Pumps	\$1,472	\$0	\$90	\$0	\$1,563	\$313	\$0	\$281	\$2,156	\$3
9.3	Circulating Water System Auxiliaries	\$10,141	\$0	\$1,338	\$0	\$11,479	\$2,296	\$0	\$2,066	\$15,842	\$25
9.4	Circulating Water Piping	\$0	\$3,008	\$2,724	\$0	\$5,732	\$1,146	\$0	\$1,032	\$7,910	\$12
9.5	Make-up Water System	\$359	\$0	\$461	\$0	\$820	\$164	\$0	\$148	\$1,132	\$2
9.6	Component Cooling Water System	\$443	\$0	\$340	\$0	\$784	\$157	\$0	\$141	\$1,082	\$2
9.7	Circulating Water System Foundations	\$0	\$696	\$1,156	\$0	\$1,851	\$370	\$0	\$444	\$2,666	\$4
	Subtotal	\$23,591	\$3,704	\$9,494	\$0	\$36,789	\$7,358	\$0	\$6,733	\$50,880	\$79
	11Accessory Electric Plant										
11.1	Generator Equipment	\$2,473	\$0	\$1,866	\$0	\$4,339	\$868	\$0	\$781	\$5,988	\$9
11.2	Station Service Equipment	\$6,727	\$0	\$577	\$0	\$7,305	\$1,461	\$0	\$1,315	\$10,080	\$16
11.3	Switchgear & Motor Control	\$9,606	\$0	\$1,667	\$0	\$11,272	\$2,254	\$0	\$2,029	\$15,555	\$24
11.4	Conduit & Cable Tray	\$0	\$2,321	\$6,689	\$0	\$9,011	\$1,802	\$0	\$1,622	\$12,435	\$19
11.5	Wire & Cable	\$0	\$3,465	\$6,194	\$0	\$9,659	\$1,932	\$0	\$1,739	\$13,330	\$21
11.6	Protective Equipment	\$430	\$0	\$1,492	\$0	\$1,922	\$384	\$0	\$346	\$2,652	\$4
11.7	Standby Equipment	\$630	\$0	\$582	\$0	\$1,212	\$242	\$0	\$218	\$1,672	\$3
11.8	Main Power Transformers	\$5,974	\$0	\$122	\$0	\$6,096	\$1,219	\$0	\$1,097	\$8,412	\$13
11.9	Electrical Foundations	\$0	\$89	\$227	\$0	\$316	\$63	\$0	\$76	\$455	\$1
	Subtotal	\$25,840	\$5,876	\$19,416	\$0	\$51,131	\$10,226	\$0	\$9,223	\$70,580	\$110
	12Instrumentation & Control										
12.1	Natural Gas Combined Cycle Control Equipment	\$243	\$0	\$155	\$0	\$398	\$80	\$0	\$72	\$550	\$1
12.2	Combustion Turbine Control Equipment	\$395	\$0	\$252	\$0	\$646	\$129	\$0	\$116	\$892	\$1
12.3	Steam Turbine Control Equipment	\$390	\$0	\$248	\$0	\$638	\$128	\$0	\$115	\$881	\$1
12.4	Other Major Component Control Equipment	\$656	\$0	\$418	\$0	\$1,075	\$215	\$54	\$201	\$1,545	\$2
12.5	Signal Processing Equipment	\$546	\$0	\$17	\$0	\$562	\$112	\$0	\$101	\$776	\$1
12.6	Control Boards, Panels & Racks	\$145	\$0	\$88	\$0	\$233	\$47	\$12	\$44	\$335	\$1
12.7	Distributed Control System Equipment	\$8,045	\$0	\$246	\$0	\$8,291	\$1,658	\$415	\$1,554	\$11,918	\$19
12.8	Instrument Wiring & Tubing	\$664	\$531	\$2,125	\$0	\$3,321	\$664	\$166	\$623	\$4,774	\$7

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO
ELECTRICITY

Case:		B31B.95	– 2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		640					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
12.9	Other Instrumentation & Controls Equipment	\$460	\$0	\$1,065	\$0	\$1,525	\$305	\$76	\$286	\$2,193	\$3
	Subtotal	\$11,543	\$531	\$4,615	\$0	\$16,690	\$3,338	\$722	\$3,112	\$23,862	\$37
	13										
13.1	Site Preparation	\$0	\$554	\$11,771	\$0	\$12,326	\$2,465	\$0	\$2,958	\$17,749	\$28
13.2	Site Improvements	\$0	\$1,783	\$2,356	\$0	\$4,139	\$828	\$0	\$993	\$5,961	\$9
13.3	Site Facilities	\$1,711	\$0	\$1,795	\$0	\$3,507	\$701	\$0	\$842	\$5,050	\$8
	Subtotal	\$1,711	\$2,337	\$15,923	\$0	\$19,972	\$3,994	\$0	\$4,793	\$28,759	\$45
	14										
14.1	Combustion Turbine Area	\$0	\$346	\$183	\$0	\$528	\$106	\$0	\$95	\$729	\$1
14.3	Steam Turbine Building	\$0	\$3,067	\$4,081	\$0	\$7,148	\$1,430	\$0	\$1,287	\$9,865	\$15
14.4	Administration Building	\$0	\$359	\$243	\$0	\$602	\$120	\$0	\$108	\$831	\$1
14.5	Circulation Water Pump House	\$0	\$80	\$39	\$0	\$119	\$24	\$0	\$21	\$165	\$0
14.6	Water Treatment Buildings	\$0	\$414	\$377	\$0	\$791	\$158	\$0	\$142	\$1,092	\$2
14.7	Machine Shop	\$0	\$537	\$344	\$0	\$880	\$176	\$0	\$158	\$1,215	\$2
14.8	Warehouse	\$0	\$418	\$252	\$0	\$670	\$134	\$0	\$121	\$925	\$1
14.9	Other Buildings & Structures	\$0	\$308	\$223	\$0	\$531	\$106	\$0	\$96	\$733	\$1
14.10	Waste Treating Building & Structures	\$0	\$704	\$1,258	\$0	\$1,962	\$392	\$0	\$353	\$2,707	\$4
	Subtotal	\$0	\$6,233	\$7,000	\$0	\$13,232	\$2,646	\$0	\$2,382	\$18,261	\$29
	Total	\$420,658	\$87,178	\$234,932	\$0	\$742,768	\$148,554	\$47,658	\$166,823	\$1,105,803	\$1,727

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-46. Case B31B.95 owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$6,988	\$11
1 Month Maintenance Materials	\$1,236	\$2
1 Month Non-fuel Consumables	\$692	\$1
1 Month Waste Disposal	\$7	\$0
25% of 1 Months Fuel Cost at 100% CF	\$3,729	\$6
2% of TPC	\$22,116	\$35
Total	\$34,769	\$54
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	\$1,011	\$2
0.5% of TPC (spare parts)	\$5,529	\$9
Total	\$6,540	\$10
Other Costs		
Initial Cost for Catalyst and Chemicals	\$847	\$1
Land	\$300	\$0
Other Owner's Costs	\$165,871	\$259
Financing Costs	\$29,857	\$47
Total Overnight Costs (TOC)	\$1,343,987	\$2,099
TASC Multiplier (IOU, 33 year)	1.093	
Total As-Spent Cost (TASC)	\$1,468,503	\$2,293

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-47. Case B31B.95 initial and annual operating and maintenance costs

Case:	B31B.95	-2x1 CT NGCC w/ CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	640	Heat Rate-net (Btu/kWh):	7,220		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	1.0	
Operating Labor Burden:		30.00	% of base	Operator:	3.3	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	6.3	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$2,776,628	\$4.336
Maintenance Labor:					\$8,404,105	\$13.124
Administrative & Support Labor:					\$2,795,183	\$4.365
Property Taxes and Insurance:					\$22,116,067	\$34.537
Total:					\$36,091,984	\$56.362
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$12,606,158	\$2.64385
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	3,238	\$1.90	\$0	\$1,908,434	\$0.40025
Makeup and Waste Water Treatment Chemicals (ton):	0	9.6	\$550	\$0	\$1,645,645	\$0.34514
Ammonia (19 wt%, ton):	0	3.50	\$300	\$0	\$325,651	\$0.06830
SCR Catalyst (ft³):	5,649	3.10	\$150	\$847,299	\$144,041	\$0.03021
CO ₂ Capture System Chemicals ^A :	Proprietary				\$2,055,608	\$0.43112
Triethylene Glycol (gal):	w/equip.	466	\$6.80	\$0	\$983,451	\$0.20626
Subtotal:				\$847,299	\$7,062,830	\$1.48127
Waste Disposal						
SCR Catalyst (ft³):	0	3.10	\$2.50	\$0	\$2,401	\$0.00050
Triethylene Glycol (gal):	0	466	\$0.35	\$0	\$50,619	\$0.01062
Thermal Reclaimer Unit Waste (ton):	0	1.831	\$38.0	\$0	\$21,582	\$0.00453
Subtotal:				\$0	\$74,602	\$0.01565
Variable Operating Costs Total:				\$847,299	\$19,743,590	\$4.14076
Fuel Cost						
Natural Gas (MMBtu):	0	110,955	\$4.42	\$0	\$152,160,133	\$31.91207
Total:				\$0	\$152,160,133	\$31.91207

^ACO₂ Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit 5-48. Case B31B.95 LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	21.8	32%
Fixed	7.6	11%
Variable	4.1	6%
Fuel	31.9	46%
Total (Excluding T&S)	65.4	N/A
CO ₂ T&S	3.7	5%
Total (Including T&S)	69.1	N/A

5.3 H-FRAME NGCC CASES

This section contains an evaluation of plant designs for cases B32A, B32B.90, and B32B.95. The balance of this section is organized as follows:

- Key System Assumptions is a summary of study and modeling assumptions relevant to cases B32A, B32B.90, and B32B.95.
- Sparing Philosophy is provided for cases B32A, B32B.90, and B32B.95.
- Process and System Description provides an overview of the technology operation as applied to cases B32A, B32B.90, and B32B.95. The systems that are common to all NGCC cases were covered in Section 5.3.3. and only features that are unique to cases B32A, B32B.90, and B32B.95 are discussed further in this section.
- Performance Results provides the main modeling results from cases B32A, B32B.90, and B32B.95, including the performance summary, environmental performance, carbon balance, water balance, mass and energy balance diagrams, and energy balance table.
- Equipment List provides an itemized list of major equipment for cases B32A, B32B.90, and B32B.95 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs for cases B32A, B32B.90, and B32B.95.

5.3.1 Key System Assumptions

System assumptions for cases B32A, B32B.90, and B32B.95 are compiled in Exhibit 5-49.

Exhibit 5-49. NGCC H-frame plant study configuration matrix

	Case B32A w/o CO ₂ Capture	Case B32B.90 w/CO ₂ Capture	Case B32B.95 w/o CO ₂ Capture
Steam Cycle, MPa/°C/°C (psia/°F/°F)	18.5/585/562 (2,683/1,085/1,044)		
Fuel	Natural Gas		
Fuel Pressure at Plant Battery Limit MPa (psia)	3.8 (550)		
Condenser Pressure, mm Hg (in. Hg)	50.8 (2)		
Cooling Water to Condenser, °C (°F)	16 (60)		
Cooling Water from Condenser, °C (°F)	27 (80)		
Stack Temperature, °C (°F)	82 (181)	38 (100)	38 (100)
SO ₂ Control	Low Sulfur Fuel		
NO _x Control	LNB and SCR		
SCR Efficiency, % ^A	85.4	86.4	86.5
Ammonia Slip (End of Catalyst Life), ppmv	10		
Particulate Control	N/A		
Mercury Control	N/A		
CO ₂ Control	N/A	CANSOLV	
Overall Carbon Capture, % ^A	N/A	90	95
CO ₂ Sequestration	N/A	Off-site Saline Formation	

^ARemoval efficiencies are based on the flue gas content

5.3.1.1 Balance of Plant – B32A, B32B.90, and B32B.95

The balance of plant assumptions are generally common to both F-frame and H-frame NGCC cases. The one discrepancy between the cases is that for H-frame NGCC, the natural gas pipeline supply is at 3.8 MPa (550 psia) and 27°C (80°F). Balance of plant assumptions are presented in Exhibit 5-50.

Exhibit 5-50. NGCC balance of plant assumptions

Parameter	Value
Cooling System	Recirculating Wet Cooling Tower
Fuel and Other Storage	
Natural Gas	Pipeline supply at 3.8 MPa (550 psia) and 27°C (80°F)
Plant Distribution Voltage	
Motors below 1 hp	110/220 V
Motors between 1 hp and 250 hp	480 V

Parameter	Value
Motors between 250 hp and 5,000 hp	4,160 V
Motors above 5,000 hp	13,800 V
Steam and CT generators	18,000 V
Grid Interconnection voltage	345 kV
<u>Water and Wastewater</u>	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and DI water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 m ³ /d (1,500 gpd)
Water Discharge	Blowdown is treated for chloride and metals and discharged.

5.3.2 Sparing Philosophy

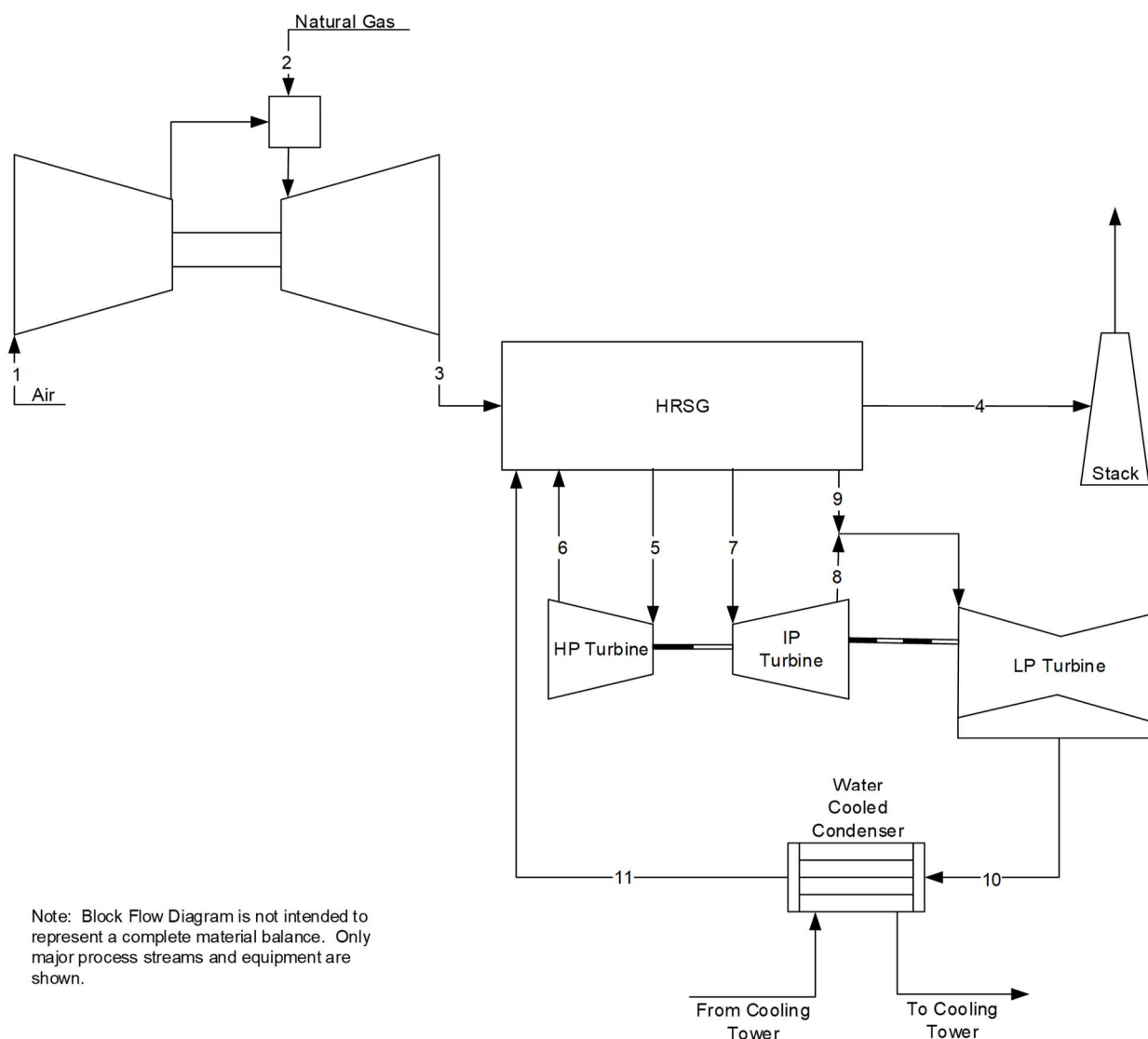
Dual trains are used to accommodate the size of commercial CTs. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- Two state-of-the-art 2017 H-Class CTGs (2 x 50 percent)
- Two 3-pressure reheat HRSGs with self-supporting stacks and SCR systems (2 x 50 percent)
- One 3-pressure reheat, triple-admission STG (1 x 100 percent)
- For Cases B32B.90 and B32B.95, one CO₂ absorption system, consisting of an absorber, stripper, and ancillary equipment (1 x 100 percent) and two CO₂ compression systems (2 x 50 percent)

5.3.3 Case B32A – NGCC without CO₂ Capture Process Description

In this section, the NGCC process without CO₂ capture is described. The system description follows the BFD in Exhibit 5-51 and stream numbers reference the same exhibit. Exhibit 5-52 provides process data for the numbered streams in the BFD. The BFD shows only one of the two CT/HRSG trains, but the flow rates in the stream table are the total for two systems.

Exhibit 5-51. Case B32A block flow diagram, NGCC without CO₂ capture



For case B32A, ambient air (stream 1) is supplied to an inlet filter and compressed before being combined with natural gas (stream 2) in the dry LNB, which is operated to control the rotor inlet temperature at 1,447°C (2,636°F). The flue gas exits the turbine at 596°C (1,105°F) (stream 3) and passes into the HRSG. The HRSG generates both the main steam and reheat steam for the steam turbine. Flue gas exits the HRSG at 86°C (187°F) (stream 4) and passes to the plant stack.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-52. Case B32A stream table, NGCC without capture

	1	2	3	4	5	6	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₂ H ₆	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0100	0.0408	0.0408	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0000	0.0873	0.0873	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N ₂	0.7732	0.0160	0.7429	0.7429	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.2074	0.0000	0.1201	0.1201	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	177,074	7,158	184,439	184,439	31,382	31,382	38,734	38,734	5,627	44,362	44,401
V-L Flowrate (kg/hr)	5,109,811	124,025	5,233,836	5,233,836	565,348	565,348	697,809	697,809	101,377	799,186	799,904
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	596	86	585	336	562	296	287	38	38
Pressure (MPa, abs)	0.10	3.79	0.11	0.10	18.50	3.62	3.31	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg) ^A	30.23	12.56	798.45	228.81	3,509.09	3,066.29	3,593.96	3,054.97	3,037.05	2,359.81	160.78
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-4,496.67	-675.71	-1,245.35	-12,471.21	-12,914.01	-12,386.33	-12,925.33	-12,943.24	-13,620.48	-15,819.51
Density (kg/m ³)	1.2	28.8	0.4	1.0	51.8	13.9	8.7	2.0	2.0	0.1	992.8
V-L Molecular Weight	28.857	17.328	28.377	28.377	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	390,381	15,780	406,618	406,618	69,185	69,185	85,395	85,395	12,406	97,801	97,888
V-L Flowrate (lb/hr)	11,265,204	273,429	11,538,633	11,538,633	1,246,380	1,246,380	1,538,406	1,538,406	223,498	1,761,904	1,763,487
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,105	187	1,085	637	1,044	565	549	101	101
Pressure (psia)	14.7	550.0	15.5	14.8	2,683.2	525.0	479.8	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb) ^A	13.0	5.4	343.3	98.4	1,508.6	1,318.3	1,545.1	1,313.4	1,305.7	1,014.5	69.1
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-1,933.2	-290.5	-535.4	-5,361.7	-5,552.0	-5,325.2	-5,556.9	-5,564.6	-5,855.8	-6,801.2
Density (lb/ft ³)	0.076	1.799	0.026	0.060	3.233	0.869	0.546	0.125	0.124	0.003	61.977

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

5.3.4 Case B32A – Performance Results

The plant produces a net output of 992 MW at a net plant efficiency of 55.1 percent (HHV basis).

Overall plant performance is summarized in Exhibit 5-53; Exhibit 5-54 provides a detailed breakdown of the auxiliary power requirements.

Exhibit 5-53. Case B32A plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	686
Steam Turbine Power, MWe	324
Total Gross Power, MWe	1,009
CO ₂ Capture/Removal Auxiliaries, kWe	–
CO ₂ Compression, kWe	–
Balance of Plant, kWe	16,923
Total Auxiliaries, MWe	17
Net Power, MWe	992
HHV Net Plant Efficiency, %	55.1
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,537 (6,196)
HHV Combustion Turbine Efficiency, %	38.0
LHV Net Plant Efficiency, %	61.0
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	5,900 (5,592)
LHV Combustion Turbine Efficiency, %	42.2
Steam Turbine Cycle Efficiency, %	39.1
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	9,213 (8,732)
CO ₂ Capture Rate, %	0
Condenser Duty, GJ/hr (MMBtu/hr)	1,757 (1,666)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	–
Natural Gas Feed Flow, kg/hr (lb/hr)	124,025 (273,429)
HHV Thermal Input, kWt	1,801,631
LHV Thermal Input, kWt	1,626,150
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.014 (3.6)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.011 (2.8)

Exhibit 5-54. Case B32A plant power summary

Power Summary	
Combustion Turbine Power, MWe	686
Steam Turbine Power, MWe	324
Total Gross Power, MWe	1,009
Auxiliary Load Summary	
Circulating Water Pumps, kWe	3,510
Combustion Turbine Auxiliaries, kWe	1,320
Condensate Pumps, kWe	180
Cooling Tower Fans, kWe	1,810
CO ₂ Capture/Removal Auxiliaries, kWe	–
CO ₂ Compression, kWe	–
Feedwater Pumps, kWe	5,760
Ground Water Pumps, kWe	330
Miscellaneous Balance of Plant ^A , kWe	710
SCR, kWe	3
Steam Turbine Auxiliaries, kWe	230
Transformer Losses, kWe	3,070
Total Auxiliaries, MWe	17
Net Power, MWe	992

^AIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

5.3.4.1 Environmental Performance

The environmental targets for emissions of NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B32A is presented in Exhibit 5-55.

Exhibit 5-55. Case B32A air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.001)	20 (22)	0.003 (0.006)
NO _x	0.002 (0.004)	74 (82)	0.010 (0.022)
Particulate	0.001 (0.002)	39 (43)	0.005 (0.011)
Hg	0.00E+0 (0.00E+0)	0.000 (0.000)	0.00E+0 (0.00E+0)
CO	0.001 (0.002)	38 (42)	0.005 (0.011)
CO ₂	51 (119)	2,463,003 (2,714,996)	328 (723)
CO ₂ ^C	–	–	333 (735)

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

For the purpose of this report, the natural gas was assumed to contain the domestic average value of total sulfur of 0.34 gr/100 scf (4.71×10^{-4} lb-S/MMBtu). [23] It was also assumed that the added CH₄S was the sole contributor of sulfur to the natural gas. No sulfur capture systems were required.

The NGCC cases were designed to achieve approximately 1.8 ppmvd NO_x emissions (at 15 percent O₂) using a DLN burner in the CTG—the DLN burners reduce the emissions to about 9 ppmvd (at 15 percent O₂) [34]—and an SCR—the SCR system is designed for 85.4 percent NO_x reduction. [35]

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2017 H-class gas turbine achieves approximately 1.0 ppmv carbon monoxide (CO) and PM emissions. The production of PM is a result of system inefficiencies and is not produced or emitted in any significant amount.

CO₂ emissions are reduced relative to those produced by burning coal given the same power output because of the higher heat content of natural gas, the lower carbon intensity of gas relative to coal, and the higher overall efficiency of the NGCC plant relative to a coal-fired plant.

The carbon balance for the plant is shown in Exhibit 5-56. The carbon input to the plant consists of carbon in the natural gas and carbon as CO₂ in the CT air. Carbon leaves the plant as CO₂ through the stack.

Exhibit 5-56. Case B32A carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	89,581 (197,492)	Stack Gas	90,276 (199,024)
Air (CO ₂)	695 (1,532)	CO ₂ Product	—
		CO ₂ Dryer Vent	—
		CO ₂ Knockout	—
Total	90,276 (199,024)	Total	90,276 (199,024)

As shown in Exhibit 5-57, the sulfur content of the natural gas is insignificant. All sulfur in the natural gas is emitted in the stack gas.

Exhibit 5-57. Case B32A sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.3 (2.9)	Stack Gas	1.3 (2.9)
		Solvent Reclaiming	–
Total	1.3 (2.9)	Total	1.3 (2.9)

Exhibit 5-58 shows the water balance for Case B32A.

Exhibit 5-58. Case B32A water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
CO ₂ Drying	–	–	–	–	–
CO ₂ Capture System Makeup	–	–	–	–	–
CO ₂ Capture Recovery	–	–	–	–	–
CO ₂ Compression Recovery	–	–	–	–	–
Deaerator Vent	–	–	–	0.0 (7.1)	0.0 (–7.1)
Condenser Makeup	0.0 (7.1)	–	0.0 (7.1)	–	0.0 (7.1)
BFW Makeup	0.0 (7.1)	–	0.0 (7.1)	–	0.0 (7.1)
Cooling Tower	14 (3,608)	–	14 (3,608)	3.1 (811)	11 (2,797)
Total	14 (3,615)	–	14 (3,615)	3.1 (819)	11 (2,797)

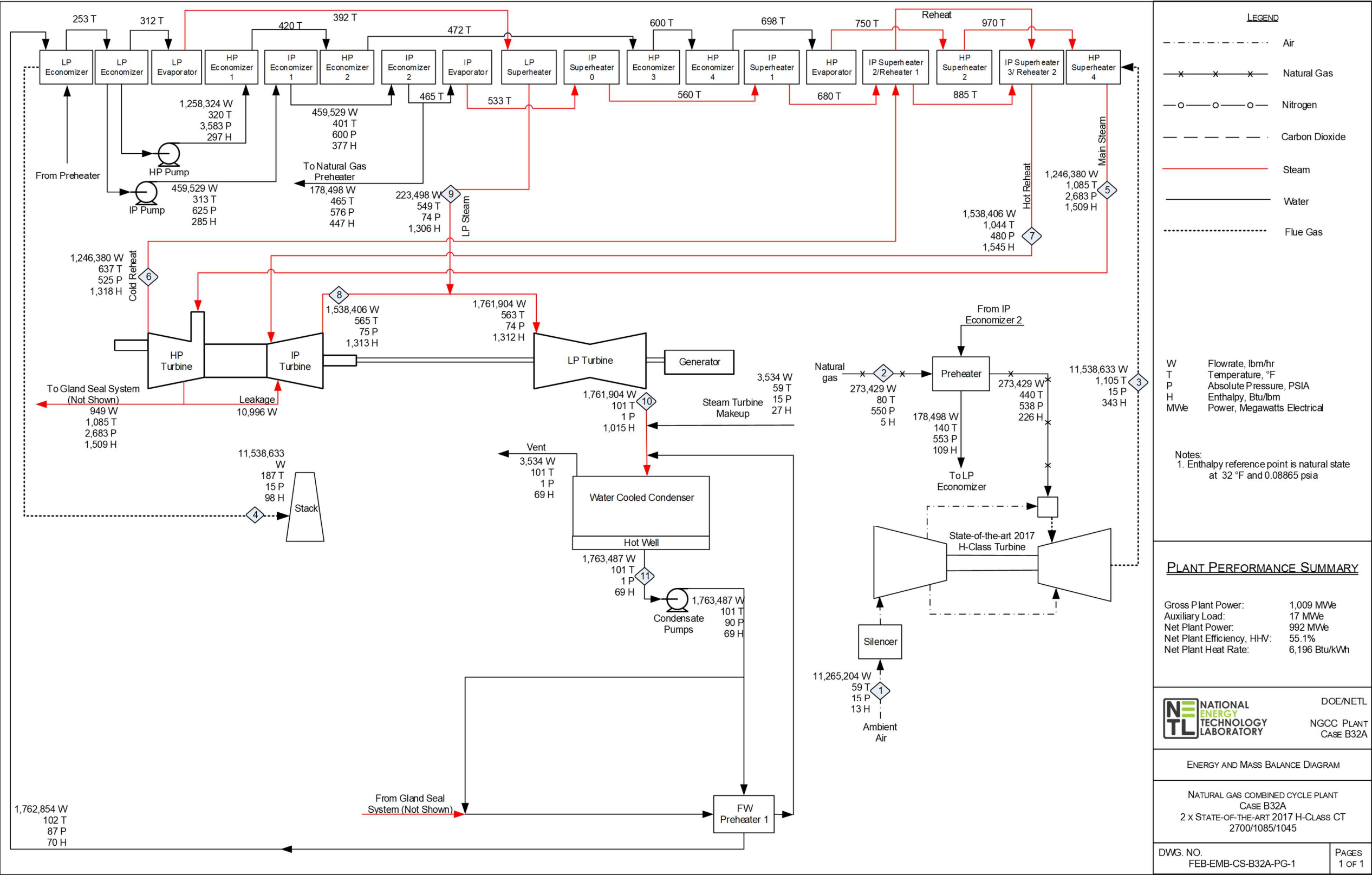
Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a surface-water source for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from groundwater. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for all purposes, such as condenser and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

5.3.4.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram for B32A is shown in Exhibit 5-59. An overall plant energy balance is provided in tabular form in Exhibit 5-60. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT, and 98.7 percent for the steam turbine.

This page intentionally left blank

Exhibit 5-59. Case B32A energy and mass balance, NGCC without CO₂ capture



This page intentionally left blank

Exhibit 5-60. Case B32A overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	6,486 (6,147)	4.3 (4.1)	–	6,490 (6,152)
Air	–	154 (146)	–	154 (146)
Raw Water Makeup	–	51 (49)	–	51 (49)
Auxiliary Power	–	–	61 (58)	61 (58)
TOTAL	6,486 (6,147)	210 (199)	61 (58)	6,757 (6,404)
Heat Out GJ/hr (MMBtu/hr)				
Stack Gas	–	1,198 (1,135)	–	1,198 (1,135)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	81 (76)	81 (76)
Cooling Tower Load ^A	–	1,784 (1,691)	–	1,784 (1,691)
CO ₂ Product Stream	–	–	–	–
Deaerator Vent	–	0.3 (0.2)	–	0.3 (0.2)
<i>Ambient Losses^B</i>	–	39 (37)	–	39 (37)
Power	–	–	3,633 (3,443)	3,633 (3,443)
TOTAL	–	3,021 (2,863)	3,713 (3,520)	6,734 (6,383)
Unaccounted Energy ^C	–	23 (22)	–	23 (22)

^AIncludes condenser, acid gas removal (AGR), and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers

^CBy difference

5.3.5 Case B32A – Major Equipment List

Major equipment items for the H-class plant with no CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 5.3.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

Case B32A – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	106,000 liters (28,000 gal)	2	0
2	Condensate Pumps	Vertical canned	14,770 lpm @ 80 m H ₂ O (3,900 gpm @ 250 ft H ₂ O)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 5,270 lpm @ 2,980 m H ₂ O (1,390 gpm @ 9,780 ft H ₂ O)	2	2
			IP water: 3,850 lpm @ 460 m H ₂ O (1,020 gpm @ 1,520 ft H ₂ O)		
4	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m ³ /min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m ³ /min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 GJ/hr (13 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,200 lpm @ 20 m H ₂ O (1,400 gpm @ 70 ft H ₂ O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	7,700 lpm @ 20 m H ₂ O (2,000 gpm @ 60 ft H ₂ O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H ₂ O (40 gpm @ 160 ft H ₂ O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
15	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
16	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	79 m ³ /min @ 3.8 MPa (2,787 acfm @ 550 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
17	Gas Metering Station	–	79 m ³ /min (2,787 acfm)	1	0

Case B32A – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	Advanced H class w/ dry low-NOx burner	345 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	380 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B32A – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 6.6 m (22 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main steam - 310,942 kg/hr, 18.4 MPa/585°C (685,509 lb/hr, 2,669 psig/1,085°F) Reheat steam – 383,796 kg/hr, 3.2 MPa/562°C (846,123 lb/hr, 465 psig/1,044°F)	2	0
3	SCR Reactor	–	2,880,000 kg/hr (6,350,000 lb/hr)	2	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	10 m ³ /min @ 108 cm WG (290 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	1.7 lpm @ 90 m H ₂ O (0.5 gpm @ 300 ft H ₂ O)	2	1
7	Ammonia Storage Tank	Horizontal tank	50,000 liter (13,000 gal)	1	0

Case B32A – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	341 MW 18.4 MPa/585°C/562°C (2,668 psig/1,085°F/1,044°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	380 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	1,930 GJ/hr (1,830 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

Case B32A – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	352,000 lpm @ 30 m (93,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/ 16°C (60°F) CWT/ 27°C (80°F) HWT/ 1,960 GJ/hr (1,860 MMBtu/hr) heat duty	1	0

Case B32A – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 380 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 360 MVA, 3-ph, 60 Hz	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 13 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 2 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B32A – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser black and white)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

5.3.6 Case B32A – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 5-61 shows a detailed breakdown of the capital costs; Exhibit 5-62 shows the owner's costs, TOC, and TASC; Exhibit 5-63 shows the initial and annual O&M costs; and Exhibit 5-64 shows the LCOE breakdown.

The estimated TPC of the NGCC with no CO₂ capture is \$796/kW. No process contingency was included in this case because all elements of the technology are commercially proved. The project contingency is 13.7 percent of TPC. The LCOE is \$42.7/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-61. Case B32A total plant cost details

Case:		B32A	– 2x1 CT NGCC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		992					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
3		Feedwater & Miscellaneous BOP Systems									
3.1	Feedwater System	\$1,892	\$3,244	\$1,622	\$0	\$6,758	\$1,352	\$0	\$1,216	\$9,326	\$9
3.2	Water Makeup & Pretreating	\$4,409	\$441	\$2,499	\$0	\$7,349	\$1,470	\$0	\$1,764	\$10,583	\$11
3.3	Other Feedwater Subsystems	\$1,076	\$353	\$335	\$0	\$1,765	\$353	\$0	\$318	\$2,435	\$2
3.4	Service Water Systems	\$1,338	\$2,554	\$8,272	\$0	\$12,164	\$2,433	\$0	\$2,919	\$17,517	\$18
3.5	Other Boiler Plant Systems	\$286	\$104	\$260	\$0	\$649	\$130	\$0	\$117	\$895	\$1
3.6	Natural Gas Pipeline and Start-Up System	\$12,372	\$532	\$399	\$0	\$13,304	\$2,661	\$0	\$2,395	\$18,359	\$19
3.7	Waste Water Treatment Equipment	\$5,842	\$0	\$3,581	\$0	\$9,423	\$1,885	\$0	\$2,261	\$13,569	\$14
3.9	Miscellaneous Plant Equipment	\$18,904	\$2,479	\$9,607	\$0	\$30,991	\$6,198	\$0	\$7,438	\$44,626	\$45
	Subtotal	\$46,120	\$9,707	\$26,574	\$0	\$82,401	\$16,480	\$0	\$18,428	\$117,310	\$118
6		Combustion Turbine & Accessories									
6.1	Combustion Turbine Generator	\$143,342	\$0	\$8,723	\$0	\$152,065	\$30,413	\$0	\$27,372	\$209,850	\$212
6.3	Combustion Turbine Accessories	\$3,492	\$0	\$213	\$0	\$3,705	\$741	\$0	\$667	\$5,112	\$5
6.4	Compressed Air Piping	\$0	\$1,153	\$261	\$0	\$1,414	\$283	\$0	\$255	\$1,951	\$2
6.5	Combustion Turbine Foundations	\$0	\$1,301	\$1,407	\$0	\$2,708	\$542	\$0	\$650	\$3,900	\$4
	Subtotal	\$146,834	\$2,454	\$10,603	\$0	\$159,892	\$31,978	\$0	\$28,943	\$220,813	\$223
7		HRSG, Ductwork, & Stack									
7.1	Heat Recovery Steam Generator	\$64,818	\$0	\$16,205	\$0	\$81,023	\$16,205	\$0	\$14,584	\$111,811	\$113
7.2	Heat Recovery Steam Generator Accessories	\$20,681	\$0	\$3,827	\$0	\$24,509	\$4,902	\$0	\$4,412	\$33,822	\$34
7.3	Ductwork	\$0	\$1,254	\$871	\$0	\$2,125	\$425	\$0	\$383	\$2,933	\$3
7.4	Stack	\$11,993	\$0	\$2,219	\$0	\$14,212	\$2,842	\$0	\$2,558	\$19,613	\$20
7.5	Heat Recovery Steam Generator, Ductwork & Stack Foundations	\$0	\$935	\$877	\$0	\$1,812	\$362	\$0	\$435	\$2,610	\$3
7.6	Selective Catalytic Reduction System	\$1,981	\$833	\$1,161	\$0	\$3,975	\$795	\$0	\$715	\$5,485	\$6
	Subtotal	\$99,474	\$3,021	\$25,161	\$0	\$127,656	\$25,531	\$0	\$23,087	\$176,274	\$178
8		Steam Turbine & Accessories									
8.1	Steam Turbine Generator & Accessories	\$38,223	\$0	\$5,597	\$0	\$43,820	\$8,764	\$0	\$7,888	\$60,472	\$61
8.2	Steam Turbine Plant Auxiliaries	\$170	\$0	\$387	\$0	\$557	\$111	\$0	\$100	\$769	\$1
8.3	Condenser & Auxiliaries	\$8,355	\$0	\$4,009	\$0	\$12,364	\$2,473	\$0	\$2,226	\$17,062	\$17
8.4	Steam Piping	\$10,971	\$0	\$4,446	\$0	\$15,417	\$3,083	\$0	\$2,775	\$21,275	\$21
8.5	Turbine Generator Foundations	\$0	\$1,457	\$2,407	\$0	\$3,865	\$773	\$0	\$927	\$5,565	\$6

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO
ELECTRICITY

Case:		B32A	– 2x1 CT NGCC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		992					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
	Subtotal	\$57,719	\$1,457	\$16,847	\$0	\$76,023	\$15,205	\$0	\$13,916	\$105,143	\$106
9	Cooling Water System										
9.1	Cooling Towers	\$9,602	\$0	\$2,929	\$0	\$12,531	\$2,506	\$0	\$2,256	\$17,293	\$17
9.2	Circulating Water Pumps	\$1,261	\$0	\$74	\$0	\$1,335	\$267	\$0	\$240	\$1,842	\$2
9.3	Circulating Water System Auxiliaries	\$9,119	\$0	\$1,203	\$0	\$10,322	\$2,064	\$0	\$1,858	\$14,244	\$14
9.4	Circulating Water Piping	\$0	\$2,638	\$2,389	\$0	\$5,027	\$1,005	\$0	\$905	\$6,937	\$7
9.5	Make-up Water System	\$331	\$0	\$425	\$0	\$755	\$151	\$0	\$136	\$1,042	\$1
9.6	Component Cooling Water System	\$389	\$0	\$298	\$0	\$687	\$137	\$0	\$124	\$948	\$1
9.7	Circulating Water System Foundations	\$0	\$610	\$1,013	\$0	\$1,624	\$325	\$0	\$390	\$2,338	\$2
	Subtotal	\$20,701	\$3,248	\$8,332	\$0	\$32,281	\$6,456	\$0	\$5,908	\$44,645	\$45
11	Accessory Electric Plant										
11.1	Generator Equipment	\$3,096	\$0	\$2,336	\$0	\$5,432	\$1,086	\$0	\$978	\$7,496	\$8
11.2	Station Service Equipment	\$3,392	\$0	\$291	\$0	\$3,683	\$737	\$0	\$663	\$5,082	\$5
11.3	Switchgear & Motor Control	\$4,843	\$0	\$840	\$0	\$5,683	\$1,137	\$0	\$1,023	\$7,842	\$8
11.4	Conduit & Cable Tray	\$0	\$1,170	\$3,373	\$0	\$4,543	\$909	\$0	\$818	\$6,269	\$6
11.5	Wire & Cable	\$0	\$1,747	\$3,123	\$0	\$4,870	\$974	\$0	\$877	\$6,720	\$7
11.6	Protective Equipment	\$132	\$0	\$460	\$0	\$592	\$118	\$0	\$107	\$817	\$1
11.7	Standby Equipment	\$756	\$0	\$698	\$0	\$1,454	\$291	\$0	\$262	\$2,007	\$2
11.8	Main Power Transformers	\$10,189	\$0	\$208	\$0	\$10,397	\$2,079	\$0	\$1,871	\$14,348	\$14
11.9	Electrical Foundations	\$0	\$117	\$296	\$0	\$413	\$83	\$0	\$99	\$594	\$1
	Subtotal	\$22,408	\$3,034	\$11,624	\$0	\$37,066	\$7,413	\$0	\$6,697	\$51,176	\$52
12	Instrumentation & Control										
12.1	Natural Gas Combined Cycle Control Equipment	\$212	\$0	\$135	\$0	\$347	\$69	\$0	\$62	\$478	\$0
12.2	Combustion Turbine Control Equipment	\$492	\$0	\$313	\$0	\$805	\$161	\$0	\$145	\$1,112	\$1
12.3	Steam Turbine Control Equipment	\$339	\$0	\$216	\$0	\$555	\$111	\$0	\$100	\$766	\$1
12.4	Other Major Component Control Equipment	\$573	\$0	\$365	\$0	\$938	\$188	\$0	\$169	\$1,295	\$1
12.5	Signal Processing Equipment	\$475	\$0	\$14	\$0	\$489	\$98	\$0	\$88	\$675	\$1
12.6	Control Boards, Panels & Racks	\$127	\$0	\$77	\$0	\$204	\$41	\$0	\$37	\$281	\$0
12.7	Distributed Control System Equipment	\$7,024	\$0	\$214	\$0	\$7,238	\$1,448	\$0	\$1,303	\$9,988	\$10
12.8	Instrument Wiring & Tubing	\$580	\$464	\$1,855	\$0	\$2,899	\$580	\$0	\$522	\$4,001	\$4
12.9	Other Instrumentation & Controls Equipment	\$402	\$0	\$930	\$0	\$1,332	\$266	\$0	\$240	\$1,838	\$2
	Subtotal	\$10,223	\$464	\$4,120	\$0	\$14,807	\$2,961	\$0	\$2,665	\$20,434	\$21
13	Improvements to Site										
13.1	Site Preparation	\$0	\$619	\$13,140	\$0	\$13,759	\$2,752	\$0	\$3,302	\$19,813	\$20
13.2	Site Improvements	\$0	\$1,991	\$2,629	\$0	\$4,621	\$924	\$0	\$1,109	\$6,654	\$7

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B32A	– 2x1 CT NGCC w/o CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		992					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
13.3	Site Facilities	\$1,910	\$0	\$2,004	\$0	\$3,915	\$783	\$0	\$940	\$5,637	\$6
	Subtotal	\$1,910	\$2,610	\$17,774	\$0	\$22,295	\$4,459	\$0	\$5,351	\$32,105	\$32
14 Buildings & Structures											
14.1	Combustion Turbine Area	\$0	\$497	\$262	\$0	\$759	\$152	\$0	\$137	\$1,048	\$1
14.3	Steam Turbine Building	\$0	\$3,949	\$5,253	\$0	\$9,203	\$1,841	\$0	\$1,656	\$12,700	\$13
14.4	Administration Building	\$0	\$410	\$278	\$0	\$688	\$138	\$0	\$124	\$949	\$1
14.5	Circulation Water Pumphouse	\$0	\$67	\$33	\$0	\$100	\$20	\$0	\$18	\$138	\$0
14.6	Water Treatment Buildings	\$0	\$361	\$329	\$0	\$690	\$138	\$0	\$124	\$952	\$1
14.7	Machine Shop	\$0	\$616	\$393	\$0	\$1,009	\$202	\$0	\$182	\$1,393	\$1
14.8	Warehouse	\$0	\$476	\$287	\$0	\$763	\$153	\$0	\$137	\$1,053	\$1
14.9	Other Buildings & Structures	\$0	\$338	\$246	\$0	\$584	\$117	\$0	\$105	\$806	\$1
14.10	Waste Treating Building & Structures	\$0	\$802	\$1,431	\$0	\$2,233	\$447	\$0	\$402	\$3,081	\$3
	Subtotal	\$0	\$7,516	\$8,513	\$0	\$16,029	\$3,206	\$0	\$2,885	\$22,120	\$22
	Total	\$405,390	\$33,513	\$129,547	\$0	\$568,450	\$113,690	\$0	\$107,880	\$790,020	\$796

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-62. Case B32A owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$5,123	\$5
1 Month Maintenance Materials	\$883	\$1
1 Month Non-fuel Consumables	\$341	\$0
1 Month Waste Disposal	\$0	\$0
25% of 1 Months Fuel Cost at 100% CF	\$4,959	\$5
2% of TPC	\$15,800	\$16
Total	\$27,106	\$27
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	\$381	\$0
0.5% of TPC (spare parts)	\$3,950	\$4
Total	\$4,331	\$4
Other Costs		
Initial Cost for Catalyst and Chemicals	\$1,129	\$1
Land	\$300	\$0
Other Owner's Costs	\$118,503	\$119
Financing Costs	\$21,331	\$21
Total Overnight Costs (TOC)	\$962,719	\$970
TASC Multiplier (IOU, 33 year)	1.093	
Total As-Spent Cost (TASC)	\$1,051,912	\$1,060

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-63. Case B32A initial and annual operating and maintenance costs

Case:	B32A	H-frame 2x1 CT NGCC w/o CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	992	Heat Rate-net (Btu/kWh):		6,196	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	1.0	
Operating Labor Burden:		30.00	% of base	Operator:	2.0	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	5.0	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$2,192,190	\$2.209
Maintenance Labor:					\$6,004,150	\$6.051
Administrative & Support Labor:					\$2,049,085	\$2.065
Property Taxes and Insurance:					\$15,800,394	\$15.925
Total:					\$26,045,818	\$26.251
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$9,006,224	\$1.21908
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	2,603	\$1.90	\$0	\$1,534,465	\$0.20770
Makeup and Waste Water Treatment Chemicals (ton):	0	7.75	\$550	\$0	\$1,323,172	\$0.17910
Ammonia (19 wt%, ton):	0	4.59	\$300	\$0	\$427,471	\$0.05786
SCR Catalyst (ft³):	7,527	4.12	\$150	\$1,129,110	\$191,949	\$0.02598
Subtotal:				\$1,129,110	\$3,477,057	\$0.47065
Waste Disposal						
SCR Catalyst (ft³):	0	4.12	\$2.50	\$0	\$3,199	\$0.00043
Subtotal:				\$0	\$3,199	\$0.00043
Variable Operating Costs Total:				\$1,129,110	\$12,486,480	\$1.69016
Fuel Cost						
Natural Gas (MMBtu):	0	147,538	\$4.42	\$0	\$202,328,910	\$27.38708
Total:				\$0	\$202,328,910	\$27.38708

Exhibit 5-64. Case B32A LCOE breakdown

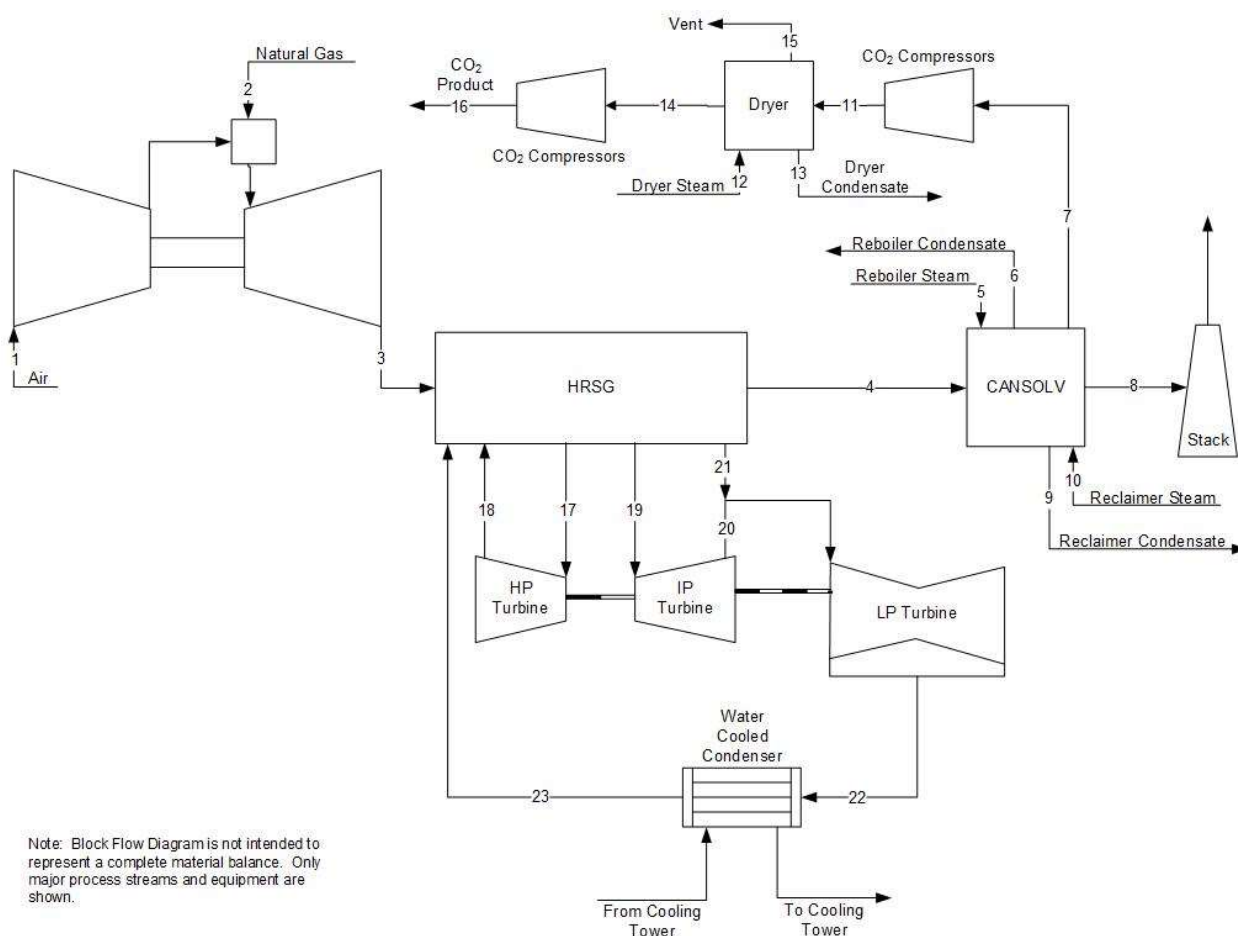
Component	Value, \$/MWh	Percentage
Capital	10.1	24%
Fixed	3.5	8%
Variable	1.7	4%
Fuel	27.4	64%
Total (Excluding T&S)	42.7	N/A
CO ₂ T&S	—	—
Total (Including T&S)	42.7	N/A

5.3.7 Case B32B.90 – NGCC with 90 Percent CO₂ Capture Process Description

The plant configuration and process description for Case B32B.90 is the same as Case B32A with the exception that the CDR technology was added for CO₂ capture. The nominal net output decreases to 883 MW because the CT designed output is fixed and the CDR facility significantly increases the auxiliary power load. Additionally, the CDR facility's steam requirements reduce the power output of the steam turbine.

The process description for Case B32B.90 is essentially the same as Case B32A with one notable exception, the addition of CO₂ capture. A BFD and stream tables for Case B32B.90 are shown in Exhibit 5-65 and Exhibit 5-66, respectively. Since the CDR facility process description was provided in Section 5.1.5, it is not repeated here.

Exhibit 5-65. Case B32B.90 block flow diagram, NGCC with CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-66. Case B32B.90 stream table, NGCC with capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000	0.0000	0.0096	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₂ H ₆	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0100	0.0408	0.0408	0.0000	0.0000	0.9778	0.0044	0.0000	0.0000	0.9957	0.0000
H ₂ O	0.0099	0.0000	0.0873	0.0873	1.0000	1.0000	0.0222	0.0550	1.0000	1.0000	0.0043	1.0000
N ₂	0.7732	0.0160	0.7429	0.7429	0.0000	0.0000	0.0000	0.8014	0.0000	0.0000	0.0000	0.0000
O ₂	0.2074	0.0000	0.1201	0.1201	0.0000	0.0000	0.0000	0.1296	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	177,074	7,158	184,439	184,439	18,350	16,807	6,918	170,972	176	176	6,794	10
V-L Flowrate (kg/hr)	5,109,811	124,025	5,233,836	5,233,836	330,582	302,778	300,468	4,815,374	3,164	3,164	298,230	181
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	596	103	296	105	31	38	214	336	29	336
Pressure (MPa, abs)	0.10	3.79	0.11	0.10	0.51	0.12	0.17	0.10	2.04	3.62	2.82	3.62
Steam Table Enthalpy (kJ/kg) ^A	30.23	12.56	798.45	246.49	3,054.97	439.34	49.44	127.14	913.81	3,066.29	-1.25	3,066.29
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-4,496.67	-675.71	-1,227.66	-12,925.33	-15,540.95	-8,979.10	-520.53	-15,066.49	-12,914.01	-8,976.09	-12,914.01
Density (kg/m ³)	1.2	28.8	0.4	0.9	2.0	954.9	3.0	1.1	848.5	13.9	58.0	13.9
V-L Molecular Weight	28.857	17.328	28.377	28.377	18.015	18.015	43.433	28.165	18.015	18.015	43.898	18.015
V-L Flowrate (lb _{mol} /hr)	390,381	15,780	406,618	406,618	40,455	37,052	15,251	376,928	387	387	14,978	22
V-L Flowrate (lb/hr)	11,265,204	273,429	11,538,633	11,538,633	728,808	667,511	662,418	10,616,083	6,976	6,976	657,485	399
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,105	217	565	221	88	100	416	637	85	637
Pressure (psia)	14.7	550.0	15.5	14.8	73.5	17.4	24.8	14.8	296.6	525.0	409.1	525.0
Steam Table Enthalpy (Btu/lb) ^A	13.0	5.4	343.3	106.0	1,313.4	188.9	21.3	54.7	392.9	1,318.3	-0.5	1,318.3
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-1,933.2	-290.5	-527.8	-5,556.9	-6,681.4	-3,860.3	-223.8	-6,477.4	-5,552.0	-3,859.0	-5,552.0
Density (lb/ft ³)	0.076	1.799	0.026	0.058	0.122	59.612	0.185	0.069	52.968	0.869	3.622	0.869

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-66. Case B32B.90 stream table, NGCC with capture (cont'd)

	13	14	15	16	17	18	19	20	21	22	23
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₂ H ₆	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0000	0.9995	0.0500	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	1.0000	0.0005	0.9500	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	10	6,766	27	6,766	31,414	31,414	38,581	38,581	5,627	25,859	42,890
V-L Flowrate (kg/hr)	181	297,704	526	297,704	565,940	565,940	695,054	695,054	101,377	465,849	772,681
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	203	29	29	30	585	336	562	296	287	38	38
Pressure (MPa, abs)	1.64	2.69	2.82	15.27	18.50	3.62	3.31	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg) ^A	863.65	-3.70	137.93	-231.09	3,509.09	3,066.29	3,593.96	3,054.97	3,037.05	2,358.86	160.78
AspenPlus Enthalpy (kJ/kg) ^B	-15,116.65	-8,967.26	-15,225.22	-9,194.65	-12,471.21	-12,914.01	-12,386.34	-12,925.33	-12,943.24	-13,621.43	-15,819.51
Density (kg/m ³)	861.8	54.9	352.5	630.1	51.8	13.9	8.7	2.0	2.0	0.1	992.8
V-L Molecular Weight	18.015	43.997	19.315	43.997	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	22	14,918	60	14,918	69,257	69,257	85,057	85,057	12,406	57,008	94,557
V-L Flowrate (lb/hr)	399	656,325	1,159	656,325	1,247,684	1,247,684	1,532,331	1,532,331	223,498	1,027,022	1,703,469
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	397	85	85	86	1,085	637	1,044	565	549	101	101
Pressure (psia)	237.4	390.4	409.1	2,214.7	2,683.2	525.0	479.8	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb) ^A	371.3	-1.6	59.3	-99.4	1,508.6	1,318.3	1,545.1	1,313.4	1,305.7	1,014.1	69.1
AspenPlus Enthalpy (Btu/lb) ^B	-6,499.0	-3,855.2	-6,545.7	-3,953.0	-5,361.7	-5,552.0	-5,325.2	-5,556.9	-5,564.6	-5,856.2	-6,801.2
Density (lb/ft ³)	53.801	3.430	22.007	39.338	3.233	0.869	0.546	0.125	0.124	0.003	61.977

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

5.3.8 Case B32B.90 – Performance Results

The Case B32B.90 modeling assumptions were presented previously in 5.3.1.

The plant produces a net output of 883 MW at a net plant efficiency of 49.0 percent (HHV basis). Overall plant performance summarized in Exhibit 5-67 provides a detailed breakdown of the auxiliary power requirements. The CDR facility, including CO₂ compression, accounts for over 67 percent of the auxiliary plant load. The CWS (CWP's and cooling tower fan) accounts for nearly 14 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility. Case B32B.90 plant power is summarized in Exhibit 5-68.

Exhibit 5-67. Case B32B.90 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	686
Steam Turbine Power, MWe	260
Total Gross Power, MWe	945
CO ₂ Capture/Removal Auxiliaries, kWe	18,000
CO ₂ Compression, kWe	23,810
Balance of Plant, kWe	20,153
Total Auxiliaries, MWe	62
Net Power, MWe	883
HHV Net Plant Efficiency, %	49.0
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,342 (6,959)
HHV Combustion Turbine Efficiency, %	38.0
LHV Net Plant Efficiency, %	54.3
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,627 (6,281)
LHV Combustion Turbine Efficiency, %	42.2
Steam Turbine Cycle Efficiency, %	46.7
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,713 (7,311)
CO ₂ Capture Rate, %	90
Condenser Duty, GJ/hr (MMBtu/hr)	1,031 (978)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	1,587 (1,505)
Natural Gas Feed Flow, kg/hr (lb/hr)	124,025 (273,429)
HHV Thermal Input, kWt	1,801,631
LHV Thermal Input, kWt	1,626,150
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.024 (6.4)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.016 (4.2)

Exhibit 5-68. Case B32B.90 plant power summary

Power Summary	
Combustion Turbine Power, MWe	686
Steam Turbine Power, MWe	260
Total Gross Power, MWe	945
Auxiliary Load Summary	
Circulating Water Pumps, kWe	5,530
Combustion Turbine Auxiliaries, kWe	1,320
Condensate Pumps, kWe	200
Cooling Tower Fans, kWe	2,860
CO ₂ Capture/Removal Auxiliaries, kWe	18,000
CO ₂ Compression, kWe	23,810
Feedwater Pumps, kWe	5,760
Ground Water Pumps, kWe	520
Miscellaneous Balance of Plant, ^A kWe	710
SCR, kWe	3
Steam Turbine Auxiliaries, kWe	230
Transformer Losses, kWe	3,020
Total Auxiliaries, MWe	62
Net Power, MWe	883

^AIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

5.3.8.1 Environmental Performance

The environmental targets for emissions of NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B32B.90 is presented in Exhibit 5-69.

Exhibit 5-69. Case B32B.90 air emissions

	kg/GJ (lb/MMBtu)	tonne/yr (Ton/year) ^A	kg/MWh _{gross} (lb/MWh _{gross})
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.001 (0.003)	69 (76)	0.010 (0.022)
Particulate	0.000 (0.000)	0 (0)	0.000 (0.000)
Hg	0.00E+0 (0.00E+0)	0.000 (0.000)	0.00E+0 (0.00E+0)
CO	0.000 (0.000)	0 (0)	0.000 (0.000)
CO ₂	5 (12)	246,300 (271,500)	35 (77)
CO ₂ ^B	—	—	37 (83)

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

For the purpose of this report, the natural gas was assumed to contain the domestic average value of total sulfur of 0.34 gr/100 scf (4.71×10^{-4} lb-S/MMBtu). [23] It was also assumed that the added CH₄S was the sole contributor of sulfur to the natural gas. No sulfur capture systems were required.

The NGCC cases were designed to achieve approximately 1.8 ppmvd NO_x emissions (at 15 percent O₂) using a DLN burner in the CTG—the DLN burners reduce the emissions to about 9 ppmvd (at 15 percent O₂) [34]—and an SCR—the SCR system is designed for 86.7 percent NO_x reduction. [35]

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2017 H-class gas turbine achieves approximately 1.0 ppmv CO and 1.0 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not present in any significant amount. Any CO or PM present in the flue gas is assumed to interact with, and be removed by, the CDR system solvent.

CO₂ emissions are reduced relative to those produced by burning coal given the same power output because of the higher heat content of natural gas, the lower carbon intensity of gas relative to coal, and the higher overall efficiency of the NGCC plant relative to a coal-fired plant.

The CDR facility removes 90 percent of the CO₂ in the flue gas.

The carbon balance for the plant is shown in Exhibit 5-70. The carbon input to the plant consists of carbon in the natural gas in addition to carbon in the CT air. Carbon leaves the plant as CO₂ in the stack gas, the CO₂ dryer's vent, and the captured CO₂ product. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in, represented by the following fraction:

$$1 - \frac{\text{Carbon in Stack}}{\text{Total Carbon In}} = \left(1 - \left(\frac{19,902}{199,024} \right) \right) * 100 = 90\%$$

Exhibit 5-70. Case B32B.90 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	89,581 (197,492)	Stack Gas	9,028 (19,902)
Air (CO ₂)	695 (1,532)	CO ₂ Product	81,234 (179,085)
		CO ₂ Dryer Vent	16 (36)
		CO ₂ Knockout	0.2 (0.4)
Total	90,276 (199,024)	Total	90,276 (199,024)

As shown in Exhibit 5-71, the sulfur content of the natural gas is insignificant, entirely comprising CH₄S (used as an odorant). [23] All sulfur in the natural gas is assumed to react with the CDR system solvent and is removed from the solvent during solvent reclaiming as a waste stream.

Exhibit 5-71. Case B32B.90 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.3 (2.9)	Stack Gas	0.0 (0.0)
		Solvent Reclaiming	1.3 (2.9)
Total	1.3 (2.9)	Total	1.3 (2.9)

Exhibit 5-72 shows the overall water balance for the plant.

Exhibit 5-72. Case B32B.90 water balance

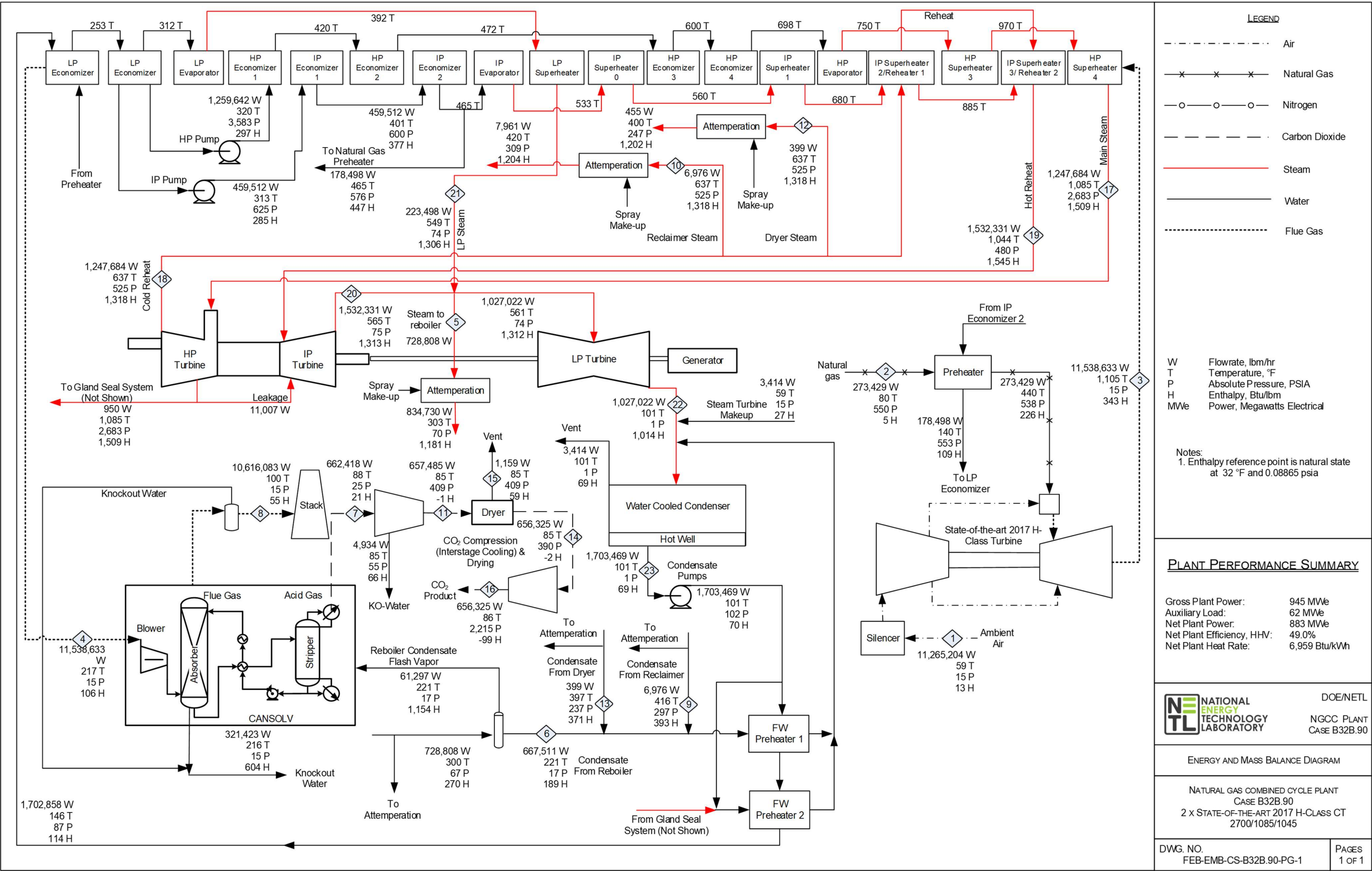
Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
CO ₂ Drying	–	–	–	0.0 (2.3)	0.0 (-2.3)
CO ₂ Capture System Makeup	–	–	–	–	–
CO ₂ Capture Recovery	–	–	–	2.4 (643)	-2.4 (-643)
CO ₂ Compression Recovery	–	–	–	0.0 (9.9)	0.0 (-9.9)
Deaerator Vent	–	–	–	0.0 (6.8)	0.0 (-6.8)
Condenser Makeup	0.0 (6.8)	–	0.0 (6.8)	–	0.0 (6.8)
BFW Makeup	0.0 (6.8)	–	0.0 (6.8)	–	0.0 (6.8)
Cooling Tower	22 (5,688)	–	22 (5,688)	4.8 (1,279)	17 (4,409)
Total	22 (5,695)	–	22 (5,695)	7.3 (1,941)	14 (3,754)

5.3.8.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram for B32B.90 is shown in Exhibit 5-73. An overall plant energy balance is provided in tabular form in Exhibit 5-74.

The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT and 98.7 percent for the steam turbine. The cooling tower load includes the condenser, capture process heat rejected to cooling water, the CO₂ compressor intercooler load, and other miscellaneous cooling loads.

Exhibit 5-73. Case B32B.90 energy and mass balance, NGCC with CO₂ capture



This page intentionally left blank

Exhibit 5-74. Case B32B.90 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	6,486 (6,147)	4.3 (4.1)	–	6,490 (6,152)
Air	–	154 (146)	–	154 (146)
Raw Water Makeup	–	81 (77)	–	81 (77)
Auxiliary Power	–	–	223 (211)	223 (211)
TOTAL	6,486 (6,147)	240 (227)	223 (211)	6,949 (6,586)
Heat Out GJ/hr (MMBtu/hr)				
Stack Gas	–	612 (580)	–	612 (580)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	80 (76)	80 (76)
Cooling Tower Load ^A	–	2,812 (2,665)	–	2,812 (2,665)
CO ₂ Product Stream	–	-69 (-65)	–	-69 (-65)
AGR Effluent	–	62 (59)	–	62 (59)
Deaerator Vent	–	0.2 (0.2)	–	0.2 (0.2)
<i>Ambient Losses^B</i>	–	43 (41)	–	43 (41)
Power	–	–	3,403 (3,226)	3,403 (3,226)
TOTAL	–	3,461 (3,280)	3,484 (3,302)	6,945 (6,582)
<i>Unaccounted Energy^C</i>	–	4.2 (4.0)	–	4.2 (4.0)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers

^CBy difference

5.3.9 Case B32B.90 – Major Equipment List

Major equipment items for the H-class plant with CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 5.3.11. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

Case B32B.90 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	102,000 liters (27,000 gal)	2	0
2	Condensate Pumps	Vertical canned	14,260 lpm @ 90 m H ₂ O (3,770 gpm @ 280 ft H ₂ O)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 5,270 lpm @ 2,980 m H ₂ O (1,390 gpm @ 9,780 ft H ₂ O)	2	2
			IP water: 3,850 lpm @ 460 m H ₂ O (1,020 gpm @ 1,520 ft H ₂ O)		
4	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m ³ /min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m ³ /min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 GJ/hr (13 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,200 lpm @ 20 m H ₂ O (1,400 gpm @ 70 ft H ₂ O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	10,900 lpm @ 20 m H ₂ O (2,900 gpm @ 60 ft H ₂ O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H ₂ O (40 gpm @ 160 ft H ₂ O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
15	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
16	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	79 m ³ /min @ 3.8 MPa (2,787 acfm @ 550 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
17	Gas Metering Station	–	79 m ³ /min (2,787 acfm)	1	0

Case B32B.90 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CANSOLV	Amine-based CO ₂ capture technology	5,757,000 kg/hr (12,692,000 lb/hr) 6.3 wt % CO ₂ concentration	1	0
2	CANSOLV LP Condensate Pump	Centrifugal	871 lpm @ 1 m H ₂ O (230 gpm @ 3 ft H ₂ O)	1	1
3	CANSOLV HP Condensate Pump	Centrifugal	8 lpm @ 5 m H ₂ O (2 gpm @ 15 ft H ₂ O)	1	1
4	CO ₂ Dryer	Triethylene glycol	Inlet: 86 m ³ /min @ 2.8 MPa (3,025 acfm @ 409 psia) Outlet: 2.7 MPa (390 psia) Water Recovered: 526 kg/hr (1,159 lb/hr)	1	0
5	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	4.0 m ³ /min @ 15.3 MPa, 82°C (153 acfm @ 2,217 psia, 180°F)	2	0
6	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 47 GJ/hr (44 MMBtu/hr)	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B32B.90 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	Advanced H class w/ dry low-NOx burner	345 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	380 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	2	0

Case B32B.90 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 5.9 m (19 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main steam – 311, 267 kg/hr, 18.4 MPa/585°C (686,226 lb/hr, 2,669 psig/1,085°F) Reheat steam – 382,280 kg/hr, 3.2 MPa/562°C (842,782 lb/hr, 465 psig/1,044°F)	2	0
3	SCR Reactor	–	2,880,000 kg/hr (6,350,000 lb/hr)	2	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	10 m ³ /min @ 108 cm WG (300 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	1.8 lpm @ 90 m H ₂ O (0.5 gpm @ 300 ft H ₂ O)	2	1
7	Ammonia Storage Tank	Horizontal tank	51,000 liter (13,000 gal)	1	0

Case B32B.90 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	274 MW 18.4 MPa/585°C/562°C (2,668 psig/1,085°F/1,044°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	300 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	1,130 GJ/hr (1,080 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

Case B32B.90 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	555,000 lpm @ 30 m (147,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 3,090 GJ/hr (2,930 MMBtu/hr) heat duty	1	0

Case B32B.90 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 380 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 240 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 13 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 29 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 10 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B32B.90 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

5.3.10 Case B32B.90 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 5-75 shows a detailed breakdown of the capital costs; Exhibit 5-76 shows the owner's costs, TOC, and TASC; Exhibit 5-77 shows the initial and annual O&M costs; and Exhibit 5-78 shows the LCOE breakdown.

The estimated TPC of the NGCC with CO₂ capture is \$1,593/kW. Process contingency represents 3.9 percent of the TPC and project contingency represents 14.9 percent. The LCOE, including CO₂ T&S costs of \$3.4/MWh, is \$64.9/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-75. Case B32B.90 total plant cost details

Case:		B32B.90	– 2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		883					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$1,894	\$3,246	\$1,623	\$0	\$6,763	\$1,353	\$0	\$1,217	\$9,333	\$11
3.2	Water Makeup & Pretreating	\$6,083	\$608	\$3,447	\$0	\$10,138	\$2,028	\$0	\$2,433	\$14,599	\$17
3.3	Other Feedwater Subsystems	\$1,077	\$353	\$336	\$0	\$1,766	\$353	\$0	\$318	\$2,437	\$3
3.4	Service Water Systems	\$1,846	\$3,524	\$11,411	\$0	\$16,781	\$3,356	\$0	\$4,027	\$24,164	\$27
3.5	Other Boiler Plant Systems	\$286	\$104	\$260	\$0	\$649	\$130	\$0	\$117	\$895	\$1
3.6	Natural Gas Pipeline and Start-Up System	\$12,372	\$532	\$399	\$0	\$13,304	\$2,661	\$0	\$2,395	\$18,359	\$21
3.7	Waste Water Treatment Equipment	\$10,785	\$0	\$6,610	\$0	\$17,394	\$3,479	\$0	\$4,175	\$25,048	\$28
3.9	Miscellaneous Plant Equipment	\$18,904	\$2,479	\$9,607	\$0	\$30,991	\$6,198	\$0	\$7,438	\$44,626	\$51
	Subtotal	\$53,246	\$10,847	\$33,692	\$0	\$97,785	\$19,557	\$0	\$22,120	\$139,462	\$158
5 Flue Gas Cleanup											
5.1	CANSOLV Carbon Dioxide (CO ₂) Removal System	\$122,385	\$57,227	\$120,178	\$0	\$299,790	\$59,958	\$53,962	\$82,742	\$496,452	\$562
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$30,338	\$4,551	\$12,586	\$0	\$47,475	\$9,495	\$0	\$11,394	\$68,364	\$77
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$284	\$45	\$122	\$0	\$451	\$90	\$0	\$108	\$649	\$1
5.12	Gas Cleanup Foundations	\$0	\$479	\$517	\$0	\$996	\$199	\$0	\$239	\$1,434	\$2
	Subtotal	\$153,007	\$62,302	\$133,403	\$0	\$348,712	\$69,742	\$53,962	\$94,483	\$566,900	\$642
6 Combustion Turbine & Accessories											
6.1	Combustion Turbine Generator	\$143,342	\$0	\$8,723	\$0	\$152,065	\$30,413	\$0	\$27,372	\$209,850	\$238
6.3	Combustion Turbine Accessories	\$3,492	\$0	\$213	\$0	\$3,705	\$741	\$0	\$667	\$5,112	\$6
6.4	Compressed Air Piping	\$0	\$1,153	\$261	\$0	\$1,414	\$283	\$0	\$255	\$1,951	\$2
6.5	Combustion Turbine Foundations	\$0	\$1,301	\$1,407	\$0	\$2,708	\$542	\$0	\$650	\$3,900	\$4
	Subtotal	\$146,834	\$2,454	\$10,603	\$0	\$159,892	\$31,978	\$0	\$28,943	\$220,813	\$250
7 HRSG, Ductwork, & Stack											
7.1	Heat Recovery Steam Generator	\$63,403	\$0	\$15,851	\$0	\$79,253	\$15,851	\$0	\$14,266	\$109,370	\$124
7.2	Heat Recovery Steam Generator Accessories	\$19,780	\$0	\$3,669	\$0	\$23,450	\$4,690	\$0	\$4,221	\$32,361	\$37
7.3	Ductwork	\$0	\$1,075	\$747	\$0	\$1,822	\$364	\$0	\$328	\$2,515	\$3
7.4	Stack	\$10,280	\$0	\$1,907	\$0	\$12,187	\$2,437	\$0	\$2,194	\$16,818	\$19
7.5	Heat Recovery Steam Generator, Ductwork & Stack Foundations	\$0	\$801	\$753	\$0	\$1,554	\$311	\$0	\$373	\$2,238	\$3
7.6	Selective Catalytic Reduction System	\$1,981	\$832	\$1,160	\$0	\$3,973	\$795	\$0	\$715	\$5,483	\$6
	Subtotal	\$95,444	\$2,709	\$24,087	\$0	\$122,240	\$24,448	\$0	\$22,096	\$168,784	\$191

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B32B.90	– 2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:		Conceptual		
Plant Size (MW, net):		883					Cost Base:		Dec 2018		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
8		Steam Turbine & Accessories									
8.1	Steam Turbine Generator & Accessories	\$32,075	\$0	\$4,697	\$0	\$36,772	\$7,354	\$0	\$6,619	\$50,745	\$57
8.2	Steam Turbine Plant Auxiliaries	\$147	\$0	\$327	\$0	\$475	\$95	\$0	\$85	\$655	\$1
8.3	Condenser & Auxiliaries	\$5,256	\$0	\$2,814	\$0	\$8,070	\$1,614	\$0	\$1,453	\$11,137	\$13
8.4	Steam Piping	\$10,971	\$0	\$4,446	\$0	\$15,417	\$3,083	\$0	\$2,775	\$21,275	\$24
8.5	Turbine Generator Foundations	\$0	\$1,242	\$2,051	\$0	\$3,293	\$659	\$0	\$790	\$4,742	\$5
	Subtotal	\$48,449	\$1,242	\$14,335	\$0	\$64,027	\$12,805	\$0	\$11,722	\$88,554	\$100
9		Cooling Water System									
9.1	Cooling Towers	\$13,278	\$0	\$4,021	\$0	\$17,299	\$3,460	\$0	\$3,114	\$23,873	\$27
9.2	Circulating Water Pumps	\$1,745	\$0	\$107	\$0	\$1,852	\$370	\$0	\$333	\$2,556	\$3
9.3	Circulating Water System Auxiliaries	\$11,386	\$0	\$1,502	\$0	\$12,888	\$2,578	\$0	\$2,320	\$17,785	\$20
9.4	Circulating Water Piping	\$0	\$3,466	\$3,139	\$0	\$6,605	\$1,321	\$0	\$1,189	\$9,115	\$10
9.5	Make-up Water System	\$394	\$0	\$507	\$0	\$901	\$180	\$0	\$162	\$1,244	\$1
9.6	Component Cooling Water System	\$511	\$0	\$392	\$0	\$903	\$181	\$0	\$163	\$1,246	\$1
9.7	Circulating Water System Foundations	\$0	\$802	\$1,331	\$0	\$2,133	\$427	\$0	\$512	\$3,072	\$3
	Subtotal	\$27,315	\$4,268	\$11,000	\$0	\$42,582	\$8,516	\$0	\$7,793	\$58,892	\$67
11		Accessory Electric Plant									
11.1	Generator Equipment	\$2,979	\$0	\$2,247	\$0	\$5,227	\$1,045	\$0	\$941	\$7,213	\$8
11.2	Station Service Equipment	\$7,783	\$0	\$668	\$0	\$8,451	\$1,690	\$0	\$1,521	\$11,662	\$13
11.3	Switchgear & Motor Control	\$11,113	\$0	\$1,928	\$0	\$13,041	\$2,608	\$0	\$2,347	\$17,997	\$20
11.4	Conduit & Cable Tray	\$0	\$2,685	\$7,739	\$0	\$10,425	\$2,085	\$0	\$1,876	\$14,386	\$16
11.5	Wire & Cable	\$0	\$4,009	\$7,166	\$0	\$11,175	\$2,235	\$0	\$2,012	\$15,422	\$17
11.6	Protective Equipment	\$552	\$0	\$1,917	\$0	\$2,469	\$494	\$0	\$444	\$3,408	\$4
11.7	Standby Equipment	\$733	\$0	\$677	\$0	\$1,410	\$282	\$0	\$254	\$1,945	\$2
11.8	Main Power Transformers	\$8,842	\$0	\$180	\$0	\$9,022	\$1,804	\$0	\$1,624	\$12,450	\$14
11.9	Electrical Foundations	\$0	\$111	\$283	\$0	\$394	\$79	\$0	\$95	\$568	\$1
	Subtotal	\$32,002	\$6,806	\$22,806	\$0	\$61,614	\$12,323	\$0	\$11,114	\$85,050	\$96
12		Instrumentation & Control									
12.1	Natural Gas Combined Cycle Control Equipment	\$251	\$0	\$160	\$0	\$410	\$82	\$0	\$74	\$566	\$1
12.2	Combustion Turbine Control Equipment	\$492	\$0	\$313	\$0	\$805	\$161	\$0	\$145	\$1,112	\$1
12.3	Steam Turbine Control Equipment	\$402	\$0	\$256	\$0	\$658	\$132	\$0	\$118	\$907	\$1
12.4	Other Major Component Control Equipment	\$681	\$0	\$434	\$0	\$1,115	\$223	\$56	\$209	\$1,602	\$2
12.5	Signal Processing Equipment	\$562	\$0	\$17	\$0	\$579	\$116	\$0	\$104	\$799	\$1
12.6	Control Boards, Panels & Racks	\$150	\$0	\$92	\$0	\$242	\$48	\$12	\$45	\$347	\$0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO
ELECTRICITY

Case:		B32B.90	– 2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		883					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
12.7	Distributed Control System Equipment	\$8,343	\$0	\$255	\$0	\$8,598	\$1,720	\$430	\$1,612	\$12,360	\$14
12.8	Instrument Wiring & Tubing	\$689	\$551	\$2,204	\$0	\$3,444	\$689	\$172	\$646	\$4,951	\$6
12.9	Other Instrumentation & Controls Equipment	\$477	\$0	\$1,105	\$0	\$1,582	\$316	\$79	\$297	\$2,274	\$3
	Subtotal	\$12,046	\$551	\$4,836	\$0	\$17,433	\$3,487	\$749	\$3,250	\$24,919	\$28
13		Improvements to Site									
13.1	Site Preparation	\$0	\$641	\$13,609	\$0	\$14,250	\$2,850	\$0	\$3,420	\$20,520	\$23
13.2	Site Improvements	\$0	\$2,061	\$2,724	\$0	\$4,786	\$957	\$0	\$1,149	\$6,891	\$8
13.3	Site Facilities	\$1,978	\$0	\$2,076	\$0	\$4,054	\$811	\$0	\$973	\$5,838	\$7
	Subtotal	\$1,978	\$2,702	\$18,409	\$0	\$23,090	\$4,618	\$0	\$5,542	\$33,249	\$38
14		Buildings & Structures									
14.1	Combustion Turbine Area	\$0	\$497	\$262	\$0	\$759	\$152	\$0	\$137	\$1,048	\$1
14.3	Steam Turbine Building	\$0	\$3,462	\$4,607	\$0	\$8,068	\$1,614	\$0	\$1,452	\$11,134	\$13
14.4	Administration Building	\$0	\$401	\$271	\$0	\$672	\$134	\$0	\$121	\$928	\$1
14.5	Circulation Water Pumphouse	\$0	\$97	\$48	\$0	\$145	\$29	\$0	\$26	\$200	\$0
14.6	Water Treatment Buildings	\$0	\$484	\$441	\$0	\$925	\$185	\$0	\$166	\$1,276	\$1
14.7	Machine Shop	\$0	\$601	\$385	\$0	\$986	\$197	\$0	\$177	\$1,361	\$2
14.8	Warehouse	\$0	\$466	\$281	\$0	\$746	\$149	\$0	\$134	\$1,030	\$1
14.9	Other Buildings & Structures	\$0	\$333	\$241	\$0	\$574	\$115	\$0	\$103	\$793	\$1
14.10	Waste Treating Building & Structures	\$0	\$784	\$1,400	\$0	\$2,184	\$437	\$0	\$393	\$3,014	\$3
	Subtotal	\$0	\$7,124	\$7,936	\$0	\$15,060	\$3,012	\$0	\$2,711	\$20,783	\$24
	Total	\$570,321	\$101,006	\$281,107	\$0	\$952,434	\$190,487	\$54,711	\$209,774	\$1,407,406	\$1,593

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-76. Case B32B.90 owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$8,421	\$10
1 Month Maintenance Materials	\$1,573	\$2
1 Month Non-fuel Consumables	\$881	\$1
1 Month Waste Disposal	\$9	\$0
25% of 1 Months Fuel Cost at 100% CF	\$4,959	\$6
2% of TPC	\$28,148	\$32
Total	\$43,991	\$50
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	\$1,288	\$1
0.5% of TPC (spare parts)	\$7,037	\$8
Total	\$8,325	\$9
Other Costs		
Initial Cost for Catalyst and Chemicals	\$1,129	\$1
Land	\$300	\$0
Other Owner's Costs	\$211,111	\$239
Financing Costs	\$38,000	\$43
Total Overnight Costs (TOC)	\$1,710,262	\$1,936
TASC Multiplier (IOU, 33 year)	1.093	
Total As-Spent Cost (TASC)	\$1,868,712	\$2,115

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-77. Case B32B.90 initial and annual operating and maintenance costs

Case:	B32B.90	– 2x1 CT NGCC w/ CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	883	Heat Rate-net (Btu/kWh):		6,959	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	1.0	
Operating Labor Burden:		30.00	% of base	Operator:	3.3	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	6.3	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$2,776,628	\$3.143
Maintenance Labor:					\$10,696,287	\$12.108
Administrative & Support Labor:					\$3,368,229	\$3.813
Property Taxes and Insurance:					\$28,148,124	\$31.862
Total:					\$44,989,268	\$50.925
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$16,044,431	\$2.43908
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	4,100	\$1.90	\$0	\$2,416,896	\$0.36742
Makeup and Waste Water Treatment Chemicals (ton):	0	12.2	\$550	\$0	\$2,084,093	\$0.31682
Ammonia (19 wt%, ton):	0	4.65	\$300	\$0	\$432,821	\$0.06580
SCR Catalyst (ft³):	7,527	4.12	\$150	\$1,129,110	\$191,949	\$0.02918
CO ₂ Capture System Chemicals ^A :	Proprietary				\$2,619,004	\$0.39814
Triethylene Glycol (gal):	w/equip.	587	\$6.80	\$0	\$1,238,900	\$0.18834
Subtotal:				\$1,129,110	\$8,983,662	\$1.36570
Waste Disposal						
SCR Catalyst (ft³):	0	4.12	\$2.50	\$0	\$3,199	\$0.00049
Triethylene Glycol (gal):	0	587	\$0.35	\$0	\$63,767	\$0.00969
Thermal Reclaimer Unit Waste (ton):	0	2.328	\$38.0	\$0	\$27,450	\$0.00417
Subtotal:				\$0	\$94,416	\$0.01435
Variable Operating Costs Total:				\$1,129,110	\$25,122,509	\$3.81913
Fuel Cost						
Natural Gas (MMBtu):	0	147,538	\$4.42	\$0	\$202,328,910	\$30.75809
Total:				\$0	\$202,328,910	\$30.75809

^ACO₂ Capture System Chemicals includes sodium hydroxide, and CANSOLV solvent

Exhibit 5-78. Case B32B.90 LCOE breakdown

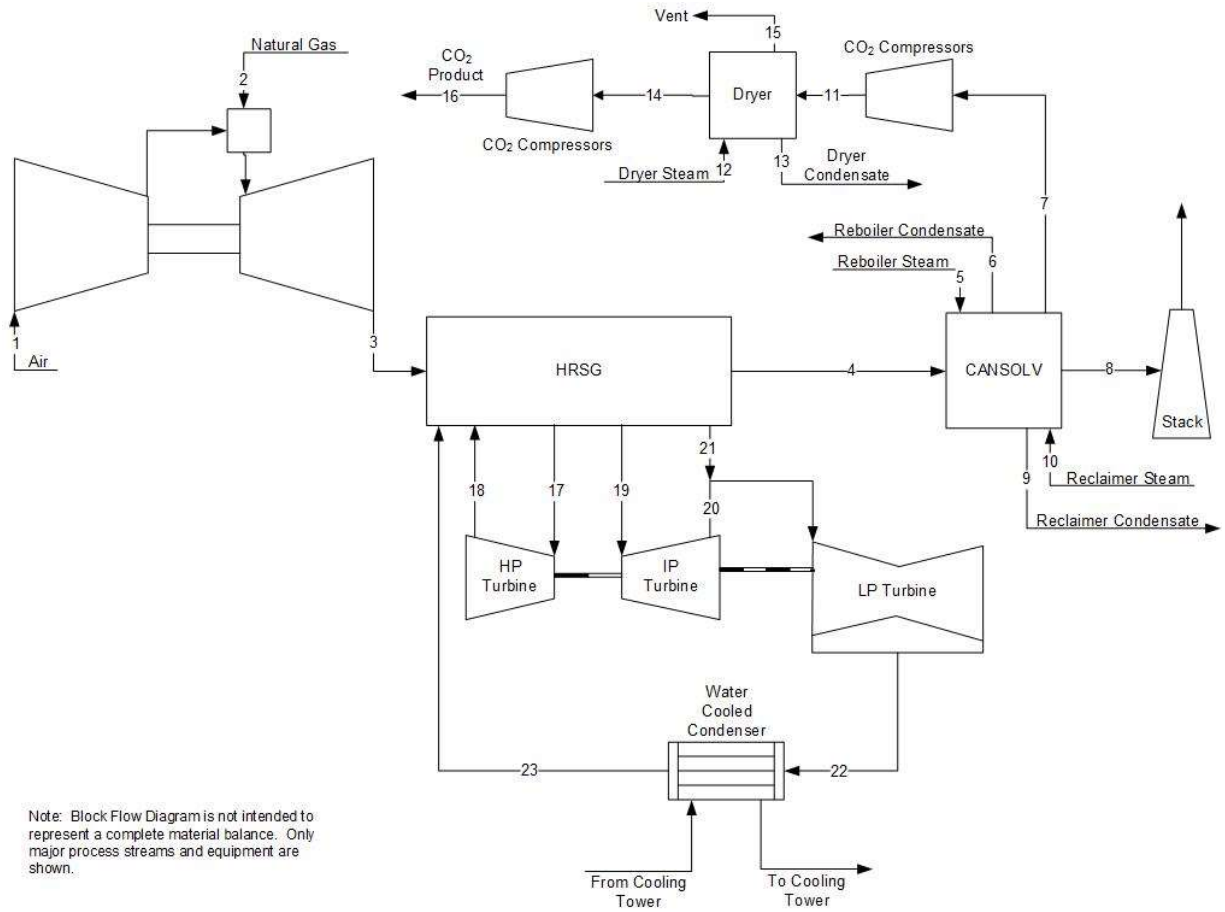
Component	Value, \$/MWh	Percentage
Capital	20.1	31%
Fixed	6.8	11%
Variable	3.8	6%
Fuel	30.8	47%
Total (Excluding T&S)	61.5	N/A
CO ₂ T&S	3.4	5%
Total (Including T&S)	64.9	N/A

5.3.11 Case B32B.95 – NGCC with 95 Percent CO₂ Capture Process Description

The plant configuration for Case B32B.95 is the same as Case B32B.90 with the exception that the CDR technology captures 95, rather than 90, percent of the CO₂ in the flue gas. The nominal net output decreases to 877 MW.

The process description for Case B32B.95 is the same as Case B32B.90. A BFD and stream tables for Case B31B.95 are shown in Exhibit 5-79 and Exhibit 5-80, respectively. Since the CDR facility process description was provided in Section 5.1.5, it is not repeated here.

Exhibit 5-79. Case B32B.95 block flow diagram, NGCC with CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-80. Case B32B.95 stream table, NGCC with capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000	0.0000	0.0096	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₂ H ₆	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0100	0.0408	0.0408	0.0000	0.0000	0.9778	0.0022	0.0000	0.0000	0.9957	0.0000
H ₂ O	0.0099	0.0000	0.0873	0.0873	1.0000	1.0000	0.0222	0.0550	1.0000	1.0000	0.0043	1.0000
N ₂	0.7732	0.0160	0.7429	0.7429	0.0000	0.0000	0.0000	0.8033	0.0000	0.0000	0.0000	0.0000
O ₂	0.2074	0.0000	0.1201	0.1201	0.0000	0.0000	0.0000	0.1299	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	177,074	7,158	184,439	184,439	19,368	17,739	7,302	170,574	176	176	7,171	11
V-L Flowrate (kg/hr)	5,109,811	124,025	5,233,836	5,233,836	348,922	319,575	317,161	4,798,440	3,164	3,164	314,798	191
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	596	104	296	105	31	38	214	336	29	336
Pressure (MPa, abs)	0.10	3.79	0.11	0.10	0.51	0.12	0.17	0.10	2.04	3.62	2.82	3.62
Steam Table Enthalpy (kJ/kg) ^A	30.23	12.56	798.45	247.46	3,054.97	439.34	49.44	127.27	913.81	3,066.29	-1.25	3,066.29
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-4,496.67	-675.71	-1,226.70	-12,925.33	-15,540.95	-8,979.10	-490.48	-15,066.49	-12,914.01	-8,976.09	-12,914.01
Density (kg/m ³)	1.2	28.8	0.4	0.9	2.0	954.9	3.0	1.1	848.5	13.9	58.0	13.9
V-L Molecular Weight	28.857	17.328	28.377	28.377	18.015	18.015	43.433	28.131	18.015	18.015	43.898	18.015
V-L Flowrate (lb _{mol} /hr)	390,381	15,780	406,618	406,618	42,699	39,108	16,099	376,051	387	387	15,810	23
V-L Flowrate (lb/hr)	11,265,204	273,429	11,538,633	11,538,633	769,240	704,543	699,219	10,578,748	6,976	6,976	694,012	421
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,105	218	565	221	88	100	416	637	85	637
Pressure (psia)	14.7	550.0	15.5	14.8	73.5	17.4	24.8	14.8	296.6	525.0	409.1	525.0
Steam Table Enthalpy (Btu/lb) ^A	13.0	5.4	343.3	106.4	1,313.4	188.9	21.3	54.7	392.9	1,318.3	-0.5	1,318.3
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-1,933.2	-290.5	-527.4	-5,556.9	-6,681.4	-3,860.3	-210.9	-6,477.4	-5,552.0	-3,859.0	-5,552.0
Density (lb/ft ³)	0.076	1.799	0.026	0.058	0.122	59.612	0.185	0.069	52.968	0.869	3.622	0.869

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-80. Case B32B.95 stream table, NGCC with capture (cont'd)

	13	14	15	16	17	18	19	20	21	22	23
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₂ H ₆	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0000	0.9995	0.0500	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	1.0000	0.0005	0.9500	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	11	7,142	29	7,142	31,414	31,414	38,581	38,581	5,627	24,840	42,805
V-L Flowrate (kg/hr)	191	314,243	555	314,243	565,941	565,941	695,047	695,047	101,375	447,500	771,139
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	203	29	29	30	585	336	562	296	287	38	38
Pressure (MPa, abs)	1.64	2.69	2.82	15.27	18.50	3.62	3.31	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg) ^A	863.65	-3.70	137.93	-231.09	3,509.09	3,066.29	3,593.96	3,054.97	3,037.05	2,358.77	160.78
AspenPlus Enthalpy (kJ/kg) ^B	-15,116.65	-8,967.26	-15,225.22	-9,194.65	-12,471.21	-12,914.01	-12,386.34	-12,925.33	-12,943.24	-13,621.52	-15,819.51
Density (kg/m ³)	861.8	54.9	352.5	630.1	51.8	13.9	8.7	2.0	2.0	0.1	992.8
V-L Molecular Weight	18.015	43.997	19.315	43.997	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	23	15,746	63	15,746	69,257	69,257	85,056	85,056	12,406	54,763	94,368
V-L Flowrate (lb/hr)	421	692,788	1,224	692,788	1,247,686	1,247,686	1,532,316	1,532,316	223,494	986,569	1,700,070
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	397	85	85	86	1,085	637	1,044	565	549	101	101
Pressure (psia)	237.4	390.4	409.1	2,214.7	2,683.2	525.0	479.8	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb) ^A	371.3	-1.6	59.3	-99.4	1,508.6	1,318.3	1,545.1	1,313.4	1,305.7	1,014.1	69.1
AspenPlus Enthalpy (Btu/lb) ^B	-6,499.0	-3,855.2	-6,545.7	-3,953.0	-5,361.7	-5,552.0	-5,325.2	-5,556.9	-5,564.6	-5,856.2	-6,801.2
Density (lb/ft ³)	53.801	3.430	22.007	39.338	3.233	0.869	0.546	0.125	0.124	0.003	61.977

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

5.3.12 Case B32B.95 – Performance Results

The Case B32B.95 modeling assumptions were presented previously in Section 5.3.1.

The plant produces a net output of 877 MW at a net plant efficiency of 48.7 percent (HHV basis). Overall plant performance summarized in Exhibit 5-81 provides a detailed breakdown of the auxiliary power requirements. The CDR facility, including CO₂ compression, accounts for over 69 percent of the auxiliary plant load. The CWS (CWP's and cooling tower fan) accounts for nearly 13 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility. Case B32B.95 plant power is summarized in Exhibit 5-82.

Exhibit 5-81. Case B32B.95 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	686
Steam Turbine Power, MWe	256
Total Gross Power, MWe	942
CO ₂ Capture/Removal Auxiliaries, kWe	19,200
CO ₂ Compression, kWe	25,130
Balance of Plant, kWe	20,213
Total Auxiliaries, MWe	65
Net Power, MWe	877
HHV Net Plant Efficiency, %	48.7
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,393 (7,007)
HHV Combustion Turbine Efficiency, %	38.0
LHV Net Plant Efficiency, %	54.0
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,672 (6,324)
LHV Combustion Turbine Efficiency, %	42.2
Steam Turbine Cycle Efficiency, %	47.3
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,609 (7,212)
CO ₂ Capture Rate, %	95
Condenser Duty, GJ/hr (MMBtu/hr)	992 (940)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	1,638 (1,552)
Natural Gas Feed Flow, kg/hr (lb/hr)	124,025 (273,429)
HHV Thermal Input, kWt	1,801,631
LHV Thermal Input, kWt	1,626,150
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.025 (6.5)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.016 (4.3)

Exhibit 5-82. Case B32B.95 plant power summary

Power Summary	
Combustion Turbine Power, MWe	686
Steam Turbine Power, MWe	256
Total Gross Power, MWe	942
Auxiliary Load Summary	
Circulating Water Pumps, kWe	5,570
Combustion Turbine Auxiliaries, kWe	1,320
Condensate Pumps, kWe	200
Cooling Tower Fans, kWe	2,880
CO ₂ Capture/Removal Auxiliaries, kWe	19,200
CO ₂ Compression, kWe	25,130
Feedwater Pumps, kWe	5,760
Ground Water Pumps, kWe	520
Miscellaneous Balance of Plant, ^A kWe	710
SCR, kWe	3
Steam Turbine Auxiliaries, kWe	230
Transformer Losses, kWe	3,020
Total Auxiliaries, MWe	65
Net Power, MWe	877

^AIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

5.3.12.1 Environmental Performance

The environmental targets for emissions of NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B32B.95 is presented in Exhibit 5-83.

Exhibit 5-83. Case B32B.95 air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.001 (0.003)	69 (76)	0.010 (0.022)
Particulate	0.000 (0.000)	0 (0)	0.000 (0.000)
Hg	0.00E+0 (0.00E+0)	0.000 (0.000)	0.00E+0 (0.00E+0)
CO	0.000 (0.000)	0 (0)	0.000 (0.000)
CO ₂	3 (6)	123,150 (135,750)	18 (39)
CO ₂ ^C	—	—	19 (42)

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

For the purpose of this report, the natural gas was assumed to contain the domestic average value of total sulfur of 0.34 gr/100 scf (4.71×10^{-4} lb-S/MMBtu). [23] It was also assumed that the added CH₄S was the sole contributor of sulfur to the natural gas. No sulfur capture systems were required.

The NGCC cases were designed to achieve approximately 1.8 ppmvd NO_x emissions (at 15 percent O₂) using a DLN burner in the CTG—the DLN burners reduce the emissions to about 9 ppmvd (at 15 percent O₂) [34]—and an SCR—the SCR system is designed for 86.7 percent NO_x reduction. [35]

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2017 H-class gas turbine achieves approximately 1.0 ppmv CO and 1.0 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not present in any significant amount. Any CO or PM present in the flue gas is assumed to interact with, and be removed by, the CDR system solvent.

CO₂ emissions are reduced relative to those produced by burning coal given the same power output because of the higher heat content of natural gas, the lower carbon intensity of gas relative to coal, and the higher overall efficiency of the NGCC plant relative to a coal-fired plant.

The CDR facility removes 95 percent of the CO₂ in the flue gas.

The carbon balance for the plant is shown in Exhibit 5-84. The carbon input to the plant consists of carbon in the natural gas in addition to carbon in the CT air. Carbon leaves the plant as CO₂ in the stack gas, the CO₂ dryer's vent, and the captured CO₂ product. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in, represented by the following fraction:

$$1 - \frac{\text{Carbon in Stack}}{\text{Total Carbon In}} = \left(1 - \left(\frac{9,951}{199,024} \right) \right) * 100 = 95\%$$

Exhibit 5-84. Case B32B.95 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	89,581 (197,492)	Stack Gas	4,514 (9,951)
Air (CO ₂)	695 (1,532)	CO ₂ Product	85,745 (189,035)
		CO ₂ Dryer Vent	17 (38)
		CO ₂ Knockout	0.2 (0.4)
Total	90,276 (199,024)	Total	90,276 (199,024)

As shown in Exhibit 5-85, the sulfur content of the natural gas is insignificant, entirely comprising CH₄S (used as an odorant). [23] All sulfur in the natural gas is assumed to react with the CDR system solvent and is removed from the solvent during solvent reclaiming as a waste stream.

Exhibit 5-85. Case B32B.95 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.3 (2.9)	Stack Gas	0.0 (0.0)
		Solvent Reclaiming	1.3 (2.9)
Total	1.3 (2.9)	Total	1.3 (2.9)

Exhibit 5-86 shows the overall water balance for the plant.

Exhibit 5-86. Case B32B.95 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
CO ₂ Drying	–	–	–	0.0 (2.4)	0.0 (-2.4)
CO ₂ Capture System Makeup	–	–	–	–	–
CO ₂ Capture Recovery	–	–	–	2.5 (651)	-2.5 (-651)
CO ₂ Compression Recovery	–	–	–	0.0 (10)	0.0 (-10)
Deaerator Vent	–	–	–	0.0 (6.8)	0.0 (-6.8)
Condenser Makeup	0.0 (6.8)	–	0.0 (6.8)	–	0.0 (6.8)
BFW Makeup	0.0 (6.8)	–	0.0 (6.8)	–	0.0 (6.8)
Cooling Tower	22 (5,727)	–	22 (5,727)	4.9 (1,288)	17 (4,439)
Total	22 (5,734)	–	22 (5,734)	7.4 (1,958)	14 (3,776)

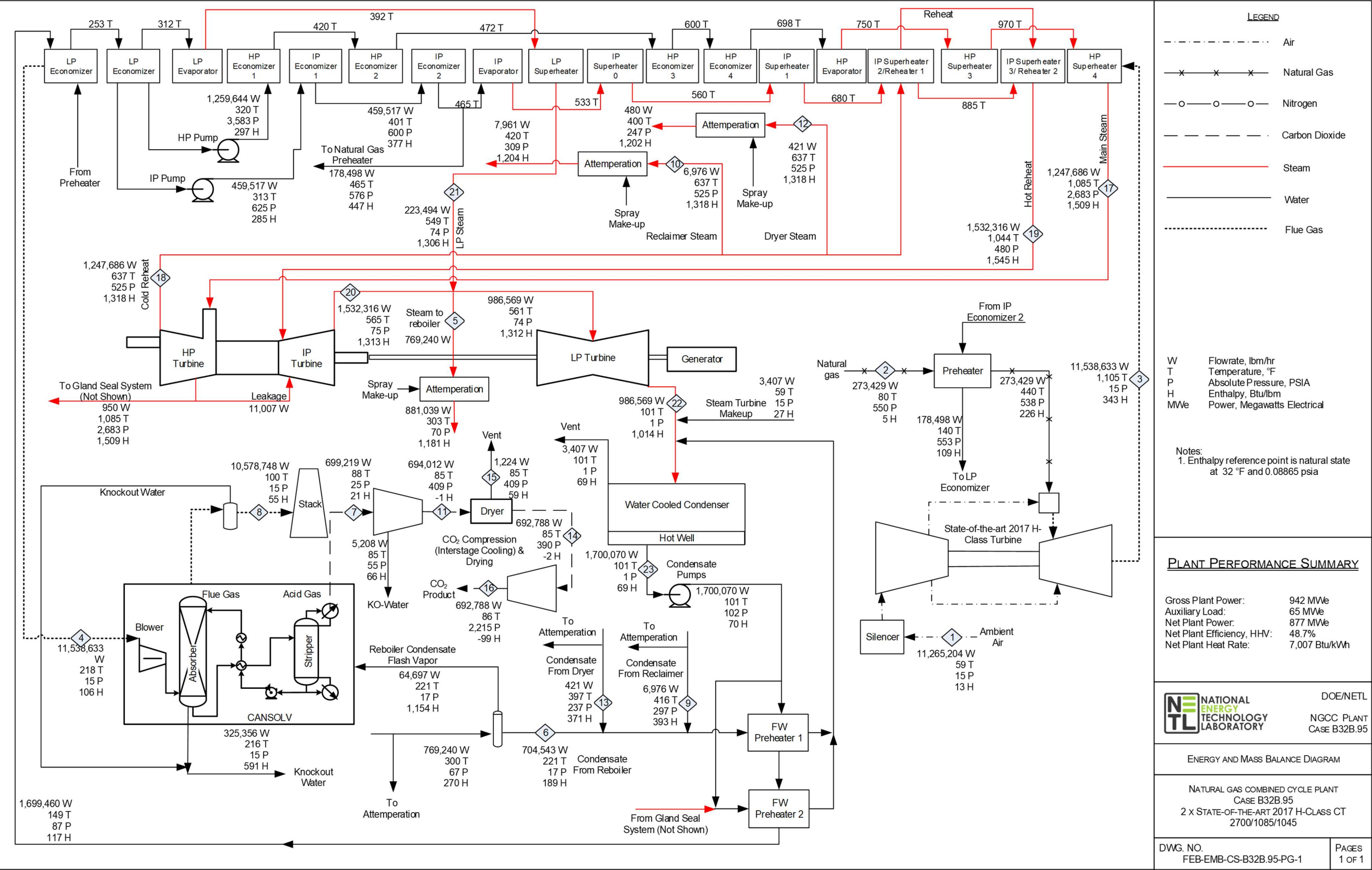
5.3.12.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram for B32B.95 is shown in Exhibit 5-87. An overall plant energy balance is provided in tabular form in Exhibit 5-88.

The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT and 98.7 percent for the steam turbine. The cooling tower load includes the condenser, capture process heat rejected to cooling water, the CO₂ compressor intercooler load, and other miscellaneous cooling loads.

This page intentionally left blank

Exhibit 5-87. Case B32B.95 energy and mass balance, NGCC with CO₂ capture



This page intentionally left blank

Exhibit 5-88. Case B32B.95 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	6,486 (6,147)	4.3 (4.1)	–	6,490 (6,152)
Air	–	154 (146)	–	154 (146)
Raw Water Makeup	–	82 (77)	–	82 (77)
Auxiliary Power	–	–	232 (220)	232 (220)
TOTAL	6,486 (6,147)	240 (228)	232 (220)	6,959 (6,596)
Heat Out GJ/hr (MMBtu/hr)				
Stack Gas	–	611 (579)	–	611 (579)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	80 (76)	80 (76)
Cooling Tower Load ^A	–	2,831 (2,683)	–	2,831 (2,683)
CO ₂ Product Stream	–	-73 (-69)	–	-73 (-69)
AGR Effluent	–	63 (60)	–	63 (60)
Deaerator Vent	–	0.2 (0.2)	–	0.2 (0.2)
<i>Ambient Losses^B</i>	–	43 (41)	–	43 (41)
Power	–	–	3,391 (3,214)	3,391 (3,214)
TOTAL	–	3,476 (3,294)	3,471 (3,290)	6,947 (6,584)
<i>Unaccounted Energy^C</i>	–	12 (11)	–	12 (11)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers

^CBy difference

5.3.13 Case B32B.95 – Major Equipment List

Major equipment items for the NGCC plant with CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 5.3.14. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B32B.95 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	102,000 liters (27,000 gal)	2	0
2	Condensate Pumps	Vertical canned	14,240 lpm @ 90 m H ₂ O (3,760 gpm @ 280 ft H ₂ O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 5,270 lpm @ 2,980 m H ₂ O (1,390 gpm @ 9,780 ft H ₂ O) IP water: 3,850 lpm @ 460 m H ₂ O (1,020 gpm @ 1,520 ft H ₂ O)	2	2
4	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m ³ /min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m ³ /min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 GJ/hr (13 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,200 lpm @ 20 m H ₂ O (1,400 gpm @ 70 ft H ₂ O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	11,000 lpm @ 20 m H ₂ O (2,900 gpm @ 60 ft H ₂ O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H ₂ O (40 gpm @ 160 ft H ₂ O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
15	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
16	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	79 m ³ /min @ 3.8 MPa (2,787 acfm @ 550 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
17	Gas Metering Station	–	79 m ³ /min (2,787 acfm)	1	0

Case B32B.95 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CANSOLV	Amine-based CO ₂ capture technology	5,757,000 kg/hr (12,692,000 lb/hr) 6.3 wt % CO ₂ concentration	1	0
2	CANSOLV LP Condensate Pump	Centrifugal	946 lpm @ 1 m H ₂ O (250 gpm @ 3 ft H ₂ O)	1	1
3	CANSOLV HP Condensate Pump	Centrifugal	8 lpm @ 5 m H ₂ O (2 gpm @ 15 ft H ₂ O)	1	1
4	CO ₂ Dryer	Triethylene glycol	Inlet: 90 m ³ /min @ 2.8 MPa (3,193 acfm @ 409 psia) Outlet: 2.7 MPa (390 psia) Water Recovered: 555 kg/hr (1,224 lb/hr)	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	m ³ /min @ 15.3 MPa, 82°C (161 acfm @ 2,217 psia, 180°F)	2	0
6	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 49 GJ/hr (47 MMBtu/hr)	2	0

Case B32B.95 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	Advanced H class w/ dry low-NOx burner	345 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	380 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	2	0

Case B32B.95 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 5.9 m (19 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main steam - 311,268 kg/hr, 18.4 MPa/585°C (686,227 lb/hr, 2,669 psig/1,085°F) Reheat steam – 382,276 kg/hr, 3.2 MPa/562°C (842,774 lb/hr, 465 psig/1,044°F)	2	0
3	SCR Reactor	–	2,880,000 kg/hr (6,350,000 lb/hr)	2	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	10 m ³ /min @ 108 cm WG (300 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	1.8 lpm @ 90 m H ₂ O (0.5 gpm @ 300 ft H ₂ O)	2	1
7	Ammonia Storage Tank	Horizontal tank	51,000 liter (13,000 gal)	1	0

Case B32B.95 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	270 MW 18.4 MPa/585°C/562°C (2,668 psig/1,085°F/1,044°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	300 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	1,090 GJ/hr (1,030 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

Case B32B.95 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	559,000 lpm @ 30 m (148,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 3,110 GJ/hr (2,950 MMBtu/hr) heat duty	1	0

Case B32B.95 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 270 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 200 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 10 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 23 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 8 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B32B.95 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

5.3.14 Case B32B.95 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 5-89 shows a detailed breakdown of the capital costs; Exhibit 5-90 shows the owner's costs, TOC, and TASC; Exhibit 5-91 shows the initial and annual O&M costs; and Exhibit 5-92 shows the LCOE breakdown.

The estimated TPC of the NGCC with CO₂ capture is \$1,630/kW. Process contingency represents 4.0 percent of the TPC and project contingency represents 14.9 percent. The LCOE, including CO₂ T&S costs of \$3.6/MWh, is \$66.0/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-89. Case B32B.95 total plant cost details

Case:		B32B.95	– 2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		877					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$1,894	\$3,246	\$1,623	\$0	\$6,763	\$1,353	\$0	\$1,217	\$9,333	\$11
3.2	Water Makeup & Pretreating	\$6,114	\$611	\$3,464	\$0	\$10,189	\$2,038	\$0	\$2,445	\$14,672	\$17
3.3	Other Feedwater Subsystems	\$1,077	\$353	\$336	\$0	\$1,766	\$353	\$0	\$318	\$2,437	\$3
3.4	Service Water Systems	\$1,855	\$3,542	\$11,468	\$0	\$16,865	\$3,373	\$0	\$4,048	\$24,286	\$28
3.5	Other Boiler Plant Systems	\$286	\$104	\$260	\$0	\$649	\$130	\$0	\$117	\$895	\$1
3.6	Natural Gas Pipeline and Start-Up System	\$12,372	\$532	\$399	\$0	\$13,304	\$2,661	\$0	\$2,395	\$18,359	\$21
3.7	Waste Water Treatment Equipment	\$10,853	\$0	\$6,652	\$0	\$17,505	\$3,501	\$0	\$4,201	\$25,207	\$29
3.9	Miscellaneous Plant Equipment	\$18,904	\$2,479	\$9,607	\$0	\$30,991	\$6,198	\$0	\$7,438	\$44,626	\$51
	Subtotal	\$53,355	\$10,868	\$33,809	\$0	\$98,031	\$19,606	\$0	\$22,179	\$139,816	\$159
5 Flue Gas Cleanup											
5.1	CANSOLV Carbon Dioxide (CO ₂) Removal System	\$127,873	\$59,335	\$124,603	\$0	\$311,812	\$62,362	\$56,126	\$86,060	\$516,360	\$589
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$31,017	\$4,653	\$12,868	\$0	\$48,537	\$9,707	\$0	\$11,649	\$69,893	\$80
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$297	\$47	\$127	\$0	\$472	\$94	\$0	\$113	\$679	\$1
5.12	Gas Cleanup Foundations	\$0	\$500	\$540	\$0	\$1,039	\$208	\$0	\$249	\$1,497	\$2
	Subtotal	\$159,187	\$64,534	\$138,138	\$0	\$361,860	\$72,372	\$56,126	\$98,072	\$588,429	\$671
6 Combustion Turbine & Accessories											
6.1	Combustion Turbine Generator	\$143,342	\$0	\$8,723	\$0	\$152,065	\$30,413	\$0	\$27,372	\$209,850	\$239
6.3	Combustion Turbine Accessories	\$3,492	\$0	\$213	\$0	\$3,705	\$741	\$0	\$667	\$5,112	\$6
6.4	Compressed Air Piping	\$0	\$1,153	\$261	\$0	\$1,414	\$283	\$0	\$255	\$1,951	\$2
6.5	Combustion Turbine Foundations	\$0	\$1,301	\$1,407	\$0	\$2,708	\$542	\$0	\$650	\$3,900	\$4
	Subtotal	\$146,834	\$2,454	\$10,603	\$0	\$159,892	\$31,978	\$0	\$28,943	\$220,813	\$252
7 HRSG, Ductwork, & Stack											
7.1	Heat Recovery Steam Generator	\$63,325	\$0	\$15,831	\$0	\$79,157	\$15,831	\$0	\$14,248	\$109,236	\$125
7.2	Heat Recovery Steam Generator Accessories	\$19,732	\$0	\$3,660	\$0	\$23,393	\$4,679	\$0	\$4,211	\$32,282	\$37
7.3	Ductwork	\$0	\$1,073	\$746	\$0	\$1,819	\$364	\$0	\$328	\$2,511	\$3
7.4	Stack	\$10,263	\$0	\$1,904	\$0	\$12,167	\$2,433	\$0	\$2,190	\$16,791	\$19
7.5	Heat Recovery Steam Generator, Ductwork & Stack Foundations	\$0	\$800	\$751	\$0	\$1,551	\$310	\$0	\$372	\$2,234	\$3
7.6	Selective Catalytic Reduction System	\$1,981	\$832	\$1,160	\$0	\$3,973	\$795	\$0	\$715	\$5,483	\$6
	Subtotal	\$95,301	\$2,706	\$24,053	\$0	\$122,061	\$24,412	\$0	\$22,064	\$168,537	\$192

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B32B.95	– 2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:		Conceptual		
Plant Size (MW, net):		877					Cost Base:		Dec 2018		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
8		Steam Turbine & Accessories									
8.1	Steam Turbine Generator & Accessories	\$31,729	\$0	\$4,646	\$0	\$36,375	\$7,275	\$0	\$6,548	\$50,198	\$57
8.2	Steam Turbine Plant Auxiliaries	\$146	\$0	\$324	\$0	\$470	\$94	\$0	\$85	\$648	\$1
8.3	Condenser & Auxiliaries	\$5,093	\$0	\$2,727	\$0	\$7,819	\$1,564	\$0	\$1,407	\$10,791	\$12
8.4	Steam Piping	\$10,971	\$0	\$4,446	\$0	\$15,417	\$3,083	\$0	\$2,775	\$21,275	\$24
8.5	Turbine Generator Foundations	\$0	\$1,230	\$2,031	\$0	\$3,261	\$652	\$0	\$783	\$4,695	\$5
Subtotal		\$47,938	\$1,230	\$14,174	\$0	\$63,342	\$12,668	\$0	\$11,597	\$87,607	\$100
9		Cooling Water System									
9.1	Cooling Towers	\$13,345	\$0	\$4,041	\$0	\$17,387	\$3,477	\$0	\$3,130	\$23,994	\$27
9.2	Circulating Water Pumps	\$1,754	\$0	\$108	\$0	\$1,861	\$372	\$0	\$335	\$2,569	\$3
9.3	Circulating Water System Auxiliaries	\$11,424	\$0	\$1,507	\$0	\$12,932	\$2,586	\$0	\$2,328	\$17,846	\$20
9.4	Circulating Water Piping	\$0	\$3,481	\$3,152	\$0	\$6,632	\$1,326	\$0	\$1,194	\$9,153	\$10
9.5	Make-up Water System	\$396	\$0	\$508	\$0	\$904	\$181	\$0	\$163	\$1,247	\$1
9.6	Component Cooling Water System	\$513	\$0	\$394	\$0	\$907	\$181	\$0	\$163	\$1,251	\$1
9.7	Circulating Water System Foundations	\$0	\$805	\$1,337	\$0	\$2,142	\$428	\$0	\$514	\$3,085	\$4
Subtotal		\$27,432	\$4,286	\$11,047	\$0	\$42,765	\$8,553	\$0	\$7,826	\$59,145	\$67
11		Accessory Electric Plant									
11.1	Generator Equipment	\$2,973	\$0	\$2,243	\$0	\$5,215	\$1,043	\$0	\$939	\$7,197	\$8
11.2	Station Service Equipment	\$7,989	\$0	\$685	\$0	\$8,674	\$1,735	\$0	\$1,561	\$11,971	\$14
11.3	Switchgear & Motor Control	\$11,407	\$0	\$1,979	\$0	\$13,386	\$2,677	\$0	\$2,409	\$18,473	\$21
11.4	Conduit & Cable Tray	\$0	\$2,756	\$7,944	\$0	\$10,700	\$2,140	\$0	\$1,926	\$14,766	\$17
11.5	Wire & Cable	\$0	\$4,115	\$7,356	\$0	\$11,471	\$2,294	\$0	\$2,065	\$15,830	\$18
11.6	Protective Equipment	\$577	\$0	\$2,005	\$0	\$2,583	\$517	\$0	\$465	\$3,564	\$4
11.7	Standby Equipment	\$732	\$0	\$675	\$0	\$1,407	\$281	\$0	\$253	\$1,942	\$2
11.8	Main Power Transformers	\$8,770	\$0	\$179	\$0	\$8,949	\$1,790	\$0	\$1,611	\$12,350	\$14
11.9	Electrical Foundations	\$0	\$111	\$282	\$0	\$393	\$79	\$0	\$94	\$566	\$1
Subtotal		\$32,448	\$6,983	\$23,349	\$0	\$62,779	\$12,556	\$0	\$11,324	\$86,659	\$99
12		Instrumentation & Control									
12.1	Natural Gas Combined Cycle Control Equipment	\$252	\$0	\$161	\$0	\$413	\$83	\$0	\$74	\$569	\$1
12.2	Combustion Turbine Control Equipment	\$492	\$0	\$313	\$0	\$805	\$161	\$0	\$145	\$1,112	\$1
12.3	Steam Turbine Control Equipment	\$404	\$0	\$257	\$0	\$661	\$132	\$0	\$119	\$912	\$1
12.4	Other Major Component Control Equipment	\$685	\$0	\$437	\$0	\$1,122	\$224	\$56	\$210	\$1,613	\$2
12.5	Signal Processing Equipment	\$565	\$0	\$17	\$0	\$582	\$116	\$0	\$105	\$803	\$1
12.6	Control Boards, Panels & Racks	\$151	\$0	\$92	\$0	\$243	\$49	\$12	\$46	\$350	\$0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO
ELECTRICITY

Case:		B32B.95	– 2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		877					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
12.7	Distributed Control System Equipment	\$8,398	\$0	\$257	\$0	\$8,655	\$1,731	\$433	\$1,623	\$12,441	\$14
12.8	Instrument Wiring & Tubing	\$693	\$555	\$2,219	\$0	\$3,467	\$693	\$173	\$650	\$4,983	\$6
12.9	Other Instrumentation & Controls Equipment	\$480	\$0	\$1,112	\$0	\$1,592	\$318	\$80	\$299	\$2,289	\$3
	Subtotal	\$12,120	\$555	\$4,865	\$0	\$17,540	\$3,508	\$754	\$3,270	\$25,072	\$29
13	Improvements to Site										
13.1	Site Preparation	\$0	\$640	\$13,586	\$0	\$14,225	\$2,845	\$0	\$3,414	\$20,485	\$23
13.2	Site Improvements	\$0	\$2,058	\$2,720	\$0	\$4,777	\$955	\$0	\$1,147	\$6,880	\$8
13.3	Site Facilities	\$1,975	\$0	\$2,072	\$0	\$4,047	\$809	\$0	\$971	\$5,828	\$7
	Subtotal	\$1,975	\$2,698	\$18,378	\$0	\$23,050	\$4,610	\$0	\$5,532	\$33,192	\$38
14	Buildings & Structures										
14.1	Combustion Turbine Area	\$0	\$497	\$262	\$0	\$759	\$152	\$0	\$137	\$1,048	\$1
14.3	Steam Turbine Building	\$0	\$3,434	\$4,569	\$0	\$8,003	\$1,601	\$0	\$1,441	\$11,044	\$13
14.4	Administration Building	\$0	\$401	\$271	\$0	\$671	\$134	\$0	\$121	\$927	\$1
14.5	Circulation Water Pumphouse	\$0	\$97	\$48	\$0	\$146	\$29	\$0	\$26	\$201	\$0
14.6	Water Treatment Buildings	\$0	\$486	\$443	\$0	\$929	\$186	\$0	\$167	\$1,282	\$1
14.7	Machine Shop	\$0	\$600	\$384	\$0	\$985	\$197	\$0	\$177	\$1,359	\$2
14.8	Warehouse	\$0	\$465	\$280	\$0	\$745	\$149	\$0	\$134	\$1,028	\$1
14.9	Other Buildings & Structures	\$0	\$333	\$241	\$0	\$574	\$115	\$0	\$103	\$792	\$1
14.10	Waste Treating Building & Structures	\$0	\$783	\$1,398	\$0	\$2,181	\$436	\$0	\$393	\$3,010	\$3
	Subtotal	\$0	\$7,096	\$7,898	\$0	\$14,993	\$2,999	\$0	\$2,699	\$20,691	\$24
	Total	\$576,591	\$103,409	\$286,313	\$0	\$966,313	\$193,263	\$56,880	\$213,506	\$1,429,961	\$1,630

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-90. Case B32B.95 owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$8,528	\$10
1 Month Maintenance Materials	\$1,598	\$2
1 Month Non-fuel Consumables	\$902	\$1
1 Month Waste Disposal	\$10	\$0
25% of 1 Months Fuel Cost at 100% CF	\$4,959	\$6
2% of TPC	\$28,599	\$33
Total	\$44,596	\$51
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	\$1,326	\$2
0.5% of TPC (spare parts)	\$7,150	\$8
Total	\$8,476	\$10
Other Costs		
Initial Cost for Catalyst and Chemicals	\$1,129	\$1
Land	\$300	\$0
Other Owner's Costs	\$214,494	\$244
Financing Costs	\$38,609	\$44
Total Overnight Costs (TOC)	\$1,737,565	\$1,980
TASC Multiplier (IOU, 33 year)	1.093	
Total As-Spent Cost (TASC)	\$1,898,546	\$2,164

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-91. Case B32B.95 initial and annual operating and maintenance costs

Case:	B32B.95	– 2x1 CT NGCC w/ CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	877	Heat Rate-net (Btu/kWh):	7,007		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor					Operating Labor Requirements per Shift	
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	1.0	
Operating Labor Burden:		30.00	% of base	Operator:	3.3	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	6.3	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$2,776,628	\$3.165
Maintenance Labor:					\$10,867,705	\$12.387
Administrative & Support Labor:					\$3,411,083	\$3.888
Property Taxes and Insurance:					\$28,599,223	\$32.597
Total:					\$45,654,638	\$52.037
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$16,301,557	\$2.49534
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	4,128	\$1.90	\$0	\$2,433,611	\$0.37252
Makeup and Waste Water Treatment Chemicals (ton):	0	12.3	\$550	\$0	\$2,098,506	\$0.32123
Ammonia (19 wt%, ton):	0	4.65	\$300	\$0	\$432,979	\$0.06628
SCR Catalyst (ft³):	7,527	4.12	\$150	\$1,129,110	\$191,949	\$0.02938
CO ₂ Capture System Chemicals ^A :	Proprietary				\$2,733,410	\$0.41841
Triethylene Glycol (gal):	w/equip.	620	\$6.80	\$0	\$1,307,727	\$0.20018
Subtotal:				\$1,129,110	\$9,198,183	\$1.40800
Waste Disposal						
SCR Catalyst (ft³):	0	4.12	\$2.50	\$0	\$3,199	\$0.00049
Triethylene Glycol (gal):	0	620	\$0.35	\$0	\$67,310	\$0.01030
Thermal Reclaimer Unit Waste (ton):	0	2.434	\$38.0	\$0	\$28,699	\$0.00439
Subtotal:				\$0	\$99,207	\$0.01519
Variable Operating Costs Total:				\$1,129,110	\$25,598,947	\$3.91853
Fuel Cost						
Natural Gas (MMBtu):	0	147,538	\$4.42	\$0	\$202,328,910	\$30.97124
Total:				\$0	\$202,328,910	\$30.97124

^ACO₂ Capture System Chemicals includes sodium hydroxide and CANSOLV solvent

Exhibit 5-92. Case B32B.95 LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	20.6	31%
Fixed	7.0	11%
Variable	3.9	6%
Fuel	31.0	47%
Total (Excluding T&S)	62.4	N/A
CO ₂ T&S	3.6	5%
Total (Including T&S)	66.0	N/A

5.4 NGCC CASE SUMMARY

The performance and cost results of the six NGCC plant configurations modeled in this report are summarized in Exhibit 5-93.

Exhibit 5-93. Estimated performance and cost results for NGCC cases

NGCC						
	State-of-the-art 2017 F-Class			State-of-the-art 2017 H-Class		
Case	B31A	B31B.90	B31B.95	B32A	B32B.90	B32B.95
PERFORMANCE						
CO ₂ Capture Rate (%)	0	90	95	0	90	95
Capacity Factor (%)	85	85	85	85	85	85
Gross Power Output (MWe)	740	692	690	1,009	945	942
Auxiliary Power Requirement (MWe)	14	47	49	17	62	65
Net Power Output (MWe)	727	645	640	992	883	877
Coal Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A
Natural Gas Flow Rate (lb/hr)	205,630	205,630	205,630	273,429	273,429	273,429
HHV Thermal Input (kW _t)	1,354,905	1,354,905	1,354,905	1,801,631	1,801,631	1,801,631
Net Plant HHV Efficiency (%)	53.6	47.6	47.3	55.1	49.0	48.7
Net Plant HHV Heat Rate (Btu/kWh)	6,363	7,169	7,220	6,196	6,959	7,007
Raw Water Withdrawal (gpm/MW _{net})	4.0	6.9	7.0	3.6	6.4	6.5
Process Water Discharge (gpm/MW _{net})	0.9	2.3	2.4	0.8	2.2	2.2
Raw Water Consumption (gpm/MW _{net})	3.1	4.6	4.7	2.8	4.2	4.3
CO ₂ Emissions (lb/MMBtu)	119	12	6	119	12	6
CO ₂ Emissions (lb/MWh-gross)	741	79	40	723	77	39
CO ₂ Emissions (lb/MWh-net)	755	85	43	735	83	42
SO ₂ Emissions (lb/MMBtu)	0.001	0.000	0.000	0.001	0.000	0.000
SO ₂ Emissions (lb/MWh-gross)	0.006	0.000	0.000	0.006	0.000	0.000
NO _x Emissions (lb/MMBtu)	0.004	0.003	0.003	0.004	0.003	0.003
NO _x Emissions (lb/MWh-gross)	0.022	0.022	0.022	0.022	0.022	0.022
PM Emissions (lb/MMBtu)	0.002	0.000	0.000	0.002	0.000	0.000
PM Emissions (lb/MWh-gross)	0.012	0.000	0.000	0.011	0.000	0.000
Hg Emissions (lb/TBtu)	0.000	0.000	0.000	0.000	0.000	0.000
Hg Emissions (lb/MWh-gross)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

NGCC						
	State-of-the-art 2017 F-Class			State-of-the-art 2017 H-Class		
Case	B31A	B31B.90	B31B.95	B32A	B32B.90	B32B.95
COST						
Total Plant Cost (2018\$/kW)	780	1,686	1,727	796	1,593	1,630
<i>Bare Erected Cost</i>	561	1,134	1,160	573	1,078	1,101
<i>Home Office Expenses</i>	112	227	232	115	216	220
<i>Project Contingency</i>	107	254	261	109	237	243
<i>Process Contingency</i>	0	71	74	0	62	65
Total Overnight Cost (2018\$/MM)	692	1,321	1,344	963	1,710	1,738
Total Overnight Cost (2018\$/kW)	952	2,049	2,099	970	1,936	1,980
<i>Owner's Costs</i>	172	363	372	174	343	351
Total As-Spent Cost (2018\$/kW)	1,040	2,239	2,293	1,060	2,115	2,164
LCOE (\$/MWh) (excluding T&S)^A	43.3	64.4	65.4	42.7	61.5	62.4
<i>Capital Costs</i>	9.9	21.3	21.8	10.1	20.1	20.6
<i>Fixed Costs</i>	3.6	7.4	7.6	3.5	6.8	7.0
<i>Variable Costs</i>	1.7	4.0	4.1	1.7	3.8	3.9
<i>Fuel Costs</i>	28.1	31.7	31.9	27.4	30.8	31.0
LCOE (\$/MWh) (including T&S)^A	43.3	67.9	69.1	42.7	64.9	66.0
<i>CO₂ T&S Costs</i>	N/A	3.5	3.7	N/A	3.4	3.6
Cost of CO₂ Captured (ex. T&S), \$/tonne^B	N/A	60.7	59.9	N/A	55.9	55.2
Cost of CO₂ Avoided (incl. T&S), \$/tonne^B	N/A	80.8	79.8	N/A	75.0	74.2

^AVarying incentives, such as tax credits, could impact the economics of the system

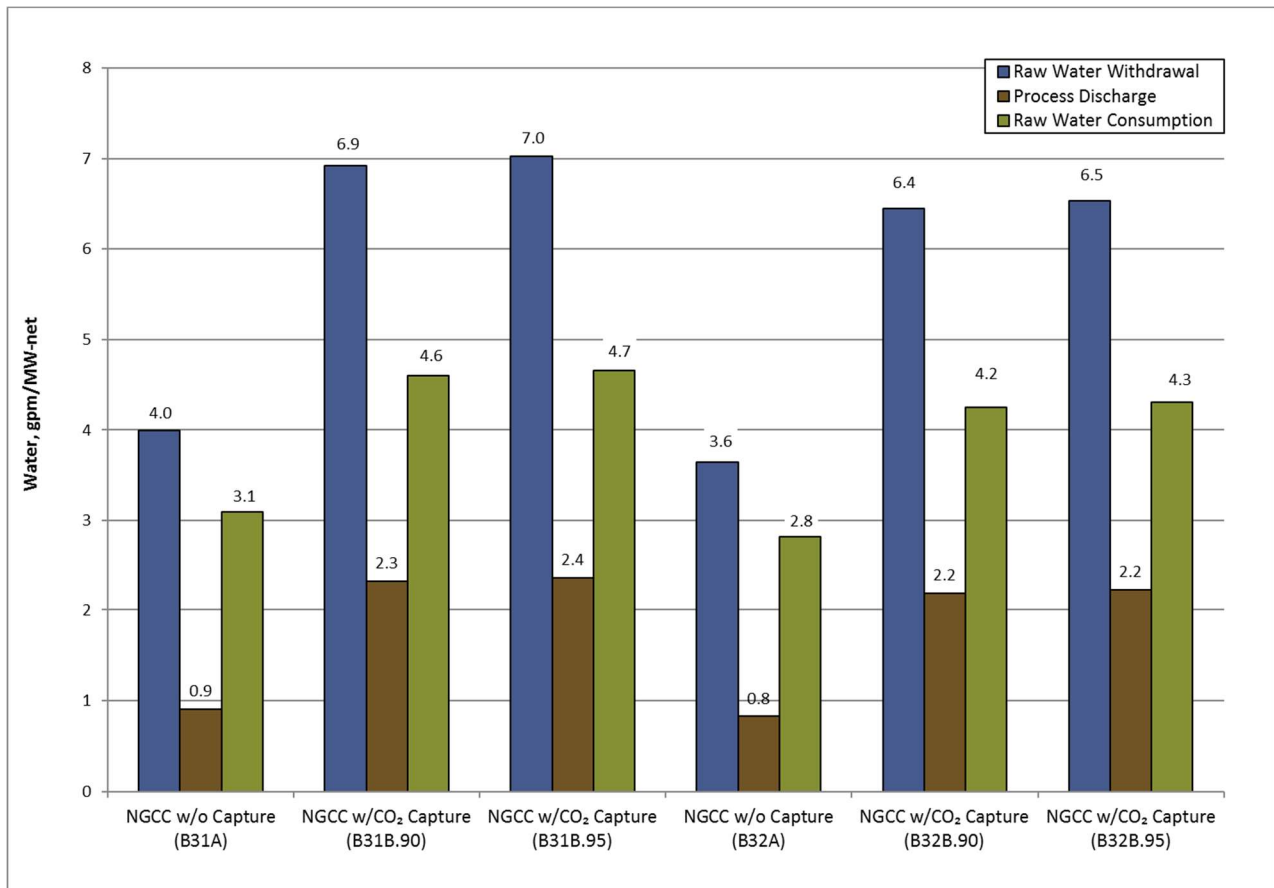
^BThe cost of CO₂ captured and cost of CO₂ avoided were calculated based on the analogous non-capture case (i.e. B31B cases use B31A as a reference and B32B cases use B32A)

The following observations can be made regarding plant performance with reference to Exhibit 5-93:

- The efficiency of the F-frame case without CO₂ capture is 53.6 percent (HHV basis) and the efficiency of the H-frame case without CO₂ capture 55.1 percent (HHV basis). Gas Turbine World provides estimated performance for a state-of-the-art 2017 F-class turbine operated on natural gas in a combined cycle mode, and the reported efficiency is 60.3 percent (LHV basis). [134] In addition, Gas Turbine World provides estimated performance for a state-of-the-art 2017 H-class turbine operated on natural gas in a combined cycle mode, and the reported efficiency is 63.2 percent (LHV basis). [134] Adjusting the result from this report to an LHV basis results in an efficiency of 59.4 percent for the F-class case and 61.0 percent for the H-class case.
- The efficiency penalty to add 90 percent CO₂ capture in the F-class case is 6.0 percentage points (11.2 percent relative to non-capture) and in the H-class case is 6.0 percentage points (11.0 percent relative to non-capture). The efficiency reduction is caused primarily by the auxiliary loads of the capture system and CO₂ compression as well as the significantly increased cooling water requirement, which increases the auxiliary load of the CWP's and the cooling tower fan. Adding 90 percent CO₂ capture results in a 34 and 45 MW increase in auxiliary load compared to the non-capture case for F-frame and H-frame, respectively.
- The addition of higher CO₂ capture rates to the F-frame cases, comparing B31B.90 and B31B.95, results in an HHV efficiency penalty of 0.3 percentage points (0.7 percent relative to B31B.90). For the H-frame cases, between B32B.90 and B32B.95 cases results in an HHV efficiency penalty of 0.3 percentage points (0.7 percent relative to B32B.90).
- Comparing Revision 4a to Revision 4, the HHV efficiency remained unchanged for Case B31A. The HHV efficiency decreased by 0.1 percentage points (0.2 percent relative to Revision 4) for case B31B.90.

The normalized water withdrawal, process discharge, and raw water consumption are shown in Exhibit 5-94.

Exhibit 5-94. Raw water withdrawal and consumption in NGCC cases



Raw water consumption for all cases is dominated by cooling tower makeup requirements, which accounts for about 99 percent of raw water in non-capture cases and 99 percent of raw water in CO₂ capture cases. The amount of raw water consumption in the CO₂ capture cases is greatly increased by the cooling water requirements of the capture process. Cooling water is required to:

- Remove the heat input by the stripping steam to cool the solvent
- Remove heat of CO₂ absorption through absorber tower intercoolers
- Remove the heat input from the auxiliary electric loads
- Remove heat in the CO₂ compressor intercoolers
- Cool the CO₂ product stream exiting the CO₂ compressor to the target specification of 30°C (86°F)

The following observations can be made:

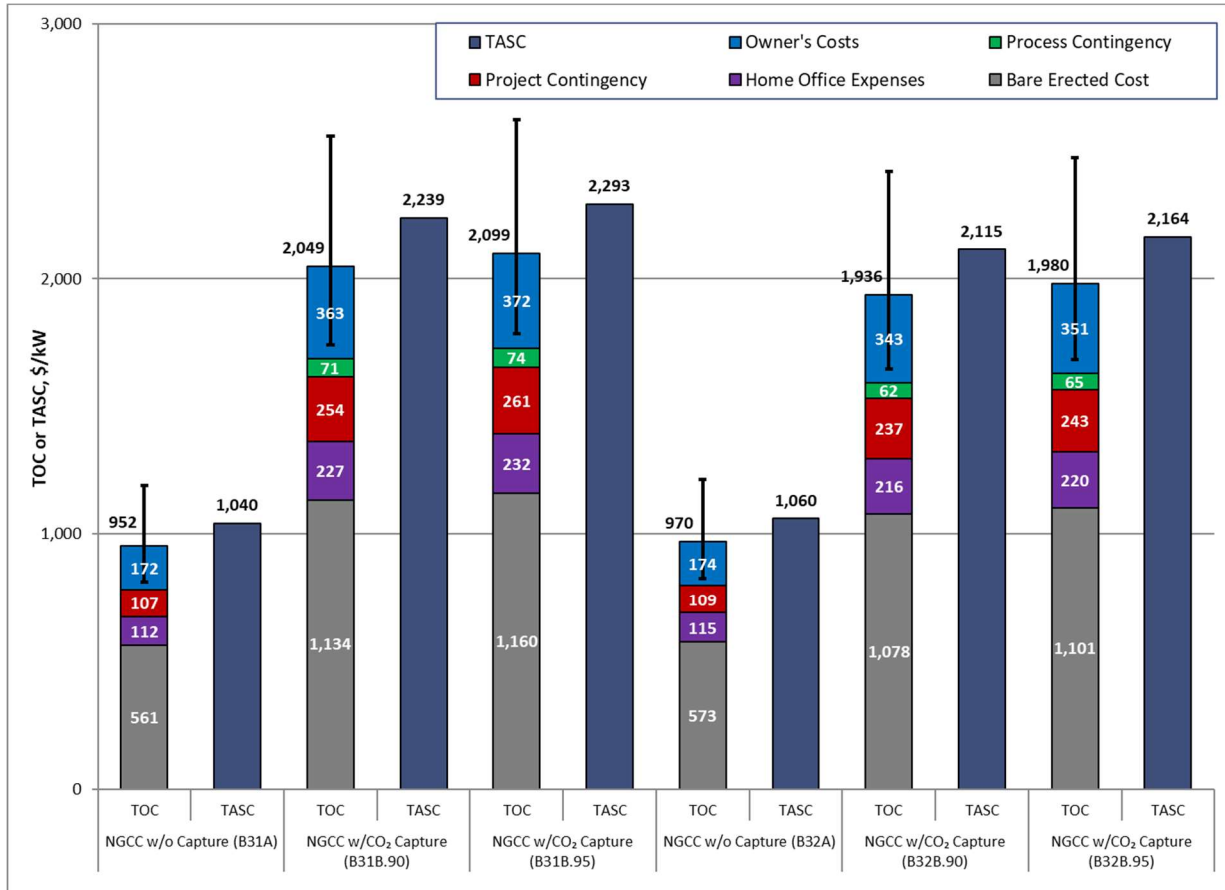
- Normalized water withdrawal increases 73–79 percent and normalized raw water consumption increases 49–53 percent in the CO₂ capture cases. The high cooling water

demand of the capture process results in a large increase in cooling tower makeup requirements.

- Cooling tower makeup comprises approximately 99 percent of the raw water consumption in both NGCC cases. There is no internal recycle of water considered.

The components of TOC and TASC are shown for the two NGCC cases in Exhibit 5-95. The addition of CO₂ capture more than doubles the TOC of the NGCC plant.

Exhibit 5-95. Plant capital cost for NGCC cases



The NGCC capital cost estimate accuracy provides an AACE Class 4 range of -15 percent/+25 percent. The error bars included in Exhibit 5-95 represent the potential TOC range relative to the maximum and minimum of the capital cost uncertainty range.

The following observations about normalized TOC (\$/kW) can be made:

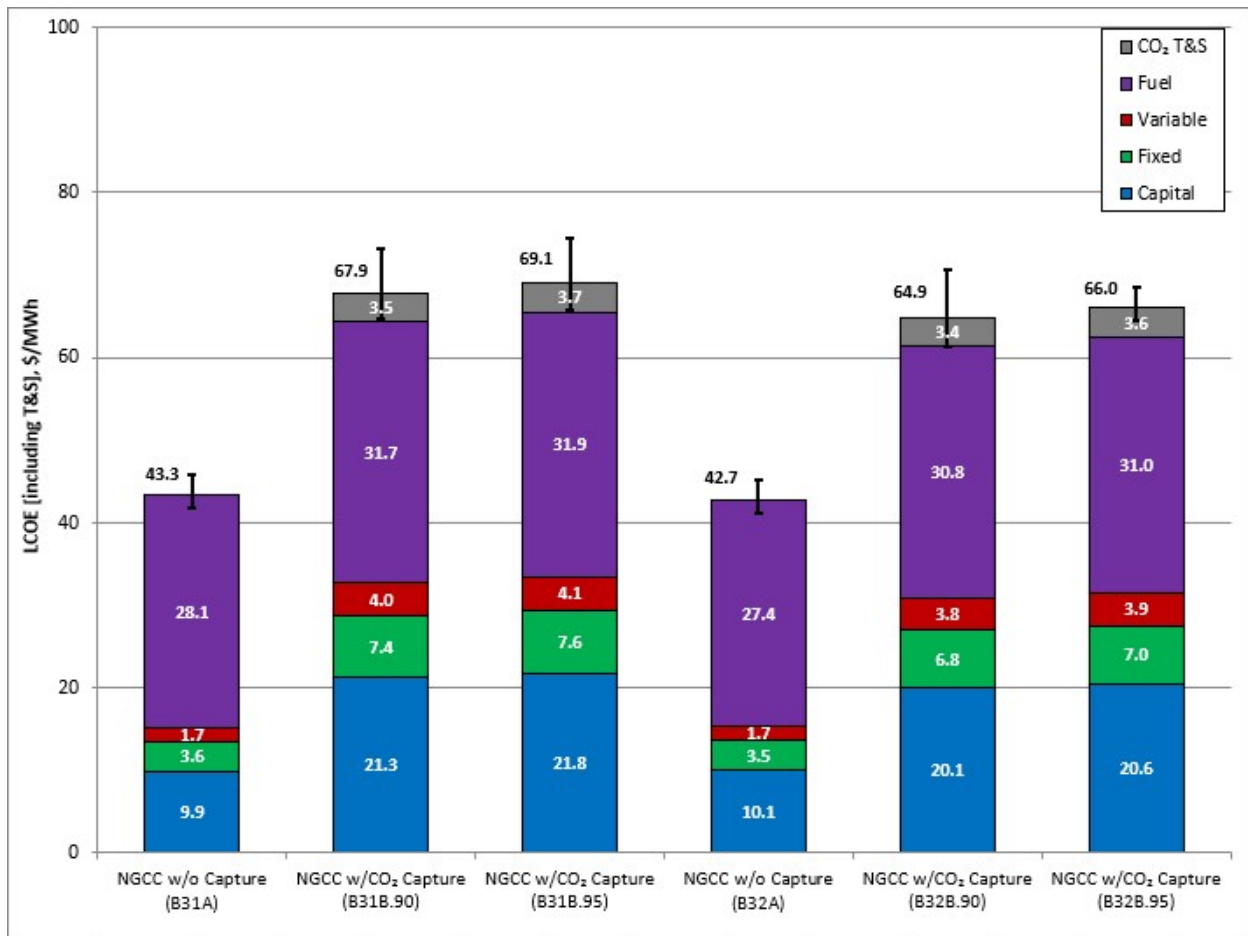
- The TOC of the non-capture H-frame case is approximately 1.9 percent greater than non-capture F-frame. The TOC of F-frame with 90 percent CO₂ capture is approximately 5.8 percent greater than H-frame with CO₂ capture. The TOC of F-frame with 95 percent CO₂ capture is approximately 6.0 percent greater than H-frame with 95 percent CO₂ capture.
- The TOC penalty for adding 90 percent CO₂ capture in the H-frame case is 100 percent and is 115 percent in the F-frame case. The TOC penalty for adding 95 percent CO₂

capture in the H-frame case is 104 percent and is 120 percent in the F-frame case. In addition to the high cost of the capture process, there is a significant increase in the cost of the cooling towers and CWPs in the CO₂ capture cases because of the larger cooling water demand discussed previously.

- Comparing the 90 percent capture cases from Revision 4a to Revision 4, the TOC decreased 15.1 percent for case B31B.90 due to the significant reduction in cost of the capture system from the revised 2021 quote.
 - In addition, due to this significant cost reduction, the TOC for the Revision 4a 95 percent F-frame capture case is 13.0 percent less than the TOC for the Revision 4 90 percent F-frame capture case.

The error bars included in Exhibit 5-96 represent the potential LCOE range relative to the maximum and minimum capital cost uncertainty ranges. The LCOE ranges presented are not reflective of other changes, such as variation in fuel price, labor price, CF, or other factors. As an example, if Case B31B.90's capital costs were determined to be at the high end of the uncertainty range (+25 percent), then the LCOE result would be \$73.2/MWh. Conversely, if at the low end of the uncertainty range (-15 percent), the LCOE result would be \$64.7/MWh.

Exhibit 5-96. LCOE of NGCC cases



The following observations can be made:

- Fuel costs represent the largest fraction of LCOE in all cases, representing 64–65 percent of the total in the non-capture cases and representing 46–47 percent in the capture cases. The CO₂ T&S component of LCOE is only 5-6 percent of the total in the CO₂ capture cases.
- The addition of higher CO₂ capture rates to the F-frame cases results in an LCOE penalty of \$1.2/MWh (1.8 percent) in Case B31B.95, compared to Case B31B.90. For the H-frame cases, the addition of higher CO₂ capture rates results in an LCOE penalty of \$1.1/MWh (1.8 percent) in Case B32B.95, compared to Case B32B.90.
- Due to the cost reductions from revised 2021 quote, when comparing the 90 percent capture cases from Revision 4a to Revision 4, the LCOE decreased 8.8 percent for case B31B.90.

The sensitivity of NGCC LCOE to CF is shown in Exhibit 5-97. NGCC is more sensitive to fuel cost than to CF, as shown in Exhibit 5-98, due to the relatively small capital component. As the CF drops, the decrease in net production is nearly offset by a corresponding decrease in fuel cost at high CF (greater than 80 percent) for the less capital intensive non-capture cases. A 33 percent increase in natural gas price (from \$4.42 to \$5.88/MMBtu) results in an LCOE increase of 21 percent in the non-capture cases and 15–16 percent in the CO₂ capture cases. Because of the higher capital cost in the CO₂ capture case, the impact of fuel price changes is slightly diminished.

Exhibit 5-97. Sensitivity of LCOE to capacity factor in NGCC cases

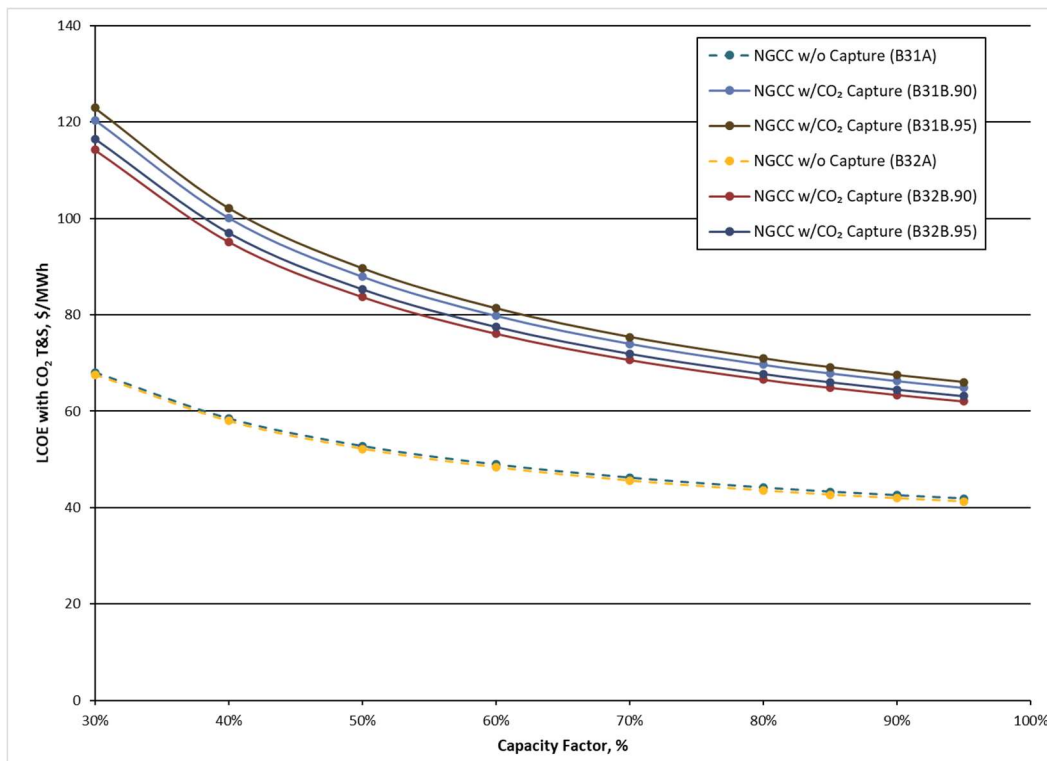
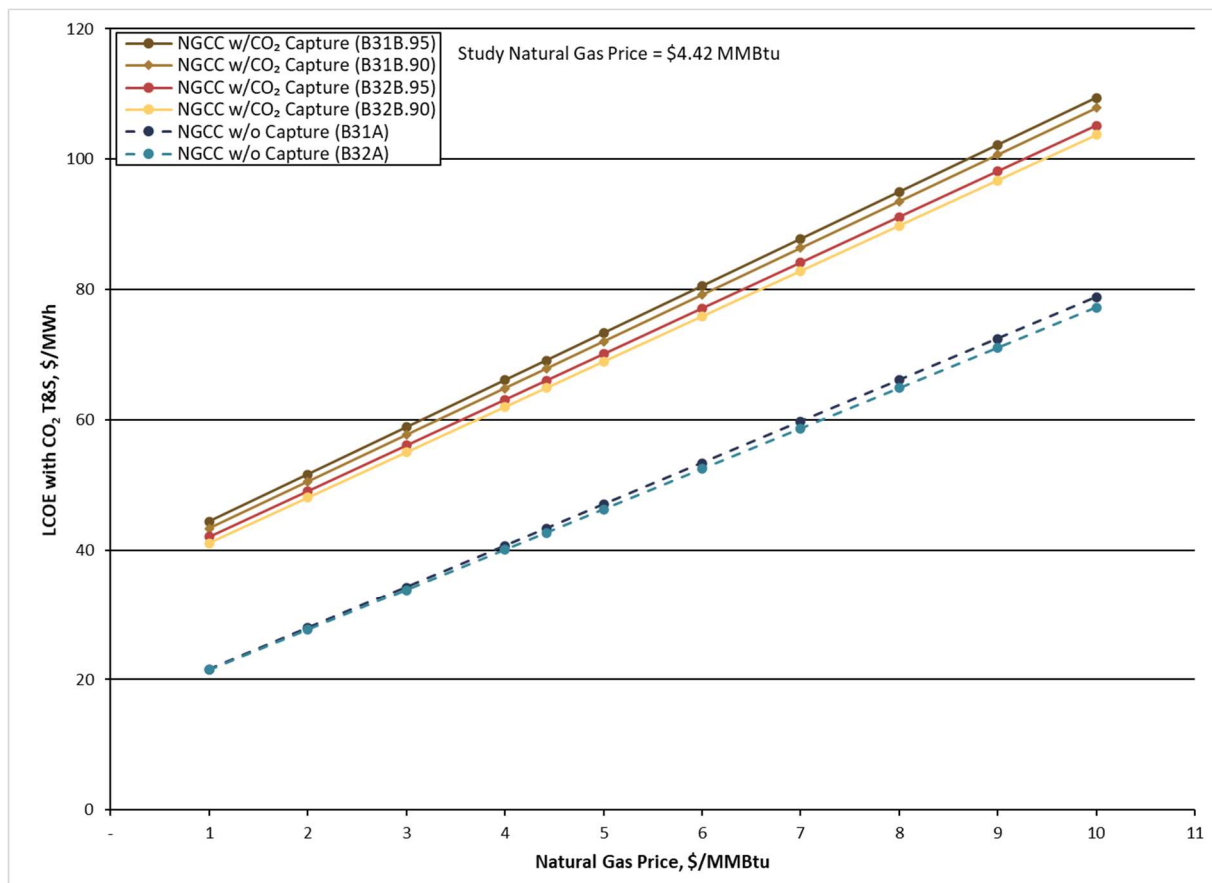


Exhibit 5-98. Sensitivity of LCOE to fuel price in NGCC cases



As presented in 2.7.4, the cost of CO₂ captured and cost of CO₂ avoided were calculated and the results for the NGCC CO₂ capture cases—using the analogous non-capture reference case (Cases B31A and B32A)—are shown in Exhibit 5-99 and Exhibit 5-100. The cost of CO₂ captured is \$55–61/tonne (\$50–55/ton) and the cost of CO₂ avoided is \$74–81/tonne (\$67–73/ton).

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 5-99. Breakdown of Cost of CO₂ Captured in NGCC cases

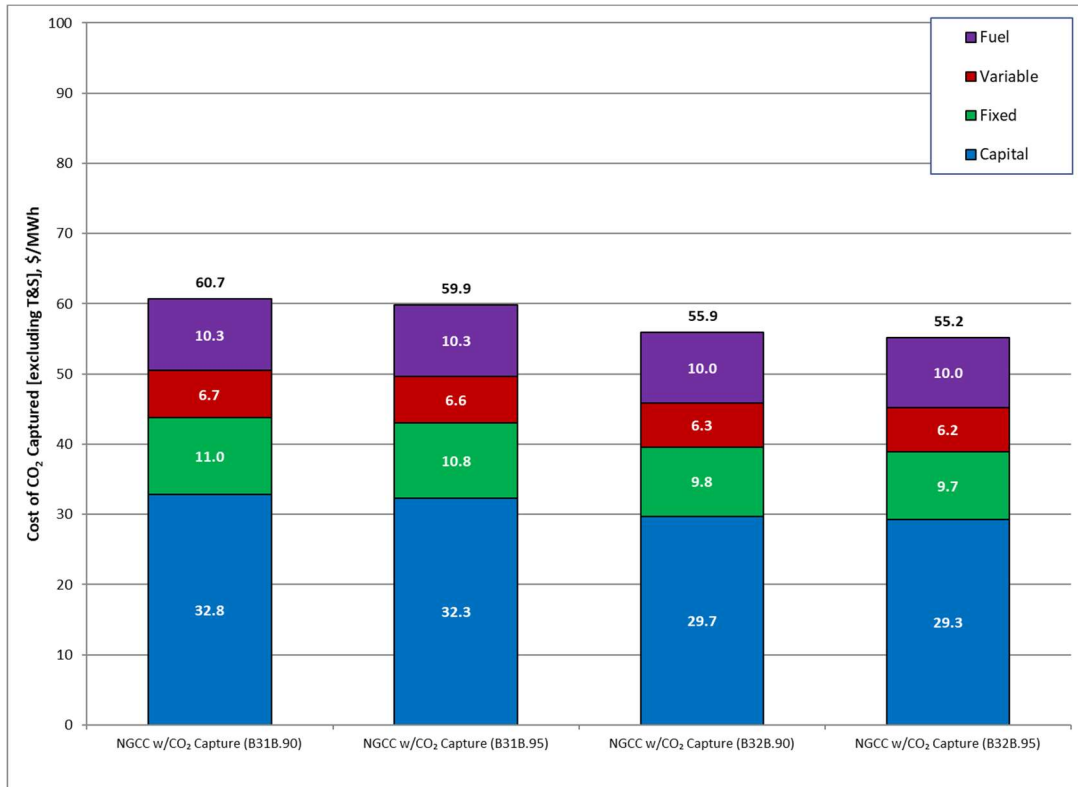
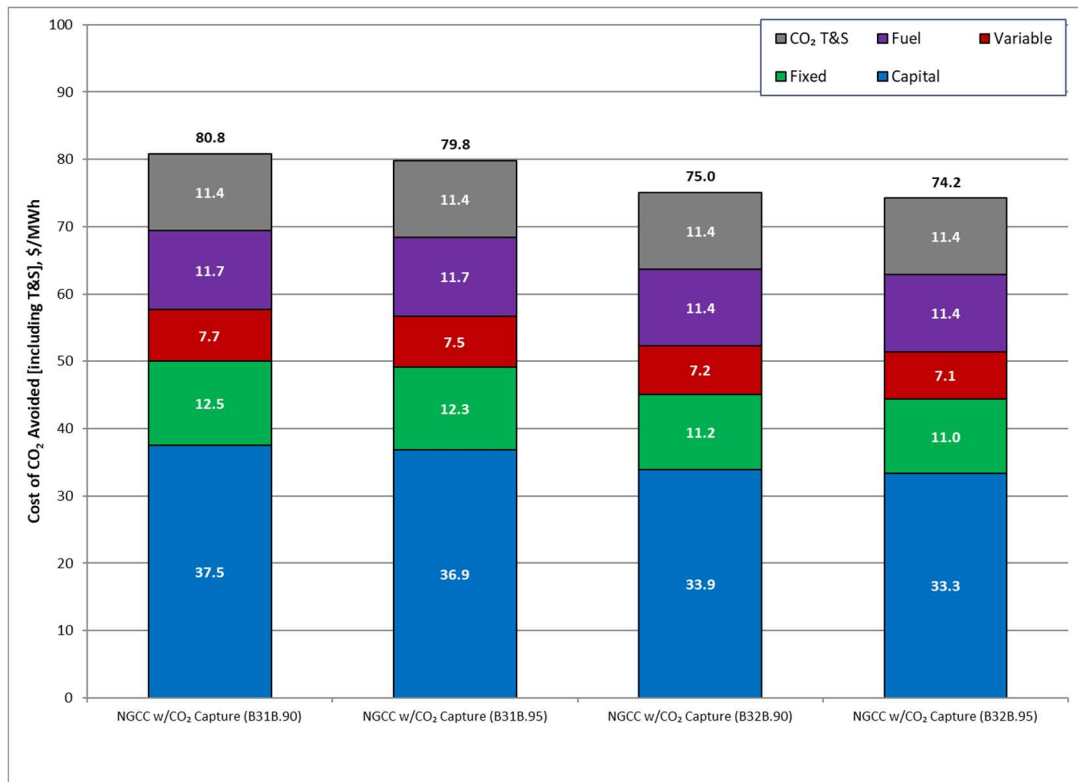


Exhibit 5-100. Breakdown of Cost of CO₂ Avoided in NGCC cases



The following observations can be made:

- Comparing the 90 percent capture cases from Revision 4a to Revision 4, the cost of CO₂ captured decreased 24 percent for case B31B.90. The cost of CO₂ avoided decreased 21 percent for case B31B.90.

6 RESULTS ANALYSIS

Summaries of the individual technologies were provided in sections 3, 4, and 5. This section provides the results of all technologies for cross-comparison.

6.1 PERFORMANCE RESULTS

Exhibit 6-1 provides a summary of the performance and environmental profile for IGCC cases, Exhibit 6-2 for PC cases, and Exhibit 6-3 for NGCC cases.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-1. Performance summary and environmental profile for IGCC cases

Case Name (Legacy Naming Convention) ^A	IGCC						
	Shell		E-Gas™ FSQ		GEP R+Q		
	B1A (5)	B1B (6)	B4A (3)	B4B (4)	B5A (1)	B5B (2)	B5B-Q (2a)
Performance							
CO ₂ Capture Rate (%)	0	90	0	90	0	90	90
Capacity Factor (%)	80	80	80	80	80	80	80
Gross Power Output (MWe)	765	696	763	742	765	741	685
Auxiliary Power Requirement (MWe)	125	177	122	185	131	185	186
Net Power Output (MWe)	640	519	641	557	634	556	499
Coal Flow Rate (lb/hr)	435,418	467,308	456,327	482,173	464,732	482,580	482,918
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HHV Thermal Input (kWt)	1,488,680	1,597,710	1,560,166	1,648,535	1,588,902	1,649,926	1,651,082
Net Plant HHV Efficiency (%)	43.0	32.5	41.1	33.8	39.9	33.7	30.2
Net Plant HHV Heat Rate (Btu/kWh)	7,940	10,497	8,308	10,101	8,554	10,118	11,287
Raw Water Withdrawal (gpm/MWnet)	6.5	9.8	6.8	9.3	7.6	9.9	12.6
Process Water Discharge (gpm/MWnet)	1.4	2.1	1.5	2.0	1.6	2.0	2.4
Raw Water Consumption (gpm/MWnet)	5.0	7.7	5.3	7.4	5.9	7.9	10.2
CO ₂ Emissions (lb/MMBtu)	200	21	199	20	197	20	20
CO ₂ Emissions (lb/MWh-gross)	1,328	161	1,391	153	1,396	151	163
CO ₂ Emissions (lb/MWh-net)	1,588	215	1,657	204	1,685	201	224
SO ₂ Emissions (lb/MMBtu) ^B	0.020	0.000	0.028	0.000	0.002	0.000	0.000
SO ₂ Emissions (lb/MWh-gross)	0.130	0.000	0.192	0.000	0.015	0.000	0.000
NO _x Emissions (lb/MMBtu)	0.059	0.049	0.056	0.049	0.054	0.048	0.048
NO _x Emissions (lb/MWh-gross)	0.390	0.382	0.393	0.371	0.379	0.364	0.394
PM Emissions (lb/MMBtu)	0.007	0.007	0.007	0.007	0.007	0.007	0.007
PM Emissions (lb/MWh-gross)	0.047	0.056	0.050	0.054	0.050	0.054	0.058
Hg Emissions (lb/TBtu)	0.452	0.383	0.430	0.396	0.423	0.395	0.365
Hg Emissions (lb/MWh-gross) ^C	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06

^A Previous versions of this report used a different naming convention (this report re-combines cases from *Cost and Performance Baseline for Fossil Energy Plants, Volume 1a* [7] and *Volume 1b*. [8]) The old case numbers are provided here, paired with the new case numbers for reference

^B Trace amounts of sulfur emissions may exist in the flue gas stream to the stack in capture cases

^C The mercury capture units were designed to attain the emissions target of 3.00x10⁻⁶ lb/MWh-gross

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-2. Performance summary and environmental profile for PC cases

Case Name (Legacy Naming Convention) ^A	PC					
	SubC PC			SC PC		
	B11A (9)	B11B.90 (10)	B11B.95	B12A (11)	B12B.90 (12)	B12B.95
Performance						
CO ₂ Capture Rate (%)	0	90	95	0	90	95
Capacity Factor (%)	85	85	85	85	85	85
Gross Power Output (MWe)	688	769	774	686	763	768
Auxiliary Power Requirement (MWe)	38	118	124	36	113	118
Net Power Output (MWe)	650	650	650	650	650	650
Coal Flow Rate (lb/hr)	493,115	630,940	640,819	473,055	600,801	609,741
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A
HHV Thermal Input (kWt)	1,685,945	2,157,162	2,190,938	1,617,359	2,054,118	2,084,684
Net Plant HHV Efficiency (%)	38.6	30.2	29.7	40.2	31.7	31.2
Net Plant HHV Heat Rate (Btu/kWh)	8,849	11,317	11,495	8,490	10,778	10,938
Raw Water Withdrawal (gpm/MWnet)	10.0	15.3	15.7	9.3	14.3	14.6
Process Water Discharge (gpm/MWnet)	2.1	3.9	4.0	1.9	3.7	3.8
Raw Water Consumption (gpm/MWnet)	8.0	11.4	11.7	7.4	10.6	10.9
CO ₂ Emissions (lb/MMBtu)	202	20	10	202	20	10
CO ₂ Emissions (lb/MWh-gross)	1,693	195	98	1,628	187	94
CO ₂ Emissions (lb/MWh-net)	1,790	230	117	1,718	219	111
SO ₂ Emissions (lb/MMBtu) ^B	0.081	0.000	0.000	0.081	0.000	0.000
SO ₂ Emissions (lb/MWh-gross)	0.675	0.000	0.000	0.649	0.000	0.000
NO _x Emissions (lb/MMBtu)	0.084	0.073	0.072	0.087	0.076	0.076
NO _x Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.700	0.700
PM Emissions (lb/MMBtu)	0.011	0.009	0.009	0.011	0.010	0.010
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.090	0.090
Hg Emissions (lb/TBtu)	0.359	0.313	0.311	0.373	0.326	0.324
Hg Emissions (lb/MWh-gross) ^C	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06

^A Previous versions of this report used a different naming convention (this report re-combines cases from *Cost and Performance Baseline for Fossil Energy Plants, Volume 1a* [7] and *Volume 1b*. [8]) The old case numbers are provided here, paired with the new case numbers for reference

^B Trace amounts of sulfur emissions may exist in the flue gas stream to the stack in capture cases

^C The mercury capture units were designed to attain the emissions target of 3.00x10⁻⁶ lb/MWh-gross

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-3. Performance summary and environmental profile for NGCC cases

Case Name (Legacy Naming Convention) ^A	NGCC					
	State-of-the-art 2017 F-Class			State-of-the-art 2017 H-class		
	B31A (13)	B31B.90 (14)	B31B.95	B32A	B32B.90	B32B.95
Performance						
CO ₂ Capture Rate (%)	0	90	95	0	90	95
Capacity Factor (%)	85	85	85	85	85	85
Gross Power Output (MWe)	740	692	690	1,009	945	942
Auxiliary Power Requirement (MWe)	14	47	49	17	62	65
Net Power Output (MWe)	727	645	640	992	883	877
Coal Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A
Natural Gas Flow Rate (lb/hr)	205,630	205,630	205,630	273,429	273,429	273,429
HHV Thermal Input (kWt)	1,354,905	1,354,905	1,354,905	1,801,631	1,801,631	1,801,631
Net Plant HHV Efficiency (%)	53.6	47.6	47.3	55.1	49.0	48.7
Net Plant HHV Heat Rate (Btu/kWh)	6,363	7,169	7,220	6,196	6,959	7,007
Raw Water Withdrawal (gpm/MWnet)	4.0	6.9	7.0	3.6	6.4	6.5
Process Water Discharge (gpm/MWnet)	0.9	2.3	2.4	0.8	2.2	2.2
Raw Water Consumption (gpm/MWnet)	3.1	4.6	4.7	2.8	4.2	4.3
CO ₂ Emissions (lb/MMBtu)	119	12	6	119	12	6
CO ₂ Emissions (lb/MWh-gross)	741	79	40	723	77	39
CO ₂ Emissions (lb/MWh-net)	755	85	43	735	83	42
SO ₂ Emissions (lb/MMBtu) ^B	0.001	0.000	0.000	0.001	0.000	0.000
SO ₂ Emissions (lb/MWh-gross)	0.006	0.000	0.000	0.006	0.000	0.000
NO _x Emissions (lb/MMBtu)	0.004	0.003	0.003	0.004	0.003	0.003
NO _x Emissions (lb/MWh-gross)	0.022	0.022	0.022	0.022	0.022	0.022
PM Emissions (lb/MMBtu)	0.002	0.000	0.000	0.002	0.000	0.000
PM Emissions (lb/MWh-gross)	0.012	0.000	0.000	0.011	0.000	0.000
Hg Emissions (lb/TBtu)	0.000	0.000	0.000	0.000	0.000	0.000
Hg Emissions (lb/MWh-gross)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

^A Previous versions of this report used a different naming convention (this report re-combines cases from *Cost and Performance Baseline for Fossil Energy Plants, Volume 1a* [7] and *Volume 1b*. [8]) The old case numbers are provided here, paired with the new case numbers for reference

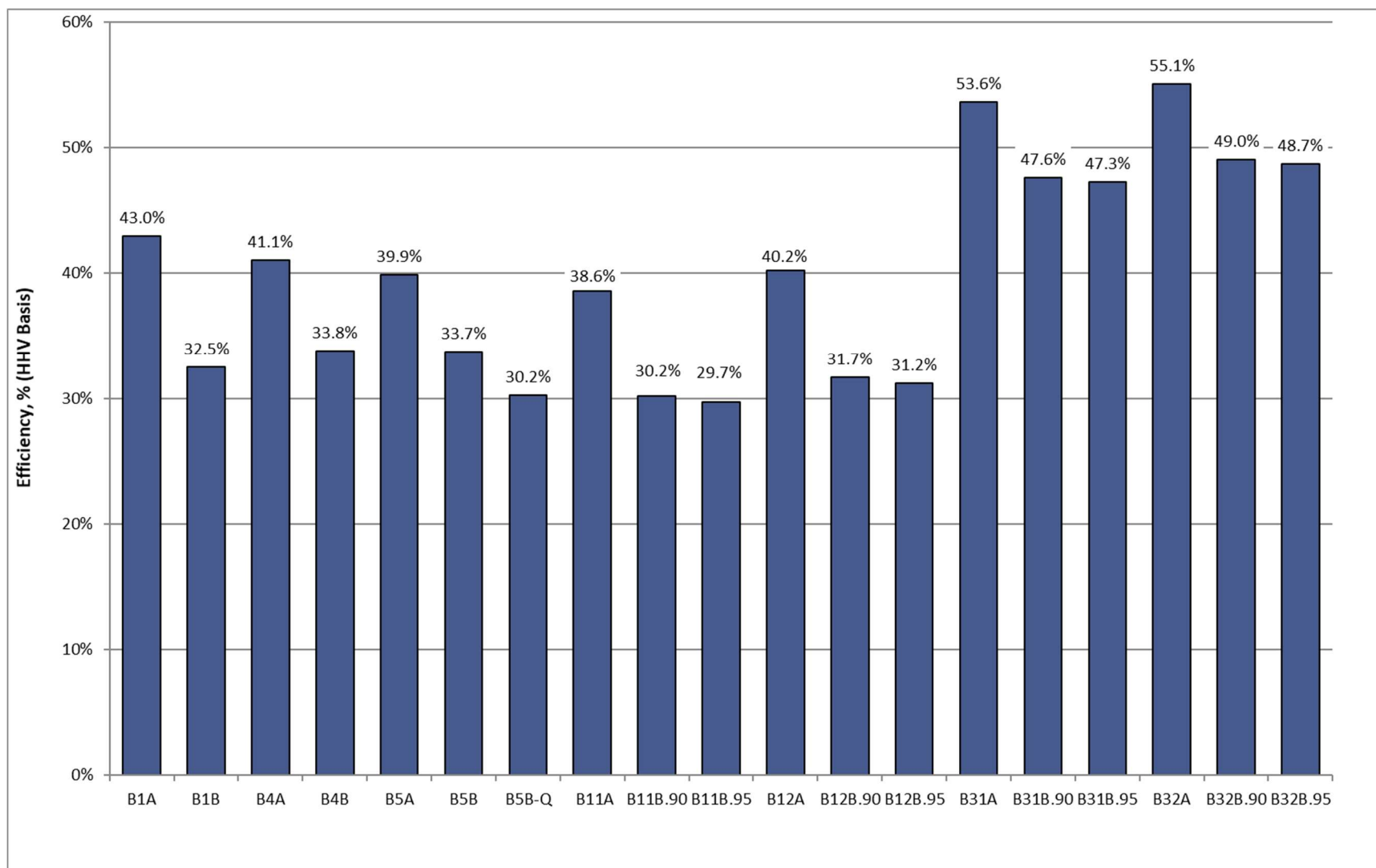
^B Trace amounts of sulfur emissions may exist in the flue gas stream to the stack in capture cases

6.1.1 Energy Efficiency

A graph of the net plant efficiency (HHV basis) is provided in Exhibit 6-4. The primary conclusions that can be drawn are:

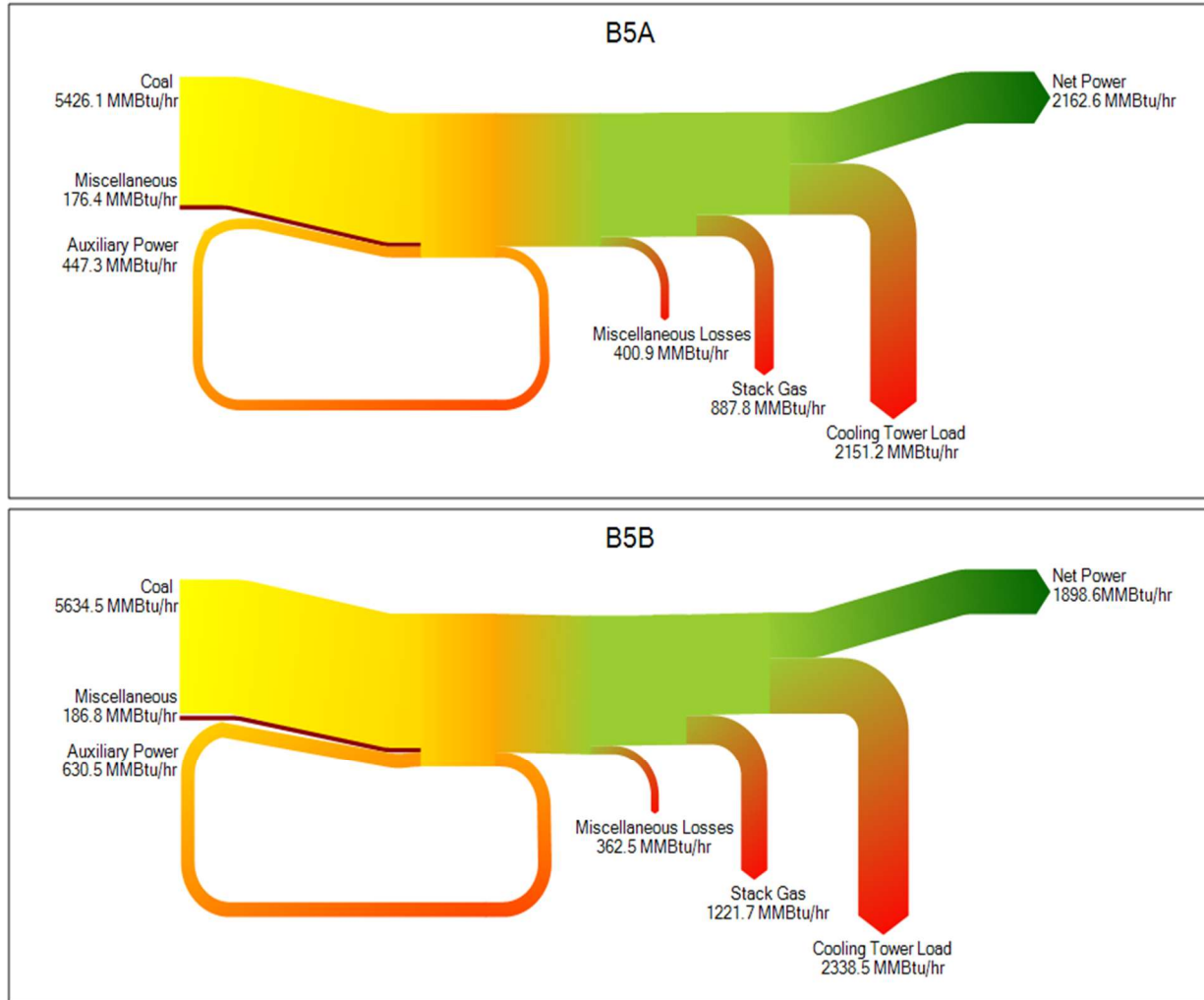
- The NGCC cases have the highest net efficiency of all the technologies, both without CO₂ capture (55.1 percent in Case B32A) and with CO₂ capture (49.0 percent in Case B32B.90). The next highest non-NGCC system efficiency is the non-capture Shell IGCC, with an efficiency of 43.0 percent.
- For the IGCC cases, adding CO₂ capture results in a relative efficiency penalty of 15–24 percent (6–10 percentage points).
- For the PC cases, adding 90 percent CO₂ capture results in a relative efficiency penalty of 22–23 percent for Sub PC cases (8–9 percentage points) and 21–22 percent for SC PC (9 percentage points).
 - The addition of higher CO₂ capture rates in SubC PC cases, comparing B11B.90 and B11B.95, results in an HHV efficiency penalty of 0.5 percentage points (1.6 percent relative to B11B.90). For the SC PC cases, comparing B12B.90 and B12B.95, the addition of higher CO₂ capture rates results in an HHV efficiency penalty of 0.5 percentage points (1.5 percent relative to B12B.90).
- For the NGCC case, adding 90 percent CO₂ capture results in a relative efficiency penalty of 11–12 percent (6 percentage points) for F-frame cases and 11–12 percent (6 percentage points) for H-frame.
 - The addition of higher CO₂ capture rates to the F-frame cases, comparing B31B.90 and B31B.95, results in an HHV efficiency penalty of 0.3 percentage points (0.7 percent relative to B31B.90). For the H-frame cases, comparing B32B.90 and B32B.95, the addition of higher CO₂ capture rates results in an HHV efficiency penalty of 0.3 percentage points (0.7 percent relative to B32B.90).
- The NGCC penalty is less than the PC penalty because:
 - Natural gas is less carbon intensive than coal (based on the fuel compositions used in this study, natural gas contains 32 lb carbon/MMBtu (13.7 kg/GJ) [HHV] of heat input and coal contains 55 lb/MMBtu (23.6 kg/GJ) [HHV]).
 - The NGCC non-capture plant is more efficient, thus there is less total CO₂ to capture and compress (NGCC non-capture CO₂ emissions are approximately 56–59 percent lower than the PC cases) when normalized to equivalent net power outputs.
 - These effects are offset slightly by the lower concentration of CO₂ in the NGCC flue gas (4 percent versus 13 percent for PC).

Exhibit 6-4. Net plant efficiency (HHV basis)



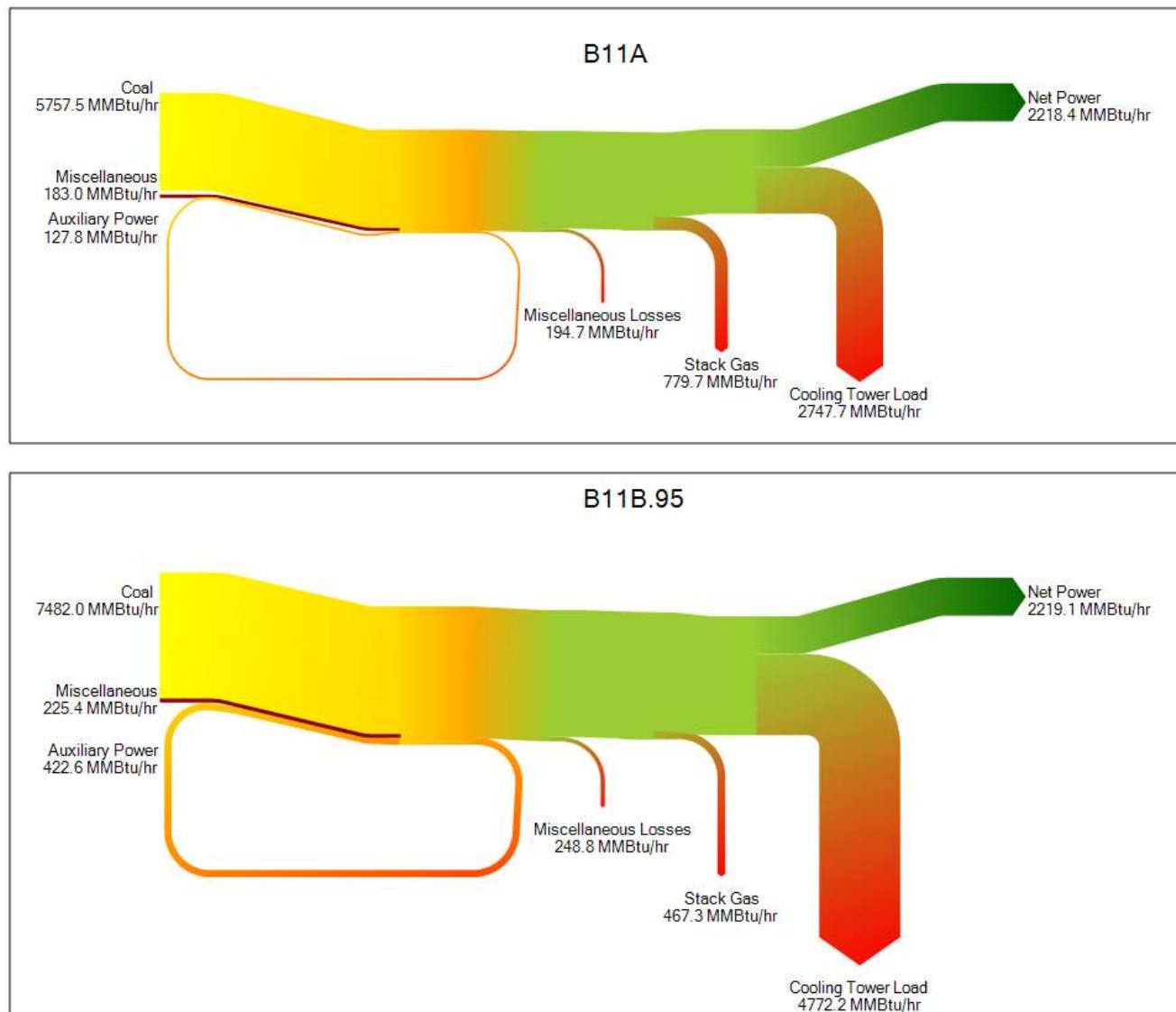
Sankey diagrams for select IGCC (GEP), PC (SC), and NGCC cases, both with and without CO₂ capture, are shown in Exhibit 6-5 through Exhibit 6-9. Discussion and cross-technology comparisons follow the exhibits.

Exhibit 6-5. GEP IGCC Sankey diagram with and without CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-6. SubC PC Sankey diagram with and without CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-7. SC PC Sankey diagram with and without CO₂ capture

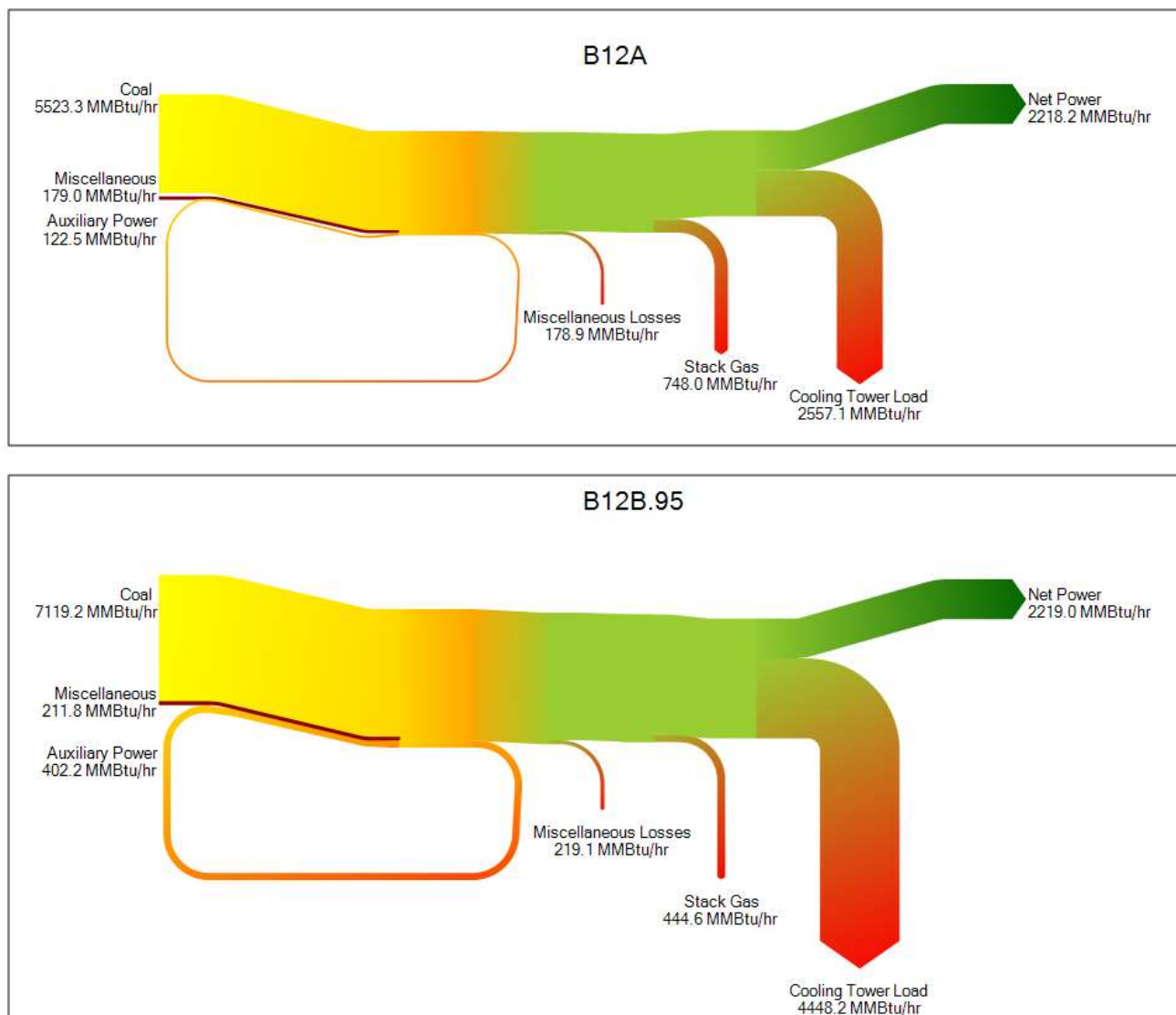


Exhibit 6-8. NGCC F-class Sankey diagram with and without CO₂ capture

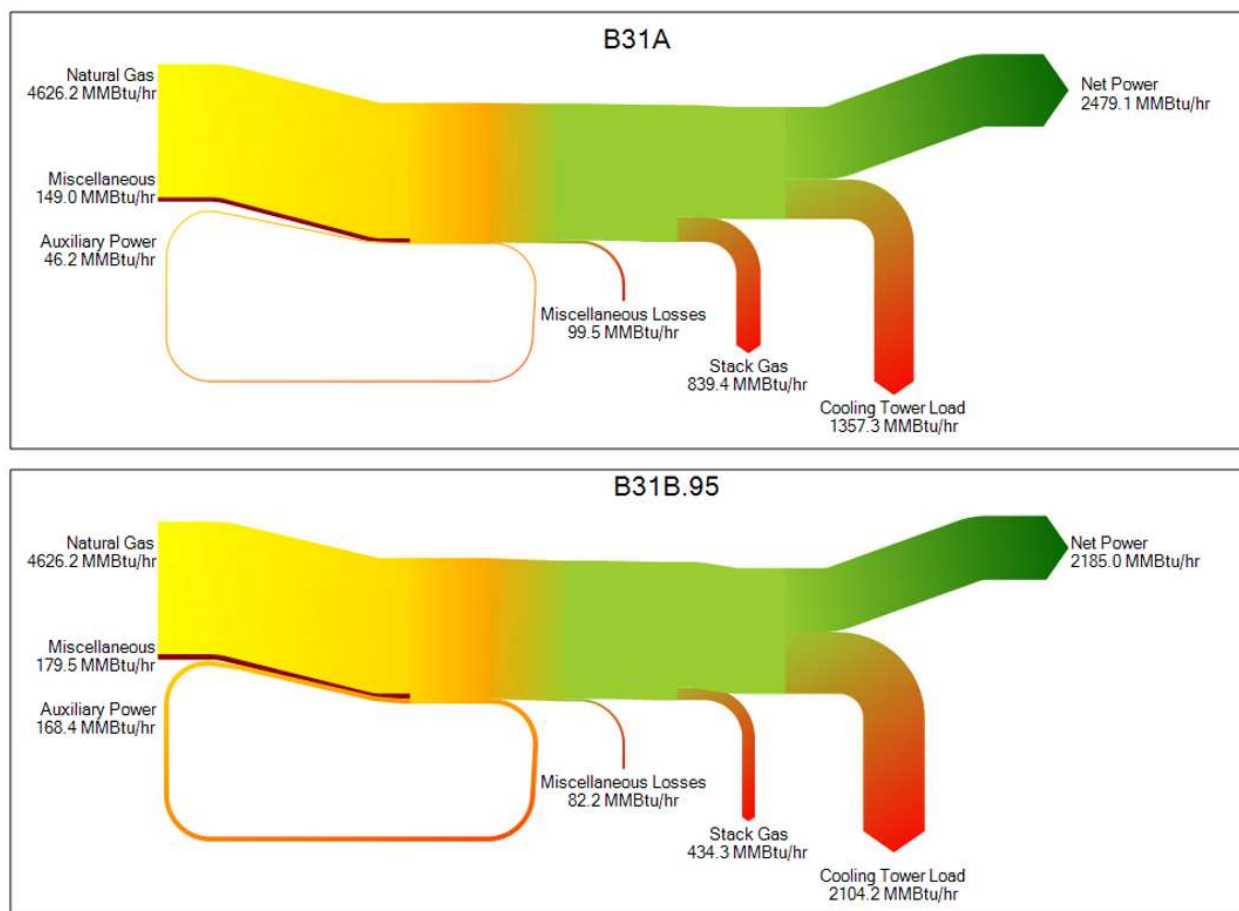
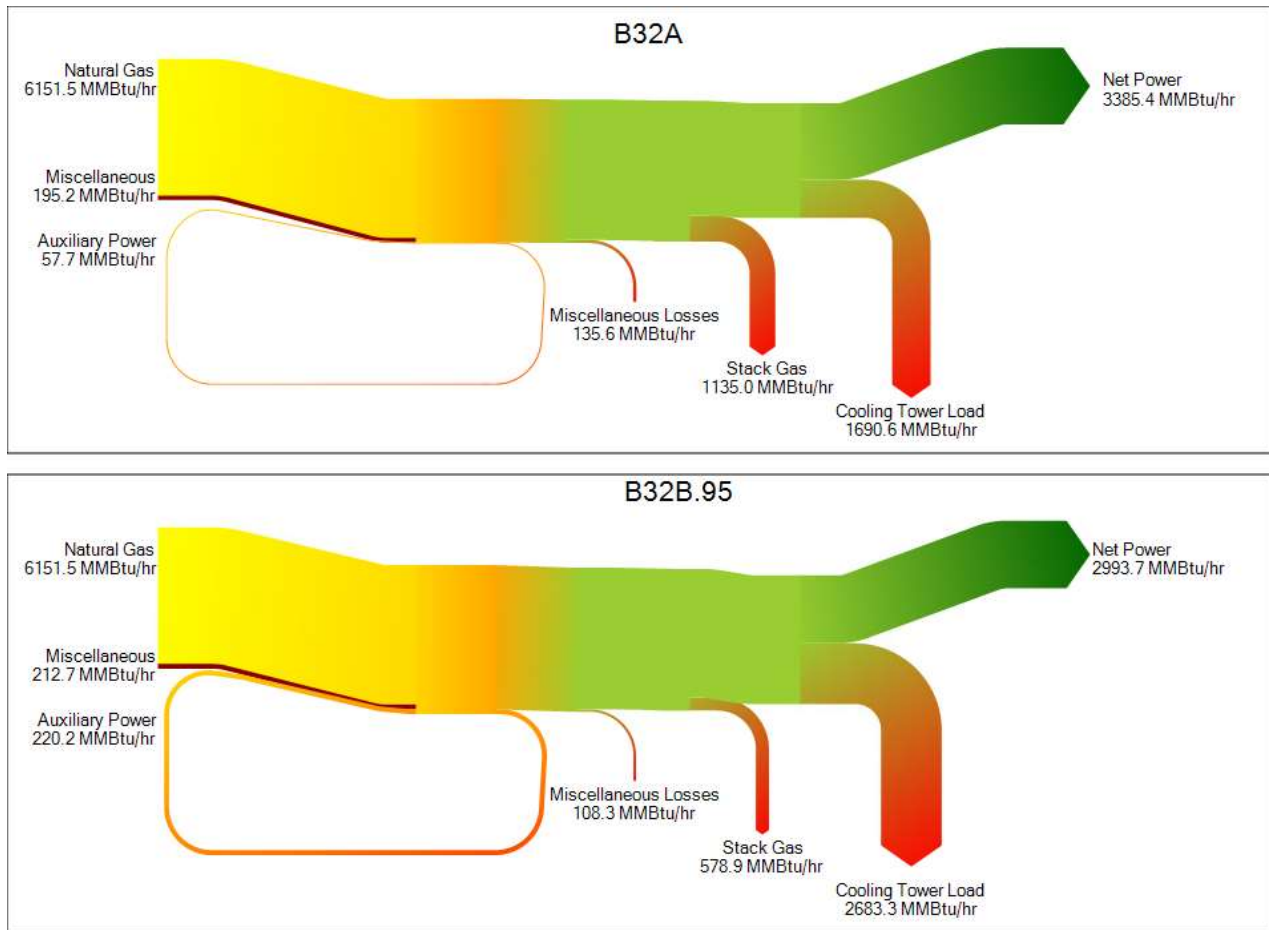


Exhibit 6-9. NGCC H-class Sankey diagram with and without CO₂ capture



The miscellaneous losses category is used to simplify the diagrams for the numerous, but relatively small, heat outlet streams, and includes different items across the three technology types. In IGCC cases, this category includes miscellaneous process steam, slag, sulfur, blowdown streams, ambient losses, CO₂ product, and others. In PC cases, this category includes bottom and fly ash, sulfur, gypsum, blowdown streams, deaerator vent, ambient losses, CO₂ product, AGR effluent, and others. In NGCC cases, this category includes deaerator vent, ambient losses, CO₂ product, AGR effluent, and others.

The NGCC cases considered in this study result in the highest net plant efficiencies. The net plant efficiencies of the non-capture PC and IGCC cases, and capture PC and IGCC cases, are relatively tightly grouped. In comparing the Sankey diagram results of PC and IGCC non-capture cases, several observations can be made:

- The additional sub-systems required by IGCC to facilitate the gasification of coal to power the Brayton topping cycle increase the auxiliary load requirements, as compared to PC.
- The size of the Rankine cycle (output basis) in PC plants is larger than IGCC or NGCC, which contributes to the larger cooling tower load observed in PC plants.

- The miscellaneous losses are larger for IGCC as compared to PC or NGCC, driven primarily by larger losses in the slag, sulfur, and blowdown streams of IGCC cases as compared to PC cases.

These same observations made for non-capture cases can be made in comparing the three technologies with CO₂ capture; however, the magnitude of the comparison changes. For example, the impact of the Rankine cycle output on cooling tower load is still present, but the addition of CO₂ capture imparts additional load on the cooling tower, thus creating an even larger cooling tower load for PC cases with capture as compared to IGCC or NGCC cases with capture.

6.1.2 Environmental Emissions

Estimated emissions of Hg, HCl, PM, NO_x, and SO₂ are all at or below the applicable regulatory limits currently in effect for all cases. Emissions results for each case were provided in Exhibit 6-1 through Exhibit 6-3.

Natural gas does not contain Hg, PM, or HCl, which makes its environmental profile more attractive compared to PC and IGCC cases. In this report, it was assumed that the only sulfur present in natural gas is from the addition of the odorant, mercaptan. This results in an SO₂ emission rate below the regulatory limits without any further control.

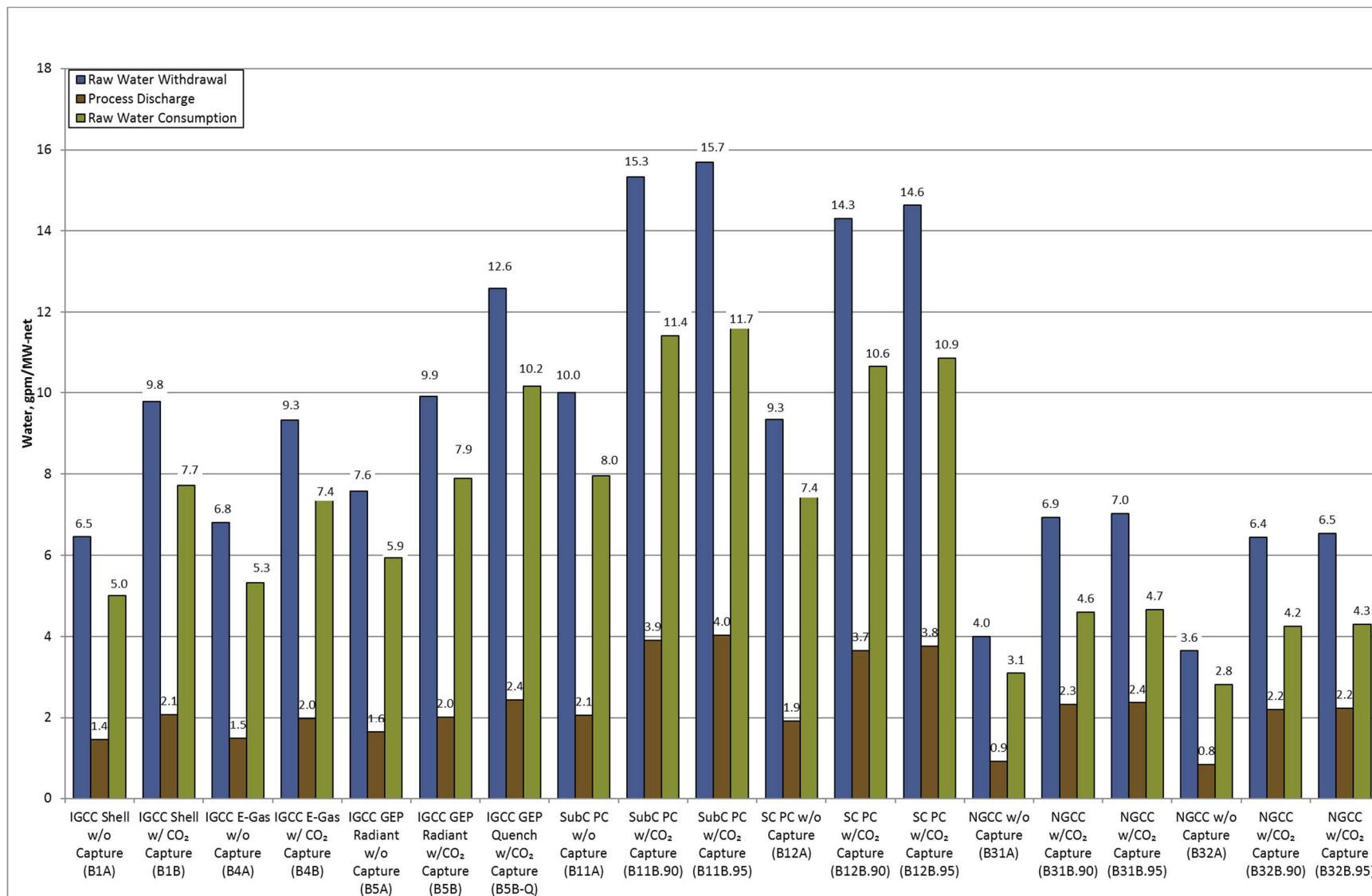
Systems required to bring the cases considered in this report into compliance with the ELG rule represent new sub-systems as compared to previous versions of this study. For the PC cases, the FGD wastewater blowdown flow rate range to be treated by the SDE spans 208–284 lpm (55–75 gpm). The approximate performance impact of implementing the SDE across the six PC cases is a 0.25–0.27 percentage point (absolute) decrease in the HHV net plant efficiency. This is due primarily to the diversion of warm flue gas away from the air preheater and to the evaporator, with an additional minor impact resulting from the small auxiliary load required by the SDE. For the IGCC cases, the syngas scrubber blowdown flow rate range to be treated by the vacuum flash, brine concentrator, and crystallizer ZLD system spans 1,050–2,400 lpm (277–635 gpm), with Case B5B-Q having the highest flow rate for treatment. The other six IGCC cases span a tighter range of 1,050–1,257 lpm (277–332 gpm). The approximate performance impact of implementing the ZLD system across the seven IGCC cases is a 0.10–0.20 percentage point (absolute) decrease in the HHV net plant efficiency, with six of the seven IGCC cases falling at or around a 0.10 percentage point decrease. This is due primarily to the steam extraction necessary, as well as the auxiliary load for the total ZLD system, which is significantly larger than the auxiliary load required for the SDE applied in PC cases.

6.1.3 Water Use

Three water values are presented for each technology in Exhibit 6-10: raw water withdrawal, process discharge, and raw water consumption. Each value is normalized by net output.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-10. Raw water withdrawal and consumption



The primary conclusions that can be drawn are:

- NGCC has the lowest raw water consumption of all cases for both non-capture and CO₂ capture cases. The results are expected given the higher steam turbine output in the PC and IGCC cases, which results in higher condenser duties, higher cooling water flows, and, ultimately, higher cooling water makeup.
- CO₂ capture imposes a significant water demand on all technologies. The post-combustion capture technology has a significant cooling water demand that results in increased raw water consumption because of increased cooling tower blowdown and cooling tower evaporative losses. Raw water consumption increases by 49–51 percent for the NGCC F-frame case and 51-53 percent for the NGCC H-frame case; 44–47 percent for the Sub PC cases and 43–46 percent for the SC PC cases; and 33–71 percent for the IGCC cases.

6.2 COST RESULTS

Cost results for all IGCC, PC, and NGCC cases are presented in **Error! Reference source not found.** through **Error! Reference source not found.**.

Exhibit 6-11. Cost summary for all IGCC cases

Case Name (Legacy Naming Convention) ^A	IGCC						
	Shell		E-Gas™ FSQ		GEP R+Q		
	B1A (5)	B1B (6)	B4A (3)	B4B (4)	B5A (1)	B5B (2)	B5B-Q (2a)
Cost							
Total Plant Cost (2018\$/kW)	4,087	6,545	3,656	5,501	4,105	5,568	5,212
<i>Bare Erected Cost</i>	2,837	4,487	2,548	3,788	2,854	3,834	3,595
<i>Home Office Expenses</i>	439	691	396	585	443	592	559
<i>Project Contingency</i>	588	967	534	828	594	826	795
<i>Process Contingency</i>	222	401	179	300	214	316	262
Total Overnight Cost (2018\$/MM)	3,194	4,175	2,867	3,773	3,189	3,810	3,206
Total Overnight Cost (2018\$/kW)	4,993	8,039	4,474	6,776	5,032	6,847	6,423
<i>Owner's Costs</i>	906	1,493	818	1,275	927	1,279	1,211
Total As-Spent Cost (2018\$/kW)	5,764	9,280	5,165	7,822	5,809	7,904	7,414
LCOE (\$/MWh) (excluding T&S)^B	111.5	173.7	103.2	150.1	114.0	151.3	147.1
<i>Capital Costs</i>	58.2	93.7	52.1	79.0	58.6	79.8	74.8
<i>Fixed Costs</i>	21.3	33.5	19.2	28.4	21.4	28.7	27.3
<i>Variable Costs</i>	14.3	23.2	13.3	20.3	14.9	20.3	19.8
<i>Fuel Costs</i>	17.7	23.4	18.5	22.5	19.0	22.5	25.1
LCOE (\$/MWh) (including T&S)^B	111.5	182.3	103.2	158.3	114.0	159.4	156.2
<i>CO₂ T&S Costs</i>	N/A	8.6	N/A	8.2	N/A	8.1	9.1
Cost of CO₂ Captured (ex. T&S), \$/tonne^C	N/A	127.7	N/A	104.3	N/A	106.7	91.1
Cost of CO₂ Avoided (incl. T&S), \$/tonne^C	N/A	172.8	N/A	136.6	N/A	137.9	135.3

^AFinancing structures are presented in NETL's "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance" [4]

^BVarying incentives, such as tax credits, could impact the economics of the system

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

^cBoth the cost of CO₂ captured and cost of CO₂ avoided were calculated based on the non-capture SC PC Case B12A for all coal cases

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-12. Cost summary for all PC cases

Case Name (Legacy Naming Convention) ^A	PC					
	SubC PC			SC PC		
	B11A (9)	B11B.90 (10)	B11B.95	B12A (11)	B12B.90 (12)	B12B.95
Cost						
Total Plant Cost (2018\$/kW)	2,015	3,393	3,458	2,103	3,452	3,514
<i>Bare Erected Cost</i>	1,486	2,408	2,453	1,551	2,455	2,497
<i>Home Office Expenses</i>	260	421	429	271	430	437
<i>Project Contingency</i>	270	472	482	281	479	488
<i>Process Contingency</i>	0	91	95	0	88	92
Total Overnight Cost (2018\$/MM)	1,615	2,709	2,761	1,683	2,752	2,802
Total Overnight Cost (2018\$/kW)	2,484	4,165	4,245	2,588	4,233	4,309
<i>Owner's Costs</i>	468	772	787	485	781	795
Total As-Spent Cost (2018\$/kW)	2,867	4,808	4,900	2,988	4,886	4,974
LCOE (\$/MWh) (excluding T&S)^B	64.0	99.1	100.9	64.5	98.4	100.1
<i>Capital Costs</i>	27.2	45.7	46.6	28.4	46.4	47.3
<i>Fixed Costs</i>	9.2	14.6	14.9	9.5	14.8	15.1
<i>Variable Costs</i>	7.9	13.6	13.9	7.7	13.2	13.5
<i>Fuel Costs</i>	19.7	25.2	25.6	18.9	24.0	24.4
LCOE (\$/MWh) (including T&S)^B	64.0	108.4	110.9	64.5	107.3	109.7
<i>CO₂ T&S Costs</i>	N/A	9.3	10.0	N/A	8.9	9.5
Cost of CO₂ Captured (ex. T&S), \$/tonne^C	N/A	37.0	36.3	N/A	38.1	37.3
Cost of CO₂ Avoided (incl. T&S), \$/tonne^C	N/A	65.0	63.9	N/A	63.0	61.9

^AFinancing structures are presented in NETL's "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance" [4]

^BVarying incentives, such as tax credits, could impact the economics of the system

^CBoth the cost of CO₂ captured and cost of CO₂ avoided were calculated based on the non-capture SC PC Case B12A for all coal cases

Exhibit 6-13. Cost summary for all NGCC cases

Case Name (Legacy Naming Convention) ^A	NGCC					
	State-of-the-art 2017 F-Class			State-of-the-art 2017 H-class		
	B31A (13)	B31B.90 (14)	B31B.95	B32A	B32B.90	B32B.95
Cost						
Total Plant Cost (2018\$/kW)	780	1,686	1,727	796	1,593	1,630
<i>Bare Erected Cost</i>	561	1,134	1,160	573	1,078	1,101
<i>Home Office Expenses</i>	112	227	232	115	216	220
<i>Project Contingency</i>	107	254	261	109	237	243
<i>Process Contingency</i>	0	71	74	0	62	65
Total Overnight Cost (2018\$/MM)	692	1,321	1,344	963	1,710	1,738
Total Overnight Cost (2018\$/kW)	952	2,049	2,099	970	1,936	1,980
<i>Owner's Costs</i>	172	363	372	174	343	351
Total As-Spent Cost (2018\$/kW)	1,040	2,239	2,293	1,060	2,115	2,164
LCOE (\$/MWh) (excluding T&S)^B	43.3	64.4	65.4	42.7	61.5	62.4
<i>Capital Costs</i>	9.9	21.3	21.8	10.1	20.1	20.6
<i>Fixed Costs</i>	3.6	7.4	7.6	3.5	6.8	7.0
<i>Variable Costs</i>	1.7	4.0	4.1	1.7	3.8	3.9
<i>Fuel Costs</i>	28.1	31.7	31.9	27.4	30.8	31.0
LCOE (\$/MWh) (including T&S)^B	43.3	67.9	69.1	42.7	64.9	66.0
<i>CO₂ T&S Costs</i>	N/A	3.5	3.7	N/A	3.4	3.6
Cost of CO₂ Captured (ex. T&S), \$/tonne^C	N/A	60.7	59.9	N/A	55.9	55.2
Cost of CO₂ Avoided (incl. T&S), \$/tonne^C	N/A	80.8	79.8	N/A	75.0	74.2

^AFinancing structures are presented in NETL's "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance" [4]

^BVarying incentives, such as tax credits, could impact the economics of the system

^CThe cost of CO₂ captured and cost of CO₂ avoided were calculated based on the analogous non-capture case (i.e. B31B cases use B31A as a reference and B32B cases use B32A)

6.2.1 TOC and TASC

In Exhibit 6-14, the normalized components of TOC and TASC are shown for each technology. As described previously in the technology summary sections, each technology carries with it a different uncertainty range for the capital cost estimate. The error bars included in Exhibit 6-14 represent the potential TOC range relative to the maximum and minimum of the capital cost uncertainty range. Comparison for the capture cases can be seen in Exhibit 6-15.

The following observations about normalized TOC can be made:

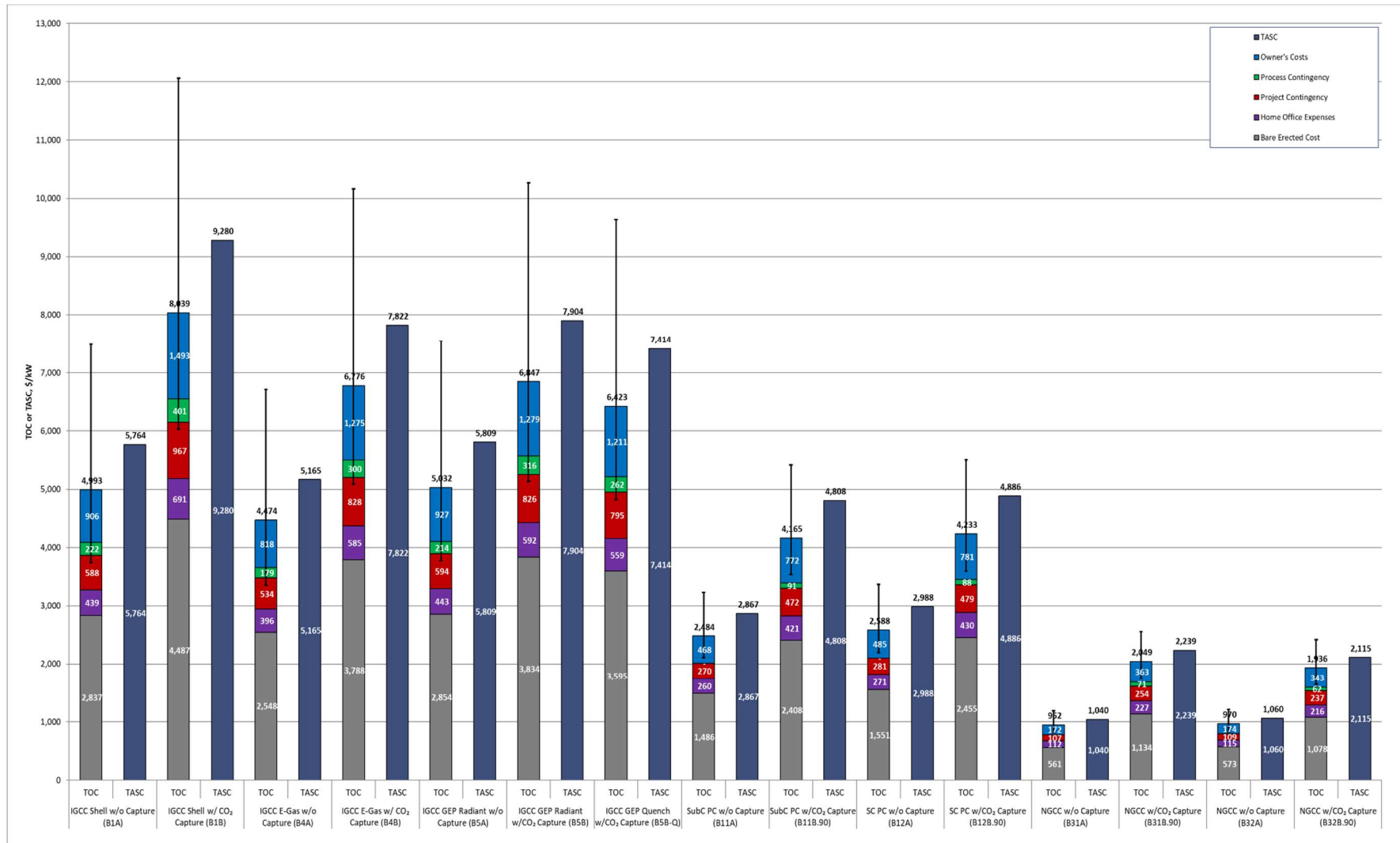
- E-GasTM has the lowest TOC cost among the non-capture IGCC cases. The E-GasTM technology has several features that lend to the lower cost, such as:
 - The firetube syngas cooler is much smaller and less expensive than a radiant section. E-GasTM can use a firetube boiler because the two-stage design reduces

the syngas temperature (slurry quench) into a range where a radiant cooler is not needed.

- The firetube syngas cooler sits next to the gasifier instead of above or below it, which reduces the height of the main gasifier structure. The E-Gas™ proprietary slag removal system—used instead of lock hoppers below the gasifier—also contributes to the lower structure height.
- The GEP Quench gasifier (GEP Radiant TOC is 7 percent greater than GEP Quench) is the low-cost technology in the IGCC CO₂ capture cases, with E-Gas™ normalized TOC approximately 6 percent higher and Shell approximately 25 percent higher.
- Based on TOC in \$/kW, NGCC H-frame capital costs are approximately 38 percent and 46 percent of the SC PC capital costs for non-capture and 90 percent capture cases, respectively.
 - The NGCC cost advantage over PC is partially enabled by the lack of emission control equipment necessitated for the adherence to current regulations.
- The addition of CO₂ capture technology significantly impacts all technologies. The TOC, on a \$/kW basis, increase from the addition of CO₂ capture technology spans the range of 28–61 percent in IGCC cases, 68–71 percent for SubC PC, and 64–66 percent for SC PC. The addition of capture to NGCC demonstrates the largest increase to TOC, on a \$/kW basis, of all cases considered – a 115–120 percent increase for F-frame cases and 100–104 percent for H-frame cases.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

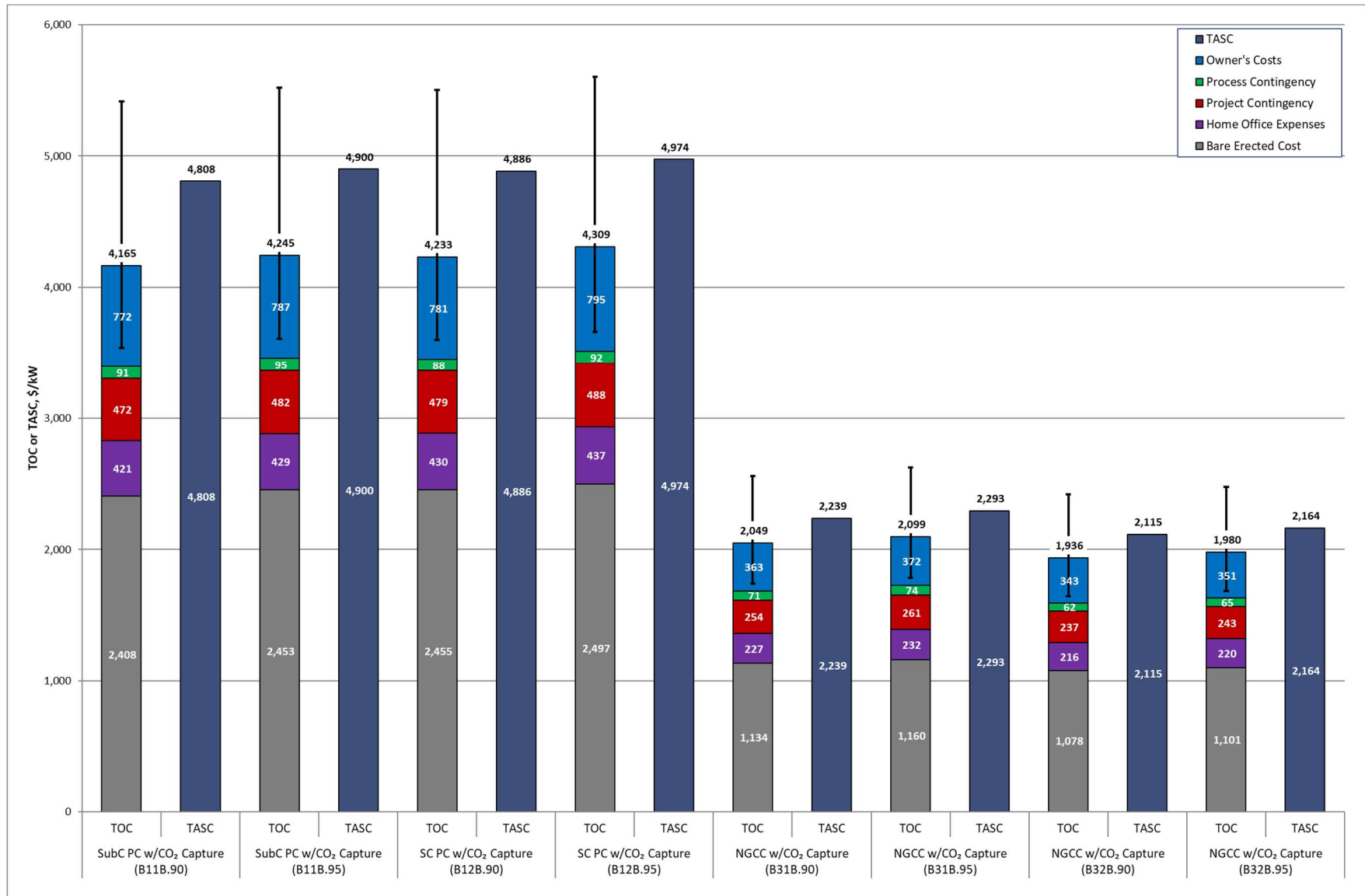
Exhibit 6-14. Plant capital costs



Note: 90 percent capture cases are shown for the PC and NGCC cases. Comparison for the capture cases can be seen in Exhibit 6-15. The TOC ranges \$4,165–4,245/kW for the SubPC cases, \$4,233–4,309/kW for the SC PC cases, \$2,049–2,099/kW for the F-frame cases, and \$1,936–1,980/kW for the H-frame cases. The TASC ranges \$4,808–4,900/kW for the SubPC cases, \$4,886–4,974/kW for the SC PC cases, \$2,239–2,293/kW for the F-frame cases, and \$2,115–2,164/kW for the H-frame cases.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-15. Plant capital costs PC and NGCC capture cases



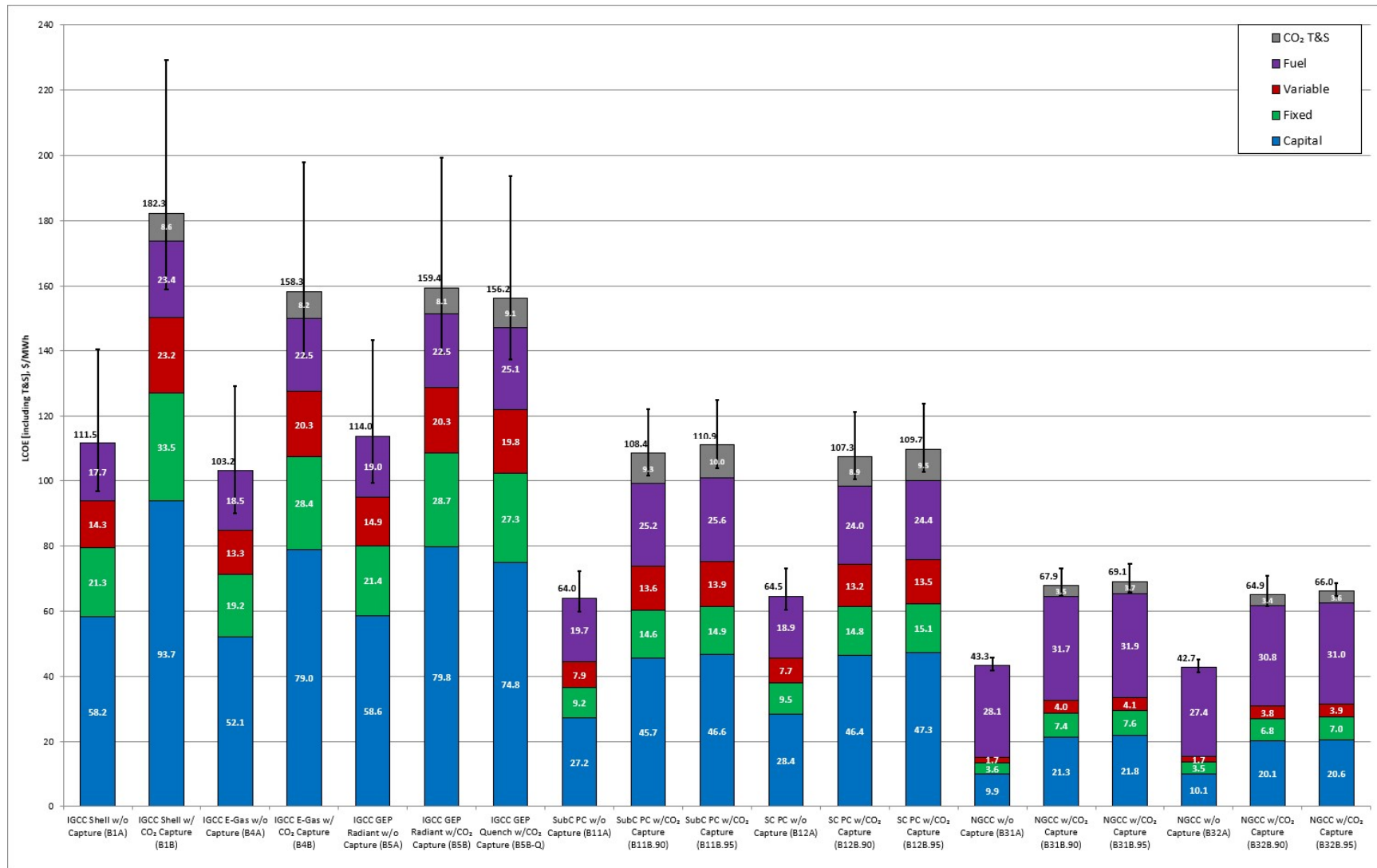
6.2.2 LCOE

A graph of the LCOE by cost component is provided in Exhibit 6-16. As described previously in the technology summary sections, each technology carries with it a different uncertainty range for the capital cost estimate. The error bars included in Exhibit 6-16 represent the potential LCOE range relative to the maximum and minimum of the capital cost uncertainty range. The LCOE ranges presented are not reflective of other parameter changes, such as variation in fuel price, labor price, CF, or other factors. The primary observations that can be made are:

- In the non-capture IGCC cases the E-GasTM gasifier has the lowest LCOE, but the differential with Shell is reduced (relative to the normalized TOC comparison) primarily because of the higher efficiency of the Shell gasifier. The Shell LCOE is 8 percent higher than E-GasTM (compared to 12 percent higher normalized TOC). The GEP gasifier LCOE is about 10 percent higher than E-GasTM.
- In the IGCC capture cases, the order of the GEP Radiant and Shell gasifiers is reversed, with GEP Quench being the lowest LCOE option. The range is from \$156.2/MWh for GEP Quench to \$182.3/MWh for Shell, with E-GasTM and GEP Radiant intermediate at \$158.3/MWh and \$159.4/MWh, respectively, including T&S. The LCOE CO₂ capture premium for the cases averages 48 percent (range of 37–64 percent).
- LCOE is dominated by the capital cost component in IGCC and PC cases. In IGCC, capital costs account for at least 50 percent of the total LCOE (excluding T&S costs). In PC cases, capital costs account for 43–47 percent of the LCOE. In NGCC cases, the capital component is a smaller LCOE contributor, representing 23–33 percent of the LCOE.
- Fuel costs represent the largest portion of the LCOE in NGCC cases, ranging 49–65 percent of the total LCOE (excluding T&S costs). In PC cases, the fuel contribution is less, at 24–31 percent of the LCOE. In IGCC cases, the fuel contribution is the smallest, ranging 13–18 percent of the LCOE.
- The CO₂ T&S LCOE component represents 5–9 percent of the total LCOE across the cases with CO₂ capture considered in this study.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-16. LCOE by cost component



Note: Financing structures are presented in NETL's "QGES: Cost Estimation Methodology for NETL Assessments of Power Plant Performance" [4]

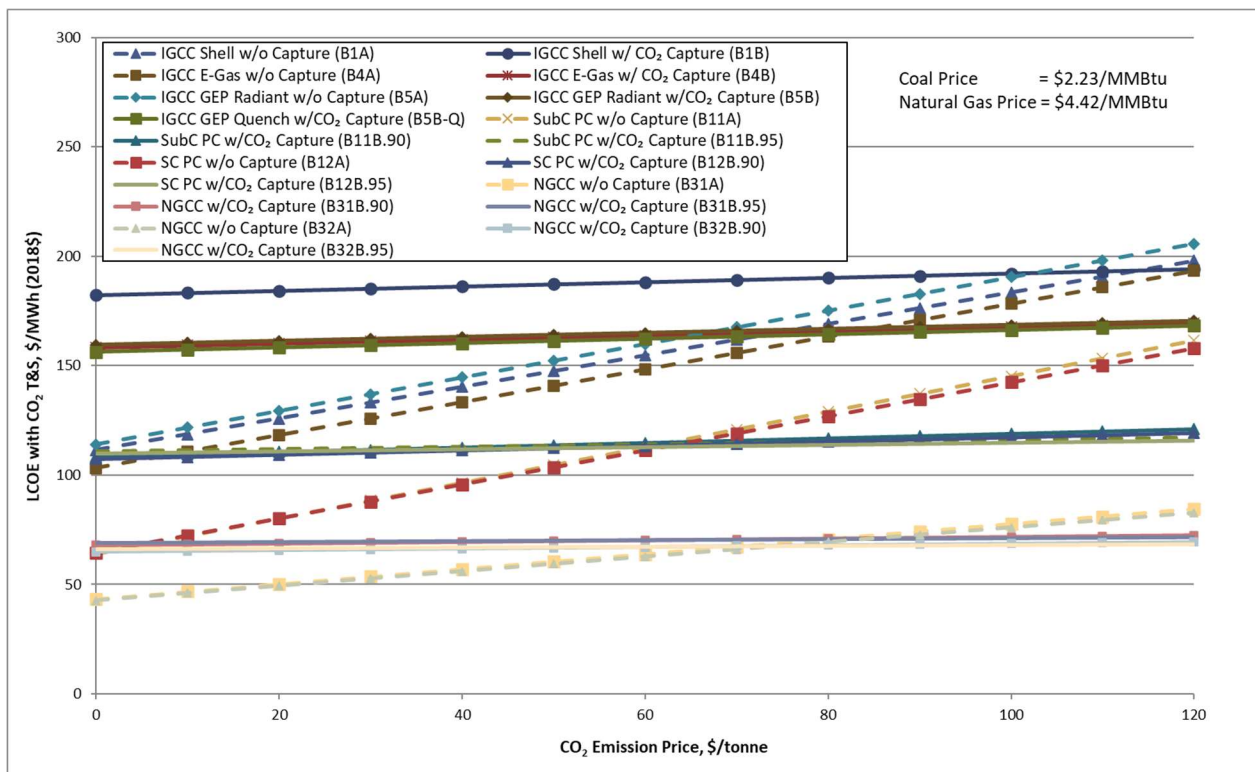
6.2.3 CO₂ Emission Price Impact

If future legislation assigns a cost to carbon emissions, all the technologies examined in this report will become more expensive. The technologies without carbon capture will be impacted to a larger extent than those with carbon capture, and coal-based technologies will be impacted more than natural gas-based technologies.

The cost of CO₂ avoided for 90 percent capture cases is shown in Exhibit 6-17 as the intersection of the CO₂ capture PC and IGCC cases lines with the line for the SC PC non-capture case and the intersection of the NGCC CO₂ capture case line with the line for the NGCC non-capture case. For example, the cost of CO₂ avoided is \$62–\$65/tonne (\$56–\$59/ton) for PC, \$135–\$173/tonne (\$123–\$157/ton) for IGCC, and \$74–\$81/tonne (\$67–\$73/ton) for NGCC.

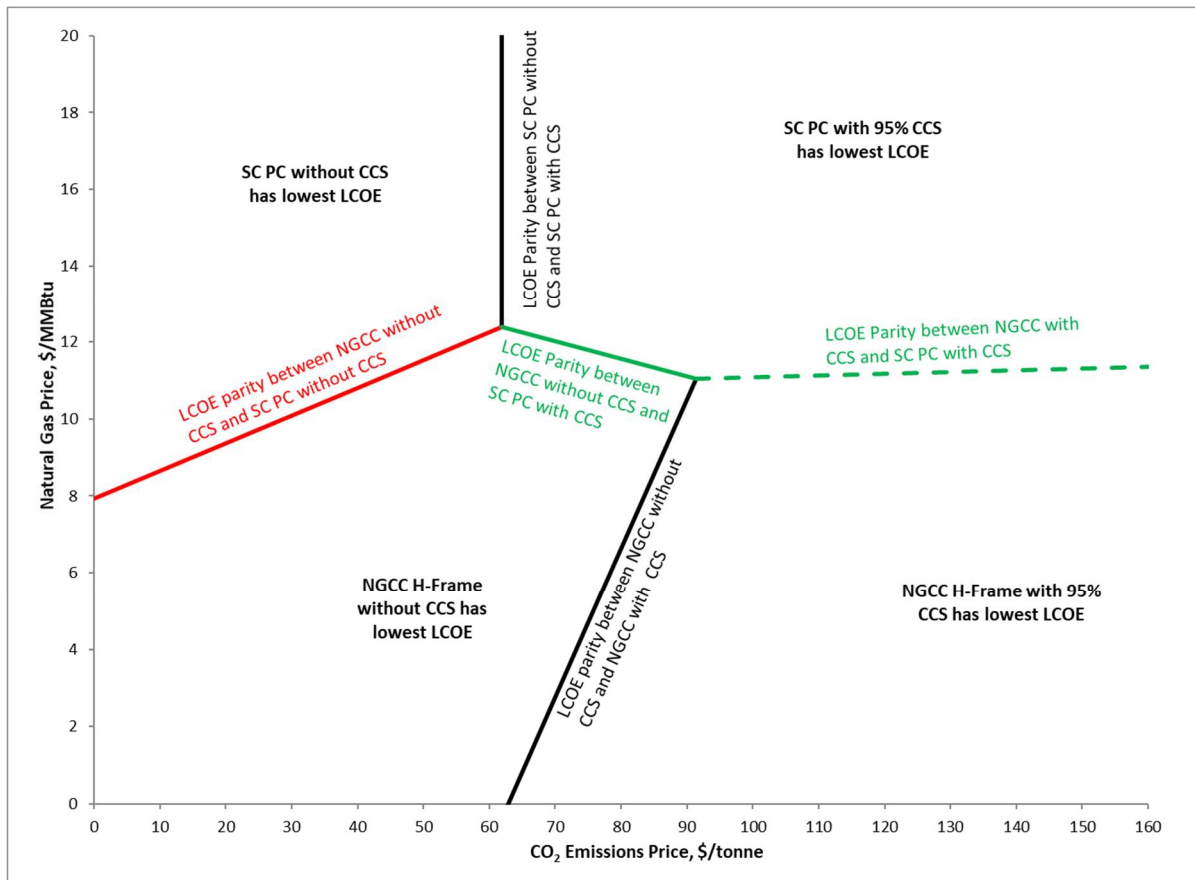
The curves in Exhibit 6-17 represent the study design conditions (CF) and fuel prices used for each technology; namely an 80 or 85 percent CF (IGCC or PC/NGCC) and \$2.11/GJ (\$2.23/MMBtu) for coal and \$4.19/GJ (\$4.42/MMBtu) for natural gas.

Exhibit 6-17. Impact of carbon emissions price on study technologies



The impact of CO₂ emissions price and natural gas price and the implications on the competitiveness of the capture technologies can also be considered in a “phase diagram” type plot, as shown in Exhibit 6-18. The exhibit only considers the competitiveness of NGCC and PC cases, as IGCC has been demonstrated to consistently be a higher cost option. The lines in the plot represent cost parity between different pairs of technologies. Where cases include CO₂ capture, the reference cases include 95 percent capture.

Exhibit 6-18. Lowest cost power generation options comparing NGCC and PC



The plot demonstrates the following points:

- Non-capture plants are the low-cost option below a CO₂ price of \$63/tonne (\$57/ton).
- NGCC is preferred when natural gas prices are below \$7.9/MMBtu (and a CF of 85 percent). SC PC plants are preferred when natural gas prices are above \$12.4/MMBtu.

6.2.4 CO₂ Sales Price Impact

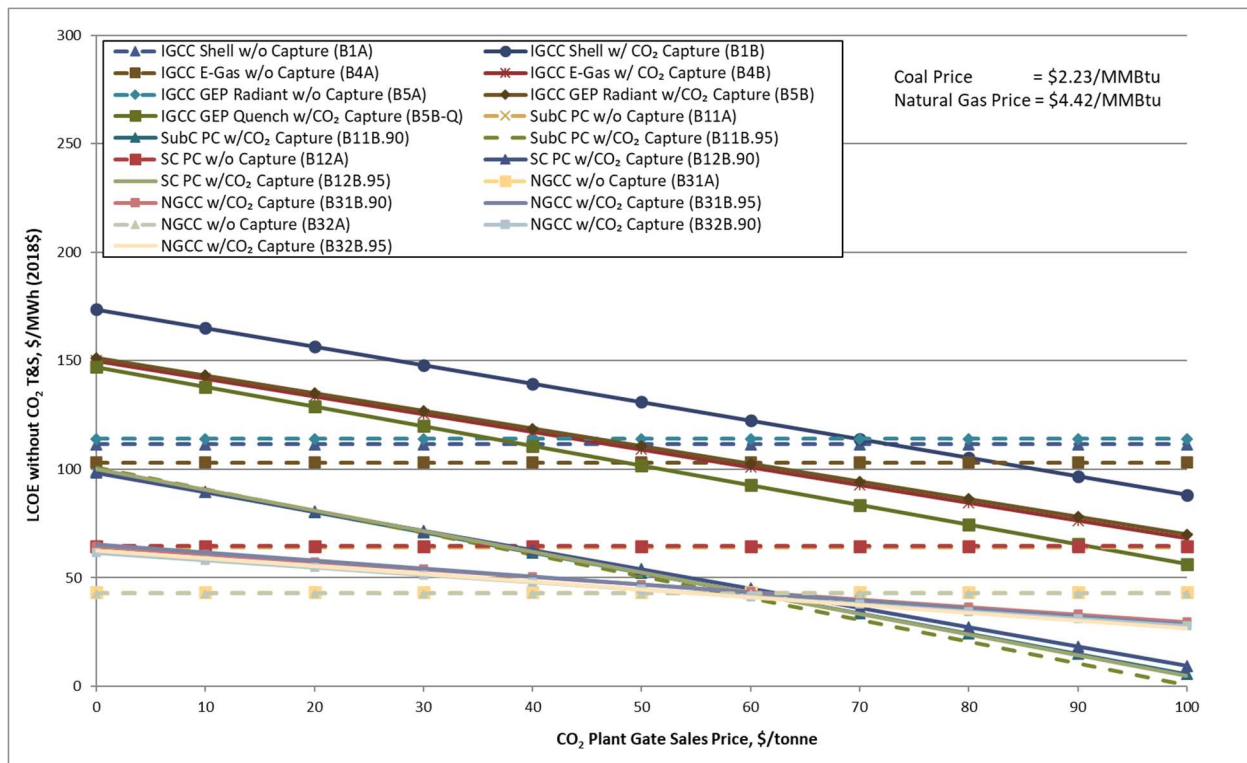
Sale of the captured CO₂ for utilization and storage in CO₂ enhanced oil recovery (EOR) has the potential to provide a revenue stream for capture plant configurations. The plant gate CO₂ sales price will ultimately depend on a number of factors, such as the varying performance of a CO₂ EOR flood, plant location, and crude oil prices. The cost of CO₂ captured represents the minimum CO₂ plant gate sales price that will incentivize carbon capture relative to a defined reference non-capture plant.

The industry CO₂ sales price for EOR varies from \$17/ton to \$50/ton [135] with an average price of \$40/ton, as of 2019. [136] A general rule of thumb used in academic work for estimating the CO₂ price for EOR is that one million cubic feet of CO₂ will cost approximately 2 percent of a barrel of Western Texas Intermediate oil, which results in a CO₂ sales price of \$32.18/ton, as of the writing of this report. [135]

The cost of CO₂ captured is shown in Exhibit 6-19 as the intersection of the CO₂ capture PC and IGCC case lines with the line for the SC PC non-capture case, and the intersection of the NGCC CO₂ capture case line with the line for the NGCC non-capture case. For example, when looking at the exhibit, the cost of CO₂ captured is \$36–\$38/tonne (\$33–\$35/ton) for PC, \$91–\$128/tonne (\$83–\$116/ton) for IGCC, and \$55–\$61/tonne (\$50–\$55/ton) for NGCC.

The curves in Exhibit 6-19 represent the study design conditions (CF) and fuel prices used for each technology; namely an 80 or 85 percent CF (IGCC or PC/NGCC) and \$2.11/GJ (\$2.23/MMBtu) for coal and \$4.19/GJ (\$4.42/MMBtu) for natural gas.

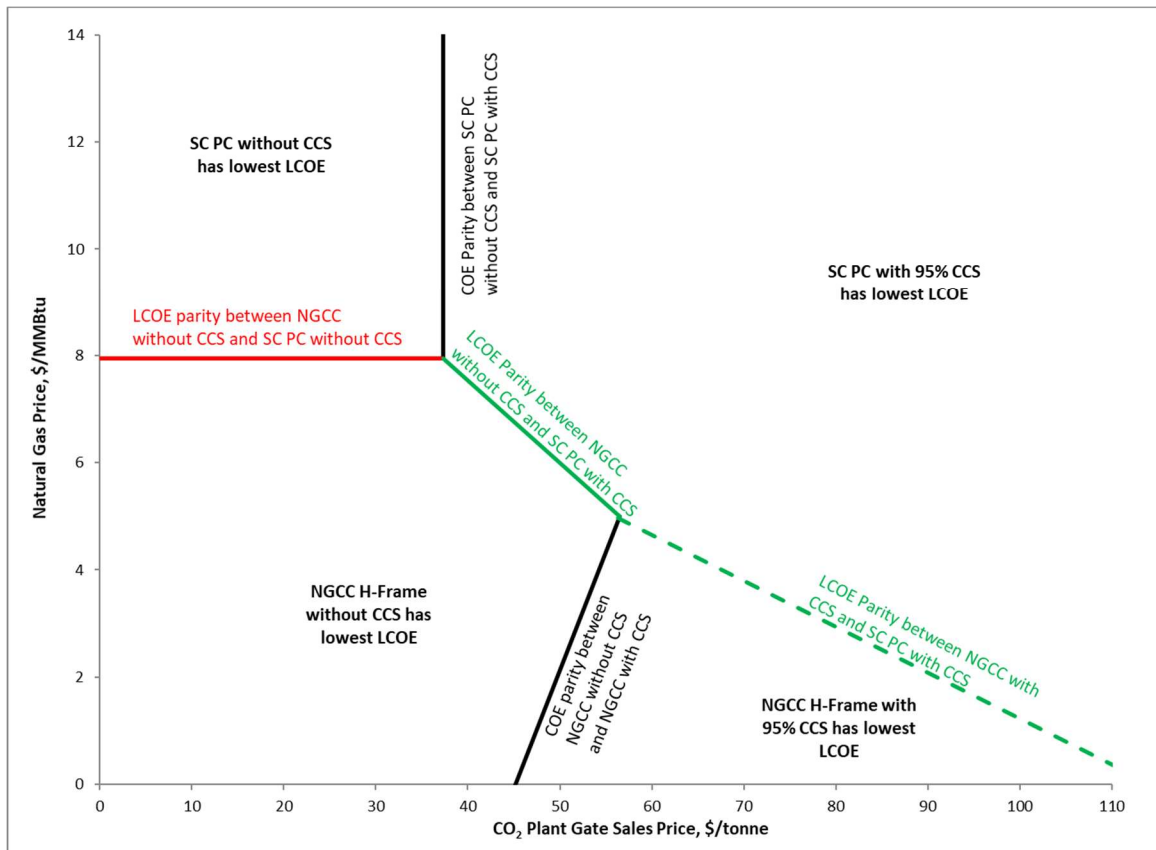
Exhibit 6-19. Impact of carbon sales price on study technologies



One of the important conclusions that can be drawn from the plot is that at a CO₂ sales price of approximately \$60/tonne (\$55/ton), the cost of NGCC with CO₂ capture is equal to that of the SubC PC and SC PC with 90 percent CO₂ capture cases. Above \$60/tonne, the PC capture cases are lower cost options than the NGCC capture case, and above approximately \$68/tonne (\$62/ton), the PC capture cases are a lower cost option than the NGCC case without capture.

As with CO₂ emission pricing shown previously, the impact of CO₂ sales price and natural gas price and the implications on the competitiveness of the capture technologies can also be considered in a “phase diagram” type plot, as shown in Exhibit 6-20. The exhibit only considers the competitiveness of NGCC and PC cases, as IGCC has been demonstrated to consistently be a higher cost option. The lines in the plot represent LCOE parity between different pairs of technologies.

Exhibit 6-20. Lowest cost power generation options comparing NGCC and PC



The plot demonstrates the following points:

- Non-capture plants are the low-cost option below a CO₂ price of \$37/tonne (\$34/ton).

NGCC is preferred when natural gas prices are below \$7.9/MMBtu with a CO₂ sale price below \$37/tonne (and a CF of 85 percent). The natural gas price that provides parity between the various NGCC and PC cases drops off at higher CO₂ revenues reaching \$2/MMBtu at approximately \$91/tonne (\$83/ton).

6.3 SENSITIVITIES

Exhibit 6-21 shows the LCOE sensitivity to natural gas costs for NGCC H-Frame and SC PC cases with 95 percent capture and without CCS, as well as the lowest LCOE IGCC cases with (GEP Quench) and without (E-Gas) CCS. The bands for the coal cases represent a variance in coal price from \$1.58–2.63/GJ (\$1.67–2.78/MMBtu) (± 25 percent of the base study value of \$2.11/GJ [\$2.23/MMBtu]). This sensitivity highlights regions of competitiveness for NGCC with SC PC and the lowest cost IGCC options, with and without CCS, as a function of the delivered natural gas price. As an example, at a coal cost of \$2.23/MMBtu, the LCOE of the non-capture SC PC case equals non-capture NGCC at a natural gas price of approximately \$8/MMBtu. For the same comparison with capture cases, SC PC is competitive with NGCC at a natural gas price of approximately \$11/MMBtu. For the lowest cost IGCC case with capture, a natural gas price in

excess of approximately \$17/MMBtu is required for competitiveness with NGCC with capture. It should be noted that this comparison does not include additional valuation for the cost of CO₂ captured/avoided. These costs could impact the price at which natural gas and coal cases are equal, given a scenario where the CO₂ captured is sold or stored to reduce the cost of emissions.

Exhibit 6-21. LCOE sensitivity to natural gas costs

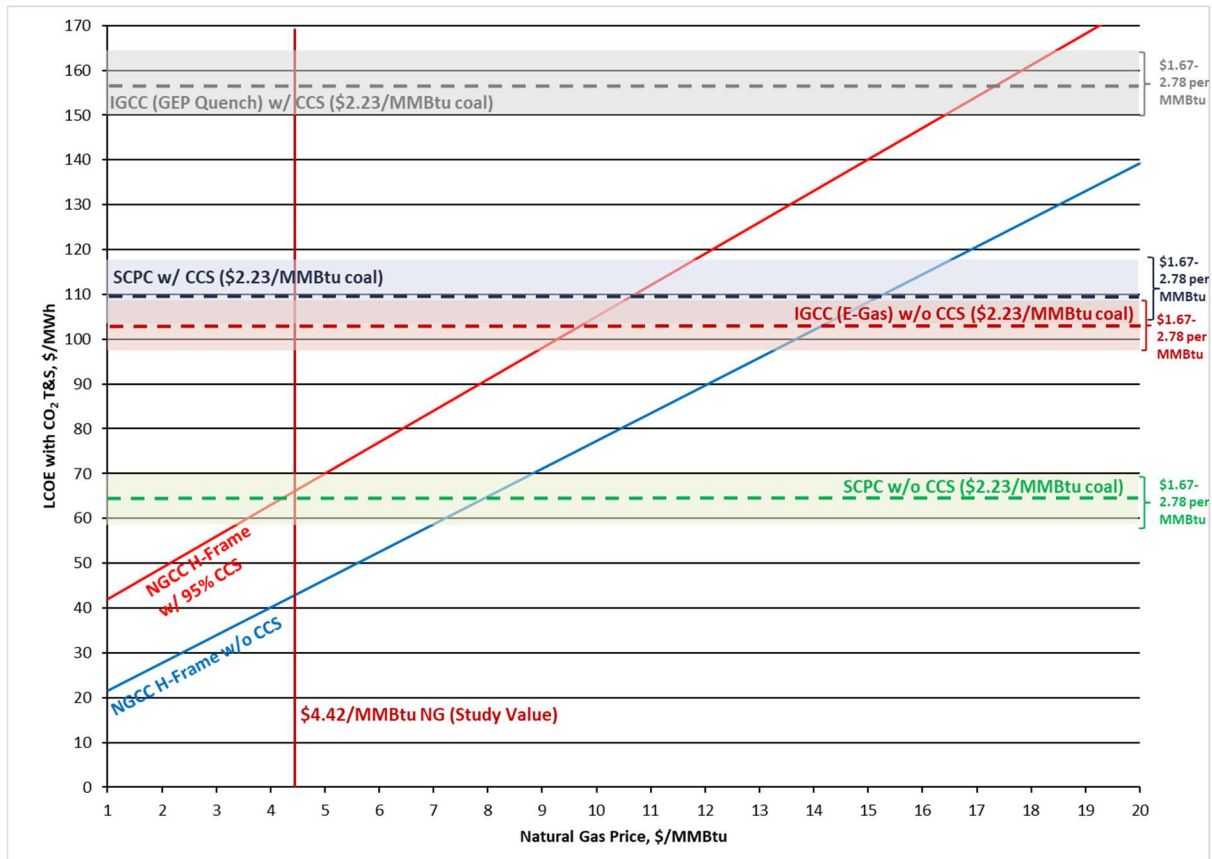
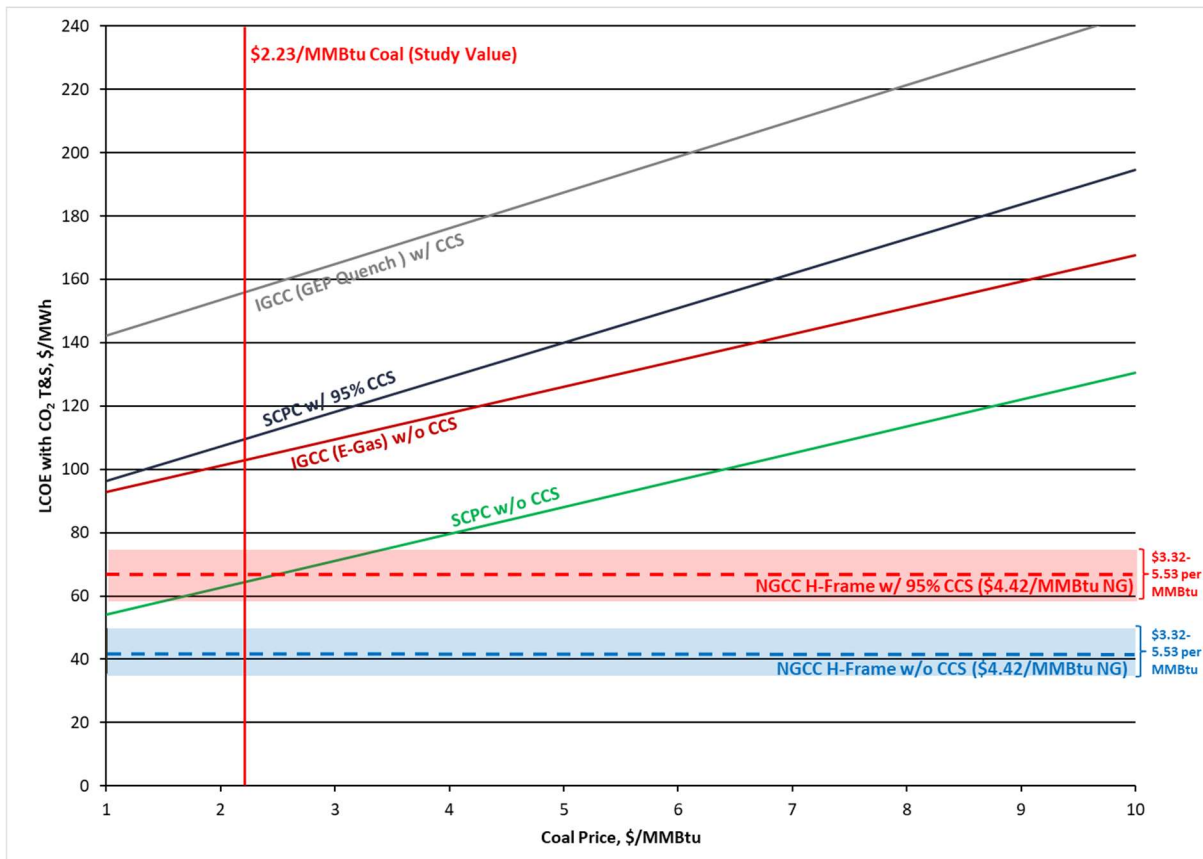


Exhibit 6-22 shows the LCOE sensitivity to coal costs for NGCC H-Frame and SC PC cases with 95 percent capture and without CCS, as well as the lowest LCOE IGCC cases with (GEP Quench) and without (E-Gas) CCS. The bands for the natural gas cases represent a variance in natural gas price of \$3.15–\$5.24/GJ (\$3.32–\$5.53/MMBtu) (± 25 percent of the base study value of \$4.19/GJ [\$4.42/MMBtu]). Similar to Exhibit 6-21, this sensitivity highlights regions of competitiveness for NGCC with SC PC and the lowest cost IGCC options, with and without CCS, as a function of the delivered coal price. As an example, at a natural gas cost of \$4.42/MMBtu, the LCOE of the capture NGCC H-Frame case equals non-capture SC PC at a coal price of approximately \$2.5/MMBtu. It should be noted that this comparison does not include additional valuation for the cost of CO₂ captured/avoided. These costs could impact the price at which natural gas and coal cases are equal, given a scenario where the CO₂ captured is sold or stored to reduce the cost of emissions.

Exhibit 6-22. LCOE sensitivity to coal costs

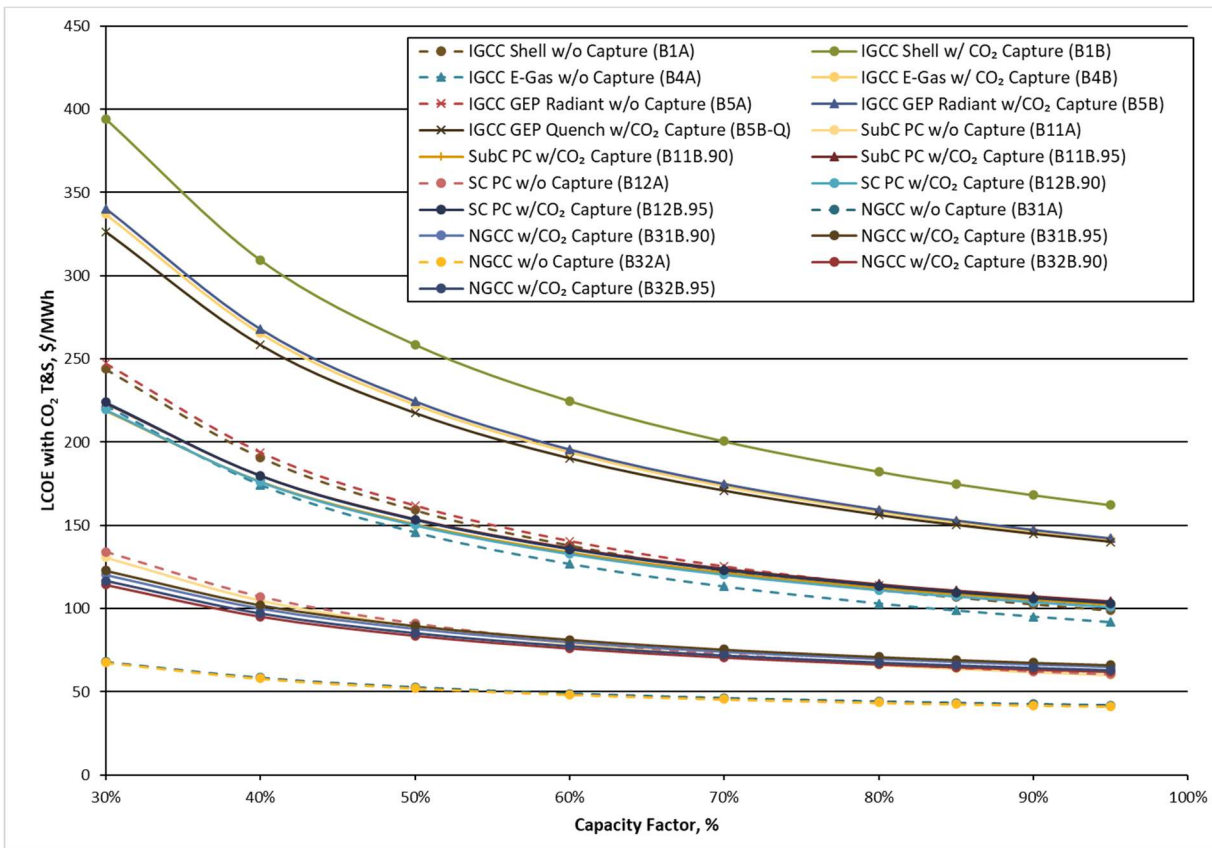


In Exhibit 6-23, the sensitivity of LCOE to CF is shown for all technologies. The curves are relatively tightly grouped by technology, and whether CO₂ capture is included or not. The CF is plotted from 30 to 95 percent. The baseline CF is 85 percent for both PC and NGCC technologies, and 80 percent for IGCC. The curves plotted in Exhibit 6-23 assume that the CF could be extended to 95 percent with no additional capital equipment and that lower capacity factors don't result in capital cost savings.

Technologies with high capital cost (IGCC with CO₂ capture, followed by PC with CO₂ capture, and IGCC without CO₂ capture) show a greater increase in LCOE with decreased CF. Conversely, NGCC with no CO₂ capture is relatively flat because the LCOE is dominated by fuel charges, which decrease as the CF decreases. Conclusions that can be drawn from Exhibit 6-23 include:

- At any CF shown, NGCC has the lowest LCOE out of the non-capture cases.
- The LCOE of NGCC with CO₂ capture is the lowest of the capture technologies, and the advantage increases as the CF decreases. The relatively low capital cost component of NGCC accounts for the increased cost differential with decreased CF. NGCC with CO₂ capture approaches competitiveness with both PC cases without CO₂ capture as the CF approaches 30 percent.

Exhibit 6-23. LCOE sensitivity to capacity factor



The next series of sensitivities illustrates the impact of various financial parameters on LCOE, cost of CO₂ capture, and cost of CO₂ avoided for SC PC and NGCC cases with and without CCS. In Exhibit 6-24, Exhibit 6-25, and Exhibit 6-26 the sensitivity of LCOE and cost of CO₂ capture/cost of CO₂ avoided to debt-to-equity (D:E) ratio is plotted. Since the baseline required return on equity (10 percent) is greater than the baseline cost of debt (5 percent), the LCOE of the more capital-intensive technologies increases more rapidly as the D:E ratio decreases. The impact of D:E ratio on cost of CO₂ capture and cost of CO₂ avoided for PC and NGCC cases is similar (on a relative basis) because the change in D:E ratio impacts the capture plant and non-capture reference plant in a consistent manner. The sensitivity of LCOE and cost of CO₂ capture/cost of CO₂ avoided to effective tax rate is plotted in Exhibit 6-27, Exhibit 6-28, and Exhibit 6-29.

The tax rate impact is relatively small for all technologies, but similar to D:E ratio, the more capital-intensive technologies are impacted to a greater extent. The most capital-intensive technology plotted, SC PC with CCS, has an LCOE increase of 5.7 percent as the effective tax rate increases from 0 to 40 percent. The least capital-intensive technology plotted, NGCC without CCS, experiences only a 3.1 percent increase in LCOE over the same effective tax rate range. The relative impact of effective tax rate on cost of CO₂ capture and cost of CO₂ avoided is nearly constant for all four technologies plotted, with a maximum 7.1 percent impact on the cost of CO₂ captured at the highest tax rate considered.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-24. LCOE sensitivity to debt-to-equity ratio

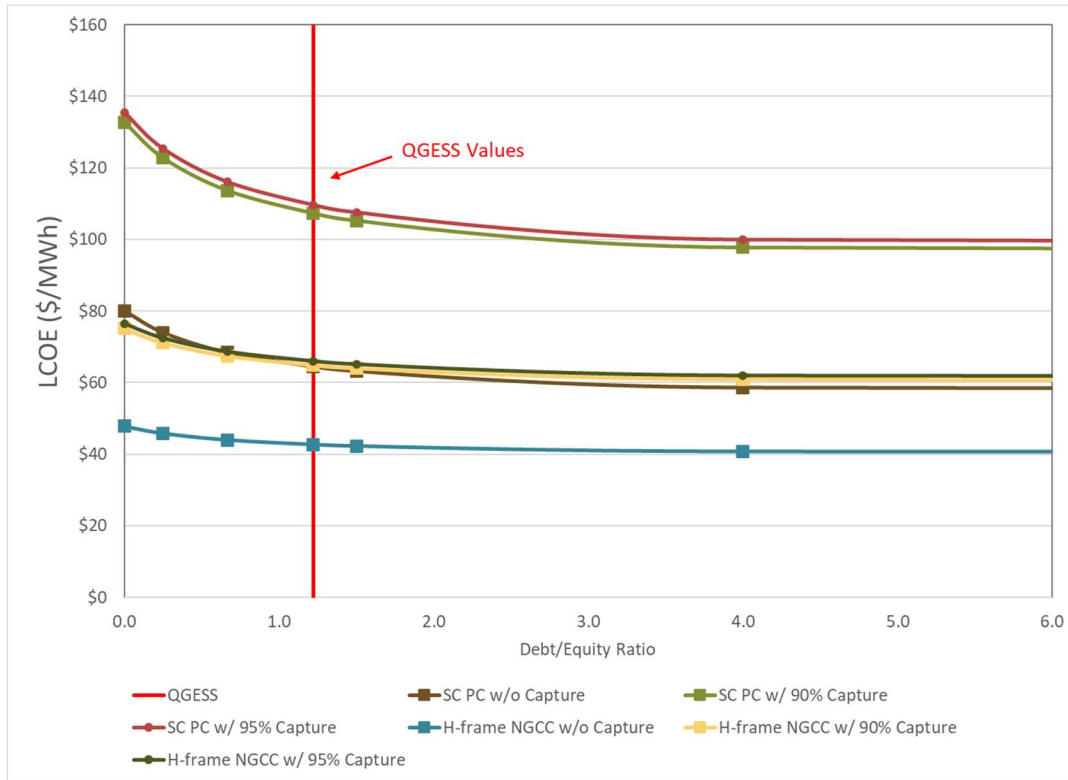
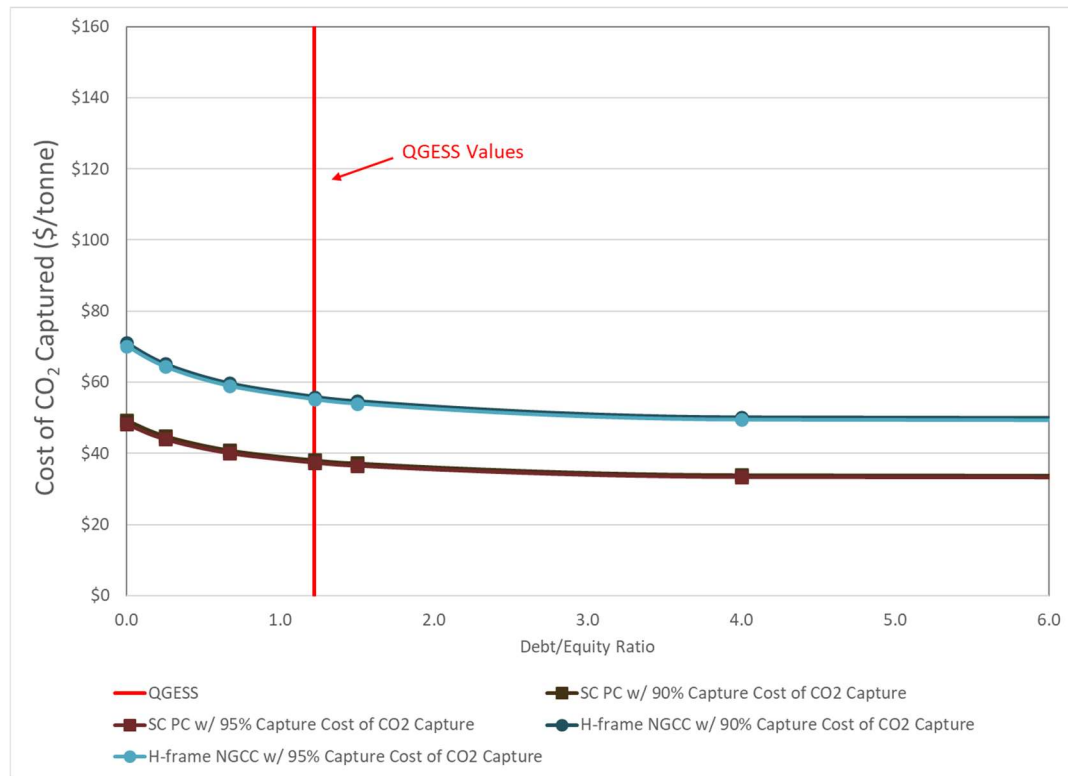


Exhibit 6-25. Cost of CO₂ captured sensitivity to debt-to-equity ratio



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-26. Cost of CO₂ avoided sensitivity to debt-to-equity ratio

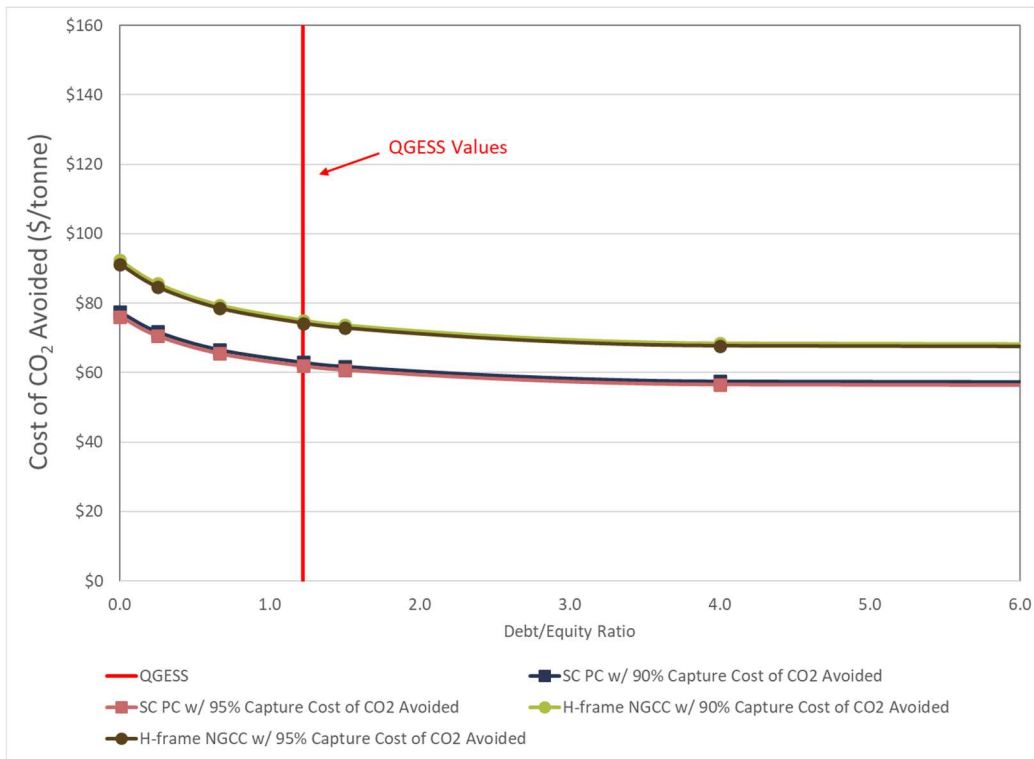
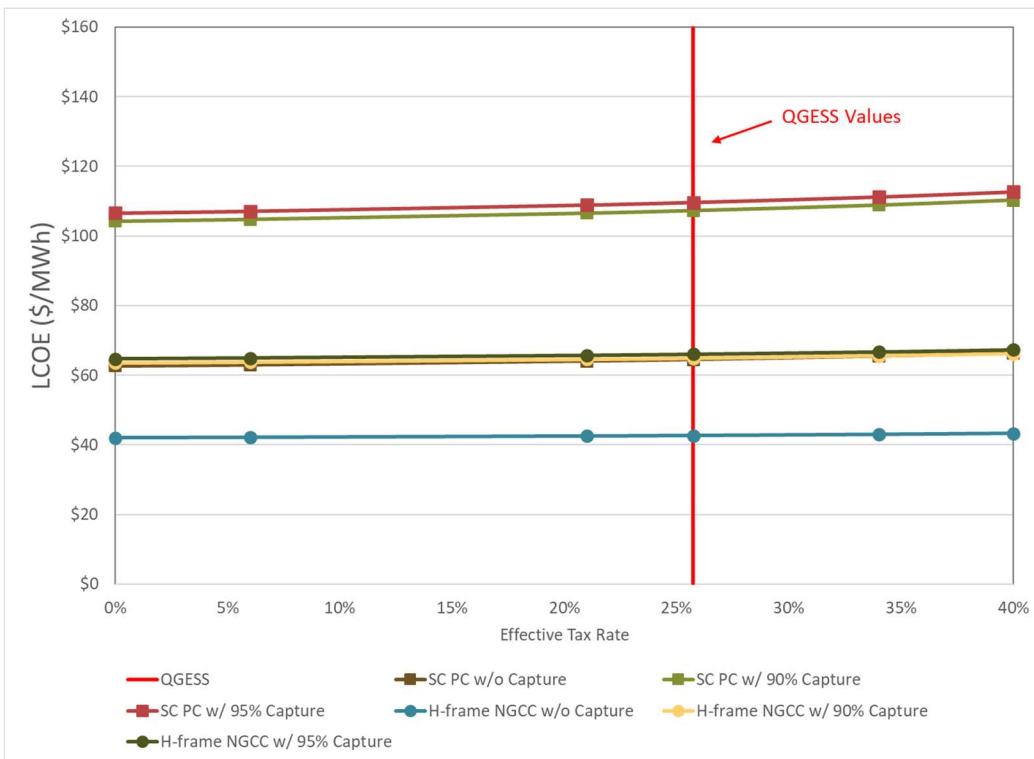


Exhibit 6-27. LCOE sensitivity to effective tax rate



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-28. Cost of CO₂ captured sensitivity to effective tax rate

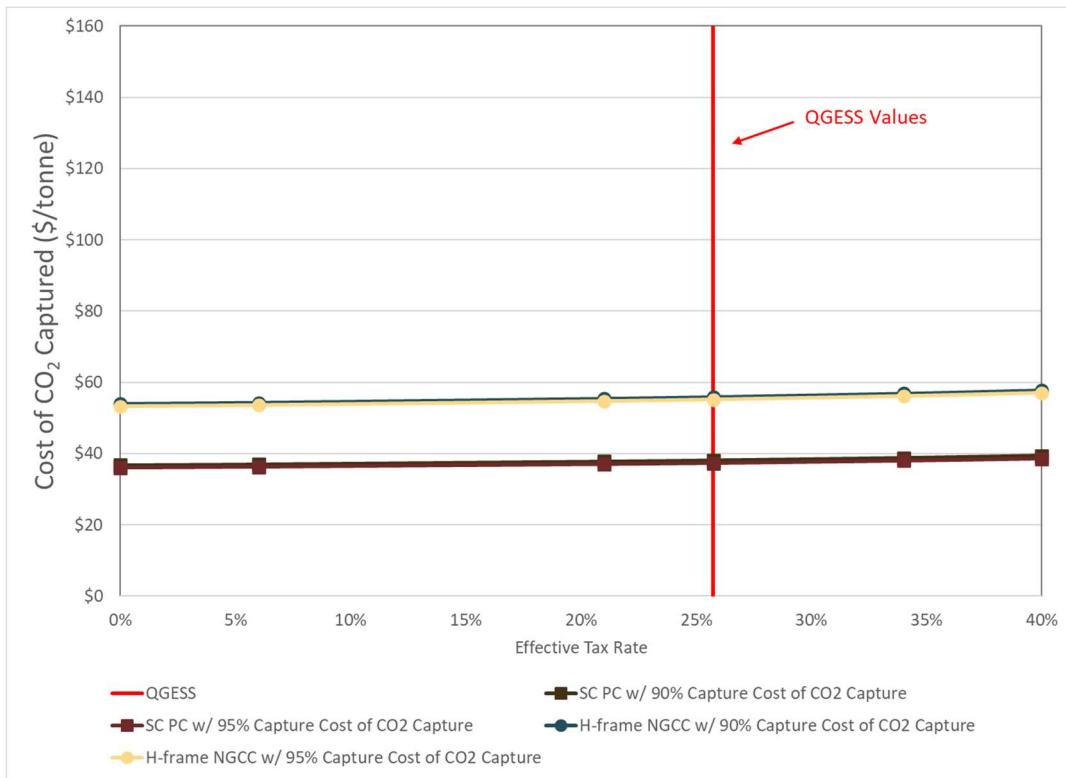
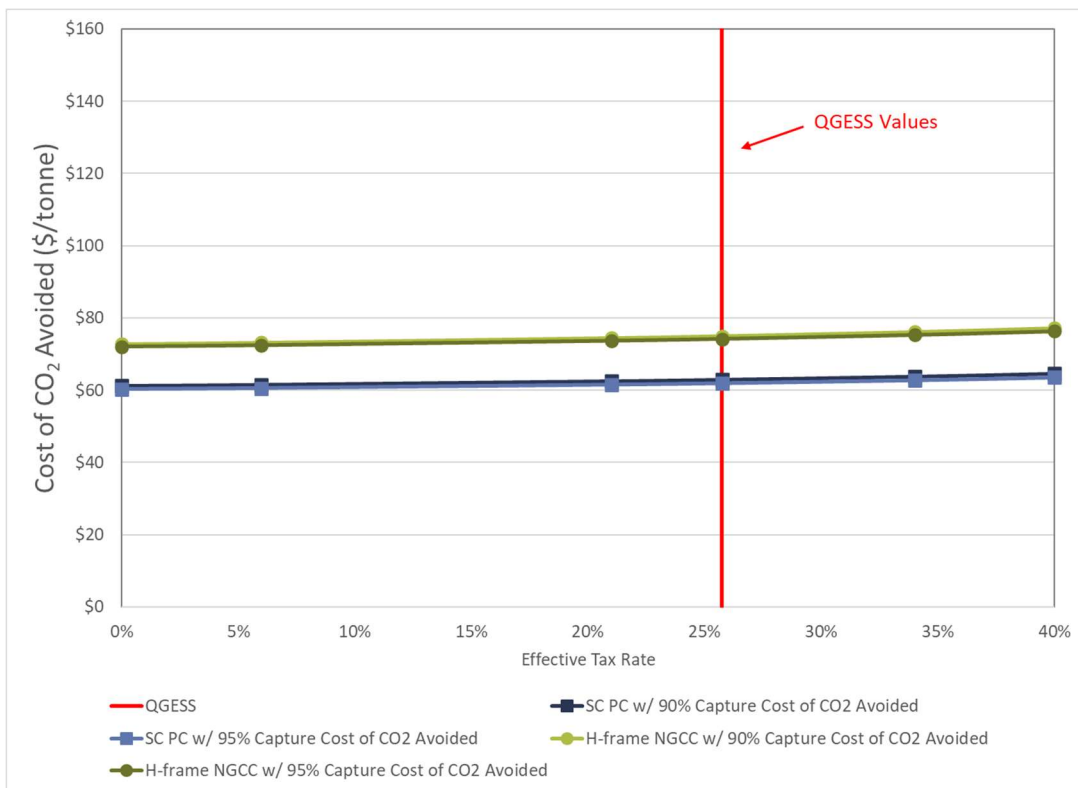


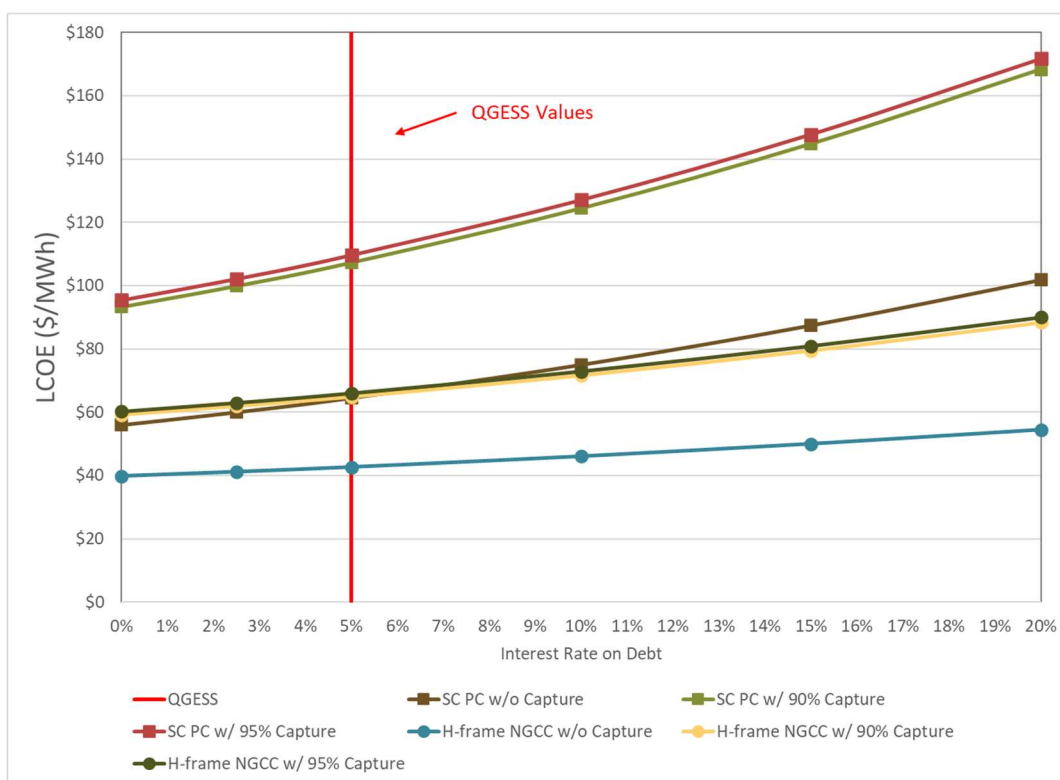
Exhibit 6-29. Cost of CO₂ avoided sensitivity to effective tax rate



The sensitivity of LCOE and cost of CO₂ capture/cost of CO₂ avoided to interest rate on debt is plotted in Exhibit 6-30, Exhibit 6-31, and Exhibit 6-32 and the sensitivity to return on equity is plotted in Exhibit 6-33, Exhibit 6-34, and Exhibit 6-35. The trends for both sensitivities are consistent with the D:E ratio sensitivity. LCOE increases more rapidly for more capital-intensive projects than less capital-intensive projects as the debt interest rate increases and the required return on equity increases. The cost of CO₂ capture and cost of CO₂ avoided for the two technologies are impacted nearly the same on a relative basis, as was the case with the D:E ratio sensitivity.

The final sensitivity examines the impact of multiple simultaneous financial parameter variations (Exhibit 6-36). At one extreme, it is assumed that the project is financed with all debt at a 0 percent interest rate and with a 0 percent tax rate. At the other extreme, 100 percent equity financing with a 20 percent required return on equity and a 40 percent effective tax rate is assumed. Four additional scenarios between these two extremes are also considered, including the baseline scenario of a D:E ratio of 55:45, an interest rate of 5 percent, a required return on equity of 10 percent, and an effective tax rate of 25.7 percent. This sensitivity illustrates the significant impact that financial parameter assumptions can have on LCOE. Using SC PC with 90 percent CCS as an example, the LCOE ranges \$74–289/MWh at the two extremes and is \$107.3/MWh at the baseline conditions. The impact on the less capital-intensive H-frame NGCC without CCS case is less extreme, but still impactful. The range of LCOE at the two extreme scenarios is \$36–85/MWh with the baseline condition resulting in an LCOE of \$43.2/MWh.

Exhibit 6-30. LCOE sensitivity to interest rate on debt



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-31. Cost of CO₂ capture sensitivity to interest rate on debt

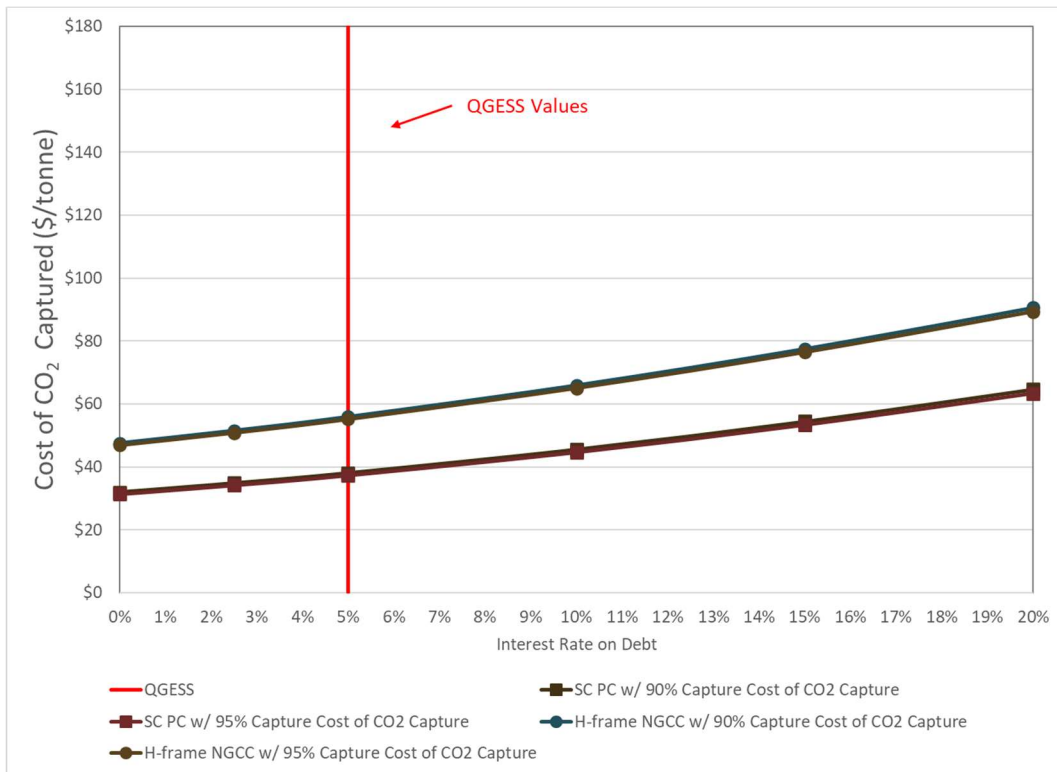
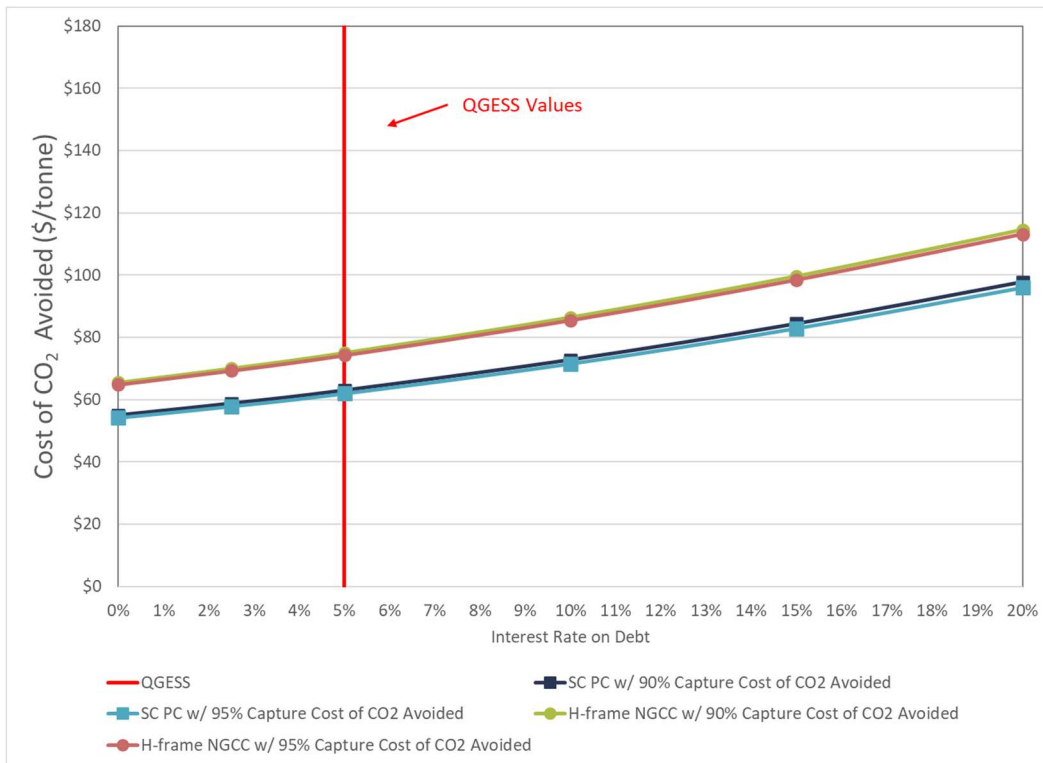


Exhibit 6-32. Cost of CO₂ avoided sensitivity to interest rate on debt



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-33. LCOE sensitivity to return on equity

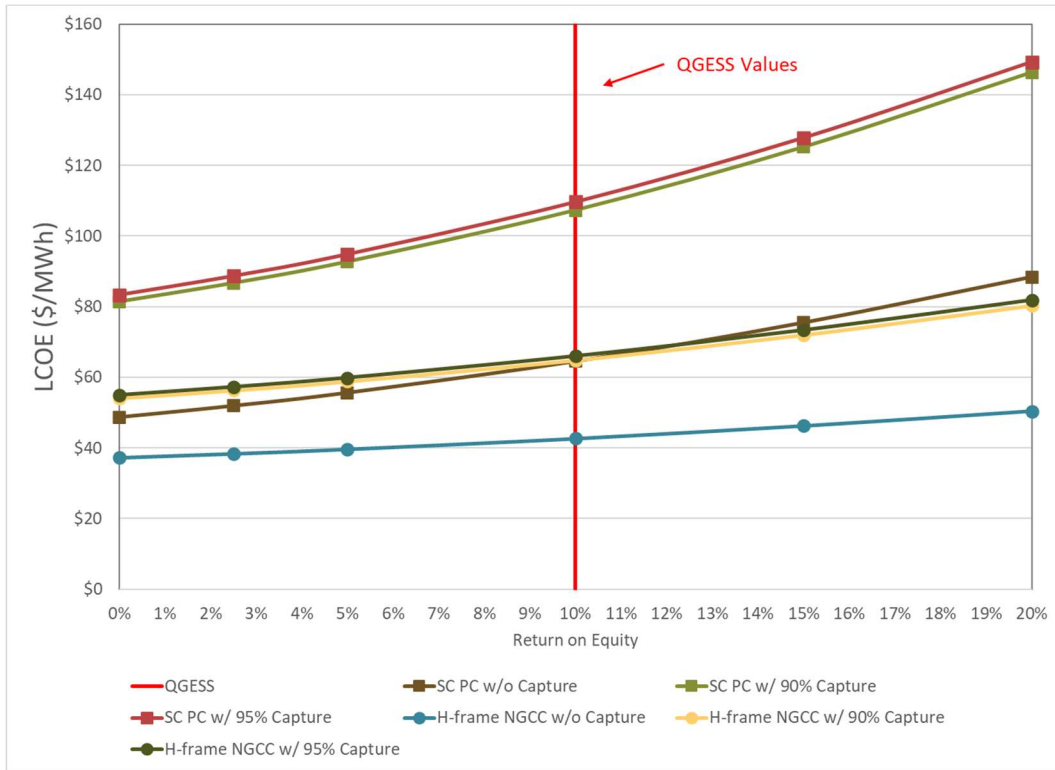
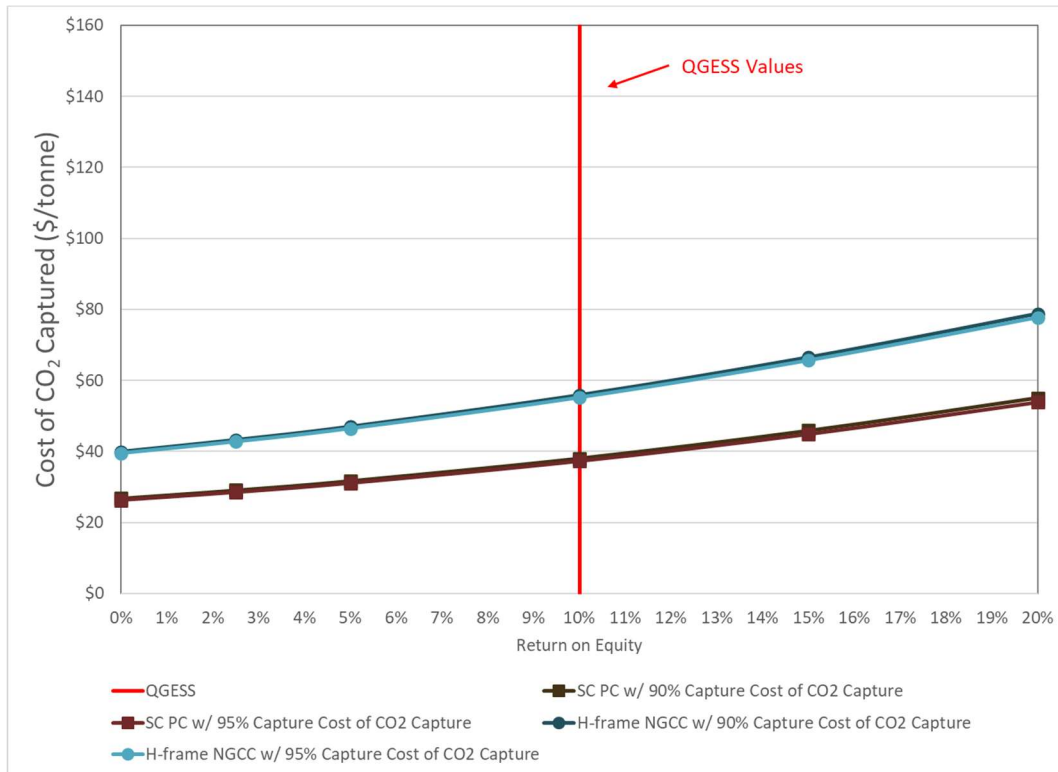


Exhibit 6-34. Cost of CO₂ capture sensitivity to return on equity

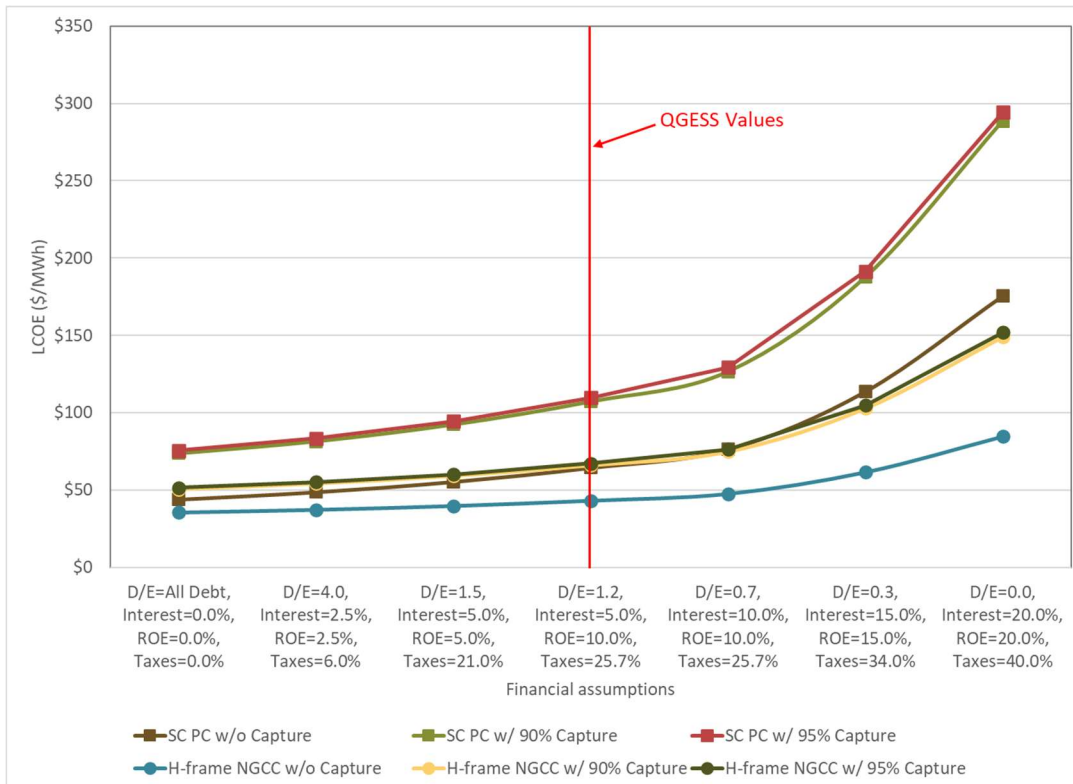


COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 6-35. Cost of CO₂ avoided sensitivity to return on equity



Exhibit 6-36. LCOE sensitivity to combined financial parameters



7 REVISION CONTROL

The initial issue of this report was published in May 2007, and updated revisions were published in November 2010, July 2015, and September 2019. Since the reissue date, updates have been made to various report sections. These modifications were made for clarification and aesthetic purposes as well as to bring all costs to the current year dollar basis.

Exhibit 7-1 contains information that was added, changed, or deleted in successive revisions.

Exhibit 7-1. Record of revisions

Revision Number	Revision Date	Description of Change	Comments
1	8/23/07	Added disclaimer to Executive Summary and Introduction	Disclaimer involves clarification on extent of participation of technology vendors
		Removed reference to cases 7 and 8 in Exhibit ES-1 and Exhibit 1-1 since they no longer exist	SNG cases moved to Volume 2 of this report as explained in the Executive Summary and Section 1
		Added Section 2.8	Explains differences in IGCC TPC estimates in this report versus costs reported by other sources
		Added Exhibit ES-14	Mercury emissions are now shown in a separate exhibit from SO ₂ , NO _x , and PM because of the different y-axis scale
		Corrected PC and NGCC CO ₂ capture case water balances	The capture process cooling water requirement for the PC and NGCC CO ₂ capture cases was overstated and has been revised
		Replaced exhibits ES-4, 3-121, 4-52, and 5-30	The old water usage figures were in gpm (absolute) and in the new figures the water numbers are normalized by net plant output
		Updated Selexol process description	Text was added to Section 3.1.5 to describe how H ₂ slip was handled in the models
		Revised PC and NGCC CO ₂ capture case energy balances (exhibits 4-21, 4-42 and 5-21)	The earlier version of the energy balances improperly accounted for the capture process heat losses. The heat removed from the capture process is rejected to the cooling tower
		Corrected Exhibit 4-13 and Exhibit 4-27	Sensible heat for combustion air in the two NGCC cases was for only one of the two combustion turbines – corrected to account for both turbines
2	10/27/10	Updated circulating water flow rate values in Section 3.1.8	Revision 1 changes to capture system cooling water flow rate were not made in the text in Section 3.1.8 (Circulating Water System)
		Added Supplemental Chapter 6 “Effect of Higher Natural Gas Prices and Dispatch-Based Capacity Factors”	N/A
		Added Supplemental Chapter 7 “Dry and Parallel Cooling”	N/A

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Revision Number	Revision Date	Description of Change	Comments
		Added Supplemental Chapter 8 “GEP IGCC in Quench-Only Configuration with CO ₂ Capture”	N/A
		Added Supplemental Chapter 9 “Sensitivity to MEA System Performance and Cost Bituminous Baseline Case B12B A”	N/A
		Updated Aspen models	Major Aspen model updates included: <ul style="list-style-type: none"> • Converting FORTRAN code-based steam cycles to Aspen blocks • Using the Peng-Robinson property method in the Aspen gasifier section • Modifying the AGR used in the IGCC cases to more closely represent commercially available technology • Increasing the capture efficiency of the E-Gas™ plant with capture to achieve 90 percent • Correcting a steam condition error in the SC PC cases with capture
		Updated case performance results	Major updates included: <ul style="list-style-type: none"> • Revising the water balances to include withdrawal and consumption • CAD-based HMB diagrams were replaced with Visio versions
		Completed updating case economic results	Major updates included: <ul style="list-style-type: none"> • Adding owner’s costs to the total plant costs to generate total overnight cost • Updating fuel costs • Revising the T&S methodology to include the July 2007 Handy-Whitman Index, pore space acquisition costs, and liability costs • Re-costing of cases based on the updated performance results • Switching to COE as the primary cost metric (as opposed to LCOE)
		Updated report tables, figures, and text to reflect the revision 2 changes	N/A
2a	9/19/2013	Section 2.7.1 was revised to clarify the text that explains the level of technology maturity reflected in the plant level cost estimates	N/A
2b	7/13/2015	Volume 1 has been split into two sub volumes	Major updates included: <ul style="list-style-type: none"> • IGCC cases are reported in Volume 1b with a cost-only update (issued as an update to revision 2a) • PC and NGCC cases are reported in Volume 1a with a cost and performance update (issued as revision 3) • Executive Summary significantly revised and shortened • Results analysis section added

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Revision Number	Revision Date	Description of Change	Comments
		Separated Supplemental Chapter 6 “Effect of Higher Natural Gas Prices and Dispatch-Based Capacity Factors” into a stand-alone report	N/A
		Separated Supplemental Chapter 7 “Impact of Dry and Parallel Cooling Systems on Cost and Performance of Fossil Fuel Power Plants” into a stand-alone report	N/A
		Incorporated the Supplemental Chapter 8 “GEP IGCC in Quench-Only Configuration with CO ₂ Capture” into the body of the report	The supplemental chapter was broken down and the information regarding the case describe within it is presented similar to cases B5A and B5B in Section 3.4.12
		Removed Supplemental Chapter 9 “Sensitivity to MEA System Performance and Cost Bituminous Baseline Case 12A”	N/A
		Updated the environmental targets to current limits published by EPA and presented in Section 2.3	MATS and NSPS regulate SO ₂ , NO _x , Filterable PM, Hg, and HCl on a lb/MWh-gross basis
		Updated Section 0 covering Capacity Factors	Additional information has been included that supports the assumptions made regarding the CFs used for each technology type
		Removed portions of Section 2.7 concerning cost estimating methodology	Many QGESS documents have been published that detail information generic to a number of studies published by NETL. In an effort to reduce the size of this report, text provided in these QGESS documents has been removed and references have been inserted that provide the QGESS document title and revision notation
		Added Cost of CO ₂ Captured methodology and results	The Cost of CO ₂ Avoided methodology has been moved from the Executive Summary and combined with the Cost of CO ₂ Captured methodology in Section 2.7.4
		Removed Section 2.7	N/A
		Updated Section 3.1.4 to reflect the use of a dual carbon bed	N/A
		Updated Section 3.1.5	Superfluous information has been removed and the remaining information has been re-organized, especially concerning AGR/gasifier pairings used in non-capture cases
		Improved the BFD depiction of the HRSGs	N/A
		Updated all cases to a new case naming convention	Example: Revision 2’s Case 1 is now Case B5A
		Updated performance tables	Major updates include: <ul style="list-style-type: none"> Table is split into two sections <ul style="list-style-type: none"> Performance summary Plant power and auxiliary load breakdown O₂:Coal ratio Cold gas efficiency

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Revision Number	Revision Date	Description of Change	Comments
			<ul style="list-style-type: none"> ○ Combustion turbine efficiency ○ Steam turbine efficiency and heat rate ○ LHV basis efficiency and heat rate
		Updated case performance results	Major updates included: <ul style="list-style-type: none"> • Added particle concentration to emissions results • Updated Energy Balance tables by adding Motor Losses and Design Allowances, Non-Condenser cooling tower loads, and ambient losses
		Completed updating case economic results	Major updates included: <ul style="list-style-type: none"> • Updated to 2011-year dollars • Revised the engineering and construction management costs • Added NG supply line • Updated the T&S costing methodology • Updated fuel prices
		Updated report tables, figures, and text to reflect the Revision 2b changes	N/A
3	7/6/2015	Volume 1 has been split into two sub volumes	Major updates included: <ul style="list-style-type: none"> • IGCC cases are reported in Volume 1b with a cost-only update (issued as an update to revision 2a) • PC and NGCC cases are reported in Volume 1a with a cost and performance update (issued as revision 3) • Executive summary significantly revised and shortened • Results analysis section added
		Separated Supplemental Chapter 6 “Effect of Higher Natural Gas Prices and Dispatch-Based Capacity Factors” into a stand-alone report	N/A
		Separated Supplemental Chapter 7 “Impact of Dry and Parallel Cooling Systems on Cost and Performance of Fossil Fuel Power Plants” into a stand-alone report	N/A
		Removed Supplemental Chapter 9 “Sensitivity to MEA System Performance and Cost Bituminous Baseline Case 12A”	
		Updated the environmental targets to current limits published by EPA and presented in Section 2.3	MATS and NSPS regulate SO ₂ , NO _x , Filterable PM, Hg, and HCl on a lb/MWh-gross basis
		Updated Section 0 covering Capacity Factors	Additional information has been included that supports the assumptions made regarding the CFs used for each technology type

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Revision Number	Revision Date	Description of Change	Comments
		Removed portions of Section 2.7 concerning cost estimating methodology	Many QGESS documents have been published that detail information generic to a number of studies published by NETL. In an effort to reduce the size of this report, text provided in these QGESS documents has been removed and references have been inserted that provide the QGESS document title and revision notation
		Cost of CO ₂ Captured methodology and results have been added	The Cost of CO ₂ Avoided methodology has been moved from the Executive Summary and combined with the Cost of CO ₂ Captured methodology in Section 2.7.4
		Section 2.8 has been updated to reflect current information	
		The combustion turbine performance characteristics have been updated	The performance provided in this report reflects a state-of-the-art 2013 F-class combustion turbine for NGCC cases
		Updated Natural Gas Composition	Methanethiol was added to the composition
		Improved the BFD depiction of the HRSGs in NGCC Case	
		All cases have been updated to a new case naming convention	Example: Revision 2's Case 9 is now Case B11A
		Performance tables have been updated	Major updates include: <ul style="list-style-type: none"> Table is split into two sections <ul style="list-style-type: none"> Performance summary Plant power and auxiliary load breakdown PC <ul style="list-style-type: none"> Steam generator efficiency Excess air Steam turbine cycle efficiency and heat rate LHV basis efficiency and heat rate NGCC <ul style="list-style-type: none"> Combustion turbine efficiency Steam turbine efficiency and heat rate LHV basis efficiency and heat rate
		Updated case performance results	Major updates included: <ul style="list-style-type: none"> Added particle concentration to emissions results Updated Energy Balance tables by adding Motor Losses and Design Allowances, Non-Condenser cooling tower loads, and ambient losses
		Updated Aspen models	Major Aspen model updates included: <ul style="list-style-type: none"> Updated steam turbine efficiency

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Revision Number	Revision Date	Description of Change	Comments
			<ul style="list-style-type: none"> Incorporated exhaust losses into LP turbine efficiency Changed Capture system in NGCC and PC cases to CANSOLV system Updated many pressure drops to percent of inlet Corrected temperature approaches Corrected pressure drops across various systems Converted to Aspen 8.2 Converted to Hierarchy models Converted steam property method to SteamNBS Updated CO₂ compression system to front loaded 8 stage design in NGCC and PC cases ACI and DSI systems were added to PC cases Boiler air preheater exit temperature was reduced to 300°F Excess O₂ is controlled at the flue gas exiting the boiler at 2.7 percent dry Combustion turbine for NGCC cases was updated Added steam extraction for CO₂ dryer
		Completed updating case economic results	Major updates included: <ul style="list-style-type: none"> Updating to 2011-year dollars Updating the T&S costing methodology Updating the capital charge factors Updating fuel prices Re-costing of cases based on the updated performance results Updating cost estimates based on recently obtained vendor quotes
		Updated report tables, figures and text to reflect the revision 3 changes	
4	9/24/2019	Volumes 1a (PC and NGCC) and 1b (IGCC) have been recombined into one report (Volume 1 – Rev4)	<ul style="list-style-type: none"> IGCC case updates began with the internal Rev4-Performance Only report PC and NGCC began with the Rev3 report
		Updated syngas scrubber performance and added vacuum flash, brine concentration, and a crystallizer	Added Section 3.1.12 to cover process water sources, define the ZLD methodology, and provide the technology descriptions of the systems used to achieve ZLD
		Added secondary SWS	Secondary SWS is used to remove ammonia from the ZLD condensate prior to being used as steam for the gasifiers
		Removed SWS from Cases B5B and B5B-Q	SWS only treats excess process water from the process water drum. These cases do not have any excess
		Reduced the chloride content of the coal	Added discussion of chloride content of coal to Section 2.2
		Updated the HHV/LHV calculation method for natural gas	Aspen Plus QVALGRS/QVALNET stream property data used to calculate natural gas heating values

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Revision Number	Revision Date	Description of Change	Comments
		Updated ASU technology description in Section 3.1.2	New information was acquired for ASU performance
		Updated WGS technology description in Section 3.1.3	New information was acquired for WGS performance
		Updated Selexol technology description in Section 3.1.5.4	New information was acquired for Selexol performance
		Updated COS hydrolysis technology description in Section 3.1.5.1	New information was acquired for COS hydrolysis performance
		Updated CO ₂ compression and drying system technology description	New information was acquired for compression and drying performance. Sections updated are: <ul style="list-style-type: none"> Section 3.1.6 Section 4.1.9
		Updated gasifier specific technology descriptions to reflect changes made to the common process areas (Section 0)	Sections updated are: <ul style="list-style-type: none"> Section 3.2.4 Section 3.2.8 Section 3.3.4 Section 3.3.8 Section 3.4.4 Section 3.4.8 Section 3.4.12
		Added chloride control to the plant study configuration matrices	N/A
		Updated performance of the steam cycle	New information was acquired for steam turbine performance for IGCC cases
		Updated NGCC combustion turbine and steam turbine description	New information was acquired for performance. Sections updated are: <ul style="list-style-type: none"> Section 5.1.2 Section 5.1.3 Section 5.1.4 Section 5.1.6 Section 5.1.7 Section 5.1.10
		Updated Shell CANSOLV system description for PC and NGCC	New information was acquired for performance. Sections updated are: <ul style="list-style-type: none"> Section 4.1.8 Section 5.1.5

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Revision Number	Revision Date	Description of Change	Comments
		Updated the PC target net plant output to 650 MW-net	New PC net output provides comparable basis for PC and NGCC capture cases (NGCC w/ capture is 646 MW-net)
		Added spray dryer evaporator for PC cases	Added Section 4.1.10 to cover process water sources and provide the technology descriptions of the spray dryer evaporator
		Updated PC mercury control system descriptions	New information was acquired for performance. Sections updated are: <ul style="list-style-type: none"> Section 4.1.6
		Additional Aspen model updates	Major Aspen model updates included: <ul style="list-style-type: none"> CO₂ compressor product water target updated to 500 ppmv H₂O Increased CO₂ compressor intercooling temperatures for final two stages of intercooling All NO_x assumed to be NO (previously considered split of NO and NO₂) Carbon extent of reaction in PC cases adjusted from 1.0 to 0.994 for bituminous PC cases DSI/ACI modeled in Aspen Plus PC boiler block split to allow for ELG spray dryer evaporator flue gas extraction FGD HCl removal efficiency updated to 99 percent FGD oxidation air stoichiometric ratio increased to 4.0 Set excess O₂ prior to the air preheater to 2.6 volume percent-dry for all PC cases Added IGCC mercury bed preheater
		Energy balance updated to report a Cooling Tower line item	Rather than split out Acid Gas Removal, Condenser, and Non-Condenser cooling loads, all three are summed in the Cooling Tower line item. The AGR cooling duty is reported separately in the Performance Summary table under the Condenser cooling duty
		PC with CO ₂ capture cases water balance updated to recycle capture system water recovered as FGD make-up; balance of water recovered sent to discharge	N/A
		Updated fixed auxiliary loads	Steam turbine, Gas turbine, and Miscellaneous Balance of Plant fixed auxiliary loads were updated
		Updated performance data throughout the report to reflect new performance results obtained from changes previously stated in this revision	
		Completed updating case economic results	Major updates included: <ul style="list-style-type: none"> Reporting results in 2018-year dollars Updating the T&S costing methodology Reverting to LCOE result, but with updated methodology

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Revision Number	Revision Date	Description of Change	Comments
			<ul style="list-style-type: none"> Updating fuel prices Re-costing of cases based on the updated performance results Revised the engineering and construction management costs, as well as some contingencies Updating cost estimates based on recently obtained vendor quotes
4a	2/14/2021	Updated ASU costs for IGCC cases	New information was acquired for ASU costs. IGCC performance was unchanged.
		Updated CANSOLV CO ₂ capture cost and performance for PC and NGCC cases	Major updates include: <ul style="list-style-type: none"> CANSOLV performance in PC cases Capture system costs in PC cases NGCC capture system description was changed to reflect current CANSOLV quote NGCC capture system performance and cost updates
		Added cases for capture greater than 90 percent for PC and NGCC technologies	Updated CANSOLV quote included cost and performance for 95 percent and max capture (97 percent for NGCC and 99 percent for PC) cases. This data was utilized to form new higher capture cases reflective of the same base technology as 90 percent capture cases.
		Added H-frame NGCC cases	2017 7HA.02 turbine vendor data was utilized to develop H-frame cases comparable to the F-frame cases. <ul style="list-style-type: none"> Section 5.3
		Miscellaneous PC performance updates	Minor updates included: <ul style="list-style-type: none"> Adjusted the APH inlet temperature and added an additional pressure drop of 7 in w.c. for the SCR Added explicit calculations for dew point temperature of H₂SO₄ plus a 29° F temperature approach at the APH exit Pressure drop across the boiler block was adjusted to maintain the expected total pressure drop Equations for motor losses for the ST were corrected to accurately reflect the impact of motor efficiencies in the energy balances
		Miscellaneous NGCC performance updates	Minor updates included: <ul style="list-style-type: none"> Adjusted the location of the HP-IP reheat mixing block in the Aspen models Adjusted streams to account for variances in modeling due to the addition of blocks for H-frame NGCC and updated capture system. This resulted in small changes through additional initialization values and conversion factors

8 REFERENCES

- [1] National Energy Technology Laboratory, "Quality Guidelines for Energy System Studies: Detailed Coal Specifications," U.S. Department of Energy, Pittsburgh, PA, 2019.
- [2] National Energy Technology Laboratory, "Quality Guidelines for Energy System Studies: Specification for Selected Feedstocks," U.S. Department of Energy, Pittsburgh, PA, 2019.
- [3] National Energy Technology Laboratory, "Quality Guidelines for Energy System Studies: Process Modeling Design Parameters," U.S. Department of Energy, Pittsburgh, PA, 2019.
- [4] National Energy Technology Laboratory, "Quality Guidelines for Energy System Studies: Cost Estimation Methodology for NETL Assessments of Power Plant Performance," U.S. Department of Energy, Pittsburgh, PA, 2019.
- [5] National Energy Technology Laboratory, "Quality Guidelines for Energy System Studies: Fuel Prices for Selected Feedstocks in NETL Studies," U.S. Department of Energy, Pittsburgh, PA, 2019.
- [6] National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants, Volume 5 - Coal Electricity Generating Units for Flexible Operation," U.S. Department of Energy, Pittsburgh, PA, 2022 (expected).
- [7] National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants, Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3," DOE/NETL-2015/1723, Pittsburgh, July 6, 2015.
- [8] National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants, Volume 1b: Bituminous Coal (IGCC) to Electricity, Revision 2b," DOE/NETL-2015/1727, Pittsburgh, July 31, 2015.
- [9] AACE International, Conducting Technical and Economic Evaluations – As Applied for the Process and Utility Industries; TCM Framework: 3.2 – Asset Planning, 3.3 Investment Decision Making, AACE International, 2003.
- [10] AACE International, Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries; TCM Framework 7.3 – Cost Estimating and Budgeting, AACE International, 2005.
- [11] W. P. Greg Kennedy, "Post-Combustion CO₂ Capture and Sequestration Demonstration Project (Final Technical Report)," [Online]. Available: <https://doi.org/10.2172/1608572>. [Accessed 12 September 2022].
- [12] S. Giannaris, D. Janowczyk, J. Ruffini, K. Hill, B. Jacobs, C. Bruce, Y. F. Feng and W. and Srisang, "SaskPower's Boundary Dam Unit 3 Carbon Capture Facility – The Journey to Achieving Reliability," 15th International Conference on Greenhouse Gas Control Technologies, Abu Dhabi, 2021.

- [13] National Carbon Capture Center, "Topical Report Budget Period Six," October 2020. [Online]. Available: <https://www.nationalcarboncapturecenter.com/wp-content/uploads/2022/08/NCCC-BP6-Report-DE-FE0022596.pdf>. [Accessed 12 September 2022].
- [14] National Carbon Capture Center, "Topical Report Budget Period 5," September 2020. [Online]. Available: <https://www.nationalcarboncapturecenter.com/wp-content/uploads/2021/07/NCCC-BP5-Report-DE-FE0022596.pdf>. [Accessed 12 September 2022].
- [15] K. C. O'Brien, Y. Lu, J. Dietsch, Z. (. Zhang, C. Maas, T. Thomas, K. Iwakura, M. Thomas, A. Donovan, P. M. Guletsky and R. Meyer, "Full-scale FEED Study for Retrofitting the Prairie State Generating Station with an 816 MWe Capture Plant using Mitsubishi Heavy Industries Post-Combustion CO₂ Capture Technology," 2022. [Online]. Available: <https://doi.org/10.2172/1879443>. [Accessed 12 September 2022].
- [16] International CCS Knowledge Center, "The Shand CCS Feasibility Study - Public Record," 2018, November. [Online]. Available: [https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_\(2021-05-12\).pdf](https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf). [Accessed 12 September 2022].
- [17] Y. Du, T. Gao, G. Rochelle and A. Bhowan, "Zero- and negative-emissions fossil-fired power plants using CO₂ capture by conventional aqueous amines," *International Journal of Greenhouse Gas Control*, vol. 111, 2021.
- [18] IEAGHG, "Towards Zero Emissions CCS on Power Plants Using Higher Capture Rates or Biomass," 2019.
- [19] National Energy Technology Laboratory, "Quality Guidelines for Energy System Studies: Capital Cost Scaling Methodology: REvision 4a Report," Department of Energy, Pittsburgh, 2022.
- [20] Mining Media, *2004 Keystone Coal Industry Manual*, Prairieville, LA: Mining Media publications, 2004.
- [21] Prairie Research Institute, "Herrin Coal Chlorine," University of Illinois at Urbana-Champaign, [Online]. Available: <https://www.isgs.illinois.edu/content/herrin-coal-chlorine>. [Accessed 24 October 2015].
- [22] National Energy Technology Laboratory, "Major Environmental Aspects of Gasification-Based Power Generation Technologies," U.S. Department of Energy, Pittsburgh, PA, 2002.
- [23] Gas Research Institute, *Variability of Natural Gas Composition in Select Major Metropolitan Areas of the United States*, Springfield: U.S. Department of Commerce, 1992.
- [24] Environmental Protection Agency, "40 CFR Part 60 - Standards of Performance for New Stationary Sources - Subpart Da," 16 February 2012. [Online]. Available: <https://www.ecfr.gov/cgi-bin/text->

- idx?SID=d52d331641a470ed3e372a78f38cca58&mc=true&node=pt40.7.60&rgrn=div5#se40.7.60_144da. [Accessed 21 May 2018].
- [25] Environmental Protection Agency, "National Emission Standards for HAPs from Coal- and Oil-Fired EGUs and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Correction," 6 April 2016. [Online]. Available: <https://www.gpo.gov/fdsys/pkg/FR-2016-04-06/pdf/2016-06563.pdf>. [Accessed 21 May 2018].
 - [26] Environmental Protection Agency, "Map of Counties Designated "Nonattainment" for Clean Air Act's National Ambient Air Quality Standards (NAAQS)," 30 April 2018. [Online]. Available: <https://www3.epa.gov/airquality/greenbook/map/mapnpoll.pdf>. [Accessed 10 June 2019].
 - [27] Environmental Protection Agency, "Electronic Code of Federal Regulations," 2013. [Online]. Available: <http://www.ecfr.gov>. [Accessed 6 February 2013].
 - [28] Environmental Protection Agency, "40 CFR Part 423 Effluent Limitations Guidelines and Standards for the Steam Electric Power," 2015.
 - [29] Environmental Protection Agency, "National Pollutant Discharge Elimination System (NPDES)," [Online]. Available: <https://www.epa.gov/npdes>. [Accessed 13 July 2017].
 - [30] G. Thomas, *Delivering the IGCC Solution*, GE Energy, January 2006.
 - [31] H. Morehead and F. Hannemann, *Siemens Technology Improvements Enhance IGCC Plant Economics*, San Francisco, CA: Gasification Technologies, October 2005.
 - [32] D. Denton, *Telephone communication*, Eastman Chemical Co.
 - [33] Environmental Protection Agency, "40 CFR Parts 60 and 63," Environmental Protection Agency (EPA), 2012. [Online]. Available: <http://www.gpo.gov/fdsys/pkg/FR-2012-02-16/pdf/2012-806.pdf>. [Accessed 6 February 2012].
 - [34] GE Power, "7F Power Plants," November 2017. [Online]. Available: https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/product/gas%20turbines/Fact%20Sheet/2018-prod-specs/7f-power-plants.pdf. [Accessed 10 May 2018].
 - [35] L. B. Davis and S. Black, "Dry Low NO_x Combustions Systems for GE Heavy-Duty Gas Turbines," GE Power Systems, October 2000.
 - [36] Environmental Protection Agency, "40 CFR Part 60 - Carbon Pollution Emissions Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule Vol. 80 No. 205," 23 October 2015. [Online]. Available: <https://www.gpo.gov/fdsys/pkg/FR-2015-10-23/pdf/2015-22842.pdf>. [Accessed 9 October 2018].

- [37] Office of the Federal Register, "Proposed Rules Vol. 83 No. 244," 20 December 2018. [Online]. Available: <https://www.govinfo.gov/content/pkg/FR-2018-12-20/pdf/2018-27052.pdf>. [Accessed 6 June 2019].
- [38] North American Electric Reliability Corporation (NERC), "Generating Availability Report," [Online]. Available: <http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx>. [Accessed July 2018].
- [39] R. Ray, "Power Engineering - Power Plant Performance in 2017," June 2018. [Online]. Available: https://digital.power-eng.com/power-eng/201806/MobilePagedArticle.action?articleId=1403573&sub_id=WqxJhzhDpKGQ#articleId1403573. [Accessed 6 July 2018].
- [40] J. Phillips, *IGCC 101*, Tampa, FL, 2011.
- [41] C. Higman, S. DellaVilla and B. Steele, *The Reliability of Integrated Gasification Combined Cycle (IGCC) Power Generation Units*, May 2006.
- [42] P. Amick, *ConocoPhillips Presentation at Gasification Technology Council Workshop for Environmental and Economic Regulators*, June 2010.
- [43] Electric Power Research Institute, *Evaluation of Alternative IGCC Plant Designs for High Availability and Near Zero Emissions: RAM Analysis and Impact of SCR*, Palo Alto, CA, December 2005.
- [44] Electric Power Research Institute, *Integrated Gasification Combined Cycle (IGCC) Design Considerations for High Availability, Volume 1: Lessons from Existing Operations*, Palo Alto, CA, 2005.
- [45] Electric Power Research Institute, *Integrated Gasification Combined Cycle (IGCC) Design Considerations for High Availability, Volume 2: RAM Modeling of Standard Designs*, Palo Alto, CA, 2007.
- [46] Electric Power Research Institute, *Gasification Technology Status*, December 2012.
- [47] R. R. Richwine, *Performance Improvement in Coal-Fired Power Stations – the Southern Company Experience*, 2004: World Energy document.
- [48] The Marley Cooling Tower Company, *Cooling Tower Fundamentals*, vol. 2nd Edition, J. C. Hensley, Ed., Mission, Kansas, 1985.
- [49] Chemical Engineering, *Chemical Engineering Plant Cost Index*, Access Intelligence, LLC, Ed., 2013.
- [50] Federal Reserve Bank of St. Louis, "Gross Domestic Product: Chain-type Price Index (GDPCTPI)," 2013. [Online]. Available: <http://research.stlouisfed.org/fred2/series/GDPCTPI>. [Accessed 20 November 2013].
- [51] National Energy Technology Laboratory, "Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs in NETL Studies," U.S. Department of Energy, Pittsburgh, PA, 2019.

- [52] McDermott International, Inc., 10 May 2018. [Online]. Available: <http://www.mcdermott-investors.com/news/press-release-details/2018/McDermott-Completes-Combination-with-CBI/default.aspx>. [Accessed 19 February 2019].
- [53] Air Products, "Air Products Completes Acquisition of Shell's Coal Gasification Technology/Patents, and Forms Strategic Alliance with Shell for Liquids (Residue) Gasification for Refineries," 7 May 2018. [Online]. Available: <http://www.airproducts.com/Company/news-center/2018/05/0507-air-products-completes-acquisition-of-shell-coal-gasification-technology-and-patents.aspx>. [Accessed 19 February 2019].
- [54] Air Products, "Air Products Syngas Solutions," 2018. [Online]. Available: <http://www.airproducts.com/~media/Files/PDF/microsites/syngassolutions/EN-Coal-Gasification-DS.pdf>. [Accessed 19 February 2019].
- [55] Air Products, "Air Products to Acquire GE's Gasification Business and Technology," 5 November 2018. [Online]. Available: <http://www.airproducts.com/Company/news-center/2018/11/1105-air-products-to-acquire-ge-gasification-business-and-technology.aspx>. [Accessed 19 February 2019].
- [56] Universal Industrial Gases, "Overview of Cryogenic Air Separation," n.d. [Online]. Available: <http://www.uigi.com/cryodist.html>. [Accessed 29 August 2013].
- [57] S. Jenkins, *Real-World Experience with IGCC – Lessons Learned in Design, Permitting, Operations and Maintenance*, URS Corporation, 2005.
- [58] R. Drnevich, *Personal communication*, Praxair, Inc., November 2002.
- [59] Katalco, "Sour Shift Designs for NETL IGCC CCS Study," Johnson Matthey Catalysts, 2009.
- [60] Calgon Carbon Corporation, "Mercury Removal from Flue Gas Streams," 2015. [Online]. Available: <http://www.calgoncarbon.com/flue-gas/>. [Accessed 10 November 2015].
- [61] National Energy Technology Laboratory, "The Cost of Mercury Removal in an IGCC Plant," U.S. Department of Energy, Pittsburgh, PA, 2002.
- [62] Calgon Carbon Corporation, "HGR-P for Mercury Removal: Pelleted Activated Carbon," 2015. [Online]. Available: https://www.calgoncarbon.com/app/uploads/HGR_P.pdf. [Accessed May 2018].
- [63] I. Barton, Interviewee, *Employed at Johnson Matthey*. [Interview]. April 2013.
- [64] Electric Power Research Institute, "Process Screening Study of Alternative Gas Treating and Sulfur Removal Systems for IGCC Power Plant Applications," December 1987.
- [65] CB&I, "E-Gas™ technology," 2013. [Online]. Available: <http://www.cbi.com/technologies/e-gas-technology-in-action>. [Accessed 1 December 2015].

- [66] National Energy Technology Laboratory, "Process Screening Analysis of Alternative Gas Treating and Sulfur Removal for Gasification, Revised Final Report," U.S. Department of Energy, Pittsburgh, PA, December 2002.
- [67] Carbon Capture Simulation Initiative, "Centrifugal Compressor Simulation User Manual," U.S. Department of Energy, 2012.
- [68] V. Bilsbak, Conditioning of CO₂ Coming from a CO₂ Capture Process for Transport and Storage Purposes, Norwegian University of Science and Technology, 2009.
- [69] NATCO Group Inc, "Glycol Dehydration Systems," 2009. [Online]. Available: <http://www.natcogroup.com>. [Accessed 22 June 2009].
- [70] M. Beychok, "Claus Process," Wikimedia Commons, 2014. [Online]. Available: http://en.wikipedia.org/wiki/Claus_process#mediaviewer/File:Claus_Sulfur_Recovery.png. [Accessed 11 June 2014].
- [71] GE Power Systems, "The 7FB: The Next Evolution of the F Gas Turbine," April 2001. [Online]. Available: https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/technical/ger/ger-4194-7fb-next-evolution-of-f-gas-turbine.pdf. [Accessed 28 May 2018].
- [72] R. D. Brdar and R. M. Jones, "GE IGCC Technology and Experience with Advanced Gas Turbines," GE Power Systems, Schenectady, NY, 10/2000.
- [73] GE Power Systems, "Specification for Fuel Gases for Combustion in Heavy-Duty Turbines," January 2002.
- [74] GE Power Systems, "Design Considerations for Heated Gas Fuel," March 2003.
- [75] R. M. Bethea, Air Pollution Control Technology, New York: Van Nostrand Reinhold Company, 1978.
- [76] S. Calvert, "How to Choose a Particulate Scrubber," *Chemical Engineering*, vol. 19, pp. 54-68, August 29, 1977.
- [77] B. Jack D and L. K. Legatski, Venturi Scrubbers, Atlanta: FMC Corporation.
- [78] Environmental Protection Agency, "SI:412C Wet Scrubber Plan Review (1998). Lesson 4: Liquid-Phase Contacting Scrubbers," EPA, 1998. [Online]. Available: http://www.apti-learn.net/lms/content/epa/courses/si_412C/index.html?cid=12&userID=43049&bookmarks=. [Accessed 27 August 2015].
- [79] Babcock & Wilcox Company, Steam, Its Generation and Use, Barberton, OH: J.B. Kitto and S. C. Stultz Eds., 2015.
- [80] The International Nickel Company, Inc., "Corrosion Resistance of the Austenitic Chromium-Nickel Stainless Steels in Chemical Environments," 1963. [Online]. Available: http://www.parrinst.com/wp-content/uploads/downloads/2011/07/Parr_Stainless-Steels-Corrosion-Info.pdf. [Accessed 30 October 2014].

- [81] STAL, "General Properties," [Online]. Available: <http://www.stal.com.cn/pdf/31631613173171.pdf>. [Accessed 30 October 2014].
- [82] CSI Designs, "Stainless Steel Selection Guide," CSI, [Online]. Available: <http://www.csidesigns.com/PDFs/SSSguide.pdf>. [Accessed 30 October 2014].
- [83] W. J. Gilbert, Jet Venturi Fume Scrubbing, Westfield: Croll-Reynolds Company.
- [84] Wabash River Coal Gasification Repowering Project, "Topical Report," U.S. Department of Energy, Morgantown, 1995.
- [85] Polk Tampa Electric, "Final Public Design Report," U.S. Department of Energy, Morgantown, 1996.
- [86] N. A. Hatcher, R. S. Alvis and R. H. Weiland, "Sour Water Stripper Performance in the Presence of Heat Stable Salts," Optimized Gas Treating, Inc.
- [87] L. Addington, C. Fitz, K. Lunsford, L. Lyddon and I. M. Siwek, "Sour Water: Where it comes from and how to handle it," Bryan Research and Engineering, Inc. and Verfahrenstechnik und Automatisierung GmbH.
- [88] The Engineering Toolbox, "Super Boiler Efficiency," [Online]. Available: http://www.engineeringtoolbox.com/feedwater-chemistry-limits-d_1064.html. [Accessed 31 August 2015].
- [89] CANSOLV, "CANSOLV CO₂ Capture System," CANSOLV Technologies Inc., 2012.
- [90] Kerestecioğlu, Ulvi and Thomas Haberle, "Handling of Trace Components for Rectisol® Wash Units," Linde Engineering, [Online]. Available: <http://www.gasification.org/uploads/eventLibrary/32KEREST.pdf>. [Accessed 28 August 2015].
- [91] CANSOLV, *Personal Communication*, CANSOLV.
- [92] Honeywell UOP, *Personal Communication*, Honeywell UOP.
- [93] W. Barbour, R. Oommen, G. Sagun Shareef and W. M. Vataavuk, "Wet Scrubbers for Acid Gas," U.S. Environmental Protection Agency, December 1995. [Online]. Available: <http://www.epa.gov/ttn/catc1/dir1/cs5-2ch1.pdf>. [Accessed 1 September 2015].
- [94] A. Kohl and R. Nielsen, Gas Purification, Fifth Edition ed., Houston: Gulf Publishing, 1997.
- [95] F. Sowa and M. Wolf, "Investigation of Different Equipment Setups for Ammonia Wash and Desulfurization," DMT GmbH & Co. KG, [Online]. Available: http://www.dmt.de/fileadmin/PDF/Broschueren/Kokereitechnik/Investigation_of_different_equipment_setups_for_ammonia_wash_and_desulfurization.pdf. [Accessed 1 September 2015].
- [96] Quick Cut Gasket & Rubber Corporation, "Chemical Resistance Chart," 2014. [Online]. Available: <http://www.quickcutgasket.com/pdf/Chemical-Resistance-Chart.pdf>. [Accessed 1 September 2015].

- [97] Nickel Development Institute, "High-Temperature Characteristics of Stainless Steels," Nickel Development Institute, [Online]. Available: http://www.nickelinstitute.org/~Media/Files/TechnicalLiterature/High_TemperatureCharacteristicsofStainlessSteel_9004_.pdf#page=. [Accessed 30 October 2014].
- [98] J. Cabe and M. Elliott, "FutureGen Project Report," U.S. Department of Energy, 2013.
- [99] Sandmeyer Steel Company, "Stainless Steel Plate," [Online]. Available: <https://www.sandmeyersteel.com/317LMN.html>. [Accessed 12 December 2017].
- [100] General Electric Energy Power & Water, "Water & Process Technologies," General Electric Energy, [Online]. Available: <http://www.ge.com/in/sites/www.ge.com.in/files/GE-recycle-water-with-zero-liquid-discharge.pdf>. [Accessed 31 August 2015].
- [101] General Electric Energy Power & Water, "Zero Liquid Discharge (ZLD). Brine Concentrators and Evaporators," General Electric Energy, [Online]. Available: http://www.gewater.com/products/equipment/thermal_evaporative/brine_concentration.jsp. [Accessed 28 March 2011].
- [102] Dan Sampson, *Personal communication*, Worley Parsons.
- [103] Black & Veatch, "Bituminous Baseline Update for Compliance with Effluent Limitation Guidelines (ELG)," U.S. Department of Energy, Pittsburgh, PA, 2017.
- [104] Electric Power Research Institute, "Coal Gasification Guidebook: Status, Applications, and Technologies," EPRI, December 1993.
- [105] E. V. Holthoon, "Shell Coal Gasification – Leading Technology Across Multiple Applications," Gasification Technologies Conference, October 6, 2009.
- [106] H. J. Van Der Ploeg, T. Chhoa and P. L. Zuideveld, "The Shell Coal Gasification Process for the US Industry," Gasification Technology Conference, Washington, D.C., October 2004.
- [107] P. Amick, "Gasification of Petcoke using the E-Gas Technology at Wabash River," in *Gasification Technologies Conference*, San Francisco, 2000.
- [108] D. Breton and C. Keeler, "Comparative IGCC Performance and Costs for Domestic Coals," Gasification Technologies Council, San Francisco, CA, October 2005.
- [109] R. Rigdon and L. Schmoe, "The IGCC Reference Plant," Gasification Technologies Conference 2005, San Francisco, CA, October 2005.
- [110] GE Power, *Personal communication*, General Electric Power, 2018.
- [111] Global Syngas Technologies Council, "The largest, mega coal-chemical project selects GE large quench technology," [Online]. Available: <https://www.globalsyngas.org/uploads/downloads/GE-on-Shenhua-Yulin.pdf>. [Accessed 9 October 2018].
- [112] R. Rigdon and K. Miles, "The Cleaner Coal Option," *Power Engineering International*, July 2006.

- [113] WorleyParsons, "Steam Conditions for PC Plant Designs Market Based Advanced Coal Power Systems Comparison Study," June 2005.
- [114] R. Storm, "Optimizing Combustion in Boilers with Low NO_x Burners," *Power Magazine*, October 1993.
- [115] R. Gansley, D. Love, P. Rader and H. Lancaster, "Cliffside Modernization Project ACQS," Presented at EUEC, Phoenix, 2013.
- [116] P. Wieslanger, "Fabric Filters for Power Applications," ALSTOM Power Environmental Systems AB, 2000.
- [117] C. Senior, "Mercury Oxidation across SCRs in Coal-Fired Power Plants," in *Mercury Control Technology R&D Program Review*, Pittsburgh, PA, 2005.
- [118] S. Hinton, A. Jimenez, C. Dene and C. Tyree, "Enhanced Mercury Control by Managing SCR Systems for Mercury and NO_x," Baltimore, August 19-23, 2012.
- [119] C. Senior and S. Johnson, Impact of Carbon-in-Ash on Mercury Removal Across Particulate Control Devices in Coal-Fired Power Plants, *Energy & Fuels*, 2005.
- [120] M. Gadgil, "20 Years of Mercury Re-emission – What Do We Know?," in *Power Plant Pollutant Control and Carbon Management "MEGA"*, Baltimore, 2016.
- [121] N. Pollack, "Novel Carbon Based Sorbents for High SO₃ Applications," Arlington, October 26-29, 2009.
- [122] Memorandum from Robert Wayland to William H. Maxwell, *Revised New Source Performance Standards (NSPS) Statistical Analysis for Mercury Emissions*, Office of Air Quality Planning and Standards, EPA, May 31, 2006.
- [123] Environmental Protection Agency, *Standalone Documentation for EPA Base Case 2004 (V.2.1.9) Using the Integrated Planning Model*, Washington, D.C., September 2005.
- [124] R. K. Srivastava, J. E. Staudt and W. Jozewicz, *Preliminary Estimates of Performance and Cost of Mercury Emission Control Technology Applications on Electric Utility Boilers: An Update*, Washington, D.C., 2004.
- [125] Environmental Protection Agency, "Steam Electric Power Generation Point Source Category: Final Detailed Study Report. EPA 821-R-09-008," [Online]. Available: https://www.epa.gov/sites/production/files/2015-06/documents/steam-electric_detailed_study_report_2009.pdf. [Accessed 15 May 2017].
- [126] Electric Power Research Institute, "Flue Gas Desulfurization (FGD) Wastewater Characterization," March 2006. [Online]. Available: <http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001010162&Mode=download>. [Accessed 15 May 2017].
- [127] National Energy Technology Laboratory, "Screening Analysis: Integrated Compressor Intercooling," U.S. Department of Energy, Pittsburgh, PA, January 2008.

- [128] Environmental Protection Agency, "Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category," Environmental Protection Agency, Washington, D.C., 2015.
- [129] Kansas City Power & Light, *Personal communication, Kansas City Power & Light*, July 2017.
- [130] W. G. Gorman and J. K. Reinker, "Steam Turbines for Utility Applications," GE Power Generation, 1994.
- [131] GE Power, "7F Heavy Duty Gas Turbine," November 2018. [Online]. Available: https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/product/gas%20turbines/Fact%20Sheet/2017-prod-specs/GEA32930A%207F_Power_Plants_R1.pdf. [Accessed 6 March 2019].
- [132] GE Power, "7HA Power Plants," November 2018. [Online]. Available: https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/product/gas%20turbines/Fact%20Sheet/2017-prod-specs/7ha-power-plants.pdf. [Accessed 6 March 2019].
- [133] Modern Power Systems, "GE's new all-air-cooled H class turbine," April 2014. [Online]. Available: <https://www.modernpowersystems.com/features/featuresges-new-all-air-cooled-h-class-turbine-4212530/>. [Accessed 6 March 2019].
- [134] Gas Turbine World, *Gas Turbine World: 2016 Performance Specs Volume 46 No. 1*, 2016.
- [135] D. Martin, K. Johnson, A. Stolberg, X. Zhang and C. D. Young, "Carbon Dioxide Removal Options: A literature REview Identifying Carbon Removal Potentials and Costs," University of Michigan, 2017.
- [136] E. Moskal and V. Nuñez-López, "Potential of CO₂-EOR for Near-Term Decarbonization," *Frontiers*, 27 September 2019. [Online]. Available: <https://www.frontiersin.org/articles/10.3389/fclim.2019.00005/full>. [Accessed 22 September 2022].
- [137] Office of the Federal Register, "Proposed Rules Vol. 82 No. 63," 4 April 2017. [Online]. Available: <https://www.govinfo.gov/content/pkg/FR-2017-04-04/pdf/2017-06597.pdf>. [Accessed 6 June 2019].
- [138] Energy Information Administration, "Natural Gas Spot and Future Prices," [Online]. Available: https://www.eia.gov/dnav/ng/ng_pri_fut_s1_d.htm. [Accessed June 2022].

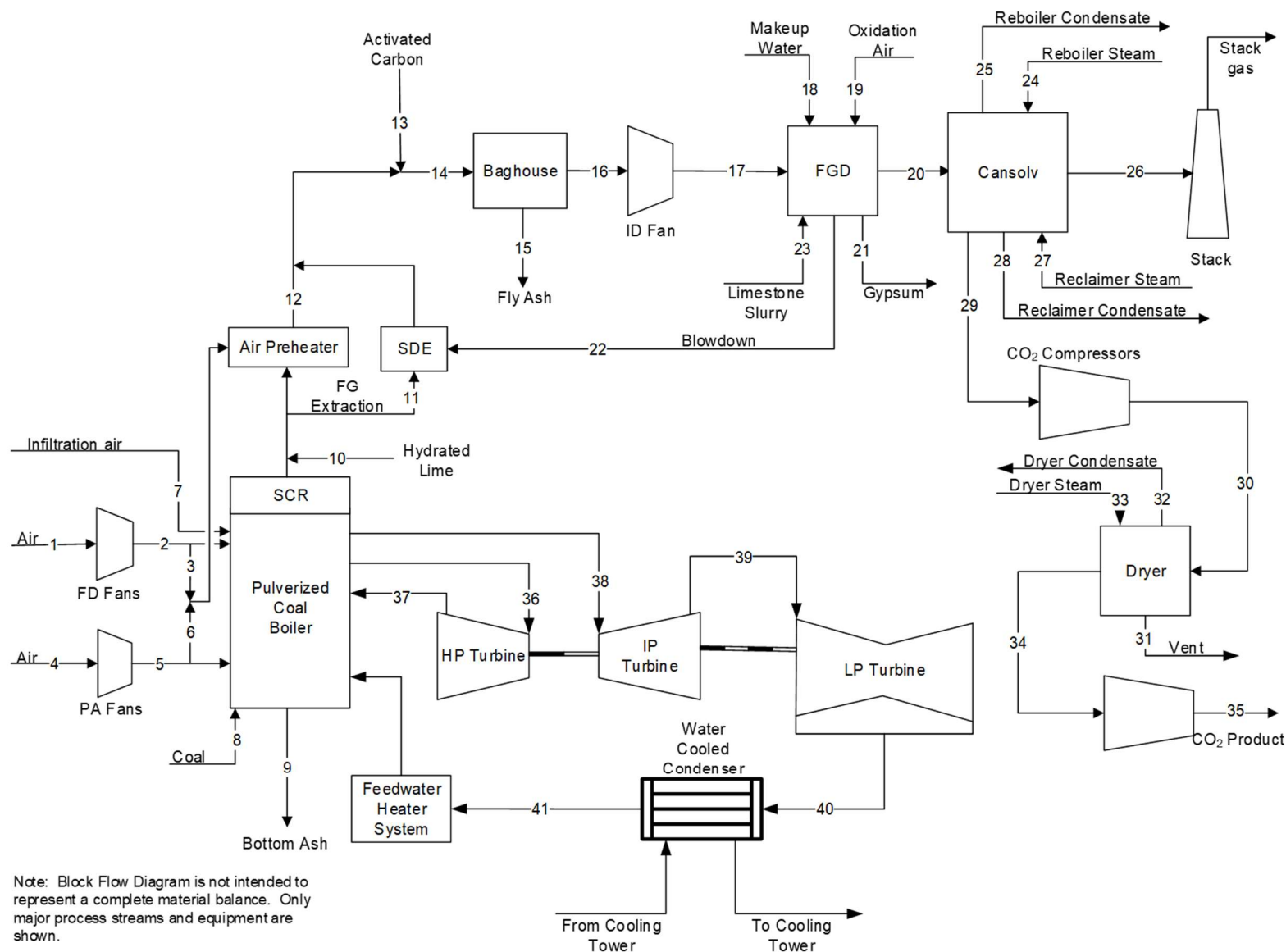
APPENDIX A: PC WITH 99 PERCENT CO₂ CAPTURE

A.1 CASE B11B.99 – SUBC PC WITH 99 PERCENT CO₂ CAPTURE PROCESS DESCRIPTION

The plant configuration and process description for Case B11B.99 are nearly the same as Case B11B.90, with the exception of 99 percent capture. Since the process descriptions of the plant and CDR facility were provided in Section 4.2.3 and Section 4.1.8, respectively, they are not repeated here.

The BFD for Case B11B.99 is shown in Exhibit A-1. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit A-2. The modeling assumptions were presented previously in Section 4.2.1.

Exhibit A-1. Case B11B.99 block flow diagram, SubC unit with CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-2. Case B11B.99 stream table, SubC unit with capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0087	0.0088	0.0000	0.0087	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379	0.0000	0.1372	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837	0.0000	0.0911	0.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340	0.0000	0.7281	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336	0.0000	0.0329	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020	0.0000	0.0020	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1158
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.8842
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	80,607	80,607	2,387	24,762	24,762	3,408	1,782	0	0	1	5,312	107,752	0	113,964	7
V-L Flowrate (kg/hr)	2,326,082	2,326,082	68,895	714,548	714,548	98,339	51,415	0	0	16	157,980	3,199,630	0	3,374,254	729
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	295,666	5,960	1,611	1,276	24,492	65	26,086	26,103
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143	15	143	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.31	-6.79	-2,453.14	-1,065.96
Density (kg/m ³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8	---	0.8	2,150.2
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694	---	29.608	104.898
V-L Flowrate (lb _{mol} /hr)	177,709	177,709	5,263	54,590	54,590	7,513	3,928	0	0	2	11,710	237,553	0	251,247	15
V-L Flowrate (lb/hr)	5,128,133	5,128,133	151,888	1,575,309	1,575,309	216,801	113,350	0	0	36	348,286	7,053,978	0	7,438,957	1,607
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	651,832	13,140	3,552	2,813	53,995	143	57,509	57,548
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289	59	289	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1	14.7	14.1	14.1
Steam Table Enthalpy (Btu/lb) ^A	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4	-2.9	-1,054.7	-458.3
Density (lb/ft ³)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052	---	0.052	134.232

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-2. Case B11B.99 stream table, SubC unit with capture (continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0103	0.0000	0.0000	0.0000	0.0000
CO ₂	0.1372	0.1372	0.0000	0.0003	0.1245	0.0001	0.0000	0.0000	0.0000	0.0000	0.0016	0.0000	0.0000	0.9783	0.9975
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0911	0.0911	0.9999	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000	1.0000	0.0807	1.0000	1.0000	0.0217	0.0025
HCl	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000	0.0000	0.8614	0.0000	0.0000	0.0000	0.0000
O ₂	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000	0.0000	0.0460	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0001	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	113,957	113,957	6,658	4,770	127,394	268	900	3,708	41,091	37,635	100,609	410	410	16,042	15,733
V-L Flowrate (kg/hr)	3,373,508	3,373,508	119,965	137,657	3,661,337	4,833	16,644	66,812	740,259	677,999	2,770,628	7,383	7,383	696,950	691,380
Solids Flowrate (kg/hr)	0	0	0	0	0	43,473	253	28,601	0	0	0	0	0	0	0
Temperature (°C)	143	156	15	15	57	15	57	15	266	105	45	355	214	31	29
Pressure (MPa, abs)	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.48	0.12	0.10	4.28	2.04	0.17	2.81
Steam Table Enthalpy (kJ/kg) ^A	287.58	302.09	-47.80	30.23	297.00	---	---	---	2,994.07	439.34	179.65	3,098.44	913.81	46.68	-3.05
AspenPlus Enthalpy (kJ/kg) ^B	-2,464.17	-2,449.66	-	-97.58	-2,939.24	-12,513.34	-15,496.21	-	-	-	-710.95	-	-	-8,978.62	-8,972.51
Density (kg/m ³)	0.8	0.9	1,003.7	1.2	1.1	878.3	979.4	1,003.7	2.0	954.9	1.1	16.0	848.5	3.0	57.8
V-L Molecular Weight	29.603	29.603	18.019	28.857	28.740	18.021	18.494	18.019	18.015	18.015	27.539	18.015	18.015	43.445	43.945
V-L Flowrate (lb _{mol} /hr)	251,232	251,232	14,678	10,517	280,856	591	1,984	8,175	90,589	82,970	221,804	903	903	35,366	34,685
V-L Flowrate (lb/hr)	7,437,311	7,437,311	264,477	303,482	8,071,867	10,655	36,693	147,294	1,631,992	1,494,733	6,108,188	16,277	16,277	1,536,511	1,524,231
Solids Flowrate (lb/hr)	0	0	0	0	0	95,841	559	63,054	0	0	0	0	0	0	0
Temperature (°F)	289	313	59	59	135	59	135	59	511	221	113	671	416	87	85
Pressure (psia)	13.9	15.3	14.7	14.7	14.8	14.7	14.7	14.7	70.0	17.4	14.8	620.5	296.6	24.7	407.6
Steam Table Enthalpy (Btu/lb) ^A	123.6	129.9	-20.5	13.0	127.7	---	---	---	1,287.2	188.9	77.2	1,332.1	392.9	20.1	-1.3
AspenPlus Enthalpy (Btu/lb) ^B	-1,059.4	-1,053.2	-6,885.2	-42.0	-1,263.6	-5,379.8	-6,662.2	-6,446.4	-5,583.1	-6,681.4	-305.7	-5,538.2	-6,477.4	-3,860.1	-3,857.5
Density (lb/ft ³)	0.051	0.055	62.658	0.076	0.067	54.833	61.145	62.658	0.123	59.612	0.066	1.000	52.968	0.184	3.609

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-2. Case B11B.99 stream table, SubC unit with capture (continued)

	31	32	33	34	35	36	37	38	39	40	41
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0500	0.0000	0.0000	0.9995	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	33	20	20	15,700	15,700	137,407	127,843	127,843	107,263	49,602	71,297
V-L Flowrate (kg/hr)	637	363	363	690,742	690,742	2,475,431	2,303,125	2,303,125	1,932,365	893,599	1,284,442
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	29	203	476	29	30	566	355	566	267	38	39
Pressure (MPa, abs)	2.81	1.64	2.42	2.68	15.27	16.65	4.28	4.19	0.52	0.01	1.32
Steam Table Enthalpy (kJ/kg) ^A	137.94	863.65	3,408.95	-3.59	-231.09	3,473.89	3,098.44	3,593.58	2,994.07	2,340.01	162.43
AspenPlus Enthalpy (kJ/kg) ^B	-15,225.22	-15,116.65	-12,571.34	-8,967.15	-9,194.65	-12,506.41	-12,881.86	-12,386.71	-12,986.23	-13,640.29	-15,817.87
Density (kg/m ³)	351.5	861.8	7.1	54.7	630.1	47.7	16.0	11.1	2.1	0.1	993.3
V-L Molecular Weight	19.315	18.015	18.015	43.997	43.997	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	73	44	44	34,612	34,612	302,931	281,845	281,845	236,473	109,354	157,184
V-L Flowrate (lb/hr)	1,405	801	801	1,522,826	1,522,826	5,457,392	5,077,521	5,077,521	4,260,136	1,970,050	2,831,710
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	85	397	888	85	86	1,050	671	1,050	512	101	101
Pressure (psia)	407.6	237.4	350.5	389.1	2,214.7	2,414.7	620.5	608.1	75.0	1.0	190.7
Steam Table Enthalpy (Btu/lb) ^A	59.3	371.3	1,465.6	-1.5	-99.4	1,493.5	1,332.1	1,545.0	1,287.2	1,006.0	69.8
AspenPlus Enthalpy (Btu/lb) ^B	-6,545.7	-6,499.0	-5,404.7	-3,855.2	-3,953.0	-5,376.8	-5,538.2	-5,325.3	-5,583.1	-5,864.3	-6,800.5
Density (lb/ft ³)	21.943	53.801	0.446	3.416	39.338	2.975	1.000	0.692	0.132	0.003	62.010

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

A.1.1 Case B11B.99 – Performance Results

Overall plant performance is summarized in Exhibit A-3; Exhibit A-4 provides a detailed breakdown of the auxiliary power requirements.

The CDR facility, including CO₂ compression, accounts for over half of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for over 12 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility and CO₂ compressors.

Unlike the NGCC cases where gross output was fixed by the available size of the CTs, the PC cases utilize boilers and steam turbines that can be procured at nearly any desired output. By increasing the boiler and turbine/generator size to account for the greater auxiliary load imposed by the CDR facility and CO₂ compressors, a net output of 650 MW is maintained at a reduced net plant efficiency of 29.2 percent (HHV basis).

Exhibit A-3. Case B11B.99 plant performance summary

Performance Summary	
Total Gross Power, MWe	780
CO ₂ Capture/Removal Auxiliaries, kWe	21,900
CO ₂ Compression, kWe	55,300
Balance of Plant, kWe	52,440
Total Auxiliaries, MWe	130
Net Power, MWe	650
HHV Net Plant Efficiency, %	29.2
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	12,334 (11,691)
LHV Net Plant Efficiency, %	30.3
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,897 (11,276)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	56.6
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	6,358 (6,026)
Condenser Duty, GJ/hr (MMBtu/hr)	2,231 (2,115)
CO ₂ Capture Rate, %	99
AGR Duty, GJ/hr (MMBtu/hr)	2,443 (2,316)
As-Received Coal Feed, kg/hr (lb/hr)	295,666 (651,832)
Limestone Sorbent Feed, kg/hr (lb/hr)	28,601 (63,054)
HHV Thermal Input, kWt	2,228,591
LHV Thermal Input, kWt	2,149,503
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.061 (16.1)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.045 (11.9)
Excess Air, %	20.3

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-4. Case B11B.99 plant power summary

Power Summary	
Steam Turbine Power, MWe	780
Total Gross Power, MWe	780
Auxiliary Load Summary	
Activated Carbon Injection, kWe	40
Ash Handling, kWe	970
Baghouse, kWe	130
Circulating Water Pumps, kWe	10,160
CO ₂ Capture/Removal Auxiliaries, kWe	21,900
CO ₂ Compression, kWe	55,300
Coal Handling and Conveying, kWe	550
Condensate Pumps, kWe	720
Cooling Tower Fans, kWe	5,250
Dry Sorbent Injection, kWe	80
Flue Gas Desulfurizer, kWe	4,570
Forced Draft Fans, kWe	1,520
Ground Water Pumps, kWe	950
Induced Draft Fans, kWe	14,020
Miscellaneous Balance of Plant ^{A,B} , kWe	2,250
Primary Air Fans, kWe	1,800
Pulverizers, kWe	4,430
SCR, kWe	50
Sorbent Handling & Reagent Preparation, kWe	1,380
Spray Dryer Evaporator, kWe	330
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,740
Total Auxiliaries, MWe	130
Net Power, MWe	650

^ABoiler feed pumps are turbine driven

^BIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

A.1.1.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B11B.99 is presented in Exhibit A-5. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit A-5. Case B11B.99 air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.031 (0.072)	1,844 (2,033)	0.318 (0.700)
Particulate	0.004 (0.009)	237 (261)	0.041 (0.090)
Hg	1.32E-7 (3.08E-7)	0.008 (0.009)	1.36E-6 (3.00E-6)
CO ₂	1 (2)	53,522 (58,998)	9 (20)
CO ₂ ^C	—	—	11 (24)
mg/Nm ³			
Particulate Concentration ^{D,E}	12.47		

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

^DConcentration of particles in the flue gas after the baghouse

^ENormal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The SO₂ emissions are further reduced to 0.37 ppmv using a NaOH based polishing scrubber in the CDR facility. The remaining low concentration of SO₂ is essentially completely removed in the CDR absorber vessel resulting in very low SO₂ emissions (reported as zero here).

NO_x boiler emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 79.5 percent to 0.03 kg/GJ (0.07 lb/MMBtu).

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and wet FGD) is 97.6 percent.

Ninety-nine percent of the CO₂ in the flue gas is removed in CDR facility.

The carbon balance for the plant is shown in Exhibit A-6. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon leaves the plant mostly as CO₂ product from the CO₂ compression train; however, some CO₂ exits through the stack, the PAC is captured in the fabric filter, unburned

carbon remains in the bottom ash, and some leaves as gypsum. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in (minus unburnt carbon in the ash), represented by the following fraction:

$$1 - \frac{\text{Carbon in Stack}}{\text{Total Carbon In} - \text{Unburnt Carbon}} = \left(1 - \left(\frac{4,325}{423,017 - 499}\right) * \right) 100 = 99\%$$

Exhibit A-6. Case B11B.99 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	188,471 (415,508)	Stack Gas	1,962 (4,325)
Air (CO ₂)	439 (968)	FGD Product	223 (493)
PAC	65 (143)	Baghouse	969 (2,137)
FGD Reagent	2,902 (6,398)	Bottom Ash	226 (499)
		CO ₂ Product	188,476 (415,519)
		CO ₂ Dryer Vent	20 (44)
		CO ₂ Knockout	0.5 (1.2)
Total	191,877 (423,017)	Total	191,877 (423,017)

Exhibit A-7 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur removed in the polishing scrubber, and sulfur removed in the baghouse.

Exhibit A-7. Case B11B.99 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	7,411 (16,338)	FGD Product	6,967 (15,360)
		Stack Gas	—
		Polishing Scrubber and Solvent Reclaiming	145 (319)
		Baghouse	299 (658)
Total	7,411 (16,338)	Total	7,411 (16,338)

Exhibit A-8 shows the overall water balance for the plant. The exhibit is presented in an identical manner as was for Case B11A. The only notable difference is the FGD makeup water source. In CO₂ capture cases, a significant amount of water is recovered from the initial CDR facility cooling step. This water would otherwise be discharged; however, it is suitable to be used as FGD makeup. The balance of the water from the CDR facility is sent to discharge.

Exhibit A-8. Case B11B.99 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
FGD Process Makeup	2.0 (529)	2.0 (529)	–	–	–
FGD Slurry Water	1.1 (295)	1.1 (295)	–	–	–
CO ₂ Drying	–	–	–	0.0 (2.8)	0.0 (-2.8)
CO ₂ Capture Recovery	–	–	–	1.2 (304)	-1.2 (-304)
CO ₂ Compression KO	–	–	–	0.1 (25)	-0.1 (-25)
Deaerator Vent	–	–	–	0.1 (22)	-0.1 (-22)
Condenser Makeup	0.5 (133)	–	0.5 (133)	–	0.5 (133)
BFW Makeup	0.5 (133)	–	0.5 (133)	–	0.5 (133)
Cooling Tower	40 (10,450)	0.4 (110)	39 (10,340)	8.9 (2,350)	30 (7,990)
BFW Blowdown	–	0.4 (110)	-0.4 (-110)	–	-0.4 (-110)
Total	43 (11,406)	3.5 (934)	40 (10,472)	10 (2,704)	29 (7,769)

A.1.1.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for the Case B11B.99 PC boiler, the FGD unit, CDR system and steam cycle in Exhibit A-9 and Exhibit A-10. An overall plant energy balance is provided in tabular form in Exhibit A-11.

The power out is the steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a generator efficiency of 98.5 percent. The cooling tower load includes the condenser, capture process heat rejected to cooling water, the CO₂ compressor intercooler load, and other miscellaneous cooling loads.

This page intentionally left blank.

Exhibit A-9. Case B11B.99 energy and mass balance, SubC PC boiler with CO₂ capture

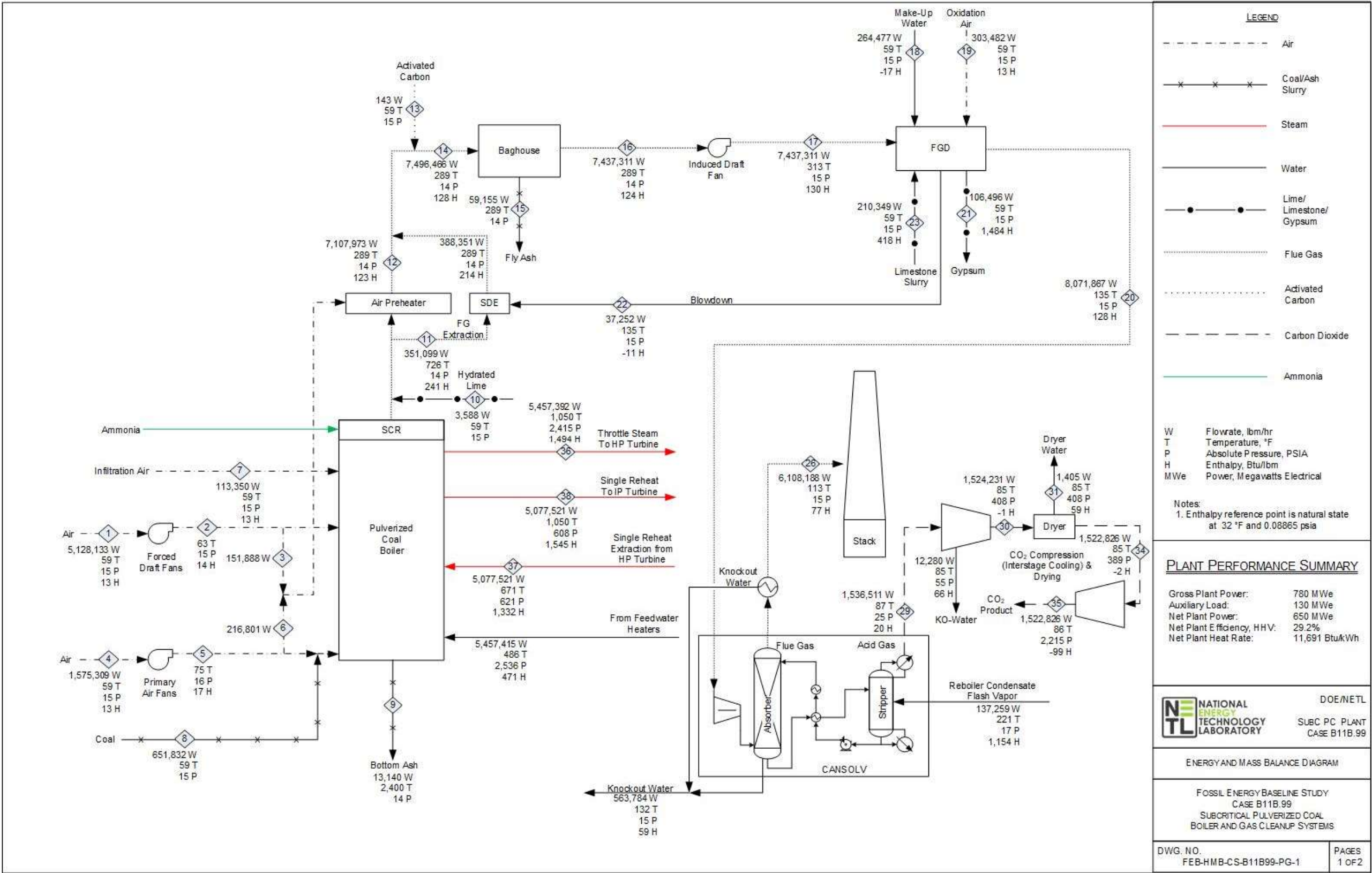


Exhibit A-10. Case B11B.99 energy and mass balance, SubC steam cycle

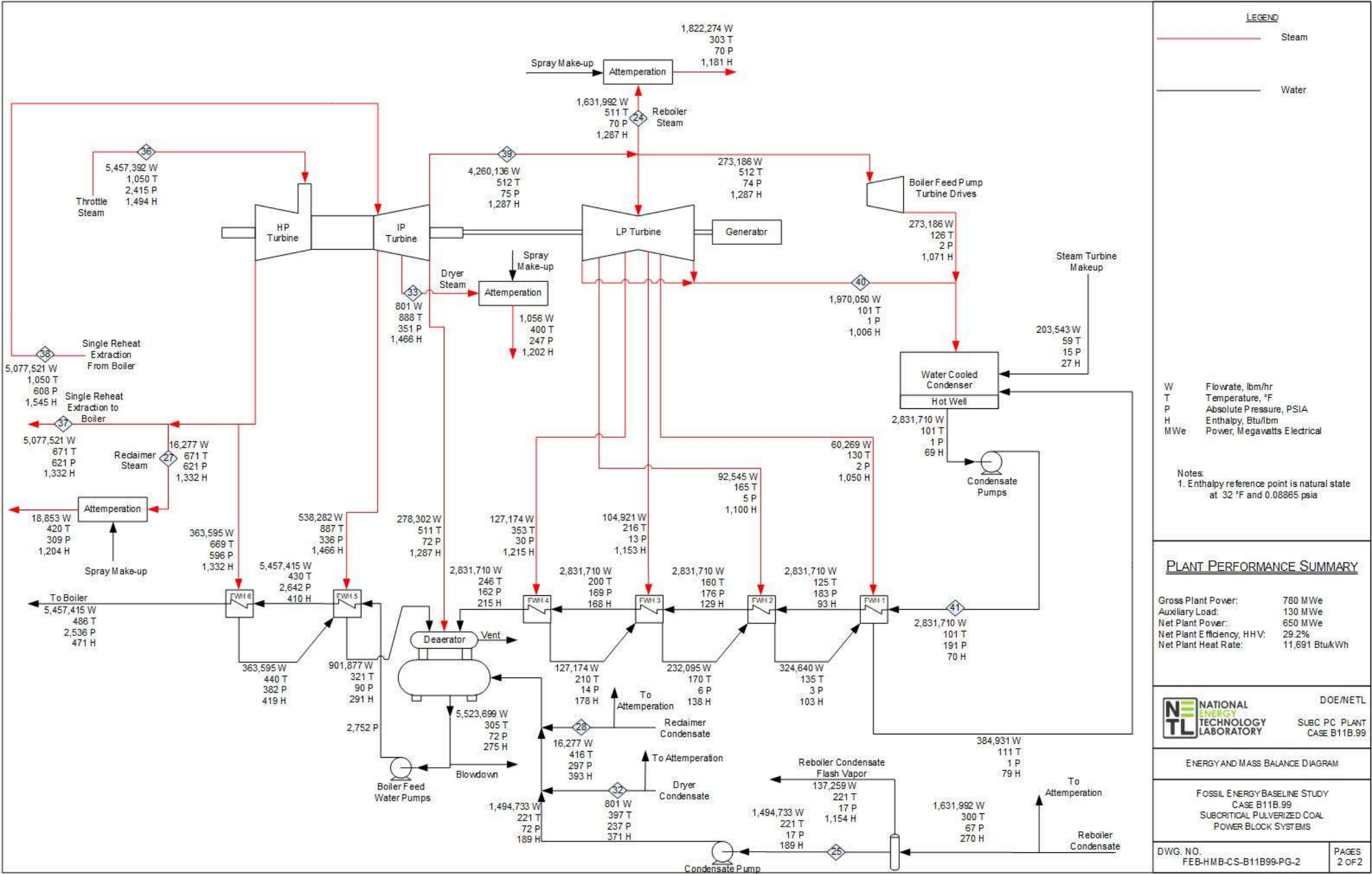


Exhibit A-11. Case B11B.99 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	8,023 (7,604)	6.7 (6.4)	—	8,030 (7,611)
Air	—	93 (89)	—	93 (89)
Raw Water Makeup	—	149 (141)	—	149 (141)
Limestone	—	0.6 (0.6)	—	0.6 (0.6)
Auxiliary Power	—	—	467 (442)	467 (442)
TOTAL	8,023 (7,604)	250 (237)	467 (442)	8,739 (8,283)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	—	7.6 (7.2)	—	7.6 (7.2)
Fly Ash	—	2.7 (2.6)	—	2.7 (2.6)
Stack Gas	—	498 (472)	—	498 (472)
Sulfur	2.7 (2.6)	0.0 (0.0)	—	2.7 (2.6)
Gypsum	—	2.8 (2.7)	—	2.8 (2.7)
Motor Losses and Design Allowances	—	—	52 (49)	52 (49)
Cooling Tower Load ^A	—	5,166 (4,896)	—	5,166 (4,896)
CO ₂ Product Stream	—	-160 (-151)	—	-160 (-151)
AGR Effluent	—	59 (56)	—	59 (56)
Blowdown Streams and Deaerator Vent	—	19 (18)	—	19 (18)
<i>Ambient Losses^B</i>	—	187 (178)	—	187 (178)
Power	—	—	2,808 (2,662)	2,808 (2,662)
TOTAL	2.7 (2.6)	5,783 (5,481)	2,860 (2,711)	8,646 (8,195)
<i>Unaccounted Energy^C</i>	—	93 (89)	—	93 (89)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^CBy difference

A.1.2 Case B11B.99 – Major Equipment List

Major equipment items for the SubC PC plant with CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.2.10. In general, the design conditions include a 10 percent

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

Case B11B.99 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	60 tonne (70 ton)	2	1
9	Feeder	Vibratory	240 tonne/hr (270 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	490 tonne/hr (540 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	240 tonne (270 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	490 tonne/hr (540 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	490 tonne/hr (540 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,080 tonne (1,200 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 12 tonne (13 ton) Feeder - 70 kg/hr (160 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 300 tonne (330 ton) Feeder - 1,790 kg/hr (3,950 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	120 tonne/hr (132 tph)	1	0
23	Limestone Conveyor No. 1	Belt	120 tonne/hr (132 tph)	1	0
24	Limestone Reclaim Hopper	N/A	24 tonne (26 ton)	1	0
25	Limestone Reclaim Feeder	Belt	94 tonne/hr (104 tph)	1	0
26	Limestone Conveyor No. 2	Belt	94 tonne/hr (104 tph)	1	0
27	Limestone Day Bin	w/ actuator	378 tonne (416 ton)	2	0

Case B11B.99 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	54 tonne/hr (60 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	54 tonne/hr (60 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	31 tonne/hr (35 tph)	1	1
4	Limestone Ball Mill	Rotary	31 tonne/hr (35 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	120,000 liters (31,800 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	2,000 lpm @ 10m H ₂ O (530 gpm @ 40 ft H ₂ O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5-cyclone bank	500 lpm (130 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
9	Limestone Slurry Storage Tank with Agitator	Field erected	680,000 liters (180,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,420 lpm @ 9m H ₂ O (370 gpm @ 30 ft H ₂ O)	1	1

Case B11B.99 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,987,000 liters (525,000 gal)	2	0
2	Condensate Pumps	Vertical canned	11,900 lpm @ 200 m H ₂ O (3,130 gpm @ 500 ft H ₂ O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,378,000 kg/hr (3,038,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	23,000 lpm @ 2,300 m H ₂ O (6,000 gpm @ 7,500 ft H ₂ O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	6,800 lpm @ 2,300 m H ₂ O (1,800 gpm @ 7,500 ft H ₂ O)	2	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	350,000 kg/hr (780,000 lb/hr)	4	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	350,000 kg/hr (780,000 lb/hr)	4	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	350,000 kg/hr (780,000 lb/hr)	4	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	350,000 kg/hr (780,000 lb/hr)	4	0
10	HP Feedwater Heater 5	Horizontal U-tube	1,360,000 kg/hr (3,000,000 lb/hr)	2	0
11	HP Feedwater Heater 6	Horizontal U-tube	1,360,000 kg/hr (3,000,000 lb/hr)	2	0
12	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
13	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
14	Service Air Compressors	Flooded Screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H ₂ O (5,500 gpm @ 100 ft H ₂ O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	10,700 lpm @ 20 m H ₂ O (2,810 gpm @ 60 ft H ₂ O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	4,260 lpm @ 270 m H ₂ O (1,130 gpm @ 880 ft H ₂ O)	5	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
22	Filtered Water Pumps	Stainless steel, single suction	1,600 lpm @ 50 m H ₂ O (420 gpm @ 160 ft H ₂ O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,539,000 liter (406,600 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	1,010 lpm (270 gpm)	1	1
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,720 m ³ /min (96,100 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 160 lpm (40 gpm) @ 19,982 ppmw Cl ⁻	2	1

Case B11B.99 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum, wall-fired, low NO _x burners, overfire air	2,720,000 kg/hr steam @ 16.5 MPa/566°C/566°C (6,000,000 lb/hr steam @ 2,400 psig/1,050°F/1,050°F)	1	0
2	Primary Air Fan	Centrifugal	393,000 kg/hr, 5,400 m ³ /min @ 101 cm WG (866,000 lb/hr, 189,400 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,279,000 kg/hr, 17,500 m ³ /min @ 26 cm WG (2,820,000 lb/hr, 617,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,855,000 kg/hr, 37,600 m ³ /min @ 114 cm WG (4,091,000 lb/hr, 1,327,000 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,510,000 kg/hr (7,740,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	140 m ³ /min @ 108 cm WG (4,800 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	151,000 liter (39,800 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	29 lpm @ 90 m H ₂ O (8 gpm @ 300 ft H ₂ O)	2	1

Case B11B.99 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,856,000 kg/hr (4,091,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	62,900 m ³ /min (2,220,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	219,000 lpm @ 65 m H ₂ O (57,700 gpm @ 210 ft H ₂ O)	5	1
4	Bleed Pumps	Horizontal centrifugal	6,040 lpm (1,600 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	1,030 m ³ /min @ 0.3 MPa (36,490 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,510 lpm (400 gpm) per cyclone	2	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
8	Vacuum Filter Belt	Horizontal belt	48 tonne/hr (53 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	920 lpm @ 13 m H ₂ O (240 gpm @ 40 ft H ₂ O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	600,000 lpm (160,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	2,200 lpm @ 21 m H ₂ O (580 gpm @ 70 ft H ₂ O)	1	1
12	Activated Carbon Injectors	---	70 kg/hr (160 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,790 kg/hr (3,950 lb/hr)	1	0
14	CANSOLV	Amine-based CO ₂ capture technology	4,027,000 kg/hr (8,879,000 lb/hr) 19.1 wt % CO ₂ concentration	1	0
15	CANSOLV LP Condensate Pump	Centrifugal	1,585 lpm @ 1 m H ₂ O (419 gpm @ 3 ft H ₂ O)	1	1
16	CANSOLV IP Condensate Pump	Centrifugal	22 lpm @ 4.6 m H ₂ O (6 gpm @ 15 ft H ₂ O)	1	1
17	CO ₂ Dryer	Triethylene glycol	Inlet: 199 m ³ /min @ 2.8 MPa (7,039 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Recovered: 637 kg/hr (1,405 lb/hr)	1	0
18	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	10.0 m ³ /min @ 15.3 MPa, 82°C (355 acfm @ 2,217 psia, 180°F)	2	0
19	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 109 GJ/hr (103 MMBtu/hr)	1	0

Case B11B.99 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.5 m (21 ft) diameter	1	0

Case B11B.99 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	821 MW 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	910 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,230 GJ/hr (2,330 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B11B.99 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	1,019,000 lpm @ 30 m (269,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 5,680 GJ/hr (5,390 MMBtu/hr) heat duty	1	0

Case B11B.99 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	6.6 tonne/hr (7.2 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	26 m ³ /min @ 0.2 MPa (936 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,740 tonne (1,920 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	160 tonne/hr (180 tph)	1	0

Case B11B.99 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 31 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 58 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 21 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B11B.99 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

A.1.3 Case B11B.99 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit A-12 shows a detailed breakdown of the capital costs; Exhibit A-13 shows the owner's costs, TOC, and TASC; Exhibit A-14 shows the initial and annual O&M costs; and Exhibit A-15 shows the LCOE breakdown.

The estimated TPC of the SubC PC boiler with CO₂ capture is \$3,543/kW. Process contingency represents 2.8 percent of the TPC and project contingency represents 13.9 percent. The LCOE, including CO₂ T&S costs of \$10.6/MWh, is \$113.8/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-12. Case B11B.99 total plant cost details

Case:		B11B.99	– SubC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1		Coal & Sorbent Handling									
1.1	Coal Receive & Unload	\$1,234	\$0	\$556	\$0	\$1,790	\$313	\$0	\$316	\$2,419	\$4
1.2	Coal Stackout & Reclaim	\$4,052	\$0	\$906	\$0	\$4,958	\$868	\$0	\$874	\$6,700	\$10
1.3	Coal Conveyors	\$37,337	\$0	\$8,877	\$0	\$46,214	\$8,087	\$0	\$8,145	\$62,447	\$96
1.4	Other Coal Handling	\$5,190	\$0	\$1,092	\$0	\$6,282	\$1,099	\$0	\$1,107	\$8,489	\$13
1.5	Sorbent Receive & Unload	\$238	\$0	\$70	\$0	\$308	\$54	\$0	\$54	\$417	\$1
1.6	Sorbent Stackout & Reclaim	\$1,738	\$0	\$314	\$0	\$2,053	\$359	\$0	\$362	\$2,773	\$4
1.7	Sorbent Conveyors	\$2,634	\$573	\$638	\$0	\$3,845	\$673	\$0	\$678	\$5,196	\$8
1.8	Other Sorbent Handling	\$127	\$30	\$65	\$0	\$222	\$39	\$0	\$39	\$300	\$0
1.9	Coal & Sorbent Handling Foundations	\$0	\$1,619	\$2,134	\$0	\$3,753	\$657	\$0	\$661	\$5,071	\$8
	Subtotal	\$52,551	\$2,221	\$14,653	\$0	\$69,425	\$12,149	\$0	\$12,236	\$93,811	\$144
2		Coal & Sorbent Preparation & Feed									
2.1	Coal Crushing & Drying	\$2,661	\$0	\$511	\$0	\$3,172	\$555	\$0	\$559	\$4,286	\$7
2.2	Prepared Coal Storage & Feed	\$8,957	\$0	\$1,929	\$0	\$10,885	\$1,905	\$0	\$1,919	\$14,709	\$23
2.5	Sorbent Preparation Equipment	\$1,171	\$51	\$240	\$0	\$1,461	\$256	\$0	\$258	\$1,975	\$3
2.6	Sorbent Storage & Feed	\$1,960	\$0	\$742	\$0	\$2,703	\$473	\$0	\$476	\$3,652	\$6
2.9	Coal & Sorbent Feed Foundation	\$0	\$777	\$681	\$0	\$1,458	\$255	\$0	\$257	\$1,971	\$3
	Subtotal	\$14,749	\$828	\$4,103	\$0	\$19,680	\$3,444	\$0	\$3,469	\$26,593	\$41
3		Feedwater & Miscellaneous BOP Systems									
3.1	Feedwater System	\$4,037	\$6,920	\$3,460	\$0	\$14,417	\$2,523	\$0	\$2,541	\$19,481	\$30
3.2	Water Makeup & Pretreating	\$8,602	\$860	\$4,875	\$0	\$14,337	\$2,509	\$0	\$3,369	\$20,216	\$31
3.3	Other Feedwater Subsystems	\$3,154	\$1,034	\$983	\$0	\$5,171	\$905	\$0	\$911	\$6,988	\$11
3.4	Service Water Systems	\$2,744	\$5,238	\$16,961	\$0	\$24,943	\$4,365	\$0	\$5,862	\$35,169	\$54
3.5	Other Boiler Plant Systems	\$777	\$283	\$707	\$0	\$1,767	\$309	\$0	\$311	\$2,387	\$4
3.6	Natural Gas Pipeline and Start-Up System	\$3,596	\$155	\$116	\$0	\$3,867	\$677	\$0	\$682	\$5,225	\$8
3.7	Waste Water Treatment Equipment	\$14,340	\$0	\$8,789	\$0	\$23,130	\$4,048	\$0	\$5,435	\$32,613	\$50
3.8	Spray Dryer Evaporator	\$17,832	\$0	\$10,323	\$0	\$28,155	\$4,927	\$0	\$6,617	\$39,699	\$61
3.9	Miscellaneous Plant Equipment	\$204	\$27	\$104	\$0	\$334	\$59	\$0	\$79	\$472	\$1
	Subtotal	\$55,287	\$14,517	\$46,317	\$0	\$116,121	\$20,321	\$0	\$25,807	\$162,249	\$249
4		Pulverized Coal Boiler & Accessories									
4.9	Pulverized Coal Boiler & Accessories	\$233,252	\$0	\$152,327	\$0	\$385,579	\$67,476	\$0	\$67,958	\$521,014	\$801
4.10	Selective Catalytic Reduction System	\$30,416	\$0	\$19,848	\$0	\$50,264	\$8,796	\$0	\$8,859	\$67,919	\$104
4.11	Boiler Balance of Plant	\$1,631	\$0	\$1,065	\$0	\$2,696	\$472	\$0	\$475	\$3,642	\$6
4.12	Primary Air System	\$1,700	\$0	\$1,110	\$0	\$2,810	\$492	\$0	\$495	\$3,798	\$6
4.13	Secondary Air System	\$2,575	\$0	\$1,682	\$0	\$4,257	\$745	\$0	\$750	\$5,752	\$9

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B11B.99	– SubC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
4.14	Induced Draft Fans	\$5,555	\$0	\$3,628	\$0	\$9,182	\$1,607	\$0	\$1,618	\$12,408	\$19
4.15	Major Component Rigging	\$93	\$0	\$61	\$0	\$154	\$27	\$0	\$27	\$208	\$0
4.16	Boiler Foundations	\$0	\$421	\$370	\$0	\$792	\$139	\$0	\$140	\$1,070	\$2
	Subtotal	\$275,222	\$421	\$180,091	\$0	\$455,734	\$79,753	\$0	\$80,323	\$615,810	\$947
	5 Flue Gas Cleanup										
5.1	CANSOLV Carbon Dioxide (CO ₂) Removal System	\$162,152	\$70,071	\$147,150	\$0	\$379,373	\$66,390	\$64,493	\$89,295	\$599,551	\$922
5.2	WFGD Absorber Vessels & Accessories	\$84,141	\$0	\$17,997	\$0	\$102,138	\$17,874	\$0	\$18,002	\$138,014	\$212
5.3	Other FGD	\$1,345	\$0	\$1,035	\$0	\$2,380	\$417	\$0	\$420	\$3,216	\$5
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$47,518	\$7,128	\$15,646	\$0	\$70,292	\$12,301	\$0	\$16,519	\$99,112	\$152
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$539	\$86	\$231	\$0	\$855	\$150	\$0	\$201	\$1,206	\$2
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$2,828	\$622	\$2,781	\$0	\$6,231	\$1,090	\$0	\$1,098	\$8,420	\$13
5.9	Particulate Removal (Bag House & Accessories) (included with 5.2)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5.12	Gas Cleanup Foundations	\$0	\$210	\$184	\$0	\$395	\$69	\$0	\$70	\$533	\$1
5.13	Gypsum Dewatering System	\$800	\$0	\$135	\$0	\$935	\$164	\$0	\$165	\$1,263	\$2
	Subtotal	\$299,324	\$78,117	\$185,158	\$0	\$562,599	\$98,455	\$64,493	\$125,768	\$851,316	\$1,309
	7 Ductwork & Stack										
7.3	Ductwork	\$0	\$764	\$531	\$0	\$1,294	\$227	\$0	\$228	\$1,749	\$3
7.4	Stack	\$8,849	\$0	\$5,143	\$0	\$13,991	\$2,448	\$0	\$2,466	\$18,906	\$29
7.5	Duct & Stack Foundations	\$0	\$211	\$250	\$0	\$461	\$81	\$0	\$108	\$651	\$1
	Subtotal	\$8,849	\$975	\$5,924	\$0	\$15,747	\$2,756	\$0	\$2,803	\$21,305	\$33
	8 Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	\$65,453	\$0	\$7,499	\$0	\$72,953	\$12,767	\$0	\$12,858	\$98,577	\$152
8.2	Steam Turbine Plant Auxiliaries	\$1,492	\$0	\$3,172	\$0	\$4,664	\$816	\$0	\$822	\$6,302	\$10
8.3	Condenser & Auxiliaries	\$12,309	\$0	\$4,176	\$0	\$16,486	\$2,885	\$0	\$2,906	\$22,276	\$34
8.4	Steam Piping	\$38,944	\$0	\$15,784	\$0	\$54,729	\$9,577	\$0	\$9,646	\$73,952	\$114
8.5	Turbine Generator Foundations	\$0	\$233	\$384	\$0	\$617	\$108	\$0	\$145	\$870	\$1
	Subtotal	\$118,199	\$233	\$31,016	\$0	\$149,448	\$26,153	\$0	\$26,376	\$201,978	\$311
	9 Cooling Water System										
9.1	Cooling Towers	\$20,914	\$0	\$6,468	\$0	\$27,382	\$4,792	\$0	\$4,826	\$37,000	\$57
9.2	Circulating Water Pumps	\$2,994	\$0	\$211	\$0	\$3,206	\$561	\$0	\$565	\$4,332	\$7
9.3	Circulating Water System Auxiliaries	\$17,262	\$0	\$2,284	\$0	\$19,546	\$3,421	\$0	\$3,445	\$26,412	\$41

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO
ELECTRICITY

Case: B11B.99		– SubC PC w/ CO ₂ Capture					Estimate Type:			Conceptual		
Plant Size (MW, net):		650						Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost		
				Direct	Indirect			Process	Project	\$/1,000	\$/kW	
9.4	Circulating Water Piping	\$0	\$7,983	\$7,229	\$0	\$15,212	\$2,662	\$0	\$2,681	\$20,555	\$32	
9.5	Make-up Water System	\$1,330	\$0	\$1,708	\$0	\$3,038	\$532	\$0	\$535	\$4,105	\$6	
9.6	Component Cooling Water System	\$1,244	\$0	\$955	\$0	\$2,198	\$385	\$0	\$387	\$2,970	\$5	
9.7	Circulating Water System Foundations	\$0	\$740	\$1,229	\$0	\$1,970	\$345	\$0	\$463	\$2,777	\$4	
	Subtotal	\$43,744	\$8,723	\$20,084	\$0	\$72,551	\$12,697	\$0	\$12,903	\$98,151	\$151	
	10 Ash & Spent Sorbent Handling Systems											
10.6	Ash Storage Silos	\$1,224	\$0	\$3,744	\$0	\$4,967	\$869	\$0	\$876	\$6,712	\$10	
10.7	Ash Transport & Feed Equipment	\$4,163	\$0	\$4,127	\$0	\$8,290	\$1,451	\$0	\$1,461	\$11,201	\$17	
10.9	Ash/Spent Sorbent Foundation	\$0	\$853	\$1,050	\$0	\$1,903	\$333	\$0	\$447	\$2,683	\$4	
	Subtotal	\$5,387	\$853	\$8,920	\$0	\$15,160	\$2,653	\$0	\$2,784	\$20,597	\$32	
	11 Accessory Electric Plant											
11.1	Generator Equipment	\$2,692	\$0	\$2,031	\$0	\$4,723	\$826	\$0	\$832	\$6,382	\$10	
11.2	Station Service Equipment	\$7,976	\$0	\$684	\$0	\$8,660	\$1,516	\$0	\$1,526	\$11,702	\$18	
11.3	Switchgear & Motor Control	\$12,382	\$0	\$2,148	\$0	\$14,530	\$2,543	\$0	\$2,561	\$19,634	\$30	
11.4	Conduit & Cable Tray	\$0	\$1,610	\$4,639	\$0	\$6,248	\$1,093	\$0	\$1,101	\$8,443	\$13	
11.5	Wire & Cable	\$0	\$4,263	\$7,619	\$0	\$11,882	\$2,079	\$0	\$2,094	\$16,055	\$25	
11.6	Protective Equipment	\$55	\$0	\$191	\$0	\$246	\$43	\$0	\$43	\$332	\$1	
11.7	Standby Equipment	\$832	\$0	\$768	\$0	\$1,599	\$280	\$0	\$282	\$2,161	\$3	
11.8	Main Power Transformers	\$7,076	\$0	\$144	\$0	\$7,221	\$1,264	\$0	\$1,273	\$9,757	\$15	
11.9	Electrical Foundations	\$0	\$225	\$572	\$0	\$796	\$139	\$0	\$187	\$1,123	\$2	
	Subtotal	\$31,012	\$6,097	\$18,795	\$0	\$55,905	\$9,783	\$0	\$9,900	\$75,588	\$116	
	12 Instrumentation & Control											
12.1	Pulverized Coal Boiler Control Equipment	\$818	\$0	\$146	\$0	\$963	\$169	\$0	\$170	\$1,302	\$2	
12.3	Steam Turbine Control Equipment	\$730	\$0	\$84	\$0	\$814	\$142	\$0	\$143	\$1,100	\$2	
12.5	Signal Processing Equipment	\$928	\$0	\$166	\$0	\$1,094	\$191	\$0	\$193	\$1,478	\$2	
12.6	Control Boards, Panels & Racks	\$284	\$0	\$173	\$0	\$457	\$80	\$23	\$84	\$644	\$1	
12.7	Distributed Control System Equipment	\$8,010	\$0	\$1,429	\$0	\$9,438	\$1,652	\$472	\$1,734	\$13,296	\$20	
12.8	Instrument Wiring & Tubing	\$561	\$449	\$1,795	\$0	\$2,804	\$491	\$140	\$515	\$3,951	\$6	
12.9	Other Instrumentation & Controls Equipment	\$689	\$0	\$1,596	\$0	\$2,286	\$400	\$114	\$420	\$3,220	\$5	
	Subtotal	\$12,020	\$449	\$5,388	\$0	\$17,857	\$3,125	\$749	\$3,260	\$24,991	\$38	
	13 Improvements to Site											
13.1	Site Preparation	\$0	\$463	\$9,848	\$0	\$10,311	\$1,804	\$0	\$2,423	\$14,539	\$22	
13.2	Site Improvements	\$0	\$2,293	\$3,030	\$0	\$5,324	\$932	\$0	\$1,251	\$7,507	\$12	
13.3	Site Facilities	\$2,621	\$0	\$2,749	\$0	\$5,370	\$940	\$0	\$1,262	\$7,572	\$12	
	Subtotal	\$2,621	\$2,757	\$15,628	\$0	\$21,005	\$3,676	\$0	\$4,936	\$29,617	\$46	
	14 Buildings & Structures											

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B11B.99	– SubC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
14.2	Boiler Building	\$0	\$11,588	\$10,183	\$0	\$21,771	\$3,810	\$0	\$3,837	\$29,418	\$45
14.3	Steam Turbine Building	\$0	\$16,106	\$15,001	\$0	\$31,107	\$5,444	\$0	\$5,483	\$42,033	\$65
14.4	Administration Building	\$0	\$1,046	\$1,106	\$0	\$2,152	\$377	\$0	\$379	\$2,909	\$4
14.5	Circulation Water Pump House	\$0	\$197	\$156	\$0	\$354	\$62	\$0	\$62	\$478	\$1
14.6	Water Treatment Buildings	\$0	\$494	\$451	\$0	\$945	\$165	\$0	\$167	\$1,277	\$2
14.7	Machine Shop	\$0	\$553	\$371	\$0	\$923	\$162	\$0	\$163	\$1,248	\$2
14.8	Warehouse	\$0	\$415	\$416	\$0	\$831	\$145	\$0	\$146	\$1,123	\$2
14.9	Other Buildings & Structures	\$0	\$291	\$248	\$0	\$539	\$94	\$0	\$95	\$728	\$1
14.10	Waste Treating Building & Structures	\$0	\$646	\$1,960	\$0	\$2,606	\$456	\$0	\$459	\$3,522	\$5
	Subtotal	\$0	\$31,336	\$29,893	\$0	\$61,228	\$10,715	\$0	\$10,792	\$82,735	\$127
	Total	\$918,965	\$147,526	\$565,971	\$0	\$1,632,461	\$285,681	\$65,243	\$321,356	\$2,304,741	\$3,543

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-13. Case B11B.99 owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$13,695	\$21
1 Month Maintenance Materials	\$2,169	\$3
1 Month Non-Fuel Consumables	\$3,571	\$5
1 Month Waste Disposal	\$1,022	\$2
25% of 1 Months Fuel Cost at 100% CF	\$3,090	\$5
2% of TPC	\$46,095	\$71
Total	\$69,642	\$107
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	\$30,994	\$48
0.5% of TPC (spare parts)	\$11,524	\$18
Total	\$42,518	\$65
Other Costs		
Initial Cost for Catalyst and Chemicals	\$2,823	\$4
Land	\$900	\$1
Other Owner's Costs	\$345,711	\$531
Financing Costs	\$62,228	\$96
Total Overnight Costs (TOC)	\$2,828,562	\$4,349
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	\$3,265,325	\$5,020

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-14. Case B11B.99 initial and annual operating and maintenance costs

Case:	B11B.99	– SubC PC w/ CO ₂ Capture		Cost Base:	Dec 2018
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):	11,691	Capacity Factor (%):	85
Operating & Maintenance Labor					
Operating Labor			Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	2.0
Operating Labor Burden:		30.00	% of base	Operator:	11.3
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0
				Lab Techs, etc.:	2.0
				Total:	16.3
Fixed Operating Costs					
				Annual Cost	
				(\$)	(\$/kW-net)
Annual Operating Labor:				\$7,161,008	\$11.009
Maintenance Labor:				\$14,750,341	\$22.677
Administrative & Support Labor:				\$5,477,837	\$8.421
Property Taxes and Insurance:				\$46,094,817	\$70.865
Total:				\$73,484,003	\$112.972
Variable Operating Costs					
				(\$)	(\$/MWh-net)
Maintenance Material:				\$22,125,512	\$4.56825
Consumables					
	Initial Fill	Per Day	Per Unit	Initial Fill	
Water (/1000 gallons):	0	7,540	\$1.90	\$0	\$4,444,730
Makeup and Waste Water Treatment Chemicals (ton):	0	22.5	\$550.00	\$0	\$3,832,697
Brominated Activated Carbon (ton):	0	1.71	\$1,600.00	\$0	\$849,536
Enhanced Hydrated Lime (ton):	0	43.1	\$240.00	\$0	\$3,206,247
Limestone (ton):	0	757	\$22.00	\$0	\$5,164,524
Ammonia (19 wt%, ton):	0	75.8	\$300.00	\$0	\$7,057,930
SCR Catalyst (ft ³):	18,817	17.2	\$150.00	\$2,822,500	\$799,708
CO ₂ Capture System Chemicals ^A :	Proprietary			\$9,567,510	\$1.97540
Triethylene Glycol (gal):	w/equip.	712	\$6.80	\$0	\$1,501,744
Subtotal:				\$2,822,500	\$36,424,624
Waste Disposal					
Fly Ash (ton)	0	710	\$38.00	\$0	\$8,368,922
Bottom Ash (ton)	0	158	\$38.00	\$0	\$1,858,966
SCR Catalyst (ft ³):	0	17.2	\$2.50	\$0	\$13,328
Triethylene Glycol (gal):	0	712	\$0.35	\$0	\$77,296
Thermal Reclaimer Unit Waste (ton):	0	8.77	\$38.00	\$0	\$103,432
Subtotal:				\$0	\$10,421,944
By-Products					
Gypsum (ton)	0	1150	\$0.00	\$0	\$0
Subtotal:				\$0	\$0
Variable Operating Costs Total:				\$2,822,500	\$68,972,080
Fuel Cost					
Illinois Number 6 (ton):	0	7,822	\$51.96	\$0	\$126,090,124
Total:				\$0	\$126,090,124

^ACO₂ Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit A-15. Case B11B.99 LCOE breakdown

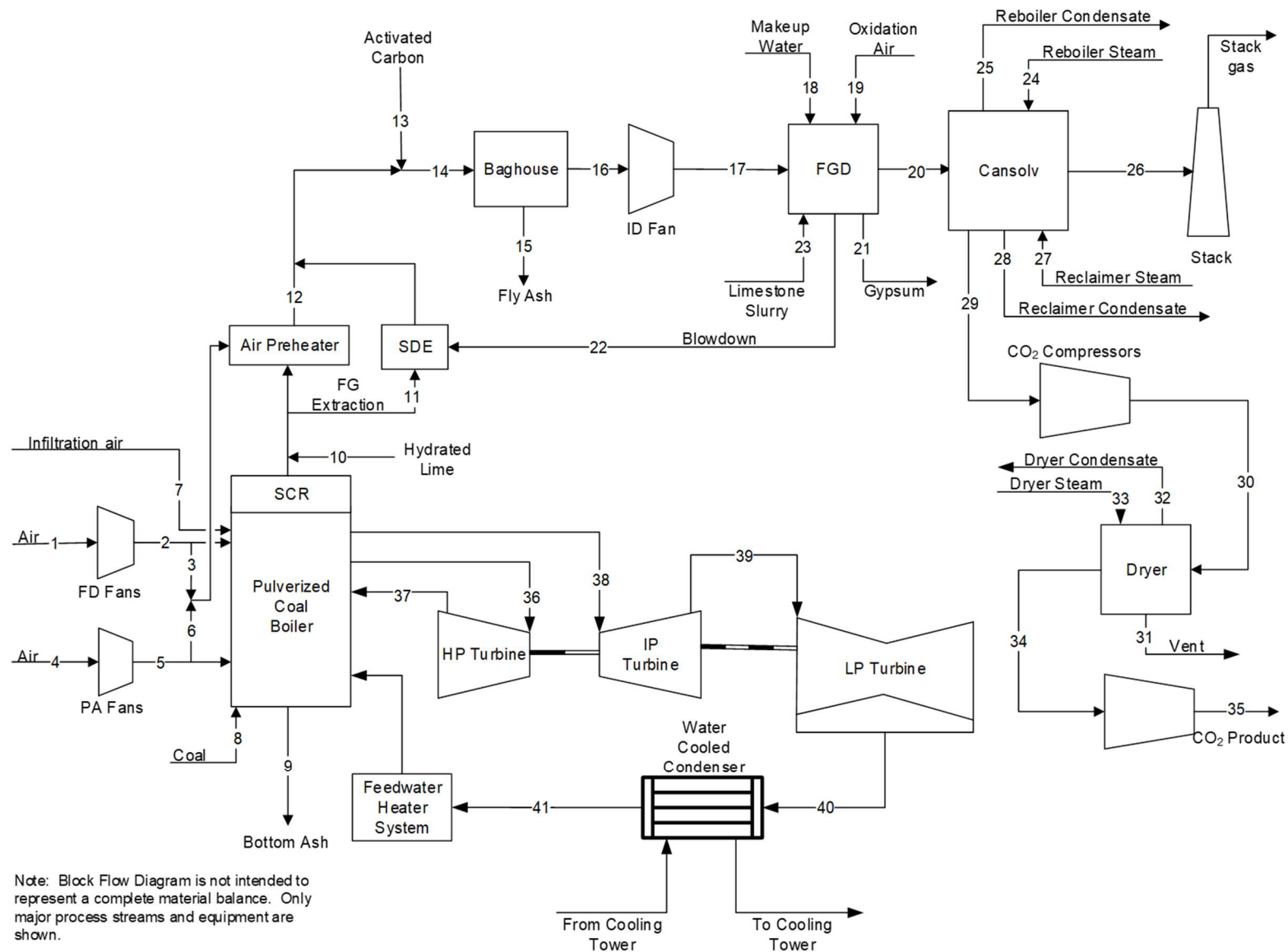
Component	Value, \$/MWh	Percentage
Capital	47.7	42%
Fixed	15.2	13%
Variable	14.2	13%
Fuel	26.0	23%
Total (Excluding T&S)	103.1	N/A
CO ₂ T&S	10.6	9%
Total (Including T&S)	113.8	N/A

A.2 CASE B12B.99 – SC PC WITH 99 PERCENT CO₂ CAPTURE PROCESS DESCRIPTION

The plant configuration and process description for Case B12B.99 are nearly the same as Case B12B.90, with the exception of 99 percent capture. Since the process descriptions of the plant and CDR facility were provided in Section 4.3.3 and Section 4.1.8, respectively, they are not repeated here.

The BFD for Case B12B.99 is shown in Exhibit A-16. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit A-17. The modeling assumptions were presented previously in Section 4.3.1.

Exhibit A-16. Case B12B.99 block flow diagram, SC unit with CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-17. Case B12B.99 stream table, SC unit with capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0087	0.0088	0.0000	0.0087	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379	0.0000	0.1372	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837	0.0000	0.0911	0.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340	0.0000	0.7281	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336	0.0000	0.0329	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020	0.0000	0.0020	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1158
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.8842
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	76,638	76,638	2,270	23,542	23,542	3,240	1,694	0	0	1	5,050	102,446	0	108,352	7
V-L Flowrate (kg/hr)	2,211,534	2,211,534	65,503	679,360	679,360	93,497	48,883	0	0	15	150,200	3,042,064	0	3,208,088	693
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	281,106	5,667	1,532	1,213	23,286	62	24,801	24,818
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143	15	143	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	13,402.95	-2,261.17	-2,394.31	-6.79	-2,453.14	-1,065.96
Density (kg/m ³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8	---	0.8	2,150.2
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694	---	29.608	104.898
V-L Flowrate (lb _{mol} /hr)	168,957	168,957	5,004	51,902	51,902	7,143	3,735	0	0	2	11,134	225,855	0	238,875	15
V-L Flowrate (lb/hr)	4,875,597	4,875,597	144,409	1,497,732	1,497,732	206,125	107,768	0	0	34	331,134	6,706,604	0	7,072,624	1,528
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	619,732	12,493	3,378	2,674	51,336	136	54,677	54,714
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289	59	289	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1	14.7	14.1	14.1
Steam Table Enthalpy (Btu/lb) ^A	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4	-2.9	-1,054.7	-458.3
Density (lb/ft ³)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052	---	0.052	134.232

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-17. Case B12B.99 stream table, SC unit with capture (continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0103	0.0000	0.0000	0.0000	0.0000
CO ₂	0.1372	0.1372	0.0000	0.0003	0.1245	0.0001	0.0000	0.0000	0.0000	0.0000	0.0016	0.0000	0.0000	0.9783	0.9975
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0911	0.0911	0.9999	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000	1.0000	0.0807	1.0000	1.0000	0.0217	0.0025
HCl	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000	0.0000	0.8614	0.0000	0.0000	0.0000	0.0000
O ₂	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000	0.0000	0.0460	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0001	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	108,345	108,345	6,330	4,535	121,121	255	856	3,525	38,969	35,691	95,654	399	399	15,252	14,958
V-L Flowrate (kg/hr)	3,207,378	3,207,378	114,053	130,878	3,481,034	4,595	15,824	63,521	702,030	642,985	2,634,187	7,179	7,179	662,628	657,333
Solids Flowrate (kg/hr)	0	0	0	0	0	41,332	241	27,192	0	0	0	0	0	0	0
Temperature (°C)	143	156	15	15	57	15	57	15	269	105	45	342	214	31	29
Pressure (MPa, abs)	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.48	0.12	0.10	4.90	2.04	0.17	2.81
Steam Table Enthalpy (kJ/kg) ^A	287.58	302.09	-47.80	30.23	297.00	---	---	---	3,000.14	439.34	179.65	3,049.81	913.81	46.68	-3.05
AspenPlus Enthalpy (kJ/kg) ^B	-2,464.17	-2,449.66	-16,015.01	-97.58	-2,939.24	-12,513.34	-15,496.21	-14,994.25	-12,980.15	-15,540.95	-710.95	-12,930.48	-15,066.49	-8,978.62	-8,972.51
Density (kg/m ³)	0.8	0.9	1,003.7	1.2	1.1	878.3	979.4	1,003.7	2.0	954.9	1.1	19.2	848.5	3.0	57.8
V-L Molecular Weight	29.603	29.603	18.019	28.857	28.740	18.021	18.494	18.019	18.015	18.015	27.539	18.015	18.015	43.445	43.945
V-L Flowrate (lb _{mol} /hr)	238,860	238,860	13,955	9,999	267,025	562	1,886	7,772	85,911	78,685	210,881	879	879	33,625	32,977
V-L Flowrate (lb/hr)	7,071,059	7,071,059	251,444	288,537	7,674,367	10,130	34,886	140,041	1,547,711	1,417,540	5,807,389	15,828	15,828	1,460,845	1,449,170
Solids Flowrate (lb/hr)	0	0	0	0	0	91,121	531	59,949	0	0	0	0	0	0	0
Temperature (°F)	289	313	59	59	135	59	135	59	516	221	113	648	416	87	85
Pressure (psia)	13.9	15.3	14.7	14.7	14.8	14.7	14.7	14.7	70.0	17.4	14.8	710.8	296.6	24.7	407.6
Steam Table Enthalpy (Btu/lb) ^A	123.6	129.9	-20.5	13.0	127.7	---	---	---	1,289.8	188.9	77.2	1,311.2	392.9	20.1	-1.3
AspenPlus Enthalpy (Btu/lb) ^B	-1,059.4	-1,053.2	-6,885.2	-42.0	-1,263.6	-5,379.8	-6,662.2	-6,446.4	-5,580.5	-6,681.4	-305.7	-5,559.1	-6,477.4	-3,860.1	-3,857.5
Density (lb/ft ³)	0.051	0.055	62.658	0.076	0.067	54.833	61.145	62.658	0.122	59.612	0.066	1.197	52.968	0.184	3.609

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-17. Case B12B.99 stream table, SC unit with capture (continued)

	31	32	33	34	35	36	37	38	39	40	41
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0500	0.0000	0.0000	0.9995	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	31	19	19	14,927	14,927	137,466	114,524	114,524	98,617	39,687	63,202
V-L Flowrate (kg/hr)	606	350	350	656,726	656,726	2,476,484	2,063,176	2,063,176	1,776,620	714,965	1,138,608
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	29	203	461	29	30	593	342	593	270	38	39
Pressure (MPa, abs)	2.81	1.64	2.14	2.68	15.27	24.23	4.90	4.80	0.52	0.01	1.26
Steam Table Enthalpy (kJ/kg) ^A	137.94	863.65	3,379.61	-3.59	-231.09	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.36
AspenPlus Enthalpy (kJ/kg) ^B	-15,225.22	-15,116.65	-12,600.69	-8,967.15	-9,194.65	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.93
Density (kg/m ³)	351.5	861.8	6.4	54.7	630.1	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	19.315	18.015	18.015	43.997	43.997	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	69	43	43	32,908	32,908	303,060	252,481	252,481	217,414	87,494	139,337
V-L Flowrate (lb/hr)	1,336	771	771	1,447,834	1,447,834	5,459,713	4,548,524	4,548,524	3,916,776	1,576,229	2,510,200
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	85	397	862	85	86	1,100	648	1,100	517	101	101
Pressure (psia)	407.6	237.4	310.1	389.1	2,214.7	3,514.7	710.8	696.6	75.0	1.0	183.1
Steam Table Enthalpy (Btu/lb) ^A	59.3	371.3	1,453.0	-1.5	-99.4	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb) ^B	-6,545.7	-6,499.0	-5,417.3	-3,855.2	-3,953.0	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft ³)	21.943	53.801	0.402	3.416	39.338	4.319	1.197	0.768	0.131	0.003	62.009

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

A.2.1 Case B12B.99 – Performance Results

Overall plant performance is summarized in Exhibit A-18; Exhibit A-19 provides a detailed breakdown of the auxiliary power requirements.

The CDR facility, including CO₂ compression, accounts for over half of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for over 12 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility and CO₂ compressors.

Unlike the NGCC cases where gross output was fixed by the available size of the CTs, the PC cases utilize boilers and steam turbines that can be procured at nearly any desired output. By increasing the boiler and turbine/generator size to account for the greater auxiliary load imposed by the CDR facility and CO₂ compressors, a net output of 650 MW is maintained at a reduced net plant efficiency of 30.7 percent (HHV basis).

Exhibit A-18. Case B12B.99 plant performance summary

Performance Summary	
Total Gross Power, MWe	774
CO ₂ Capture/Removal Auxiliaries, kWe	20,800
CO ₂ Compression, kWe	52,580
Balance of Plant, kWe	49,900
Total Auxiliaries, MWe	123
Net Power, MWe	650
HHV Net Plant Efficiency, %	30.7
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,728 (11,116)
LHV Net Plant Efficiency, %	31.8
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,311 (10,721)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	59.1
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	6,096 (5,777)
Condenser Duty, GJ/hr (MMBtu/hr)	2,017 (1,912)
CO ₂ Capture Rate, %	99
AGR Duty, GJ/hr (MMBtu/hr)	2,323 (2,202)
As-Received Coal Feed, kg/hr (lb/hr)	281,106 (619,732)
Limestone Sorbent Feed, kg/hr (lb/hr)	27,192 (59,949)
HHV Thermal Input, kWt	2,118,843
LHV Thermal Input, kWt	2,043,650
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.057 (15.0)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.042 (11.1)
Excess Air, %	20.3

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-19. Case B12B.99 plant power summary

Power Summary	
Steam Turbine Power, MWe	774
Total Gross Power, MWe	774
Auxiliary Load Summary	
Activated Carbon Injection, kWe	40
Ash Handling, kWe	920
Baghouse, kWe	120
Circulating Water Pumps, kWe	9,460
CO ₂ Capture/Removal Auxiliaries, kWe	20,800
CO ₂ Compression, kWe	52,580
Coal Handling and Conveying, kWe	540
Condensate Pumps, kWe	810
Cooling Tower Fans, kWe	4,890
Dry Sorbent Injection, kWe	80
Flue Gas Desulfurizer, kWe	4,340
Forced Draft Fans, kWe	1,440
Ground Water Pumps, kWe	880
Induced Draft Fans, kWe	13,330
Miscellaneous Balance of Plant ^{A,B} , kWe	2,250
Primary Air Fans, kWe	1,710
Pulverizers, kWe	4,210
SCR, kWe	50
Sorbent Handling & Reagent Preparation, kWe	1,310
Spray Dryer Evaporator, kWe	310
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,710
Total Auxiliaries, MWe	123
Net Power, MWe	650

^ABoiler feed pumps are turbine driven

^BIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

A.2.1.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 2.3. A summary of the plant air emissions for Case B12B.99 is presented in Exhibit A-20. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit A-20. Case B12B.99 air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.032 (0.075)	1,829 (2,016)	0.318 (0.700)
Particulate	0.004 (0.010)	235 (259)	0.041 (0.090)
Hg	1.38E-7 (3.21E-7)	0.008 (0.009)	1.36E-6 (3.00E-6)
CO ₂	1 (2)	50,886 (56,092)	9 (19)
CO ₂ ^C	—	—	11 (23)
mg/Nm ³			
Particulate Concentration ^{D,E}	13.01		

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

^DConcentration of particles in the flue gas after the baghouse

^ENormal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The SO₂ emissions are further reduced to 0.37 ppmv using a NaOH based polishing scrubber in the CDR facility. The remaining low concentration of SO₂ is essentially completely removed in the CDR absorber vessel resulting in very low SO₂ emissions (reported as zero here).

NO_x emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 78.6 percent to 0.03 kg/GJ (0.08 lb/MMBtu).

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and wet FGD) is 97.5 percent.

Ninety-nine percent of the CO₂ in the flue gas is removed in CDR facility.

The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD. Carbon leaves the plant mostly as CO₂ product from the CO₂ compression train; however, some CO₂ exits through the stack, the PAC is captured in the fabric filter, unburned carbon remains in the bottom ash, and some leaves as gypsum. The

carbon balance is given in Exhibit A-21. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in (minus unburnt carbon in the ash), represented by the following fraction:

$$1 - \frac{\text{Carbon in Stack}}{\text{Total Carbon In} - \text{Unburnt Carbon}} = \left(1 - \left(\frac{4,112}{402,186 - 474} \right) \right) * 100 = 99\%$$

Exhibit A-21. Case B12B.99 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	179,190 (395,046)	Stack Gas	1,865 (4,112)
Air (CO ₂)	418 (921)	FGD Product	212 (468)
PAC	62 (136)	Baghouse	922 (2,032)
FGD Reagent	2,759 (6,083)	Bottom Ash	215 (474)
		CO ₂ Product	179,195 (395,057)
		CO ₂ Dryer Vent	19 (42)
		CO ₂ Knockout	0.5 (1.1)
Total	182,428 (402,186)	Total	182,428 (402,186)

Exhibit A-22 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur emitted in the stack gas, and sulfur removed in the polishing scrubber.

Exhibit A-22. Case B12B.99 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	7,046 (15,533)	FGD Product	6,624 (14,604)
		Stack Gas	0 (0)
		Polishing Scrubber and Solvent Reclaiming	138 (303)
		Baghouse	284 (626)
Total	7,046 (15,533)	Total	7,046 (15,533)

Exhibit A-23 shows the overall water balance for the plant. The exhibit is presented in an identical manner as for Case B12A. The only notable difference is the FGD makeup water source. In CO₂ capture cases, a significant amount of water is recovered from the initial CDR facility cooling step. This water would otherwise be discharged; however, it is suitable to be used as FGD makeup. The balance of the water from the CDR facility is sent to discharge.

Exhibit A-23. Case B12B.99 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
FGD Process Makeup	1.9 (503)	1.9 (503)	–	–	–
FGD Slurry Water	1.1 (280)	1.1 (280)	–	–	–
CO ₂ Drying	–	–	–	0.0 (2.7)	0.0 (-2.7)
CO ₂ Capture Recovery	–	–	–	1.1 (288)	-1.1 (-288)
CO ₂ Compression KO	–	–	–	0.1 (23)	-0.1 (-23)
Deaerator Vent	–	–	–	0.1 (22)	-0.1 (-22)
Condenser Makeup	0.1 (22)	–	0.1 (22)	–	0.1 (22)
BFW Makeup	0.1 (22)	–	0.1 (22)	–	0.1 (22)
Cooling Tower	37 (9,735)	–	37 (9,735)	8.3 (2,189)	29 (7,546)
BFW Blowdown	–	–	–	–	–
Total	40 (10,540)	3.0 (783)	37 (9,757)	9.6 (2,526)	27 (7,231)

A.2.1.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for the Case B12B.99 PC boiler, the FGD unit, CDR system, and steam cycle in Exhibit A-24 and Exhibit A-25. An overall plant energy balance is provided in tabular form in Exhibit A-26.

The power out is the steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by a generator efficiency of 98.5 percent. The cooling tower load includes the condenser, capture process heat rejected to cooling water, the CO₂ compressor intercooler load, and other miscellaneous cooling loads.

This page intentionally left blank

Exhibit A-24. Case B12B.99 energy and mass balance, SC PC boiler with CO₂ capture

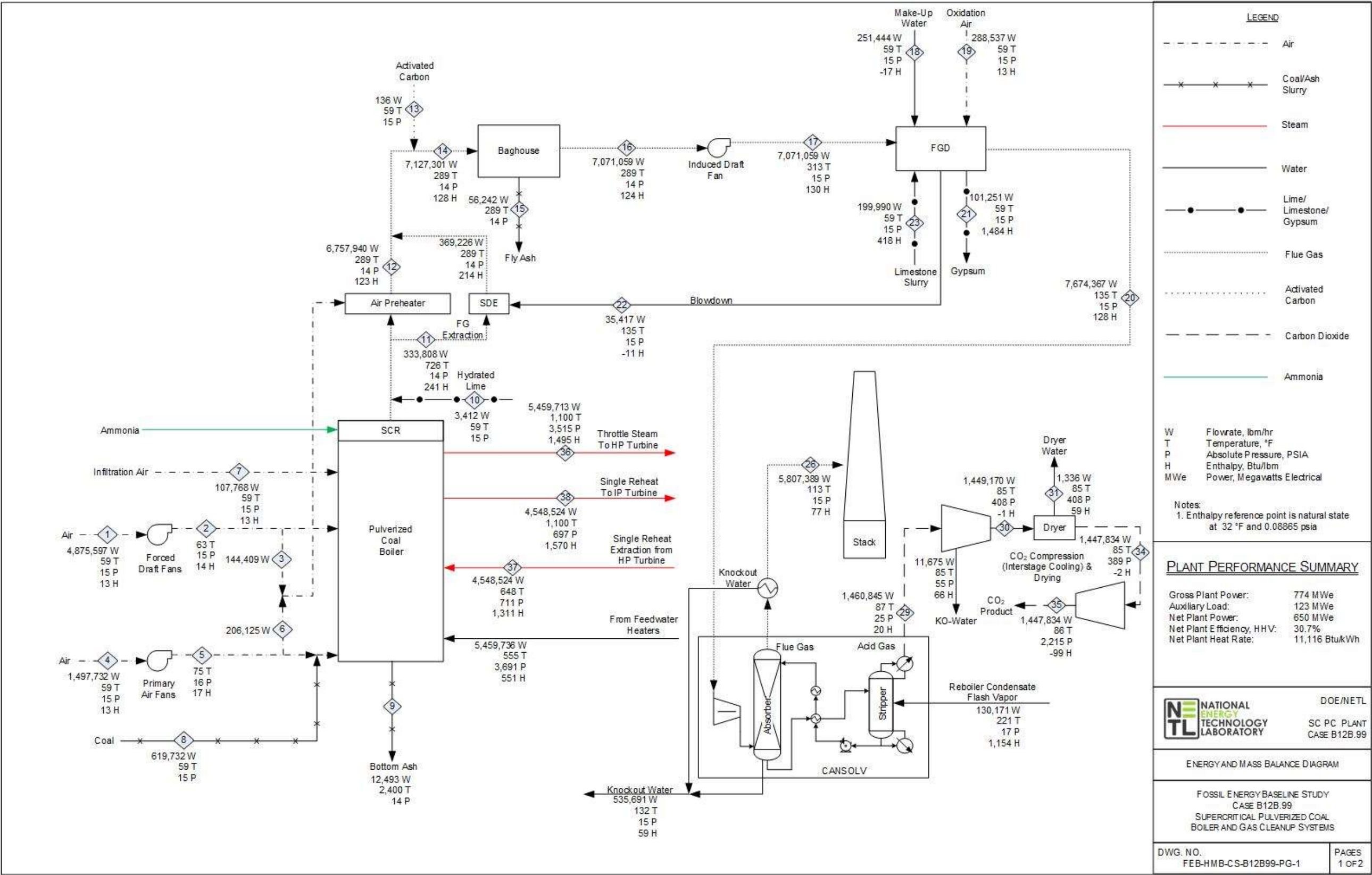


Exhibit A-25. Case B12B.99 energy and mass balance, SC steam cycle

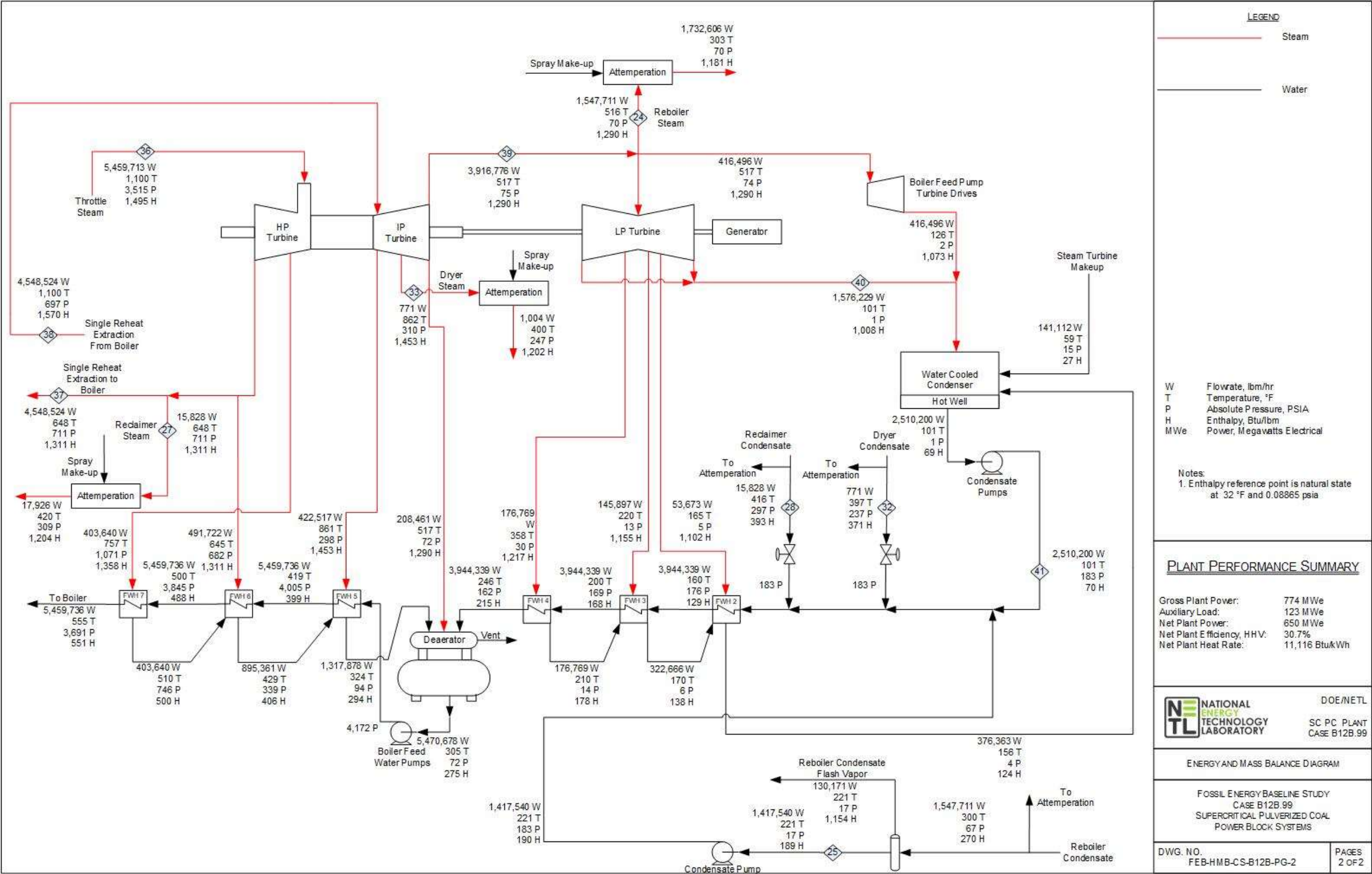


Exhibit A-26. Case B12B.99 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	7,628 (7,230)	6.4 (6.0)	—	7,634 (7,236)
Air	—	89 (84)	—	89 (84)
Raw Water Makeup	—	139 (132)	—	139 (132)
Limestone	—	0.6 (0.6)	—	0.6 (0.6)
Auxiliary Power	—	—	444 (421)	444 (421)
TOTAL	7,628 (7,230)	235 (222)	444 (421)	8,306 (7,873)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	—	7.2 (6.8)	—	7.2 (6.8)
Fly Ash	—	2.6 (2.5)	—	2.6 (2.5)
Stack Gas	—	473 (449)	—	473 (449)
Sulfur	2.6 (2.4)	0.0 (0.0)	—	2.6 (2.4)
Gypsum	—	2.7 (2.5)	—	2.7 (2.5)
Motor Losses and Design Allowances	—	—	51 (49)	51 (49)
Cooling Tower Load ^A	—	4,812 (4,561)	—	4,812 (4,561)
CO ₂ Product Stream	—	-152 (-144)	—	-152 (-144)
AGR Effluent	—	56 (53)	—	56 (53)
Blowdown Streams and Deaerator Vent	—	3.1 (3.0)	—	3.1 (3.0)
<i>Ambient Losses^B</i>	—	180 (171)	—	180 (171)
Power	—	—	2,785 (2,640)	2,785 (2,640)
TOTAL	2.6 (2.4)	5,386 (5,105)	2,837 (2,689)	8,226 (7,796)
<i>Unaccounted Energy^C</i>	—	81 (76)	—	81 (76)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^CBy difference

A.2.2 Case B12B.99 – Major Equipment List

Major equipment items for the SC PC plant with CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.3.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B12B.99 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	60 tonne (60 ton)	2	1
9	Feeder	Vibratory	230 tonne/hr (260 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	460 tonne/hr (510 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	230 tonne (260 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	460 tonne/hr (510 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	460 tonne/hr (510 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,030 tonne (1,140 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 11 tonne (13 ton) Feeder - 70 kg/hr (150 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 290 tonne (320 ton) Feeder - 1,700 kg/hr (3,750 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	114 tonne/hr (126 tph)	1	0
23	Limestone Conveyor No. 1	Belt	114 tonne/hr (126 tph)	1	0
24	Limestone Reclaim Hopper	N/A	22 tonne (25 ton)	1	0
25	Limestone Reclaim Feeder	Belt	90 tonne/hr (99 tph)	1	0
26	Limestone Conveyor No. 2	Belt	90 tonne/hr (99 tph)	1	0
27	Limestone Day Bin	w/ actuator	359 tonne (396 ton)	2	0

Case B12B.99 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	52 tonne/hr (57 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	52 tonne/hr (57 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	30 tonne/hr (33 tph)	1	1
4	Limestone Ball Mill	Rotary	30 tonne/hr (33 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	116,000 liters (30,600 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,950 lpm @ 10m H ₂ O (510 gpm @ 40 ft H ₂ O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5-cyclone bank	490 lpm (130 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	647,000 liters (171,000 gal)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,350 lpm @ 9m H ₂ O (360 gpm @ 30 ft H ₂ O)	1	1

Case B12B.99 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	328,000 liters (86,700 gal)	2	0
2	Condensate Pumps	Vertical canned	10,500 lpm @ 200 m H ₂ O (2,780 gpm @ 500 ft H ₂ O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,365,000 kg/hr (3,009,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	23,000 lpm @ 3,500 m H ₂ O (6,000 gpm @ 11,400 ft H ₂ O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	6,800 lpm @ 3,500 m H ₂ O (1,800 gpm @ 11,400 ft H ₂ O)	2	0
6	LP Feedwater Heater 2A/2B	Horizontal U-tube	490,000 kg/hr (1,080,000 lb/hr)	4	0
7	LP Feedwater Heater 3A/3B	Horizontal U-tube	490,000 kg/hr (1,080,000 lb/hr)	4	0
8	LP Feedwater Heater 4A/4B	Horizontal U-tube	490,000 kg/hr (1,080,000 lb/hr)	4	0
9	HP Feedwater Heater 5	Horizontal U-tube	1,360,000 kg/hr (3,000,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	1,360,000 kg/hr (3,000,000 lb/hr)	2	0
11	HP Feedwater Heater 7	Horizontal U-tube	1,360,000 kg/hr (3,000,000 lb/hr)	2	0
12	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
13	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
14	Service Air Compressors	Flooded Screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H ₂ O (5,500 gpm @ 100 ft H ₂ O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	9,900 lpm @ 20 m H ₂ O (2,610 gpm @ 60 ft H ₂ O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	3,950 lpm @ 270 m H ₂ O (1,040 gpm @ 880 ft H ₂ O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	1,200 lpm @ 50 m H ₂ O (320 gpm @ 160 ft H ₂ O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,159,000 liter (306,200 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO	330 lpm (90 gpm)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
		membrane assembly, electrodeionization unit			
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,590 m ³ /min (91,400 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 150 lpm (40 gpm) @ 19,982 ppmw Cl ⁻	2	1

Case B12B.99 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, once-through, wall-fired, low NOx burners, overfire air	2,720,000 kg/hr steam @ 24.1 MPa/593°C/593°C (6,010,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	374,000 kg/hr, 5,100 m ³ /min @ 101 cm WG (824,000 lb/hr, 180,100 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,216,000 kg/hr, 16,600 m ³ /min @ 26 cm WG (2,682,000 lb/hr, 586,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,764,000 kg/hr, 35,700 m ³ /min @ 114 cm WG (3,889,000 lb/hr, 1,262,000 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,340,000 kg/hr (7,360,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	130 m ³ /min @ 108 cm WG (4,500 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	142,000 liter (37,400 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	27 lpm @ 90 m H ₂ O (7 gpm @ 300 ft H ₂ O)	2	1

Case B12B.99 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,764,000 kg/hr (3,890,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	59,800 m ³ /min (2,110,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	208,000 lpm @ 65 m H ₂ O (54,900 gpm @ 210 ft H ₂ O)	5	1
4	Bleed Pumps	Horizontal centrifugal	5,740 lpm (1,520 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	980 m ³ /min @ 0.3 MPa (34,690 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,440 lpm (380 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	45 tonne/hr (50 tph) of 50 wt % slurry	2	1
9	Filtrate Water	Horizontal centrifugal	870 lpm @ 13 m H ₂ O (230 gpm @ 40 ft H ₂ O)	1	1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
	Return Pumps				
10	Filtrate Water Return Storage Tank	Vertical, lined	570,000 lpm (150,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	2,090 lpm @ 21 m H ₂ O (550 gpm @ 70 ft H ₂ O)	1	1
12	Activated Carbon Injectors	---	70 kg/hr (150 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,700 kg/hr (3,750 lb/hr)	1	0
14	CANSOLV	Amine-based CO ₂ capture technology	3,829,000 kg/hr (8,442,000 lb/hr) 19.1 wt % CO ₂ concentration	1	0
15	CANSOLV LP Condensate Pump	Centrifugal	1,540 lpm @ 1 m H ₂ O (407 gpm @ 3 ft H ₂ O)	1	1
16	CANSOLV IP Condensate Pump	Centrifugal	17 lpm @ 4.6 m H ₂ O (5 gpm @ 15 ft H ₂ O)	1	1
17	CO ₂ Dryer	Triethylene glycol	Inlet: 190 m ³ /min @ 2.8 MPa (6,692 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Recovered: 606 kg/hr (1,336 lb/hr)	1	0
18	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	10.0 m ³ /min @ 15.3 MPa, 82°C (337 acfm @ 2,217 psia, 180°F)	2	0
19	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 103 GJ/hr (98 MMBtu/hr)	1	0

Case B12B.99 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.3 m (21 ft) diameter	1	0

Case B12B.99 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	814 MW 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	900 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,110 GJ/hr (2,100 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B12B.99 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	950,000 lpm @ 30 m (251,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 5,290 GJ/hr (5,020 MMBtu/hr) heat duty	1	0

Case B12B.99 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	6.2 tonne/hr (6.9 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	25 m ³ /min @ 0.2 MPa (890 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,650 tonne (1,820 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	150 tonne/hr (170 tph)	1	0

Case B12B.99 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 29 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 55 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 20 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B12B.99 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

A.2.3 Case B12B.99 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit A-27 shows a detailed breakdown of the capital costs; Exhibit A-28 shows the owner's costs, TOC, and TASC; Exhibit A-29 shows the initial and annual O&M costs; and Exhibit A-30 shows the LCOE breakdown.

The estimated TPC of the SC PC boiler with CO₂ capture is \$3,596/kW. Process contingency represents 2.7 percent of the TPC and project contingency represents 13.9 percent. The LCOE, including CO₂ T&S costs of \$10.1/MWh, is \$112.4/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-27. Case B12B.99 total plant cost details

Case:		B12B.99	– SC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1		Coal & Sorbent Handling									
1.1	Coal Receive & Unload	\$1,196	\$0	\$539	\$0	\$1,735	\$304	\$0	\$306	\$2,345	\$4
1.2	Coal Stackout & Reclaim	\$3,927	\$0	\$878	\$0	\$4,805	\$841	\$0	\$847	\$6,493	\$10
1.3	Coal Conveyors	\$36,189	\$0	\$8,607	\$0	\$44,796	\$7,839	\$0	\$7,895	\$60,531	\$93
1.4	Other Coal Handling	\$5,028	\$0	\$1,057	\$0	\$6,085	\$1,065	\$0	\$1,072	\$8,222	\$13
1.5	Sorbent Receive & Unload	\$230	\$0	\$69	\$0	\$299	\$52	\$0	\$53	\$404	\$1
1.6	Sorbent Stackout & Reclaim	\$1,683	\$0	\$304	\$0	\$1,988	\$348	\$0	\$350	\$2,686	\$4
1.7	Sorbent Conveyors	\$2,551	\$555	\$617	\$0	\$3,724	\$652	\$0	\$656	\$5,032	\$8
1.8	Other Sorbent Handling	\$123	\$29	\$63	\$0	\$215	\$38	\$0	\$38	\$290	\$0
1.9	Coal & Sorbent Handling Foundations	\$0	\$1,661	\$2,190	\$0	\$3,851	\$674	\$0	\$679	\$5,204	\$8
	Subtotal	\$50,928	\$2,245	\$14,325	\$0	\$67,498	\$11,812	\$0	\$11,896	\$91,207	\$140
2		Coal & Sorbent Preparation & Feed									
2.1	Coal Crushing & Drying	\$2,574	\$0	\$494	\$0	\$3,068	\$537	\$0	\$541	\$4,146	\$6
2.2	Prepared Coal Storage & Feed	\$8,663	\$0	\$1,865	\$0	\$10,529	\$1,842	\$0	\$1,856	\$14,227	\$22
2.5	Sorbent Preparation Equipment	\$1,133	\$49	\$232	\$0	\$1,414	\$247	\$0	\$249	\$1,911	\$3
2.6	Sorbent Storage & Feed	\$1,899	\$0	\$716	\$0	\$2,615	\$458	\$0	\$461	\$3,534	\$5
2.9	Coal & Sorbent Feed Foundation	\$0	\$752	\$659	\$0	\$1,411	\$247	\$0	\$249	\$1,906	\$3
	Subtotal	\$14,269	\$801	\$3,967	\$0	\$19,037	\$3,331	\$0	\$3,355	\$25,724	\$40
3		Feedwater & Miscellaneous BOP Systems									
3.1	Feedwater System	\$4,059	\$6,959	\$3,479	\$0	\$14,497	\$2,537	\$0	\$2,555	\$19,590	\$30
3.2	Water Makeup & Pretreating	\$8,159	\$816	\$4,624	\$0	\$13,599	\$2,380	\$0	\$3,196	\$19,174	\$29
3.3	Other Feedwater Subsystems	\$3,188	\$1,045	\$993	\$0	\$5,226	\$915	\$0	\$921	\$7,062	\$11
3.4	Service Water Systems	\$2,585	\$4,936	\$15,983	\$0	\$23,504	\$4,113	\$0	\$5,523	\$33,141	\$51
3.5	Other Boiler Plant Systems	\$789	\$287	\$717	\$0	\$1,793	\$314	\$0	\$316	\$2,423	\$4
3.6	Natural Gas Pipeline and Start-Up System	\$3,392	\$146	\$109	\$0	\$3,647	\$638	\$0	\$643	\$4,929	\$8
3.7	Waste Water Treatment Equipment	\$13,502	\$0	\$8,276	\$0	\$21,778	\$3,811	\$0	\$5,118	\$30,707	\$47
3.8	Spray Dryer Evaporator	\$17,322	\$0	\$10,029	\$0	\$27,351	\$4,786	\$0	\$6,427	\$38,564	\$59
3.9	Miscellaneous Plant Equipment	\$227	\$30	\$115	\$0	\$372	\$65	\$0	\$88	\$525	\$1
	Subtotal	\$53,225	\$14,218	\$44,325	\$0	\$111,768	\$19,559	\$0	\$24,787	\$156,114	\$240
4		Pulverized Coal Boiler & Accessories									
4.9	Pulverized Coal Boiler & Accessories	\$274,416	\$0	\$156,361	\$0	\$430,776	\$75,386	\$0	\$75,924	\$582,087	\$895
4.10	Selective Catalytic Reduction System	\$30,895	\$0	\$17,642	\$0	\$48,537	\$8,494	\$0	\$8,555	\$65,586	\$101
4.11	Boiler Balance of Plant	\$1,801	\$0	\$1,026	\$0	\$2,828	\$495	\$0	\$498	\$3,821	\$6
4.12	Primary Air System	\$1,729	\$0	\$985	\$0	\$2,714	\$475	\$0	\$478	\$3,668	\$6
4.13	Secondary Air System	\$2,619	\$0	\$1,492	\$0	\$4,111	\$719	\$0	\$725	\$5,555	\$9
4.14	Induced Draft Fans	\$5,649	\$0	\$3,219	\$0	\$8,868	\$1,552	\$0	\$1,563	\$11,983	\$18
4.15	Major Component Rigging	\$95	\$0	\$54	\$0	\$149	\$26	\$0	\$26	\$201	\$0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B12B.99	– SC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
4.16	Boiler Foundations	\$0	\$407	\$358	\$0	\$765	\$134	\$0	\$135	\$1,033	\$2
	Subtotal	\$317,204	\$407	\$181,137	\$0	\$498,748	\$87,281	\$0	\$87,904	\$673,933	\$1,036
5		Flue Gas Cleanup									
5.1	CANSOLV Carbon Dioxide (CO ₂) Removal System	\$156,749	\$67,980	\$142,758	\$0	\$367,487	\$64,310	\$62,473	\$86,497	\$580,768	\$893
5.2	WFGD Absorber Vessels & Accessories	\$81,096	\$0	\$17,346	\$0	\$98,441	\$17,227	\$0	\$17,350	\$133,019	\$205
5.3	Other FGD	\$1,294	\$0	\$996	\$0	\$2,290	\$401	\$0	\$404	\$3,094	\$5
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$45,917	\$6,888	\$15,352	\$0	\$68,157	\$11,927	\$0	\$16,017	\$96,101	\$148
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$519	\$82	\$222	\$0	\$823	\$144	\$0	\$193	\$1,161	\$2
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$2,727	\$600	\$2,681	\$0	\$6,007	\$1,051	\$0	\$1,059	\$8,117	\$12
5.9	Particulate Removal (Bag House & Accessories) (included with 5.2)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5.12	Gas Cleanup Foundations	\$0	\$202	\$177	\$0	\$379	\$66	\$0	\$67	\$512	\$1
5.13	Gypsum Dewatering System	\$776	\$0	\$131	\$0	\$906	\$159	\$0	\$160	\$1,225	\$2
	Subtotal	\$289,077	\$75,752	\$179,662	\$0	\$544,491	\$95,286	\$62,473	\$121,747	\$823,996	\$1,267
7		Ductwork & Stack									
7.3	Ductwork	\$0	\$753	\$523	\$0	\$1,276	\$223	\$0	\$225	\$1,724	\$3
7.4	Stack	\$8,822	\$0	\$5,127	\$0	\$13,949	\$2,441	\$0	\$2,459	\$18,849	\$29
7.5	Duct & Stack Foundations	\$0	\$210	\$250	\$0	\$460	\$80	\$0	\$108	\$649	\$1
	Subtotal	\$8,822	\$963	\$5,899	\$0	\$15,685	\$2,745	\$0	\$2,791	\$21,221	\$33
8		Steam Turbine & Accessories									
8.1	Steam Turbine Generator & Accessories	\$73,628	\$0	\$8,205	\$0	\$81,833	\$14,321	\$0	\$14,423	\$110,577	\$170
8.2	Steam Turbine Plant Auxiliaries	\$1,671	\$0	\$3,557	\$0	\$5,228	\$915	\$0	\$921	\$7,064	\$11
8.3	Condenser & Auxiliaries	\$10,689	\$0	\$3,627	\$0	\$14,316	\$2,505	\$0	\$2,523	\$19,344	\$30
8.4	Steam Piping	\$43,951	\$0	\$17,813	\$0	\$61,764	\$10,809	\$0	\$10,886	\$83,459	\$128
8.5	Turbine Generator Foundations	\$0	\$261	\$431	\$0	\$692	\$121	\$0	\$163	\$976	\$2
	Subtotal	\$129,939	\$261	\$33,633	\$0	\$163,833	\$28,671	\$0	\$28,916	\$221,419	\$340
9		Cooling Water System									
9.1	Cooling Towers	\$19,867	\$0	\$6,144	\$0	\$26,011	\$4,552	\$0	\$4,585	\$35,148	\$54
9.2	Circulating Water Pumps	\$2,811	\$0	\$207	\$0	\$3,017	\$528	\$0	\$532	\$4,077	\$6
9.3	Circulating Water System Auxiliaries	\$16,519	\$0	\$2,179	\$0	\$18,698	\$3,272	\$0	\$3,296	\$25,266	\$39
9.4	Circulating Water Piping	\$0	\$7,636	\$6,915	\$0	\$14,551	\$2,547	\$0	\$2,565	\$19,663	\$30
9.5	Make-up Water System	\$1,270	\$0	\$1,631	\$0	\$2,901	\$508	\$0	\$511	\$3,920	\$6
9.6	Component Cooling Water System	\$1,190	\$0	\$913	\$0	\$2,103	\$368	\$0	\$371	\$2,841	\$4
9.7	Circulating Water System Foundations	\$0	\$711	\$1,180	\$0	\$1,891	\$331	\$0	\$444	\$2,666	\$4
	Subtotal	\$41,656	\$8,347	\$19,170	\$0	\$69,173	\$12,105	\$0	\$12,303	\$93,581	\$144
10		Ash & Spent Sorbent Handling Systems									
10.6	Ash Storage Silos	\$1,190	\$0	\$3,640	\$0	\$4,830	\$845	\$0	\$851	\$6,527	\$10

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B12B.99	– SC PC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
10.7	Ash Transport & Feed Equipment	\$4,046	\$0	\$4,012	\$0	\$8,058	\$1,410	\$0	\$1,420	\$10,889	\$17
10.9	Ash/Spent Sorbent Foundation	\$0	\$827	\$1,019	\$0	\$1,846	\$323	\$0	\$434	\$2,603	\$4
	Subtotal	\$5,237	\$827	\$8,671	\$0	\$14,735	\$2,579	\$0	\$2,705	\$20,019	\$31
11		Accessory Electric Plant									
11.1	Generator Equipment	\$2,679	\$0	\$2,021	\$0	\$4,701	\$823	\$0	\$828	\$6,352	\$10
11.2	Station Service Equipment	\$7,806	\$0	\$670	\$0	\$8,475	\$1,483	\$0	\$1,494	\$11,452	\$18
11.3	Switchgear & Motor Control	\$12,118	\$0	\$2,102	\$0	\$14,220	\$2,488	\$0	\$2,506	\$19,215	\$30
11.4	Conduit & Cable Tray	\$0	\$1,575	\$4,540	\$0	\$6,115	\$1,070	\$0	\$1,078	\$8,263	\$13
11.5	Wire & Cable	\$0	\$4,172	\$7,457	\$0	\$11,628	\$2,035	\$0	\$2,050	\$15,713	\$24
11.6	Protective Equipment	\$55	\$0	\$191	\$0	\$246	\$43	\$0	\$43	\$332	\$1
11.7	Standby Equipment	\$828	\$0	\$765	\$0	\$1,593	\$279	\$0	\$281	\$2,153	\$3
11.8	Main Power Transformers	\$7,036	\$0	\$144	\$0	\$7,179	\$1,256	\$0	\$1,265	\$9,701	\$15
11.9	Electrical Foundations	\$0	\$224	\$568	\$0	\$792	\$139	\$0	\$186	\$1,117	\$2
	Subtotal	\$30,522	\$5,970	\$18,457	\$0	\$54,949	\$9,616	\$0	\$9,731	\$74,297	\$114
12		Instrumentation & Control									
12.1	Pulverized Coal Boiler Control Equipment	\$812	\$0	\$145	\$0	\$957	\$167	\$0	\$169	\$1,293	\$2
12.3	Steam Turbine Control Equipment	\$728	\$0	\$81	\$0	\$809	\$142	\$0	\$143	\$1,093	\$2
12.5	Signal Processing Equipment	\$922	\$0	\$164	\$0	\$1,086	\$190	\$0	\$191	\$1,468	\$2
12.6	Control Boards, Panels & Racks	\$282	\$0	\$172	\$0	\$454	\$79	\$23	\$83	\$640	\$1
12.7	Distributed Control System Equipment	\$7,958	\$0	\$1,419	\$0	\$9,377	\$1,641	\$469	\$1,723	\$13,210	\$20
12.8	Instrument Wiring & Tubing	\$557	\$446	\$1,783	\$0	\$2,786	\$488	\$139	\$512	\$3,925	\$6
12.9	Other Instrumentation & Controls Equipment	\$685	\$0	\$1,586	\$0	\$2,271	\$398	\$114	\$417	\$3,200	\$5
	Subtotal	\$11,945	\$446	\$5,351	\$0	\$17,741	\$3,105	\$744	\$3,239	\$24,829	\$38
13		Improvements to Site									
13.1	Site Preparation	\$0	\$466	\$9,885	\$0	\$10,351	\$1,811	\$0	\$2,432	\$14,594	\$22
13.2	Site Improvements	\$0	\$2,302	\$3,042	\$0	\$5,344	\$935	\$0	\$1,256	\$7,535	\$12
13.3	Site Facilities	\$2,631	\$0	\$2,759	\$0	\$5,390	\$943	\$0	\$1,267	\$7,600	\$12
	Subtotal	\$2,631	\$2,768	\$15,686	\$0	\$21,085	\$3,690	\$0	\$4,955	\$29,729	\$46
14		Buildings & Structures									
14.2	Boiler Building	\$0	\$11,598	\$10,193	\$0	\$21,791	\$3,813	\$0	\$3,841	\$29,445	\$45
14.3	Steam Turbine Building	\$0	\$16,121	\$15,014	\$0	\$31,136	\$5,449	\$0	\$5,488	\$42,072	\$65
14.4	Administration Building	\$0	\$1,047	\$1,107	\$0	\$2,154	\$377	\$0	\$380	\$2,911	\$4
14.5	Circulation Water Pump House	\$0	\$190	\$150	\$0	\$340	\$59	\$0	\$60	\$459	\$1
14.6	Water Treatment Buildings	\$0	\$472	\$430	\$0	\$901	\$158	\$0	\$159	\$1,218	\$2
14.7	Machine Shop	\$0	\$553	\$371	\$0	\$923	\$162	\$0	\$163	\$1,247	\$2
14.8	Warehouse	\$0	\$416	\$416	\$0	\$832	\$146	\$0	\$147	\$1,124	\$2
14.9	Other Buildings & Structures	\$0	\$290	\$247	\$0	\$537	\$94	\$0	\$95	\$726	\$1
14.10	Waste Treating Building & Structures	\$0	\$644	\$1,950	\$0	\$2,593	\$454	\$0	\$457	\$3,504	\$5
	Subtotal	\$0	\$31,330	\$29,878	\$0	\$61,208	\$10,711	\$0	\$10,788	\$82,707	\$127
	Total	\$955,453	\$144,335	\$560,161	\$0	\$1,659,949	\$290,491	\$63,217	\$325,118	\$2,338,775	\$3,596

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-28. Case B12B.99 owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$13,831	\$21
1 Month Maintenance Materials	\$2,201	\$3
1 Month Non-Fuel Consumables	\$3,372	\$5
1 Month Waste Disposal	\$971	\$1
25% of 1 Months Fuel Cost at 100% CF	\$2,938	\$5
2% of TPC	\$46,776	\$72
Total	\$70,090	\$108
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	\$29,439	\$45
0.5% of TPC (spare parts)	\$11,694	\$18
Total	\$41,133	\$63
Other Costs		
Initial Cost for Catalyst and Chemicals	\$2,684	\$4
Land	\$900	\$1
Other Owner's Costs	\$350,816	\$539
Financing Costs	\$63,147	\$97
Total Overnight Costs (TOC)	\$2,867,544	\$4,409
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	\$3,310,327	\$5,090

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-29. Case B12B.99 initial and annual operating and maintenance costs

Case:	B12B.99	– SC PC w/ CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):	11,116		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	% of base	Operator:	11.3	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	2.0	
				Total:	16.3	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$7,161,008	\$11.010
Maintenance Labor:					\$14,968,161	\$23.013
Administrative & Support Labor:					\$5,532,292	\$8.506
Property Taxes and Insurance:					\$46,775,505	\$71.916
Total:					\$74,436,966	\$114.444
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$22,452,242	\$4.63599
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	7,025	\$1.90	\$0	\$4,141,138	\$0.85507
Makeup and Waste Water Treatment Chemicals (ton):	0	20.9	\$550.00	\$0	\$3,570,909	\$0.73733
Brominated Activated Carbon (ton):	0	1.63	\$1,600.00	\$0	\$807,700	\$0.16678
Enhanced Hydrated Lime (ton):	0	40.9	\$240.00	\$0	\$3,048,354	\$0.62943
Limestone (ton):	0	719	\$22.00	\$0	\$4,910,195	\$1.01387
Ammonia (19 wt%, ton):	0	71.3	\$300.00	\$0	\$6,635,587	\$1.37013
SCR Catalyst (ft³):	17,890	16.3	\$150.00	\$2,683,505	\$760,327	\$0.15699
CO ₂ Capture System Chemicals ^A :	Proprietary				\$9,096,350	\$1.87824
Triethylene Glycol (gal):	w/equip.	677	\$6.80	\$0	\$1,427,790	\$0.29481
Subtotal:				\$2,683,505	\$34,398,351	\$7.10265
Waste Disposal						
Fly Ash (ton)	0	675	\$38.00	\$0	\$7,956,790	\$1.64294
Bottom Ash (ton)	0	150	\$38.00	\$0	\$1,767,420	\$0.36494
SCR Catalyst (ft³):	0	16.3	\$2.50	\$0	\$12,672	\$0.00262
Triethylene Glycol (gal):	0	677	\$0.35	\$0	\$73,489	\$0.01517
Thermal Reclaimer Unit Waste (ton):	0	8.34	\$38.00	\$0	\$98,339	\$0.02031
Subtotal:				\$0	\$9,908,711	\$2.04597
By-Products						
Gypsum (ton)	0	1093	\$0.00	\$0	\$0	\$0.00000
Subtotal:				\$0	\$0	\$0.00000
Variable Operating Costs Total:				\$2,683,505	\$66,759,304	\$13.78462
Fuel Cost						
Illinois Number 6 (ton):	0	7,437	\$51.96	\$0	\$119,880,788	\$24.75328
Total:				\$0	\$119,880,788	\$24.75328

^ACO₂ Capture System Chemicals includes NaOH and CANSOLV Solvent

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit A-30. Case B12B.99 LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	48.4	43%
Fixed	15.4	14%
Variable	13.8	12%
Fuel	24.8	22%
Total (Excluding T&S)	102.3	N/A
CO ₂ T&S	10.1	9%
Total (Including T&S)	112.4	N/A

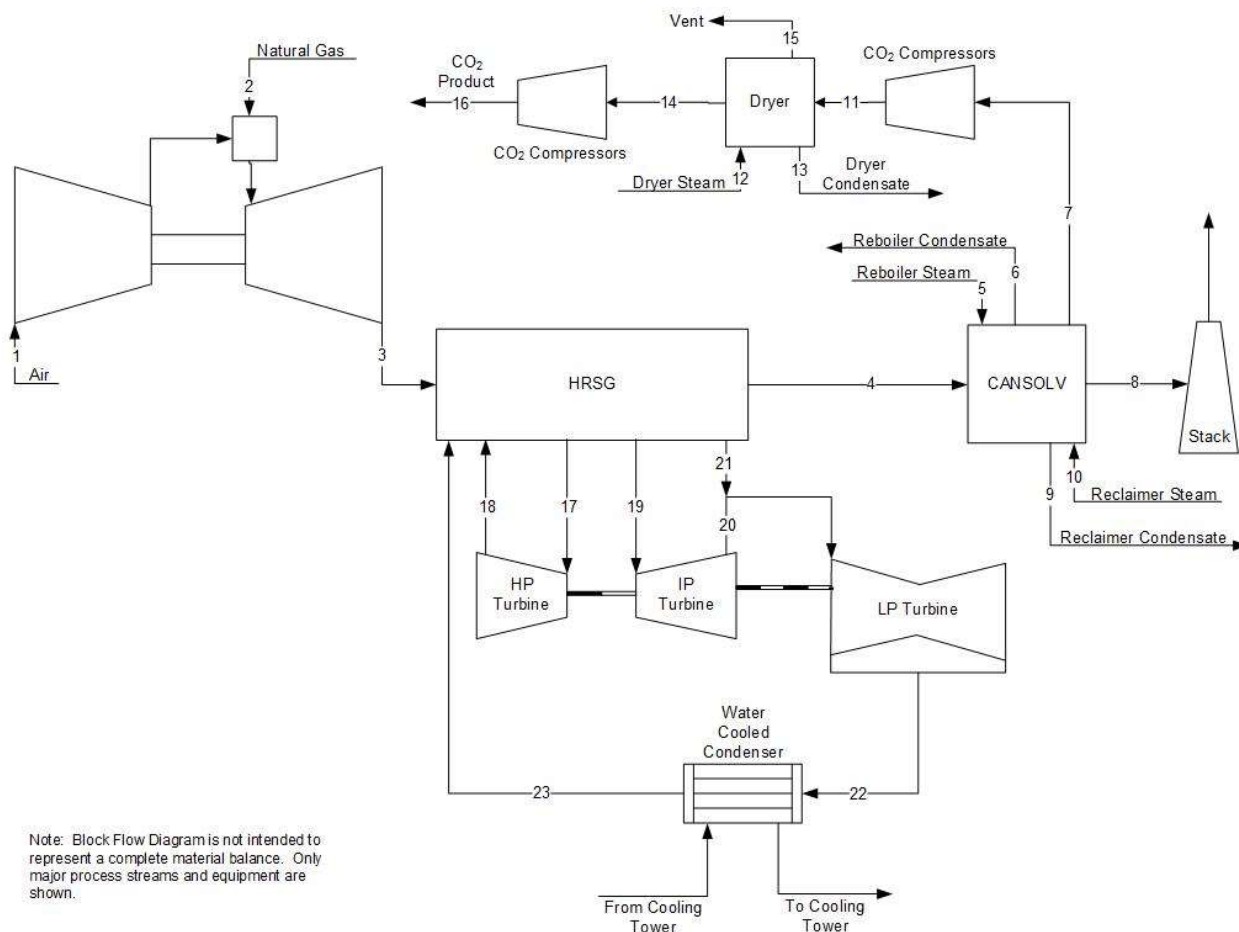
APPENDIX B – NGCC WITH 97 PERCENT CO₂ CAPTURE

B.1 CASE B31B.97 – NGCC WITH 97 PERCENT CO₂ CAPTURE PROCESS DESCRIPTION

The plant configuration for Case B31B.97 is the same as Case B31B.90 with the exception that the CDR technology captures 97, rather than 90, percent of the CO₂ in the flue gas. The nominal net output decreases to 637 MW.

The process description for Case B31B.97 is the same as Case B31B.90. A BFD and stream tables for Case B31B.97 are shown in Exhibit B-1 and Exhibit B-2, respectively. Since the CDR facility process description was provided in Section 5.1.5, it is not repeated here.

Exhibit B-1. Case B31B.97 block flow diagram, NGCC with CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit B-2. Case B31B.97 stream table, NGCC with capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000	0.0000	0.0096	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₂ H ₆	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0100	0.0408	0.0408	0.0000	0.0000	0.9778	0.0013	0.0000	0.0000	0.9957	0.0000
H ₂ O	0.0099	0.0000	0.0875	0.0875	1.0000	1.0000	0.0222	0.0582	1.0000	1.0000	0.0043	1.0000
N ₂	0.7732	0.0160	0.7428	0.7428	0.0000	0.0000	0.0000	0.8015	0.0000	0.0000	0.0000	0.0000
O ₂	0.2074	0.0000	0.1200	0.1200	0.0000	0.0000	0.0000	0.1294	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	132,867	5,383	138,406	138,406	15,101	13,831	5,607	128,274	129	129	5,506	8
V-L Flowrate (kg/hr)	3,834,126	93,272	3,927,398	3,927,398	272,052	249,171	243,536	3,602,357	2,330	2,330	241,722	144
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	625	101	308	105	31	39	214	356	29	356
Pressure (MPa, abs)	0.10	2.96	0.11	0.10	0.51	0.12	0.17	0.10	2.04	3.74	2.82	3.74
Steam Table Enthalpy (kJ/kg) ^A	30.23	22.04	832.68	244.85	3,080.22	439.34	49.44	133.62	913.81	3,112.11	-1.25	3,112.11
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-4,487.18	-644.44	-1,232.28	-12,900.08	-15,540.95	-8,979.10	-505.19	-15,066.49	-12,868.18	-8,976.09	-12,868.18
Density (kg/m ³)	1.2	22.1	0.4	0.9	1.9	954.9	3.0	1.1	848.5	13.8	58.0	13.8
V-L Molecular Weight	28.857	17.328	28.376	28.376	18.015	18.015	43.433	28.083	18.015	18.015	43.898	18.015
V-L Flowrate (lb _{mol} /hr)	292,921	11,867	305,132	305,132	33,292	30,492	12,362	282,796	285	285	12,140	18
V-L Flowrate (lb/hr)	8,452,800	205,630	8,658,430	8,658,430	599,771	549,327	536,904	7,941,838	5,137	5,137	532,906	317
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,156	213	586	221	88	102	416	672	85	672
Pressure (psia)	14.7	430.0	15.5	14.8	73.5	17.4	24.8	14.8	296.6	542.3	409.1	542.3
Steam Table Enthalpy (Btu/lb) ^A	13.0	9.5	358.0	105.3	1,324.3	188.9	21.3	57.4	392.9	1,338.0	-0.5	1,338.0
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-1,929.1	-277.1	-529.8	-5,546.0	-6,681.4	-3,860.3	-217.2	-6,477.4	-5,532.3	-3,859.0	-5,532.3
Density (lb/ft ³)	0.076	1.380	0.025	0.058	0.119	59.612	0.185	0.069	52.968	0.863	3.622	0.863

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit B-2. Case B31B.97 stream table, NGCC with capture (continued)

	13	14	15	16	17	18	19	20	21	22	23
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₂ H ₆	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0000	0.9995	0.0500	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	1.0000	0.0005	0.9500	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	8	5,484	22	5,484	26,993	26,993	31,038	31,038	4,030	19,967	33,979
V-L Flowrate (kg/hr)	144	241,296	426	241,296	486,294	486,294	559,161	559,161	72,598	359,707	612,136
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	203	29	29	30	585	356	584	308	281	38	38
Pressure (MPa, abs)	1.64	2.69	2.82	15.27	16.50	3.74	3.51	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg) ^A	863.65	-3.70	137.93	-231.09	3,528.08	3,112.11	3,642.67	3,080.22	3,024.62	2,375.88	160.78
AspenPlus Enthalpy (kJ/kg) ^B	15,116.65	8,967.26	15,225.22	9,194.65	12,452.22	12,868.18	12,337.62	12,900.08	12,955.67	13,604.41	15,819.51
Density (kg/m ³)	861.8	54.9	352.5	630.1	45.6	13.8	9.0	2.0	2.0	0.1	992.8
V-L Molecular Weight	18.015	43.997	19.315	43.997	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	18	12,091	49	12,091	59,510	59,510	68,427	68,427	8,884	44,019	74,910
V-L Flowrate (lb/hr)	317	531,966	940	531,966	1,072,094	1,072,094	1,232,739	1,232,739	160,051	793,018	1,349,529
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	397	85	85	86	1,085	672	1,084	587	538	101	101
Pressure (psia)	237.4	390.4	409.1	2,214.7	2,393.1	542.3	508.6	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb) ^A	371.3	-1.6	59.3	-99.4	1,516.8	1,338.0	1,566.1	1,324.3	1,300.4	1,021.4	69.1
AspenPlus Enthalpy (Btu/lb) ^B	-6,499.0	-3,855.2	-6,545.7	-3,953.0	-5,353.5	-5,532.3	-5,304.2	-5,546.0	-5,569.9	-5,848.8	-6,801.2
Density (lb/ft ³)	53.801	3.430	22.007	39.338	2.849	0.863	0.563	0.122	0.125	0.003	61.977

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

B.1.1 Case B31B.97 – Performance Results

The Case B31B.97 modeling assumptions were presented previously in Section 5.1.

The plant produces a net output of 637 MW at a net plant efficiency of 47.0 percent (HHV basis). Overall plant performance is summarized in Exhibit B-3. Exhibit B-4 provides a detailed breakdown of the auxiliary power requirements. The CDR facility, including CO₂ compression, accounts for over 68 percent of the auxiliary plant load. The CWS (CWP and cooling tower fan) accounts for nearly 13 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility.

Exhibit B-3. Case B31B.97 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	477
Steam Turbine Power, MWe	210
Total Gross Power, MWe	687
CO ₂ Capture/Removal Auxiliaries, kWe	15,200
CO ₂ Compression, kWe	19,290
Balance of Plant, kWe	16,072
Total Auxiliaries, MWe	51
Net Power, MWe	637
HHV Net Plant Efficiency, %	47.0
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,659 (7,260)
HHV Combustion Turbine Efficiency, %	35.2
LHV Net Plant Efficiency, %	52.1
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,913 (6,552)
LHV Combustion Turbine Efficiency, %	39.0
Steam Turbine Cycle Efficiency, %	48.0
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,495 (7,104)
CO ₂ Capture Rate, %	97
Condenser Duty, GJ/hr (MMBtu/hr)	803 (761)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	1,268 (1,201)
Natural Gas Feed Flow, kg/hr (lb/hr)	93,272 (205,630)
HHV Thermal Input, kWt	1,354,905
LHV Thermal Input, kWt	1,222,936
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.027 (7.1)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.018 (4.8)

Exhibit B-4. Case B31B.97 plant power summary

Power Summary	
Combustion Turbine Power, MWe	477
Steam Turbine Power, MWe	210
Total Gross Power, MWe	687
Auxiliary Load Summary	
Circulating Water Pumps, kWe	4,390
Combustion Turbine Auxiliaries, kWe	1,020
Condensate Pumps, kWe	170
Cooling Tower Fans, kWe	2,270
CO ₂ Capture/Removal Auxiliaries, kWe	15,200
CO ₂ Compression, kWe	19,290
Feedwater Pumps, kWe	4,830
Ground Water Pumps, kWe	410
Miscellaneous Balance of Plant ^A , kWe	570
SCR, kWe	2
Steam Turbine Auxiliaries, kWe	200
Transformer Losses, kWe	2,210
Total Auxiliaries, MWe	51
Net Power, MWe	637

^AIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

B.1.1.1 Environmental Performance

The environmental targets for emissions of NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B31B.97 is presented in Exhibit B-5.

Exhibit B-5. Case B31B.97 air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.001 (0.003)	52 (57)	0.010 (0.022)
Particulate	0.000 (0.000)	0 (0)	0.000 (0.000)
Hg	0.00E+0 (0.00E+0)	0.000 (0.000)	0.00E+0 (0.00E+0)
CO	0.000 (0.000)	0 (0)	0.000 (0.000)
CO ₂	2 (4)	55,568 (61,253)	11 (24)
CO ₂ ^C	—	—	12 (26)

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^cCO₂ emissions based on net power instead of gross power

For the purpose of this report, the natural gas was assumed to contain the domestic average value of total sulfur of 0.34 gr/100 scf (4.71×10^{-4} lb-S/MMBtu). [23] It was also assumed that the added CH₄S was the sole contributor of sulfur to the natural gas. No sulfur capture systems were required.

The NGCC cases were designed to achieve approximately 1.8 ppmvd NO_x emissions (at 15 percent O₂) using a DLN burner in the CTG—the DLN burners reduce the emissions to about 9 ppmvd (at 15 percent O₂) [34]—and an SCR—the SCR system is designed for 86.7 percent NO_x reduction. [35]

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2017 F-Class gas turbine achieves approximately 1.0 ppmv CO and 1.0 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not present in any significant amount. Any CO or PM present in the flue gas is assumed to interact with, and be removed by, the CDR system solvent.

CO₂ emissions are reduced relative to those produced by burning coal given the same power output because of the higher heat content of natural gas, the lower carbon intensity of gas relative to coal, and the higher overall efficiency of the NGCC plant relative to a coal-fired plant.

The CDR facility removes 97 percent of the CO₂ in the flue gas.

The carbon balance for the plant is shown in Exhibit B-6. The carbon input to the plant consists of carbon in the natural gas in addition to carbon in the CT air. Carbon leaves the plant as CO₂ in the stack gas, the CO₂ dryer's vent, and the captured CO₂ product. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in, represented by the following fraction:

$$1 - \frac{\text{Carbon in Stack}}{\text{Total Carbon In}} = \left(1 - \left(\frac{4,490}{149,672} \right) \right) * 100 = 97\%$$

Exhibit B-6. Case B31B.97 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	67,369 (148,523)	Stack Gas	2,037 (4,490)
Air (CO ₂)	521 (1,150)	CO ₂ Product	65,840 (145,153)
		CO ₂ Dryer Vent	13 (29)
		CO ₂ Knockout	0.1 (0.3)
Total	67,890 (149,672)	Total	67,890 (149,672)

As shown in Exhibit B-7, the sulfur content of the natural gas is insignificant, comprised entirely of CH₄S (used as an odorant). [23] All sulfur in the natural gas is assumed to react with the CDR system solvent and is removed from the solvent during solvent reclaiming as a waste stream.

Exhibit B-7. Case B31B.97 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.0 (2.2)	Stack Gas	0.0 (0.0)
		Solvent Reclaiming	1.0 (2.2)
Total	1.0 (2.2)	Total	1.0 (2.2)

Exhibit B-8 shows the overall water balance for the plant.

Exhibit B-8. Case B31B.97 water balance

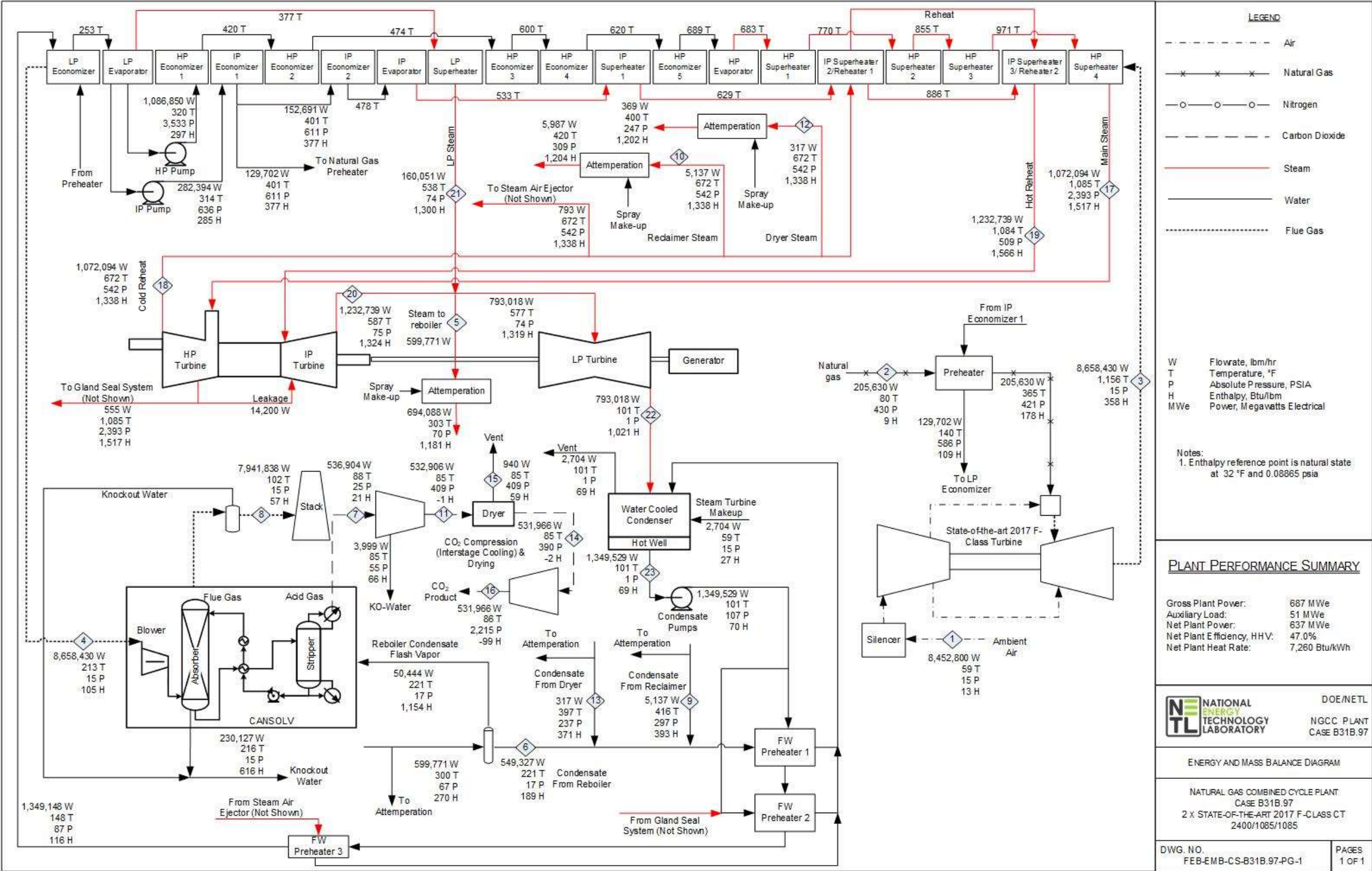
Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
CO ₂ Drying	–	–	–	0.0 (1.9)	0.0 (-1.9)
CO ₂ Capture System Makeup	–	–	–	–	–
CO ₂ Capture Recovery	–	–	–	1.7 (460)	-1.7 (-460)
CO ₂ Compression Recovery	–	–	–	0.0 (8.0)	0.0 (-8.0)
Deaerator Vent	–	–	–	0.0 (5.4)	0.0 (-5.4)
Condenser Makeup	0.0 (5.4)	–	0.0 (5.4)	–	0.0 (5.4)
BFW Makeup	0.0 (5.4)	–	0.0 (5.4)	–	0.0 (5.4)
Cooling Tower	17 (4,515)	–	17 (4,515)	3.8 (1,015)	13 (3,499)
Total	17 (4,520)	–	17 (4,520)	5.6 (1,491)	11 (3,029)

B.1.1.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram for B31B.97 is shown in Exhibit B-9. An overall plant energy balance is provided in tabular form in Exhibit B-10.

The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT, and 98.7 percent for the steam turbine. The cooling tower load includes the condenser, capture process heat rejected to cooling water, the CO₂ compressor intercooler load, and other miscellaneous cooling loads.

Exhibit B-9. Case B31B.97 energy and mass balance, NGCC with CO₂ capture



This page intentionally left blank

Exhibit B-10. Case B31B.97 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	4,878 (4,623)	3.3 (3.1)	–	4,881 (4,626)
Air	–	116 (110)	–	116 (110)
Raw Water Makeup	–	64 (61)	–	64 (61)
Auxiliary Power	–	–	182 (173)	182 (173)
TOTAL	4,878 (4,623)	183 (174)	182 (173)	5,243 (4,970)
Heat Out GJ/hr (MMBtu/hr)				
Stack Gas	–	481 (456)	–	481 (456)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	58 (55)	58 (55)
Cooling Tower Load ^A	–	2,232 (2,115)	–	2,232 (2,115)
CO ₂ Product Stream	–	-56 (-53)	–	-56 (-53)
AGR Effluent	–	45 (42)	–	45 (42)
Deaerator Vent	–	0.2 (0.2)	–	0.2 (0.2)
<i>Ambient Losses^B</i>	–	36 (34)	–	36 (34)
Power	–	–	2,475 (2,346)	2,475 (2,346)
TOTAL	–	2,738 (2,595)	2,532 (2,400)	5,270 (4,995)
<i>Unaccounted Energy^C</i>	–	-27 (-26)	–	-27 (-26)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers

^CBy difference

B.1.2 Case B31B.97 – Major Equipment List

Major equipment items for the NGCC plant with CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 0. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B31B.97 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	81,000 liters (21,000 gal)	2	0
2	Condensate Pumps	Vertical canned	11,300 lpm @ 90 m H ₂ O (2,990 gpm @ 300 ft H ₂ O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 4,550 lpm @ 2,940 m H ₂ O (1,200 gpm @ 9,640 ft H ₂ O) IP water: 2,360 lpm @ 470 m H ₂ O (620 gpm @ 1,550 ft H ₂ O)	2	2
4	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m ³ /min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m ³ /min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 GJ/hr (13 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,200 lpm @ 20 m H ₂ O (1,400 gpm @ 70 ft H ₂ O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	8,800 lpm @ 20 m H ₂ O (2,300 gpm @ 60 ft H ₂ O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H ₂ O (40 gpm @ 160 ft H ₂ O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
15	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
16	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	77 m ³ /min @ 3.0 MPa (2,732 acfm @ 430 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
17	Gas Metering Station	–	77 m ³ /min (2,732 acfm)	1	0

Case B31B.97 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CANSOLV	Amine-based CO ₂ capture technology	4,320,000 kg/hr (9,524,000 lb/hr) 6.3 wt % CO ₂ concentration	1	0
2	CANSOLV LP Condensate Pump	Centrifugal	795 lpm @ 1 m H ₂ O (210 gpm @ 3 ft H ₂ O)	1	1
3	CANSOLV HP Condensate Pump	Centrifugal	7 lpm @ 5 m H ₂ O (2 gpm @ 15 ft H ₂ O)	1	1
4	CO ₂ Dryer	Triethylene glycol	Inlet: 69 m ³ /min @ 2.8 MPa (2,452 acfm @ 409 psia) Outlet: 2.7 MPa (390 psia) Water Recovered: 426 kg/hr (940 lb/hr)	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	4.0 m ³ /min @ 15.3 MPa, 82°C (124 acfm @ 2,217 psia, 180°F)	2	0
6	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 38 GJ/hr (36 MMBtu/hr)	2	0

Case B31B.97 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	Advanced F class w/ dry low-NOx burner	240 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	270 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	2	0

Case B31B.97 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 5.1 m (17 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main steam - 267,462 kg/hr, 16.4 MPa/585°C (589,652 lb/hr, 2,378 psig/1,085°F) Reheat steam - 307,539 kg/hr, 3.4 MPa/584°C (678,006 lb/hr, 494 psig/1,084°F)	2	0
3	SCR Reactor	—	2,160,000 kg/hr (4,760,000 lb/hr)	2	0
4	SCR Catalyst	—	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	10 m ³ /min @ 108 cm WG (220 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	1.3 lpm @ 90 m H ₂ O (0.4 gpm @ 300 ft H ₂ O)	2	1
7	Ammonia Storage Tank	Horizontal tank	38,000 liter (10,000 gal)	1	0

Case B31B.97 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	221 MW 16.4 MPa/585°C/584°C (2,378 psig/1,085°F/1,084°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	250 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	880 GJ/hr (840 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

Case B31B.97 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	440,000 lpm @ 30 m (116,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 2,450 GJ/hr (2,330 MMBtu/hr) heat duty	1	0

Case B31B.97 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 270 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 190 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 11 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 24 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 8 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B31B.97 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

B.1.3 Case B31B.97 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit B-11 shows a detailed breakdown of the capital costs; Exhibit B-12 shows the owner's costs, TOC, and TASC; Exhibit B-13 shows the initial and annual O&M costs; and Exhibit B-14 shows the LCOE breakdown.

The estimated TPC of the NGCC with CO₂ capture is \$1,754/kW. Process contingency represents 4.4 percent of the TPC and project contingency represents 15.1 percent. The LCOE, including CO₂ T&S costs of \$3.8/MWh, is \$69.9/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO
ELECTRICITY

Exhibit B-11. Case B31B.97 total plant cost details

Case:		B31B.97	2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		637					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$1,698	\$2,910	\$1,455	\$0	\$6,063	\$1,213	\$0	\$1,091	\$8,367	\$13
3.2	Water Makeup & Pretreating	\$5,139	\$514	\$2,912	\$0	\$8,565	\$1,713	\$0	\$2,056	\$12,334	\$19
3.3	Other Feedwater Subsystems	\$966	\$317	\$301	\$0	\$1,583	\$317	\$0	\$285	\$2,185	\$3
3.4	Service Water Systems	\$1,559	\$2,977	\$9,640	\$0	\$14,177	\$2,835	\$0	\$3,402	\$20,415	\$32
3.5	Other Boiler Plant Systems	\$230	\$84	\$209	\$0	\$523	\$105	\$0	\$94	\$722	\$1
3.6	Natural Gas Pipeline and Start-Up System	\$9,304	\$400	\$300	\$0	\$10,005	\$2,001	\$0	\$1,801	\$13,807	\$22
3.7	Waste Water Treatment Equipment	\$8,942	\$0	\$5,481	\$0	\$14,423	\$2,885	\$0	\$3,462	\$20,769	\$33
3.9	Miscellaneous Plant Equipment	\$14,217	\$1,865	\$7,225	\$0	\$23,306	\$4,661	\$0	\$5,594	\$33,561	\$53
	Subtotal	\$42,056	\$9,066	\$27,523	\$0	\$78,645	\$15,729	\$0	\$17,784	\$112,159	\$176
5 Flue Gas Cleanup											
5.1	CANSOLV Carbon Dioxide (CO ₂) Removal System	\$108,714	\$51,104	\$107,319	\$0	\$267,137	\$53,427	\$48,085	\$73,730	\$442,378	\$695
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$27,829	\$4,175	\$11,545	\$0	\$43,549	\$8,710	\$0	\$10,452	\$62,711	\$98
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$239	\$38	\$102	\$0	\$379	\$76	\$0	\$91	\$546	\$1
5.12	Gas Cleanup Foundations	\$0	\$405	\$438	\$0	\$844	\$169	\$0	\$202	\$1,215	\$2
	Subtotal	\$136,782	\$55,722	\$119,404	\$0	\$311,908	\$62,382	\$48,085	\$84,475	\$506,850	\$796
6 Combustion Turbine & Accessories											
6.1	Combustion Turbine Generator	\$72,224	\$0	\$4,395	\$0	\$76,619	\$15,324	\$0	\$13,791	\$105,735	\$166
6.3	Combustion Turbine Accessories	\$2,626	\$0	\$160	\$0	\$2,786	\$557	\$0	\$501	\$3,845	\$6
6.4	Compressed Air Piping	\$0	\$867	\$196	\$0	\$1,063	\$213	\$0	\$191	\$1,467	\$2
6.5	Combustion Turbine Foundations	\$0	\$906	\$979	\$0	\$1,885	\$377	\$0	\$452	\$2,714	\$4
	Subtotal	\$74,850	\$1,773	\$5,730	\$0	\$82,353	\$16,471	\$0	\$14,937	\$113,760	\$179
7 HRSG, Ductwork, & Stack											
7.1	Heat Recovery Steam Generator	\$37,435	\$0	\$9,359	\$0	\$46,794	\$9,359	\$0	\$8,423	\$64,576	\$101
7.2	Heat Recovery Steam Generator Accessories	\$14,452	\$0	\$2,681	\$0	\$17,133	\$3,427	\$0	\$3,084	\$23,643	\$37
7.3	Ductwork	\$0	\$881	\$612	\$0	\$1,494	\$299	\$0	\$269	\$2,061	\$3
7.4	Stack	\$8,426	\$0	\$1,563	\$0	\$9,989	\$1,998	\$0	\$1,798	\$13,785	\$22
7.5	Heat Recovery Steam Generator, Ductwork & Stack Foundations	\$0	\$657	\$617	\$0	\$1,274	\$255	\$0	\$306	\$1,834	\$3
7.6	Selective Catalytic Reduction System	\$1,465	\$616	\$859	\$0	\$2,940	\$588	\$0	\$529	\$4,057	\$6
	Subtotal	\$61,778	\$2,154	\$15,691	\$0	\$79,623	\$15,925	\$0	\$14,409	\$109,956	\$173

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B31B.97	2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:		Conceptual		
Plant Size (MW, net):		637					Cost Base:		Dec 2018		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
8		Steam Turbine & Accessories									
8.1	Steam Turbine Generator & Accessories	\$30,984	\$0	\$4,537	\$0	\$35,522	\$7,104	\$0	\$6,394	\$49,020	\$77
8.2	Steam Turbine Plant Auxiliaries	\$126	\$0	\$280	\$0	\$406	\$81	\$0	\$73	\$561	\$1
8.3	Condenser & Auxiliaries	\$4,302	\$0	\$2,303	\$0	\$6,605	\$1,321	\$0	\$1,189	\$9,115	\$14
8.4	Steam Piping	\$9,400	\$0	\$3,810	\$0	\$13,210	\$2,642	\$0	\$2,378	\$18,230	\$29
8.5	Turbine Generator Foundations	\$0	\$1,064	\$1,756	\$0	\$2,819	\$564	\$0	\$677	\$4,060	\$6
Subtotal		\$44,812	\$1,064	\$12,687	\$0	\$58,563	\$11,713	\$0	\$10,710	\$80,986	\$127
9		Cooling Water System									
9.1	Cooling Towers	\$11,218	\$0	\$3,397	\$0	\$14,615	\$2,923	\$0	\$2,631	\$20,169	\$32
9.2	Circulating Water Pumps	\$1,478	\$0	\$91	\$0	\$1,568	\$314	\$0	\$282	\$2,164	\$3
9.3	Circulating Water System Auxiliaries	\$10,167	\$0	\$1,341	\$0	\$11,509	\$2,302	\$0	\$2,072	\$15,882	\$25
9.4	Circulating Water Piping	\$0	\$3,018	\$2,733	\$0	\$5,750	\$1,150	\$0	\$1,035	\$7,935	\$12
9.5	Make-up Water System	\$360	\$0	\$462	\$0	\$822	\$164	\$0	\$148	\$1,134	\$2
9.6	Component Cooling Water System	\$445	\$0	\$341	\$0	\$786	\$157	\$0	\$142	\$1,085	\$2
9.7	Circulating Water System Foundations	\$0	\$698	\$1,159	\$0	\$1,857	\$371	\$0	\$446	\$2,675	\$4
Subtotal		\$23,668	\$3,716	\$9,525	\$0	\$36,908	\$7,382	\$0	\$6,755	\$51,044	\$80
11		Accessory Electric Plant									
11.1	Generator Equipment	\$2,469	\$0	\$1,862	\$0	\$4,331	\$866	\$0	\$780	\$5,976	\$9
11.2	Station Service Equipment	\$6,833	\$0	\$586	\$0	\$7,420	\$1,484	\$0	\$1,336	\$10,239	\$16
11.3	Switchgear & Motor Control	\$9,757	\$0	\$1,693	\$0	\$11,450	\$2,290	\$0	\$2,061	\$15,801	\$25
11.4	Conduit & Cable Tray	\$0	\$2,358	\$6,795	\$0	\$9,153	\$1,831	\$0	\$1,647	\$12,630	\$20
11.5	Wire & Cable	\$0	\$3,520	\$6,292	\$0	\$9,812	\$1,962	\$0	\$1,766	\$13,540	\$21
11.6	Protective Equipment	\$441	\$0	\$1,533	\$0	\$1,974	\$395	\$0	\$355	\$2,725	\$4
11.7	Standby Equipment	\$629	\$0	\$581	\$0	\$1,210	\$242	\$0	\$218	\$1,669	\$3
11.8	Main Power Transformers	\$5,930	\$0	\$121	\$0	\$6,051	\$1,210	\$0	\$1,089	\$8,351	\$13
11.9	Electrical Foundations	\$0	\$89	\$226	\$0	\$316	\$63	\$0	\$76	\$454	\$1
Subtotal		\$26,059	\$5,967	\$19,689	\$0	\$51,715	\$10,343	\$0	\$9,328	\$71,385	\$112
12		Instrumentation & Control									
12.1	Natural Gas Combined Cycle Control Equipment	\$244	\$0	\$156	\$0	\$400	\$80	\$0	\$72	\$552	\$1
12.2	Combustion Turbine Control Equipment	\$395	\$0	\$252	\$0	\$646	\$129	\$0	\$116	\$892	\$1
12.3	Steam Turbine Control Equipment	\$391	\$0	\$249	\$0	\$640	\$128	\$0	\$115	\$884	\$1
12.4	Other Major Component Control Equipment	\$659	\$0	\$420	\$0	\$1,079	\$216	\$54	\$202	\$1,551	\$2
12.5	Signal Processing Equipment	\$547	\$0	\$17	\$0	\$564	\$113	\$0	\$102	\$778	\$1
12.6	Control Boards, Panels & Racks	\$145	\$0	\$89	\$0	\$234	\$47	\$12	\$44	\$336	\$1

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO
ELECTRICITY

Case:		B31B.97	2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		637					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
12.7	Distributed Control System Equipment	\$8,076	\$0	\$247	\$0	\$8,323	\$1,665	\$416	\$1,561	\$11,964	\$19
12.8	Instrument Wiring & Tubing	\$667	\$533	\$2,134	\$0	\$3,334	\$667	\$167	\$625	\$4,793	\$8
12.9	Other Instrumentation & Controls Equipment	\$462	\$0	\$1,069	\$0	\$1,531	\$306	\$77	\$287	\$2,201	\$3
	Subtotal	\$11,586	\$533	\$4,632	\$0	\$16,751	\$3,350	\$725	\$3,124	\$23,951	\$38
13		Improvements to Site									
13.1	Site Preparation	\$0	\$554	\$11,753	\$0	\$12,307	\$2,461	\$0	\$2,954	\$17,722	\$28
13.2	Site Improvements	\$0	\$1,780	\$2,353	\$0	\$4,133	\$827	\$0	\$992	\$5,952	\$9
13.3	Site Facilities	\$1,709	\$0	\$1,793	\$0	\$3,501	\$700	\$0	\$840	\$5,042	\$8
	Subtotal	\$1,709	\$2,334	\$15,899	\$0	\$19,941	\$3,988	\$0	\$4,786	\$28,715	\$45
14		Buildings & Structures									
14.1	Combustion Turbine Area	\$0	\$346	\$183	\$0	\$528	\$106	\$0	\$95	\$729	\$1
14.3	Steam Turbine Building	\$0	\$3,047	\$4,055	\$0	\$7,102	\$1,420	\$0	\$1,278	\$9,800	\$15
14.4	Administration Building	\$0	\$359	\$243	\$0	\$601	\$120	\$0	\$108	\$830	\$1
14.5	Circulation Water Pumphouse	\$0	\$80	\$40	\$0	\$120	\$24	\$0	\$22	\$165	\$0
14.6	Water Treatment Buildings	\$0	\$415	\$378	\$0	\$794	\$159	\$0	\$143	\$1,096	\$2
14.7	Machine Shop	\$0	\$536	\$343	\$0	\$879	\$176	\$0	\$158	\$1,213	\$2
14.8	Warehouse	\$0	\$418	\$252	\$0	\$670	\$134	\$0	\$121	\$924	\$1
14.9	Other Buildings & Structures	\$0	\$308	\$223	\$0	\$530	\$106	\$0	\$95	\$732	\$1
14.10	Waste Treating Building & Structures	\$0	\$703	\$1,256	\$0	\$1,960	\$392	\$0	\$353	\$2,704	\$4
	Subtotal	\$0	\$6,212	\$6,972	\$0	\$13,184	\$2,637	\$0	\$2,373	\$18,194	\$29
	Total	\$423,301	\$88,540	\$237,751	\$0	\$749,592	\$149,918	\$48,810	\$168,680	\$1,117,000	\$1,754

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit B-12. Case B31B.97 owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$7,041	\$11
1 Month Maintenance Materials	\$1,248	\$2
1 Month Non-fuel Consumables	\$705	\$1
1 Month Waste Disposal	\$8	\$0
25% of 1 Months Fuel Cost at 100% CF	\$3,729	\$6
2% of TPC	\$22,340	\$35
Total	\$35,071	\$55
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	\$1,033	\$2
0.5% of TPC (spare parts)	\$5,585	\$9
Total	\$6,618	\$10
Other Costs		
Initial Cost for Catalyst and Chemicals	\$847	\$1
Land	\$300	\$0
Other Owner's Costs	\$167,550	\$263
Financing Costs	\$30,159	\$47
Total Overnight Costs (TOC)	\$1,357,546	\$2,132
TASC Multiplier (IOU, 33 year)	1.093	
Total As-Spent Cost (TASC)	\$1,483,319	\$2,329

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit B-13. Case B31B.97 initial and annual operating and maintenance costs

Case:	B31B.97	F-frame 2x1 CT NGCC w/ CO ₂ Capture		Cost Base:	Dec 2018	
Plant Size (MW, net):	637	Heat Rate-net (Btu/kWh):	7,260	Capacity Factor (%):	85	
Operating & Maintenance Labor						
Operating Labor			Operating Labor Requirements per Shift			
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	1.0	
Operating Labor Burden:		30.00	% of base	Operator:	3.3	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	6.3	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$2,776,628	\$4.360
Maintenance Labor:					\$8,489,202	\$13.330
Administrative & Support Labor:					\$2,816,458	\$4.423
Property Taxes and Insurance:					\$22,340,006	\$35.080
Total:					\$36,422,294	\$57.192
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$12,733,803	\$2.68538
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	3,254	\$1.90	\$0	\$1,918,423	\$0.40457
Makeup and Waste Water Treatment Chemicals (ton):	0	9.7	\$550	\$0	\$1,654,259	\$0.34886
Ammonia (19 wt%, ton):	0	3.50	\$300	\$0	\$325,528	\$0.06865
SCR Catalyst (ft³):	5,649	3.10	\$150	\$847,299	\$144,041	\$0.03038
CO ₂ Capture System Chemicals ^A :	Proprietary				\$2,142,137	\$0.45175
Triethylene Glycol (gal):	w/equip.	476	\$6.80	\$0	\$1,004,155	\$0.21176
Subtotal:				\$847,299	\$7,188,542	\$1.51596
Waste Disposal						
SCR Catalyst (ft³):	0	3.10	\$2.50	\$0	\$2,401	\$0.00051
Triethylene Glycol (gal):	0	476	\$0.35	\$0	\$51,684	\$0.01090
Thermal Reclaimer Unit Waste (ton):	0	1.910	\$38.0	\$0	\$22,520	\$0.00475
Subtotal:				\$0	\$76,605	\$0.01616
Variable Operating Costs Total:				\$847,299	\$19,998,951	\$4.21750
Fuel Cost						
Natural Gas (MMBtu):	0	110,955	\$4.42	\$0	\$152,160,133	\$32.08846
Total:				\$0	\$152,160,133	\$32.08846

^ACO₂ Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit B-14. Case B31B.97 LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	22.1	32%
Fixed	7.7	11%
Variable	4.2	6%
Fuel	32.1	46%
Total (Excluding T&S)	66.1	N/A
CO ₂ T&S	3.8	5%
Total (Including T&S)	69.9	N/A

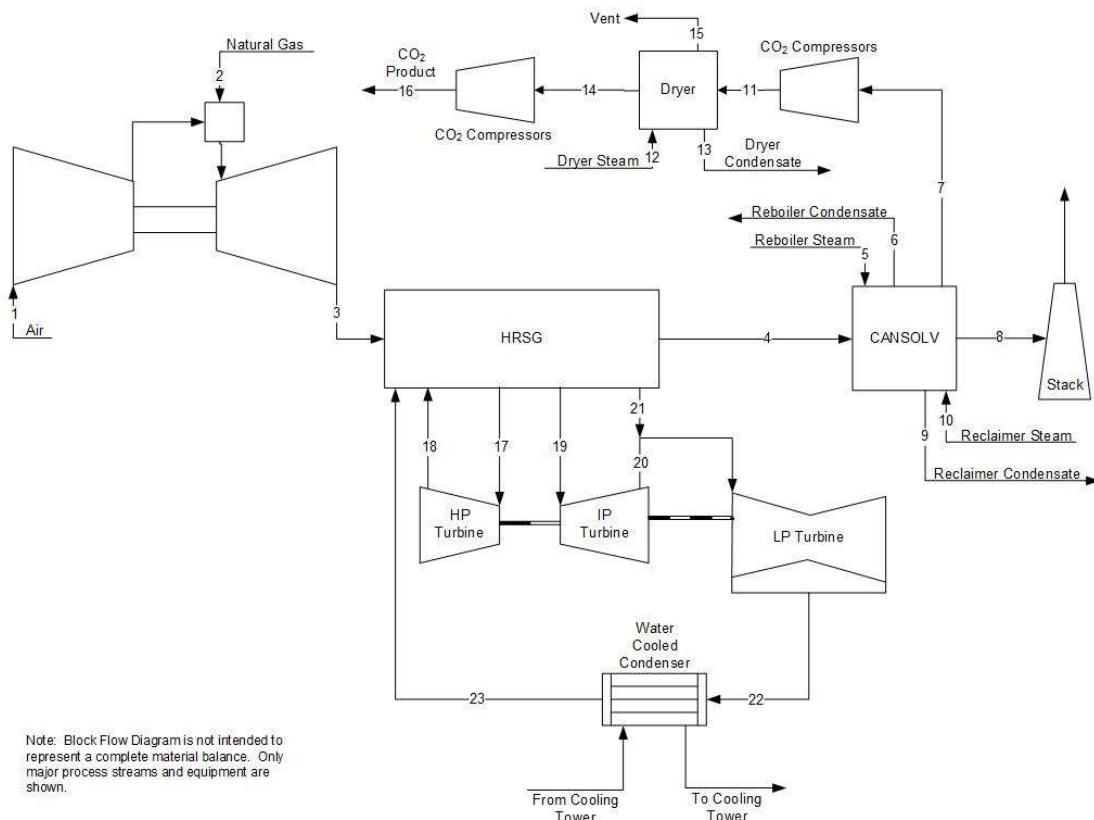
B.2 CASE B32B.97 – NGCC WITH 97 PERCENT CO₂ CAPTURE

PROCESS DESCRIPTION

The plant configuration and process description for Case B32B.97 is the same as Case B32B.90 with the exception that the CDR technology captures 97, rather than 90, percent of the CO₂ in the flue gas. The nominal net output decreases to 873 MW.

The process description for Case B32B.97 is the same as Case B32B.90. A BFD and stream tables for Case B31B.97 are shown in Exhibit B-15 and Exhibit B-16, respectively. Since the CDR facility process description was provided in Section 5.1.5, it is not repeated here.

Exhibit B-15. Case B32B.97 block flow diagram, NGCC with CO₂ capture



COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit B-16. Case B32B.97 stream table, NGCC with capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000	0.0000	0.0096	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₂ H ₆	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0100	0.0408	0.0408	0.0000	0.0000	0.9778	0.0013	0.0000	0.0000	0.9957	0.0000
H ₂ O	0.0099	0.0000	0.0873	0.0873	1.0000	1.0000	0.0222	0.0582	1.0000	1.0000	0.0043	1.0000
N ₂	0.7732	0.0160	0.7429	0.7429	0.0000	0.0000	0.0000	0.8013	0.0000	0.0000	0.0000	0.0000
O ₂	0.2074	0.0000	0.1201	0.1201	0.0000	0.0000	0.0000	0.1296	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	177,074	7,158	184,439	184,439	20,289	18,583	7,456	170,988	176	176	7,322	11
V-L Flowrate (kg/hr)	5,109,811	124,025	5,233,836	5,233,836	365,520	334,778	323,838	4,801,989	3,164	3,164	321,426	195
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	596	104	296	105	31	39	214	336	29	336
Pressure (MPa, abs)	0.10	3.79	0.11	0.10	0.51	0.12	0.17	0.10	2.04	3.62	2.82	3.62
Steam Table Enthalpy (kJ/kg) ^A	30.23	12.56	798.45	248.33	3,054.97	439.34	49.44	133.62	913.81	3,066.29	-1.25	3,066.29
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-4,496.67	-675.71	-1,225.83	-12,925.33	-15,540.95	-8,979.10	-505.13	-15,066.49	-12,914.01	-8,976.09	-12,914.01
Density (kg/m ³)	1.2	28.8	0.4	0.9	2.0	954.9	3.0	1.1	848.5	13.9	58.0	13.9
V-L Molecular Weight	28.857	17.328	28.377	28.377	18.015	18.015	43.433	28.084	18.015	18.015	43.898	18.015
V-L Flowrate (lb _{mol} /hr)	390,381	15,780	406,618	406,618	44,731	40,969	16,438	376,963	387	387	16,143	24
V-L Flowrate (lb/hr)	11,265,204	273,429	11,538,633	11,538,633	805,835	738,060	713,940	10,586,574	6,976	6,976	708,623	430
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,105	220	565	221	88	102	416	637	85	637
Pressure (psia)	14.7	550.0	15.5	14.8	73.5	17.4	24.8	14.8	296.6	525.0	409.1	525.0
Steam Table Enthalpy (Btu/lb) ^A	13.0	5.4	343.3	106.8	1,313.4	188.9	21.3	57.4	392.9	1,318.3	-0.5	1,318.3
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-1,933.2	-290.5	-527.0	-5,556.9	-6,681.4	-3,860.3	-217.2	-6,477.4	-5,552.0	-3,859.0	-5,552.0
Density (lb/ft ³)	0.076	1.799	0.026	0.057	0.122	59.612	0.185	0.069	52.968	0.869	3.622	0.869

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit B-16. Case B32B.97 stream table, NGCC with capture (cont'd)

	13	14	15	16	17	18	19	20	21	22	23
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH ₄ S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₂ H ₆	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₃ H ₈	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C ₄ H ₁₀	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0000	0.9995	0.0500	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	1.0000	0.0005	0.9500	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	11	7,293	29	7,293	31,414	31,414	38,581	38,581	5,627	23,918	42,727
V-L Flowrate (kg/hr)	195	320,859	567	320,859	565,941	565,941	695,042	695,042	101,375	430,897	769,742
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	203	29	29	30	585	336	562	296	287	38	38
Pressure (MPa, abs)	1.64	2.69	2.82	15.27	18.50	3.62	3.31	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg) ^A	863.65	-3.70	137.93	-231.09	3,509.09	3,066.29	3,593.96	3,054.97	3,037.05	2,358.68	160.78
AspenPlus Enthalpy (kJ/kg) ^B	-15,116.65	-8,967.26	-15,225.22	-9,194.65	-12,471.21	-12,914.01	-12,386.34	-12,925.33	-12,943.24	-13,621.61	-15,819.51
Density (kg/m ³)	861.8	54.9	352.5	630.1	51.8	13.9	8.7	2.0	2.0	0.1	992.8
V-L Molecular Weight	18.015	43.997	19.315	43.997	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	24	16,078	65	16,078	69,257	69,257	85,056	85,056	12,406	52,731	94,197
V-L Flowrate (lb/hr)	430	707,373	1,250	707,373	1,247,686	1,247,686	1,532,306	1,532,306	223,494	949,965	1,696,991
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	397	85	85	86	1,085	637	1,044	565	549	101	101
Pressure (psia)	237.4	390.4	409.1	2,214.7	2,683.2	525.0	479.8	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb) ^A	371.3	-1.6	59.3	-99.4	1,508.6	1,318.3	1,545.1	1,313.4	1,305.7	1,014.0	69.1
AspenPlus Enthalpy (Btu/lb) ^B	-6,499.0	-3,855.2	-6,545.7	-3,953.0	-5,361.7	-5,552.0	-5,325.2	-5,556.9	-5,564.6	-5,856.2	-6,801.2
Density (lb/ft ³)	53.801	3.430	22.007	39.338	3.233	0.869	0.546	0.125	0.124	0.003	61.977

^ASteam table reference conditions are 32.02°F & 0.089 psia

^BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

B.2.1 Case B32B.97 – Performance Results

The Case B32B.97 modeling assumptions were presented previously in Section 5.3.1.

The plant produces a net output of 873 MW at a net plant efficiency of 48.4 percent (HHV basis). Overall plant performance summarized in Exhibit B-17 provides a detailed breakdown of the auxiliary power requirements. The CDR facility, including CO₂ compression, accounts for over 69 percent of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for nearly 13 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility. Case B32B.97 plant power is summarized in Exhibit B-18.

Exhibit B-17. Case B32B.97 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	686
Steam Turbine Power, MWe	253
Total Gross Power, MWe	939
CO ₂ Capture/Removal Auxiliaries, kWe	20,200
CO ₂ Compression, kWe	25,660
Balance of Plant, kWe	20,253
Total Auxiliaries, MWe	66
Net Power, MWe	873
HHV Net Plant Efficiency, %	48.4
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,433 (7,045)
HHV Combustion Turbine Efficiency, %	38.0
LHV Net Plant Efficiency, %	53.7
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,709 (6,359)
LHV Combustion Turbine Efficiency, %	42.2
Steam Turbine Cycle Efficiency, %	47.9
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,514 (7,121)
CO ₂ Capture Rate, %	97
Condenser Duty, GJ/hr (MMBtu/hr)	955 (906)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	1,686 (1,598)
Natural Gas Feed Flow, kg/hr (lb/hr)	124,025 (273,429)
HHV Thermal Input, kWt	1,801,631
LHV Thermal Input, kWt	1,626,150
Raw Water Withdrawal, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.025 (6.6)
Raw Water Consumption, (m ³ /min)/MW _{net} (gpm/MW _{net})	0.017 (4.4)

Exhibit B-18. Case B32B.97 plant power summary

Power Summary	
Combustion Turbine Power, MWe	686
Steam Turbine Power, MWe	253
Total Gross Power, MWe	939
Auxiliary Load Summary	
Circulating Water Pumps, kWe	5,600
Combustion Turbine Auxiliaries, kWe	1,320
Condensate Pumps, kWe	200
Cooling Tower Fans, kWe	2,890
CO ₂ Capture/Removal Auxiliaries, kWe	20,200
CO ₂ Compression, kWe	25,660
Feedwater Pumps, kWe	5,760
Ground Water Pumps, kWe	520
Miscellaneous Balance of Plant, ^A kWe	710
SCR, kWe	3
Steam Turbine Auxiliaries, kWe	230
Transformer Losses, kWe	3,020
Total Auxiliaries, MWe	66
Net Power, MWe	873

^AIncludes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

B.2.1.1 Environmental Performance

The environmental targets for emissions of NO_x, SO₂, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B32B.97 is presented in Exhibit B-19.

Exhibit B-19. Case B32B.97 air emissions

	kg/GJ (lb/MMBtu)	tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.000 (0.000)	0 (0)	0.000 (0.000)
NO _x	0.001 (0.003)	69 (76)	0.010 (0.022)
Particulate	0.000 (0.000)	0 (0)	0.000 (0.000)
Hg	0.00E+0 (0.00E+0)	0.000 (0.000)	0.00E+0 (0.00E+0)
CO	0.000 (0.000)	0 (0)	0.000 (0.000)
CO ₂	2 (4)	73,890 (81,450)	11 (23)
CO ₂ ^C	—	—	11 (25)

^ACalculations based on an 85 percent capacity factor

^BEmissions based on gross power except where otherwise noted

^CCO₂ emissions based on net power instead of gross power

For the purpose of this report, the natural gas was assumed to contain the domestic average value of total sulfur of 0.34 gr/100 scf (4.71×10^{-4} lb-S/MMBtu). [23] It was also assumed that the added CH₄S was the sole contributor of sulfur to the natural gas. No sulfur capture systems were required.

The NGCC cases were designed to achieve approximately 1.8 ppmvd NO_x emissions (at 15 percent O₂) using a DLN burner in the CTG—the DLN burners reduce the emissions to about 9 ppmvd (at 15 percent O₂) [34]—and an SCR—the SCR system is designed for 86.7 percent NO_x reduction. [35]

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2017 H-class gas turbine achieves approximately 1.0 ppmv CO and 1.0 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not present in any significant amount. Any CO or PM present in the flue gas is assumed to interact with, and be removed by, the CDR system solvent.

CO₂ emissions are reduced relative to those produced by burning coal given the same power output because of the higher heat content of natural gas, the lower carbon intensity of gas relative to coal, and the higher overall efficiency of the NGCC plant relative to a coal-fired plant.

The CDR facility removes 97 percent of the CO₂ in the flue gas.

The carbon balance for the plant is shown in Exhibit B-20. The carbon input to the plant consists of carbon in the natural gas in addition to carbon in the CT air. Carbon leaves the plant as CO₂ in the stack gas, the CO₂ dryer's vent, and the captured CO₂ product. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in, represented by the following fraction:

$$1 - \frac{\text{Carbon in Stack}}{\text{Total Carbon In}} = \left(1 - \left(\frac{5,971}{199,024} \right) \right) * 100 = 97\%$$

Exhibit B-20. Case B32B.97 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	89,581 (197,492)	Stack Gas	2,708 (5,971)
Air (CO ₂)	695 (1,532)	CO ₂ Product	87,550 (193,014)
		CO ₂ Dryer Vent	18 (39)
		CO ₂ Knockout	0.2 (0.4)
Total	90,276 (199,024)	Total	90,276 (199,024)

As shown in Exhibit B-21, the sulfur content of the natural gas is insignificant, entirely comprising CH₄S (used as an odorant). [23] All sulfur in the natural gas is assumed to react with the CDR system solvent and is removed from the solvent during solvent reclaiming as a waste stream.

Exhibit B-21. Case B32B.97 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.3 (2.9)	Stack Gas	0.0 (0.0)
		Solvent Reclaiming	1.3 (2.9)
Total	1.3 (2.9)	Total	1.3 (2.9)

Exhibit B-22 shows the overall water balance for the plant.

Exhibit B-22. Case B32B.97 water balance

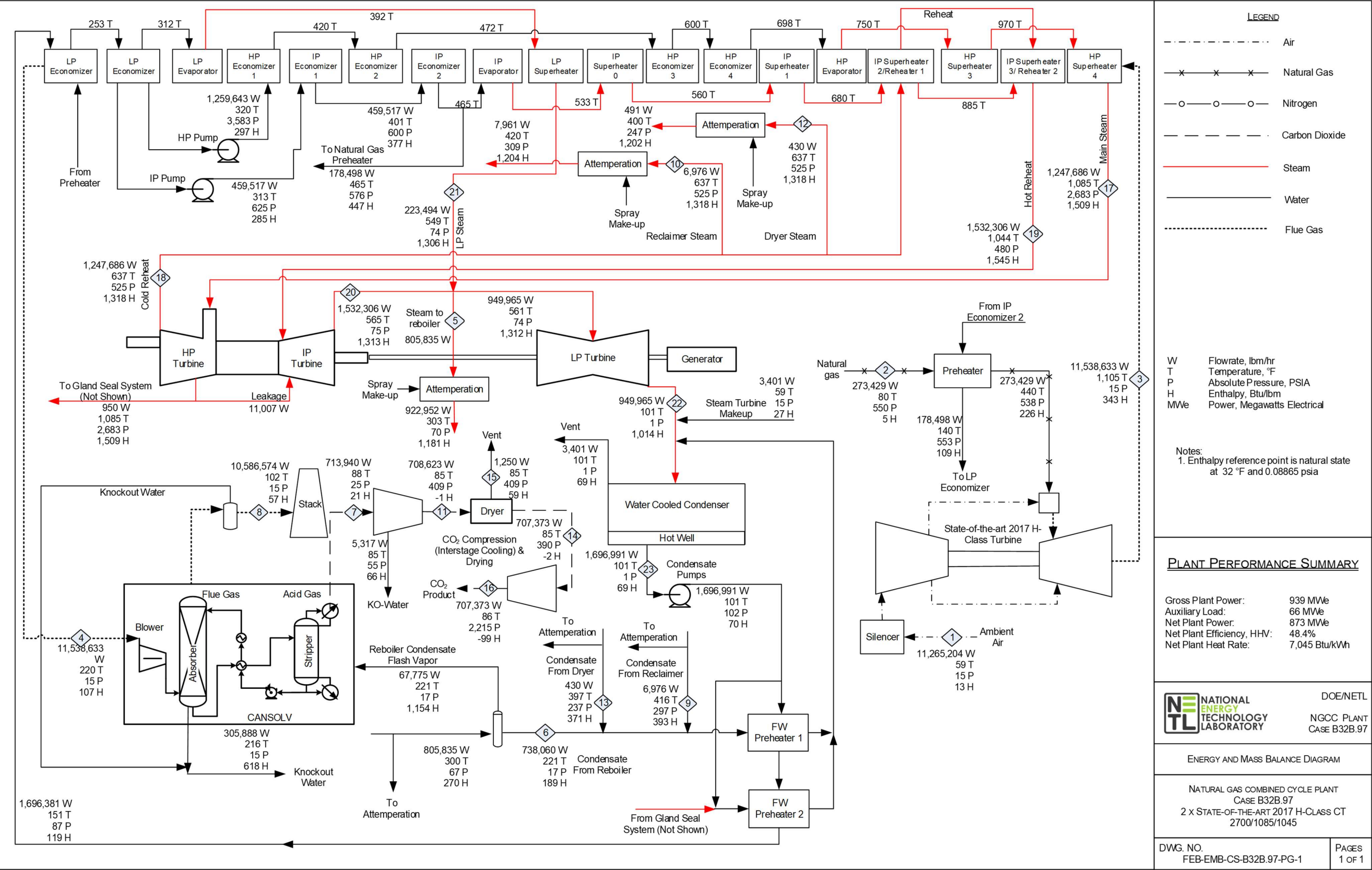
Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
CO ₂ Drying	–	–	–	0.0 (2.5)	0.0 (-2.5)
CO ₂ Capture System Makeup	–	–	–	–	–
CO ₂ Capture Recovery	–	–	–	2.3 (612)	-2.3 (-612)
CO ₂ Compression Recovery	–	–	–	0.0 (11)	0.0 (-11)
Deaerator Vent	–	–	–	0.0 (6.8)	0.0 (-6.8)
Condenser Makeup	0.0 (6.8)	–	0.0 (6.8)	–	0.0 (6.8)
BFW Makeup	0.0 (6.8)	–	0.0 (6.8)	–	0.0 (6.8)
Cooling Tower	22 (5,758)	–	22 (5,758)	4.9 (1,295)	17 (4,463)
Total	22 (5,765)	–	22 (5,765)	7.3 (1,927)	15 (3,838)

B.2.1.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram for B32B.97 is shown in Exhibit B-23. An overall plant energy balance is provided in tabular form in Exhibit B-24.

The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals is calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT and 98.7 percent for the steam turbine. The cooling tower load includes the condenser, capture process heat rejected to cooling water, the CO₂ compressor intercooler load, and other miscellaneous cooling loads.

Exhibit B-23. Case B32B.97 energy and mass balance, NGCC with CO₂ capture



This page intentionally left blank

Exhibit B-24. Case B32B.97 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	6,486 (6,147)	4.3 (4.1)	–	6,490 (6,152)
Air	–	154 (146)	–	154 (146)
Raw Water Makeup	–	82 (78)	–	82 (78)
Auxiliary Power	–	–	238 (226)	238 (226)
TOTAL	6,486 (6,147)	241 (228)	238 (226)	6,965 (6,601)
Heat Out GJ/hr (MMBtu/hr)				
Stack Gas	–	642 (608)	–	642 (608)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	80 (76)	80 (76)
Cooling Tower Load ^A	–	2,847 (2,698)	–	2,847 (2,698)
CO ₂ Product Stream	–	-74 (-70)	–	-74 (-70)
AGR Effluent	–	59 (56)	–	59 (56)
Deaerator Vent	–	0.2 (0.2)	–	0.2 (0.2)
<i>Ambient Losses^B</i>	–	43 (41)	–	43 (41)
Power	–	–	3,379 (3,203)	3,379 (3,203)
TOTAL	–	3,517 (3,333)	3,460 (3,279)	6,976 (6,612)
<i>Unaccounted Energy^C</i>	–	-12 (-11)	–	-12 (-11)

^AIncludes condenser, AGR, and miscellaneous cooling loads

^BAmbient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers

^CBy difference

B.2.2 Case B32B.97 – Major Equipment List

Major equipment items for the NGCC plant with CO₂ capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 0. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Case B32B.97 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	102,000 liters (27,000 gal)	2	0
2	Condensate Pumps	Vertical canned	14,210 lpm @ 90 m H ₂ O (3,750 gpm @ 280 ft H ₂ O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 5,270 lpm @ 2,980 m H ₂ O (1,390 gpm @ 9,780 ft H ₂ O) IP water: 3,850 lpm @ 460 m H ₂ O (1,020 gpm @ 1,520 ft H ₂ O)	2	2
4	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m ³ /min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m ³ /min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 GJ/hr (13 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,200 lpm @ 20 m H ₂ O (1,400 gpm @ 70 ft H ₂ O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H ₂ O (1,000 gpm @ 350 ft H ₂ O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H ₂ O (700 gpm @ 250 ft H ₂ O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	11,100 lpm @ 20 m H ₂ O (2,900 gpm @ 60 ft H ₂ O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H ₂ O (40 gpm @ 160 ft H ₂ O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
15	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
16	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	79 m ³ /min @ 3.8 MPa (2,787 acfm @ 550 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
17	Gas Metering Station	–	79 m ³ /min (2,787 acfm)	1	0

Case B32B.97 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CANSOLV	Amine-based CO ₂ capture technology	5,757,000 kg/hr (12,692,000 lb/hr) 6.3 wt % CO ₂ concentration	1	0
2	CANSOLV LP Condensate Pump	Centrifugal	984 lpm @ 1 m H ₂ O (260 gpm @ 3 ft H ₂ O)	1	1
3	CANSOLV HP Condensate Pump	Centrifugal	8 lpm @ 5 m H ₂ O (2 gpm @ 15 ft H ₂ O)	1	1
4	CO ₂ Dryer	Triethylene glycol	Inlet: 92 m ³ /min @ 2.8 MPa (3,260 acfm @ 409 psia) Outlet: 2.7 MPa (390 psia) Water Recovered: 567 kg/hr (1,250 lb/hr)	1	0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	CO ₂ Compressor	Integrally geared, multi-stage centrifugal	5.0 m ³ /min @ 15.3 MPa, 82°C (165 acfm @ 2,217 psia, 180°F)	2	0
6	CO ₂ Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 50 GJ/hr (48 MMBtu/hr)	2	0

Case B32B.97 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	Advanced H class w/ dry low-NOx burner	345 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	380 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	2	0

Case B32B.97 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 5.9 m (19 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main steam – 311,268 kg/hr, 18.4 MPa/585°C (686,227 lb/hr, 2,669 psig/1,085°F) Reheat steam – 382,274 kg/hr, 3.2 MPa/562°C (842,768 lb/hr, 465 psig/1,044°F)	2	0
3	SCR Reactor	–	2,880,000 kg/hr (6,350,000 lb/hr)	2	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	10 m ³ /min @ 108 cm WG (300 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	1.8 lpm @ 90 m H ₂ O (0.5 gpm @ 300 ft H ₂ O)	2	1
7	Ammonia Storage Tank	Horizontal tank	51,000 liter (13,000 gal)	1	0

Case B32B.97 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	267 MW 18.4 MPa/585°C/562°C (2,668 psig/1,085°F/1,044°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	300 MVA @ 0.9 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	1,050 GJ/hr (1,000 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

Case B32B.97 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	562,000 lpm @ 30 m (148,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 3,130 GJ/hr (2,970 MMBtu/hr) heat duty	1	0

Case B32B.97 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 270 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 200 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 10 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 23 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 8 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B32B.97 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

B.2.3 Case B32B.97 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit B-25 shows a detailed breakdown of the capital costs; Exhibit B-26 shows the owner's costs, TOC, and TASC; Exhibit B-27 shows the initial and annual O&M costs; and Exhibit B-28 shows the LCOE breakdown.

The estimated TPC of the NGCC with CO₂ capture is \$1,654/kW. Process contingency represents 4.0 percent of the TPC and project contingency represents 14.9 percent. The LCOE, including CO₂ T&S costs of \$3.7/MWh, is \$66.8/MWh.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit B-25. Case B32B.97 total plant cost details

Case:		B32B.97	– 2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		873					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
3 Feedwater & Miscellaneous BOP Systems											
3.1	Feedwater System	\$1,894	\$3,246	\$1,623	\$0	\$6,763	\$1,353	\$0	\$1,217	\$9,333	\$11
3.2	Water Makeup & Pretreating	\$6,138	\$614	\$3,478	\$0	\$10,230	\$2,046	\$0	\$2,455	\$14,731	\$17
3.3	Other Feedwater Subsystems	\$1,077	\$353	\$336	\$0	\$1,766	\$353	\$0	\$318	\$2,437	\$3
3.4	Service Water Systems	\$1,863	\$3,556	\$11,514	\$0	\$16,932	\$3,386	\$0	\$4,064	\$24,383	\$28
3.5	Other Boiler Plant Systems	\$286	\$104	\$260	\$0	\$649	\$130	\$0	\$117	\$895	\$1
3.6	Natural Gas Pipeline and Start-Up System	\$12,372	\$532	\$399	\$0	\$13,304	\$2,661	\$0	\$2,395	\$18,359	\$21
3.7	Waste Water Treatment Equipment	\$10,728	\$0	\$6,575	\$0	\$17,304	\$3,461	\$0	\$4,153	\$24,917	\$29
3.9	Miscellaneous Plant Equipment	\$18,904	\$2,479	\$9,607	\$0	\$30,991	\$6,198	\$0	\$7,438	\$44,626	\$51
	Subtotal	\$53,261	\$10,884	\$33,792	\$0	\$97,937	\$19,587	\$0	\$22,156	\$139,681	\$160
5 Flue Gas Cleanup											
5.1	CANSOLV Carbon Dioxide (CO ₂) Removal System	\$130,962	\$60,798	\$127,675	\$0	\$319,434	\$63,887	\$57,498	\$88,164	\$528,983	\$606
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$31,283	\$4,693	\$12,978	\$0	\$48,954	\$9,791	\$0	\$11,749	\$70,494	\$81
5.5	Carbon Dioxide (CO ₂) Compressor Aftercooler	\$302	\$48	\$130	\$0	\$480	\$96	\$0	\$115	\$691	\$1
5.12	Gas Cleanup Foundations	\$0	\$508	\$549	\$0	\$1,057	\$211	\$0	\$254	\$1,522	\$2
	Subtotal	\$162,547	\$66,046	\$141,331	\$0	\$369,925	\$73,985	\$57,498	\$100,282	\$601,690	\$690
6 Combustion Turbine & Accessories											
6.1	Combustion Turbine Generator	\$143,342	\$0	\$8,723	\$0	\$152,065	\$30,413	\$0	\$27,372	\$209,850	\$240
6.3	Combustion Turbine Accessories	\$3,492	\$0	\$213	\$0	\$3,705	\$741	\$0	\$667	\$5,112	\$6
6.4	Compressed Air Piping	\$0	\$1,153	\$261	\$0	\$1,414	\$283	\$0	\$255	\$1,951	\$2
6.5	Combustion Turbine Foundations	\$0	\$1,301	\$1,407	\$0	\$2,708	\$542	\$0	\$650	\$3,900	\$4
	Subtotal	\$146,834	\$2,454	\$10,603	\$0	\$159,892	\$31,978	\$0	\$28,943	\$220,813	\$253
7 HRSG, Ductwork, & Stack											
7.1	Heat Recovery Steam Generator	\$63,255	\$0	\$15,814	\$0	\$79,069	\$15,814	\$0	\$14,232	\$109,115	\$125
7.2	Heat Recovery Steam Generator Accessories	\$19,689	\$0	\$3,652	\$0	\$23,341	\$4,668	\$0	\$4,201	\$32,211	\$37
7.3	Ductwork	\$0	\$1,078	\$749	\$0	\$1,827	\$365	\$0	\$329	\$2,521	\$3
7.4	Stack	\$10,304	\$0	\$1,911	\$0	\$12,215	\$2,443	\$0	\$2,199	\$16,857	\$19
7.5	Heat Recovery Steam Generator, Ductwork & Stack Foundations	\$0	\$803	\$754	\$0	\$1,558	\$312	\$0	\$374	\$2,243	\$3
7.6	Selective Catalytic Reduction System	\$1,981	\$832	\$1,160	\$0	\$3,973	\$795	\$0	\$715	\$5,483	\$6
	Subtotal	\$95,228	\$2,713	\$24,041	\$0	\$121,983	\$24,397	\$0	\$22,050	\$168,430	\$193

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Case:		B32B.97	– 2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:		Conceptual		
Plant Size (MW, net):		873					Cost Base:		Dec 2018		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
	8 Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	\$31,412	\$0	\$4,600	\$0	\$36,012	\$7,202	\$0	\$6,482	\$49,696	\$57
8.2	Steam Turbine Plant Auxiliaries	\$144	\$0	\$321	\$0	\$466	\$93	\$0	\$84	\$643	\$1
8.3	Condenser & Auxiliaries	\$4,944	\$0	\$2,647	\$0	\$7,590	\$1,518	\$0	\$1,366	\$10,475	\$12
8.4	Steam Piping	\$10,971	\$0	\$4,446	\$0	\$15,417	\$3,083	\$0	\$2,775	\$21,275	\$24
8.5	Turbine Generator Foundations	\$0	\$1,219	\$2,012	\$0	\$3,231	\$646	\$0	\$775	\$4,652	\$5
	Subtotal	\$47,470	\$1,219	\$14,026	\$0	\$62,715	\$12,543	\$0	\$11,483	\$86,741	\$99
	9 Cooling Water System										
9.1	Cooling Towers	\$13,399	\$0	\$4,057	\$0	\$17,456	\$3,491	\$0	\$3,142	\$24,089	\$28
9.2	Circulating Water Pumps	\$1,761	\$0	\$108	\$0	\$1,869	\$374	\$0	\$336	\$2,579	\$3
9.3	Circulating Water System Auxiliaries	\$11,455	\$0	\$1,511	\$0	\$12,966	\$2,593	\$0	\$2,334	\$17,893	\$21
9.4	Circulating Water Piping	\$0	\$3,492	\$3,162	\$0	\$6,654	\$1,331	\$0	\$1,198	\$9,183	\$11
9.5	Make-up Water System	\$396	\$0	\$509	\$0	\$906	\$181	\$0	\$163	\$1,250	\$1
9.6	Component Cooling Water System	\$515	\$0	\$395	\$0	\$910	\$182	\$0	\$164	\$1,256	\$1
9.7	Circulating Water System Foundations	\$0	\$808	\$1,341	\$0	\$2,149	\$430	\$0	\$516	\$3,095	\$4
	Subtotal	\$27,525	\$4,300	\$11,085	\$0	\$42,910	\$8,582	\$0	\$7,853	\$59,345	\$68
	11 Accessory Electric Plant										
11.1	Generator Equipment	\$2,967	\$0	\$2,238	\$0	\$5,205	\$1,041	\$0	\$937	\$7,183	\$8
11.2	Station Service Equipment	\$8,113	\$0	\$696	\$0	\$8,809	\$1,762	\$0	\$1,586	\$12,156	\$14
11.3	Switchgear & Motor Control	\$11,584	\$0	\$2,010	\$0	\$13,593	\$2,719	\$0	\$2,447	\$18,759	\$21
11.4	Conduit & Cable Tray	\$0	\$2,799	\$8,067	\$0	\$10,866	\$2,173	\$0	\$1,956	\$14,995	\$17
11.5	Wire & Cable	\$0	\$4,179	\$7,470	\$0	\$11,649	\$2,330	\$0	\$2,097	\$16,075	\$18
11.6	Protective Equipment	\$593	\$0	\$2,059	\$0	\$2,652	\$530	\$0	\$477	\$3,659	\$4
11.7	Standby Equipment	\$730	\$0	\$674	\$0	\$1,405	\$281	\$0	\$253	\$1,939	\$2
11.8	Main Power Transformers	\$8,706	\$0	\$178	\$0	\$8,883	\$1,777	\$0	\$1,599	\$12,259	\$14
11.9	Electrical Foundations	\$0	\$111	\$282	\$0	\$392	\$78	\$0	\$94	\$565	\$1
	Subtotal	\$32,692	\$7,089	\$23,673	\$0	\$63,454	\$12,691	\$0	\$11,445	\$87,590	\$100
	12 Instrumentation & Control										
12.1	Natural Gas Combined Cycle Control Equipment	\$253	\$0	\$161	\$0	\$414	\$83	\$0	\$74	\$571	\$1
12.2	Combustion Turbine Control Equipment	\$492	\$0	\$313	\$0	\$805	\$161	\$0	\$145	\$1,112	\$1
12.3	Steam Turbine Control Equipment	\$405	\$0	\$258	\$0	\$663	\$133	\$0	\$119	\$915	\$1
12.4	Other Major Component Control Equipment	\$688	\$0	\$438	\$0	\$1,126	\$225	\$56	\$211	\$1,619	\$2
12.5	Signal Processing Equipment	\$567	\$0	\$17	\$0	\$584	\$117	\$0	\$105	\$806	\$1
12.6	Control Boards, Panels & Racks	\$152	\$0	\$93	\$0	\$244	\$49	\$12	\$46	\$351	\$0

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO
ELECTRICITY

Case:		B32B.97	– 2x1 CT NGCC w/ CO ₂ Capture				Estimate Type:		Conceptual		
Plant Size (MW, net):		873					Cost Base:		Dec 2018		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
12.7	Distributed Control System Equipment	\$8,430	\$0	\$258	\$0	\$8,688	\$1,738	\$434	\$1,629	\$12,489	\$14
12.8	Instrument Wiring & Tubing	\$696	\$557	\$2,227	\$0	\$3,480	\$696	\$174	\$653	\$5,003	\$6
12.9	Other Instrumentation & Controls Equipment	\$482	\$0	\$1,116	\$0	\$1,598	\$320	\$80	\$300	\$2,298	\$3
	Subtotal	\$12,164	\$557	\$4,882	\$0	\$17,603	\$3,521	\$757	\$3,282	\$25,163	\$29
13 Improvements to Site											
13.1	Site Preparation	\$0	\$639	\$13,564	\$0	\$14,203	\$2,841	\$0	\$3,409	\$20,453	\$23
13.2	Site Improvements	\$0	\$2,055	\$2,715	\$0	\$4,770	\$954	\$0	\$1,145	\$6,869	\$8
13.3	Site Facilities	\$1,972	\$0	\$2,069	\$0	\$4,041	\$808	\$0	\$970	\$5,819	\$7
	Subtotal	\$1,972	\$2,693	\$18,349	\$0	\$23,014	\$4,603	\$0	\$5,523	\$33,140	\$38
14 Buildings & Structures											
14.1	Combustion Turbine Area	\$0	\$497	\$262	\$0	\$759	\$152	\$0	\$137	\$1,048	\$1
14.3	Steam Turbine Building	\$0	\$3,408	\$4,535	\$0	\$7,943	\$1,589	\$0	\$1,430	\$10,961	\$13
14.4	Administration Building	\$0	\$400	\$271	\$0	\$671	\$134	\$0	\$121	\$925	\$1
14.5	Circulation Water Pumphouse	\$0	\$98	\$48	\$0	\$146	\$29	\$0	\$26	\$202	\$0
14.6	Water Treatment Buildings	\$0	\$488	\$444	\$0	\$932	\$186	\$0	\$168	\$1,286	\$1
14.7	Machine Shop	\$0	\$600	\$384	\$0	\$983	\$197	\$0	\$177	\$1,357	\$2
14.8	Warehouse	\$0	\$465	\$280	\$0	\$744	\$149	\$0	\$134	\$1,027	\$1
14.9	Other Buildings & Structures	\$0	\$333	\$241	\$0	\$573	\$115	\$0	\$103	\$791	\$1
14.10	Waste Treating Building & Structures	\$0	\$782	\$1,397	\$0	\$2,179	\$436	\$0	\$392	\$3,007	\$3
	Subtotal	\$0	\$7,069	\$7,862	\$0	\$14,931	\$2,986	\$0	\$2,688	\$20,605	\$24
	Total	\$579,696	\$105,025	\$289,644	\$0	\$974,365	\$194,873	\$58,255	\$215,705	\$1,443,198	\$1,654

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit B-26. Case B32B.97 owner's costs

Description	\$/1,000	\$/kW
Pre-Production Costs		
6 Months All Labor	\$8,591	\$10
1 Month Maintenance Materials	\$1,613	\$2
1 Month Non-fuel Consumables	\$918	\$1
1 Month Waste Disposal	\$10	\$0
25% of 1 Months Fuel Cost at 100% CF	\$4,959	\$6
2% of TPC	\$28,864	\$33
Total	\$44,955	\$52
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	\$1,357	\$2
0.5% of TPC (spare parts)	\$7,216	\$8
Total	\$8,573	\$10
Other Costs		
Initial Cost for Catalyst and Chemicals	\$1,129	\$1
Land	\$300	\$0
Other Owner's Costs	\$216,480	\$248
Financing Costs	\$38,966	\$45
Total Overnight Costs (TOC)	\$1,753,601	\$2,010
TASC Multiplier (IOU, 33 year)	1.093	
Total As-Spent Cost (TASC)	\$1,916,067	\$2,196

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit B-27. Case B32B.97 initial and annual operating and maintenance costs

Case:	B32B.97	H-frame 2x1 CT NGCC w/ CO ₂ Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	873	Heat Rate-net (Btu/kWh):	7,045	Capacity Factor (%):	85	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	1.0	
Operating Labor Burden:		30.00	% of base	Operator:	3.3	
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	6.3	
Fixed Operating Costs						
					Annual Cost	
					(\$)	(\$/kW-net)
Annual Operating Labor:					\$2,776,628	\$3.182
Maintenance Labor:					\$10,968,308	\$12.570
Administrative & Support Labor:					\$3,436,234	\$3.938
Property Taxes and Insurance:					\$28,863,968	\$33.079
Total:					\$46,045,138	\$52.769
Variable Operating Costs						
					(\$)	(\$/MWh-net)
Maintenance Material:					\$16,452,462	\$2.53221
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill		
Water (/1000 gallons):	0	4,151	\$1.90	\$0	\$2,446,871	\$0.37660
Makeup and Waste Water Treatment Chemicals (ton):	0	12.4	\$550	\$0	\$2,109,940	\$0.32474
Ammonia (19 wt%, ton):	0	4.65	\$300	\$0	\$432,815	\$0.06661
SCR Catalyst (ft ³):	7,527	4.12	\$150	\$1,129,110	\$191,949	\$0.02954
CO ₂ Capture System Chemicals ^A :	Proprietary				\$2,848,471	\$0.43841
Triethylene Glycol (gal):	w/equip.	633	\$6.80	\$0	\$1,335,259	\$0.20551
Subtotal:				\$1,129,110	\$9,365,304	\$1.44142
Waste Disposal						
SCR Catalyst (ft ³):	0	4.12	\$2.50	\$0	\$3,199	\$0.00049
Triethylene Glycol (gal):	0	633	\$0.35	\$0	\$68,727	\$0.01058
Thermal Reclaimer Unit Waste (ton):	0	2.540	\$38.0	\$0	\$29,946	\$0.00461
Subtotal:				\$0	\$101,872	\$0.01568
Variable Operating Costs Total:				\$1,129,110	\$25,919,637	\$3.98930
Fuel Cost						
Natural Gas (MMBtu):	0	147,538	\$4.42	\$0	\$202,328,910	\$31.14054
Total:				\$0	\$202,328,910	\$31.14054

^ACO₂ Capture System Chemicals includes ion exchange resin, sodium hydroxide, and CANSOLV solvent

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS
COAL AND NATURAL GAS TO ELECTRICITY

Exhibit B-28. Case B32B.97 LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	20.9	31%
Fixed	7.1	11%
Variable	4.0	6%
Fuel	31.1	47%
Total (Excluding T&S)	63.1	N/A
CO ₂ T&S	3.7	6%
Total (Including T&S)	66.8	N/A

APPENDIX C – SUMMARY OF CAPTURE RATES ABOVE 95 PERCENT

Commercial-scale demonstration of solvent-based post-combustion CO₂ capture systems at power generation facilities (specifically PC plants) has shown the ability to capture 90 percent of the CO₂ in the flue gas stream. [11] [12] Moreover, field-testing of post-combustion CO₂ capture technology as well as vendor and industry feedback on projects currently in the planning stages (including FEED projects sponsored by DOE) indicates that capture rates as high as 95 percent are feasible for both coal- and natural gas-fueled electricity generating units. [13] [14] [15] [16] Given the breadth of publicly-available information supporting the capability for post-combustion capture systems to remove greater than 90 percent of the CO₂ in the treated stream, cases for 90 percent and 95 percent capture on NGCC and PC are presented in the main body of this report.

It should be emphasized that technology suppliers (as reflected in vendor-supplied information provided to DOE for this study that included cost and performance estimates for >95 percent CCS (97 percent for NGCC and 99 percent for PC) study cases) as well as subject matter experts acknowledge and support that solvent-based post-combustion CO₂ capture technologies are capable of achieving CO₂ removal rates beyond 95 percent on low-purity streams representative of fossil-fueled combustion. Although technoeconomic analyses of deep decarbonization (≥ 99 percent) of combustion flue gas have been published by others, [17] [18] the relatively limited experience with design and operation of capture systems that can routinely, reliably, and economically achieve very high removal rates requires further study. Technoeconomic analysis of the higher capture rates (97% NGCC and 99% PC) are included in the Appendices to this report. The performance and environmental profile summaries for PC and NGCC cases with CO₂ capture rates greater than 95 percent are shown in Exhibit C-1; the primary conclusions that can be drawn are:

- The emissions of Hg, HCl, PM, NO_x, and SO₂ are all at or below the applicable federal regulatory limits currently in effect for PC and NGCC technologies (Natural gas contains no Hg or chloride).
- For the PC cases, adding a CO₂ capture system with a 99 percent removal rate results in a 9 percentage point (24 percent) reduction in efficiency, compared to the non-capture PC cases. For the NGCC cases, the addition of a CO₂ capture system with a 97 percent removal rate results in a 7 percentage point (12 percent) reduction in efficiency, compared to non-capture NGCC cases.

The cost results for PC and NGCC cases with CO₂ capture rates greater than 95 percent are shown in Exhibit C-2; the primary cost conclusions that can be drawn are:

- The addition of CO₂ capture increases the capital portion of the LCOE by 70–75 percent for PC cases and 107–124 percent for NGCC cases and increases the total LCOE by 74–78 percent for PC cases and 56–61 percent for NGCC cases.
- For PC cases, CO₂ T&S costs add \$10–11/MWh to the LCOE, which accounts for approximately 9 percent of the total LCOE. For NGCC cases, CO₂ T&S costs add \$4/MWh to the LCOE, which accounts for approximately 5–6 percent of the total LCOE.

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit C-1. Performance summary and environmental profile for PC and NGCC cases with CO₂ capture rates greater than 95 percent

Case Name	PC				NGCC			
	SubC PC		SC PC		State-of-the-art 2017 F-Class		State-of-the-art 2017 H-class	
	B11A	B11B.99	B12A	B12B.99	B31A	B31B.97	B32A	B32B.97
Performance								
CO ₂ Capture Rate (%)	0	99	0	99	0	97	0	97
Capacity Factor (%)	85	85	85	85	85	85	85	85
Gross Power Output (MWe)	688	780	686	774	740	687	1,009	939
Auxiliary Power Requirement (MWe)	38	130	36	123	14	51	17	66
Net Power Output (MWe)	650	650	650	650	727	637	992	873
Coal Flow Rate (lb/hr)	493,115	651,832	473,055	619,732	N/A	N/A	N/A	N/A
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	205,630	205,630	273,429	273,429
HHV Thermal Input (kWt)	1,685,945	2,228,591	1,617,359	2,118,843	1,354,905	1,354,905	1,801,631	1,801,631
Net Plant HHV Efficiency (%)	38.6	29.2	40.2	30.7	53.6	47.0	55.1	48.4
Net Plant HHV Heat Rate (Btu/kWh)	8,849	11,691	8,490	11,116	6,363	7,260	6,196	7,045
Raw Water Withdrawal (gpm/MWnet)	10.0	16.1	9.3	15.0	4.0	7.1	3.6	6.6
Process Water Discharge (gpm/MWnet)	2.1	4.2	1.9	3.9	0.9	2.3	0.8	2.2
Raw Water Consumption (gpm/MWnet)	8.0	11.9	7.4	11.1	3.1	4.8	2.8	4.4
CO ₂ Emissions (lb/MMBtu)	202	2	202	2	119	4	119	4
CO ₂ Emissions (lb/MWh-gross)	1,693	20	1,628	19	741	24	723	23
CO ₂ Emissions (lb/MWh-net)	1,790	24	1,718	23	755	26	735	25
SO ₂ Emissions (lb/MMBtu) ^A	0.081	0.000	0.081	0.000	0.001	0.000	0.001	0.000
SO ₂ Emissions (lb/MWh-gross)	0.675	0.000	0.649	0.000	0.006	0.000	0.006	0.000
NO _x Emissions (lb/MMBtu)	0.084	0.072	0.087	0.075	0.004	0.003	0.004	0.003
NO _x Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.022	0.022	0.022	0.022
PM Emissions (lb/MMBtu)	0.011	0.009	0.011	0.010	0.002	0.000	0.002	0.000
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.012	0.000	0.011	0.000
Hg Emissions (lb/TBtu)	0.359	0.308	0.373	0.321	0.000	0.000	0.000	0.000
Hg Emissions (lb/MWh-gross) ^B	3.00E-06	3.00E-06	3.00E-06	3.00E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00

^A Trace amounts of sulfur emissions may exist in the flue gas stream to the stack in capture cases

^B The mercury capture units used in the PC cases were designed to attain the emissions target of 3.00x10⁻⁶ lb/MWh-gross

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit C-2. Cost summary for PC and NGCC cases with CO₂ capture rates greater than 95 percent

Case Name ^A	PC				NGCC			
	SubC PC		SC PC		State-of-the-art 2017 F-Class		State-of-the-art 2017 H-class	
	B11A	B11B.99	B12A	B12B.99	B31A	B31B.97	B32A	B32B.97
Cost								
Total Plant Cost (2018\$/kW)	2,015	3,543	2,103	3,596	780	1,754	796	1,654
<i>Bare Erected Cost</i>	1,486	2,510	1,551	2,552	561	1,177	573	1,117
<i>Home Office Expenses</i>	260	439	271	447	112	235	115	223
<i>Project Contingency</i>	270	494	281	500	107	265	109	247
<i>Process Contingency</i>	0	100	0	97	0	77	0	67
Total Overnight Cost (2018\$/MM)	1,615	2,829	1,683	2,868	692	1,358	963	1,754
Total Overnight Cost (2018\$/kW)	2,484	4,349	2,588	4,409	952	2,132	970	2,010
<i>Owner's Costs</i>	468	805	485	813	172	378	174	356
Total As-Spent Cost (2018\$/kW)	2,867	5,020	2,988	5,090	1,040	2,329	1,060	2,196
LCOE (\$/MWh) (excluding T&S)^C	64.0	103.1	64.5	102.3	43.3	66.1	42.7	63.1
<i>Capital Costs</i>	27.2	47.7	28.4	48.4	9.9	22.1	10.1	20.9
<i>Fixed Costs</i>	9.2	15.2	9.5	15.4	3.6	7.7	3.5	7.1
<i>Variable Costs</i>	7.9	14.2	7.7	13.8	1.7	4.2	1.7	4.0
<i>Fuel Costs</i>	19.7	26.0	18.9	24.8	28.1	32.1	27.4	31.1
LCOE (\$/MWh) (including T&S)^C	64.0	113.8	64.5	112.4	43.3	69.9	42.7	66.8
<i>CO₂ T&S Costs</i>	N/A	10.6	N/A	10.1	N/A	3.8	N/A	3.7
Cost of CO₂ Captured (ex. T&S), \$/tonne^B	N/A	36.4	N/A	37.4	N/A	60.2	N/A	55.5
Cost of CO₂ Avoided (incl. T&S), \$/tonne^B	N/A	64.1	N/A	62.2	N/A	80.4	N/A	74.8

^AFinancing structures are presented in NETL's "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance" [4]

^BBoth the cost of CO₂ captured and cost of CO₂ avoided were calculated based on the non-capture SC PC Case B12A for all coal cases, and the analogous non-capture NGCC Cases (i.e., B31B cases use B31A as a reference and B32B cases use B32A)

^CVarying incentives, such as tax credits, could impact the economics of the system

Albany, OR • Anchorage, AK • Morgantown, WV • Pittsburgh, PA • Sugar Land, TX

www.netl.doe.gov

(800) 553-7681

