Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies

2021 Gasification Project Review Meeting

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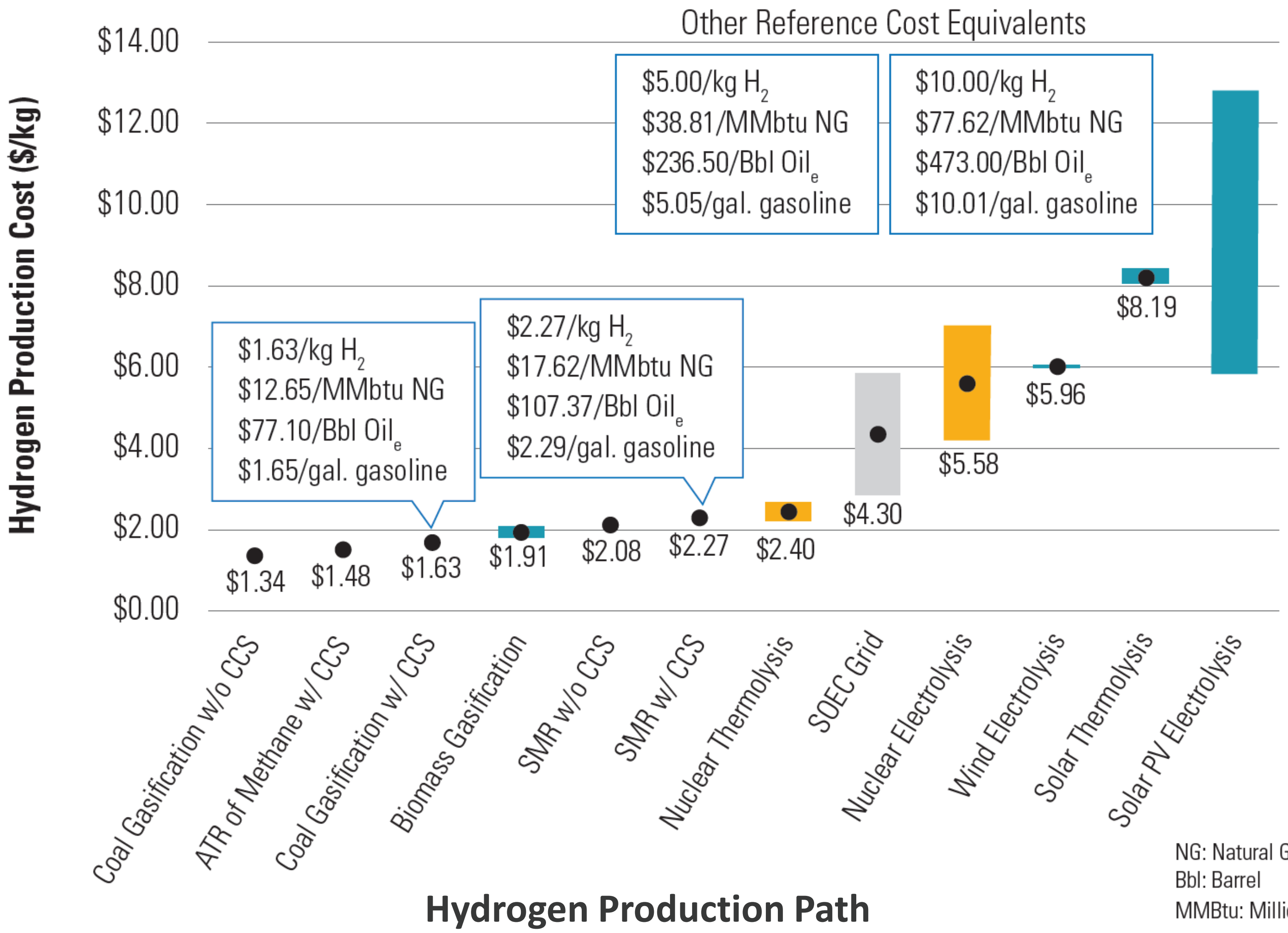
Solutions for Today | Options for Tomorrow

U.S. DEPARTMENT OF ENERGY

Objectives

- Develop a reference study for commercial H_2 production technologies with emphasis on coal gasification, co-gasification of coal with alternative feedstocks, and NG technologies using the levelized cost of H_2 (2018 $/kg) as the figure of merit
- Identify areas of R&D to further improve the performance and cost of fossil fuel-based H_2 production, including follow-on analyses
- Support ongoing and future DOE FE H_2 R&D efforts by providing a contemporary understanding of the performance and costs of commercial, fossil-based H_2 production

Current H_2 Production Costs by Technology



NG: Natural Gas
Bbl: Barrel
MMBtu: Million Btu

Fossil H_2 LCOH and Emissions

NG SMR and Gasification Routes

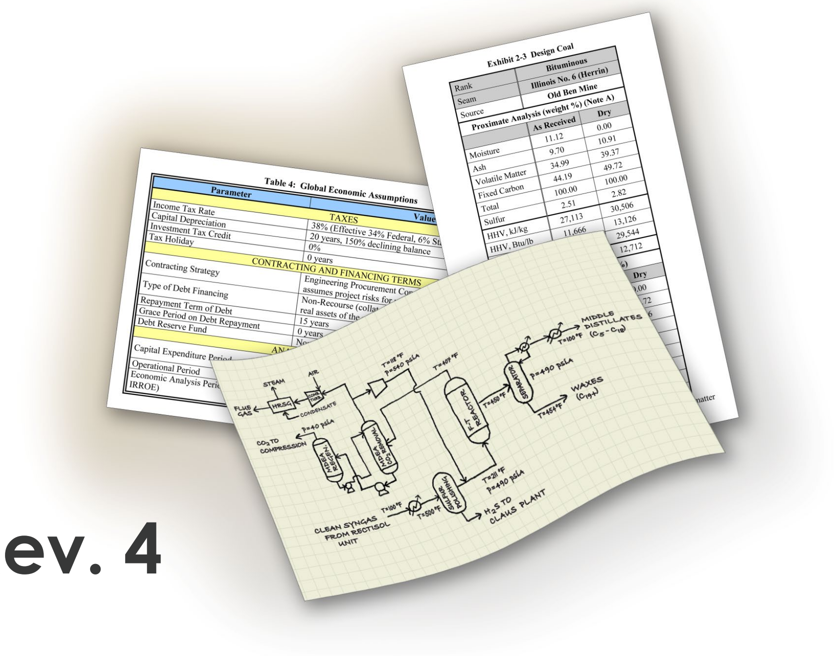
Case Description	SMR w/ CO_2 Capture		GEE-Q Gasification w/ CO_2 Capture	
	NETL 2011 [1]	NETL Preliminary Update	NETL 2011 [1]	NETL Preliminary Update
COSTS				
Financial Structure	High Risk Fuels, 33 yrs	IOU, 33 yrs	High Risk Fuels, 35 yrs	IOU, 35 yrs
Capital Charge Factor (CCF) or Fixed Charge Rate (FCR)	26.6 (CCF)	0.07 (FCR)	32.5 (CCF)	0.07 (FCR)
Year Dollar Basis	June 2007	Dec 2018	June 2007	Dec 2018
Natural Gas Price ($/MMBtu)	6.55	4.42	N/A	N/A
Coal Price ($/MMBtu)	N/A	N/A	1.64	2.23
Levelized COH excluding CO_2 TS&M, $/kg H_2	2.81	1.49	3.74	1.83
Fuel Cost, $/kg H_2	1.59	0.82	0.47	0.49
Fixed O&M Cost, $/kg H_2	0.15	0.14	0.30	0.27
Variable O&M Cost, $/kg H_2	0.28	0.26	0.42	0.33
Capital, $/kg H_2	0.80	0.27	2.55	0.74
Levelized COH including CO_2 TS&M, $/kg H_2	**2.96**	**1.58**	**4.01**	**2.01**
CO_2 TS&M, $/kg H_2	0.15	0.09	0.27	0.18

Design Basis

General Evaluation Basis

- **Performance and economic simulation will conform to the 2019 revision of NETL's QGESS reports:**
  - CO_2 Transport and Storage
  - CO_2 Purity
  - Cost Estimation Methodology
  - Capital Cost Scaling Methodology
  - Energy Balance
  - Feedstock Specifications
  - Fuel Prices
  - Process Modeling Design Parameters
  - Techno-Economic Analysis
- **Aspen models will be consistent with NETL's Bituminous Baseline Report (BBR) Rev. 4**

Quality Guidelines for Energy System Studies



Case Matrix

<table>
<tr><th>Case</th><th>Plant Type</th><th>Feedstock(s)</th><th>Reformer Type</th><th>Gasifier Type</th><th>CO_2 Capture*</th><th>H_2 Purification</th><th>Capacity Basis</th><th>Lifecycle Emissions Target (lb CO_2e/lb H_2)</th></tr>
<tr><td>1</td><td>Reforming</td><td>NG</td><td rowspan="2">SMR</td><td rowspan="3">-</td><td>0%</td><td rowspan="6">PSA</td><td rowspan="2">Single Train SMR Max
(200 MMSCFD H_2)</td><td>N/A</td></tr>
<tr><td>2</td><td>Reforming</td><td>NG**</td><td>Max</td><td>N/A**</td></tr>
<tr><td>3</td><td>Reforming</td><td>NG**</td><td>ATR</td><td>Max</td><td>Match output of Cases 4 & 5
(~247 MMSCFD H_2)</td><td>N/A**</td></tr>
<tr><td>4</td><td>Gasification</td><td>Illinois No. 6</td><td rowspan="3">-</td><td rowspan="3">Shell</td><td>0%</td><td rowspan="2">BBR Rev. 4 Case B1B Gasifier Capacity
(~247 MMSCFD H_2)</td><td>N/A</td></tr>
<tr><td>5</td><td>Gasification</td><td>Illinois No. 6</td><td>Max</td><td>N/A</td></tr>
<tr><td>6</td><td>Gasification</td><td>Illinois No. 6/Torrefied Southern Yellow Pine</td><td>Max</td><td>1400 tpd gasifier feedstock
(~50-100 MMSCFD H_2)</td><td>0</td></tr>
</table>

*CO_2 capture targets the maximum amount of feedstock carbon captured from the syngas (ATR and gasification cases) and syngas + furnace flue gas (SMR case)
**A NG/renewable natural gas (RNG) blend was originally considered for pursuit of net-zero lifecycle emission. However, recent analysis has concluded that near-term RNG production routes will not enable a net-zero plant.

"Max CO_2 Capture" Definition

- **Legacy reforming and gasification models originally considered a 90% overall capture rate**
- **An objective for this study is to pursue "maximize CO_2 capture" in all capture cases using the following definition:**
  - A 2x3 WGS reactor arrangement is incorporated in order to achieve a 97.2% CO conversion as was employed in NETL's BBR Rev. 4 Case B4B
  - SMR with CO_2 capture employs capture from both the pressurized syngas and low-pressure SMR furnace exhaust gas streams
  - ATR and gasification with CO_2 capture employs CO_2 capture from the pressurized syngas only
  - No partial bypass of AGR processes in any of the cases
  - CO_2 capture efficiencies of the AGR technologies are unchanged from NETL's BBR Rev. 4

Site Characteristics

- **The following ISO ambient conditions for a generic Midwest U.S. plant location will be used in this study [1]**

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

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_2O	0.616
CO_2	0.050
Total	100.00

[A] The 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.

Coal Characteristics

- **Use of Illinois No. 6 coal with the following fuel characteristics will be assumed for the gasification cases in this study [2]**

Rank	Bituminous	
Seam	Illinois No. 6	
Source	-	
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)	29,444 (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

[A] The proximate analysis assumes sulfur as volatile matter
[B] By difference

Natural Gas Characteristics

- **Use of natural gas with the following fuel characteristics will be assumed for the reforming cases in this study [2]**

Natural Gas		
Component		**Volume Percentage**
Methane	CH_4	93.1
Ethane	C_2H_6	3.2
Propane	C_3H_8	0.7
n-Butane	C_4H_{10}	0.4
Carbon Dioxide	CO_2	1.0
Nitrogen	N_2	1.6
Methanethiol[A]	CH_4S	5.75×10^{-6}
	Total	**100.0**
Heating Value		
	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)

[A]The sulfur content of natural gas is primarily composed of added Mercaptan (methanethiol [CH_4S]) with trace levels of hydrogen sulfide (H_2S)

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

Biomass Characteristics

- **Use of torrefied Southern pine biomass with the following fuel characteristics will be assumed in this study [3]**

Torrefied Southern Pine Biomass		
	As Received	Dry
Ultimate Analysis (weight %)		
Moisture	5.72	0.00
Carbon	59.89	63.52
Hydrogen	5.11	5.42
Nitrogen	0.41	0.44
Chlorine	0.00	0.00
Sulfur	0.00	0.00
Ash	0.51	0.54
Oxygen	28.36	30.08
Total	**100.00**	**100.00**
Heating Value		
HHV (Btu/lb)	9,749	10,340
LHV (Btu/lb)	9,203	9,825

Product Specifications

H_2 Product Purity

Characteristics	Concentration
Hydrogen Purity (vol%)	99.90
Max. CO_2 (ppm)	A
Max. CO (ppm)	A
Max. H_2S (ppb)	10
Max. H_2O (ppm)	A
Max. O_2 (ppm)	A

[A]The maximum total concentration of all oxygen containing species is 10 ppm

- **The hydrogen product will meet or exceed the purity specification shown, which will result in a product suitable for several potential applications**
- **Contaminant levels are for ammonia grade H_2 to avoid catalyst poisoning**
- **Additionally, the specification will result in a product exceeding specifications for the following ISO 14687:2019 gaseous H_2 grades**
  - Grade A – combustion applications
    - Internal combustion engines, residential/commercial heating appliances
  - Grade B – industrial power and heat applications
    - Excluding PEM fuel cells

Product Specifications

H_2 Product Pressure

- **Commercial H_2 pipeline data received**
  - Pipeline system operating pressure: 800–900 psig
  - Pressure at the plant fence needs to be 900+ psig
- **Selected a H_2 product pressure of 925 psig**
  - Additional H_2 product compression is needed to achieve this

Environmental Targets

Air Emissions

- **The primary air emission sources for the cases are**
  - SMR furnace
  - Auxiliary boiler – gasification cases
- **It is assumed the greenfield plants will be located in an attainment area, thus the inclusion of Best Available Control Technologies will be required per New Source Review**
- **The tables below include the control technologies and achievable limits assumed in the 2011 H_2 Baseline study, and are considered for this study as well [5]**

BACT Environmental Design Basis for Natural Gas Cases

Pollutant	Environmental Design Basis	
	Control Technology	**Limit**
Sulfur Oxides	Zinc oxide guard bed	Negligible
Nitrogen Oxides	Low NOx Burners	2.5 ppmv (dry) @ 15% O_2
Particulate Matter	N/A	Negligible
Mercury	N/A	Negligible

BACT Environmental Design Basis for Coal Cases

Pollutant	Environmental Design Basis	
	Control Technology	**Limit**
Sulfur Oxides	AGR + Claus Plant or equivalent performing system	99+% or ≤ 0.050 lb/10^6 Btu
Nitrogen Oxides	Low NOx Burners	15 ppmv (dry) @ 15% O_2
Particulate Matter	Cyclone/Barrier Filter/Wet Scrubber/AGR Absorber	0.015 lb/10^6 Btu
Mercury	Activated Carbon Bed or equivalent performing system	95% removal

Capacity Factor

- **The 2011 NETL H_2 Baseline [5] assumed a 90% capacity factor was representative of commercial SMR facilities**
  - It was assumed no spare reformer was required to achieve this capacity factor
- **In order to achieve an equivalent capacity factor for the gasification cases, a spare gasifier train (gasifier and raw syngas cooler) operating in hot standby was included in the design**
- **This study will maintain these two assumptions and will assume a spare ATR is not required to achieve 90 percent capacity factor**

Key System Assumptions

Reforming Plants

- **The following table summarizes assumptions about the feedstock, products, and process equipment for reforming cases**

Parameters	Design Basis
Plant Size	SMR Cases: 200 MMSCFD (44,242 lb/hr) ATR Cases: ~247 MMSCFD (54,638 lb/hr)
Hydrogen Purity	99.9 vol. %
H_2 Product Pressure	≥300 psig at plant gate
CO_2 Product Pressure	2,215 psia
Feedstock	NG & Biomethane: Pipeline, 450 psia
Reformer	Vertical tube steam methane reformer, externally heated
Water Gas Shift	High-temperature, 98% conversion
Hydrogen Purification	Pressure Swing Adsorption
PSA Retentate Gas	Recycled to reformer as fuel
Auxiliary Power Block	None
Syngas CO_2 Recovery	Coastal, proprietary MDEA, 95% removal
Stack Gas CO_2 Recovery	Proprietary MEA, achieve 90% total
CO_2 Sequestration	Off-site Saline Formation

Key System Assumptions

Gasification Plants

- **The following table summarizes assumptions about the feedstock, products, and process equipment for gasification cases**

Parameters	Design Basis
Plant Size	Coal-only cases: Maximum hydrogen production from 5,608 tpd coal feed Co-gasification cases: Maximum hydrogen production from 1,400 tpd coal & biomass feed
H_2 Product Pressure	≥300 psig at plant gate
CO_2 Product Pressure	2,215 psia
Coal Feed	Illinois No. 6
Gasifier	Shell
Oxidant	95 vol% O_2
O_2:Coal Ratio	0.720 kg O_2/kg As-Received coal
Carbon Conversion	99.5%
Gasifier Outlet Pressure	615 psia
Water Gas Shift	High-temperature, sulfur-tolerant
Auxiliary Power Block	Steam turbine generator
Hydrogen Purification	Pressure Swing Adsorption
PSA Retentate Gas	Fired in auxiliary boiler
CO_2 Recovery	Selexol

Economic Basis

Cost Estimating Methodology

- **Bottoms-up analysis**
- **Based on Aspen modeling:**
  - Equipment lists
  - Capital costs
  - O&M costs
- **AACE Class 4 methodology (-15%/+30% Uncertainty)**

Cost Estimating Methodology

Feedstock Costs

- **Delivered coal and natural gas costs will be consistent with current NETL QGESS methodology [7]**
  - Delivered Illinois No. 6 – \$2.22/MMBtu
  - Delivered NG – \$4.42/MMBtu
- **A site-delivered cost of torrefied Southern yellow pine has been calculated using an existing cost model that considers centralized production of the design feedstock and distribution to the H_2 plant [3] and levelized to be consistent with current NETL QGESS methodology [7]**
  - Delivered biomass - \$5.43/MMBtu

Cost Estimating Methodology

Utility Costs

- **Grid electricity will supply the full electrical demand of the reforming cases**
  - A grid power price of $71.7/MWh is assumed based on the 2019 average Midcontinent Independent System Operator Market price for industrial customers as reported in "Annual Electric Power Industry Report," Form EIA-861
- **If the full electrical demand is not met by the steam turbine auxiliary power block in the gasification cases, the balance will be provided by the grid**
  - Conversely, if surplus electricity is produced, it will be sold at the same grid price
- **Excess steam is assumed to be exported without additional revenue**

Cost Estimating Methodology

Levelized Cost of Hydrogen

- **The levelized cost of hydrogen will be the figure of merit for each of the six cases**
  - LCOH will be reported in $/kg, expressed in real, 2018 dollars to maintain consistency with the current QGESS cost estimating methodology [8]
- **Reforming cases will employ capital financing assumptions consistent with previous NETL assessment of refinery hydrogen:**

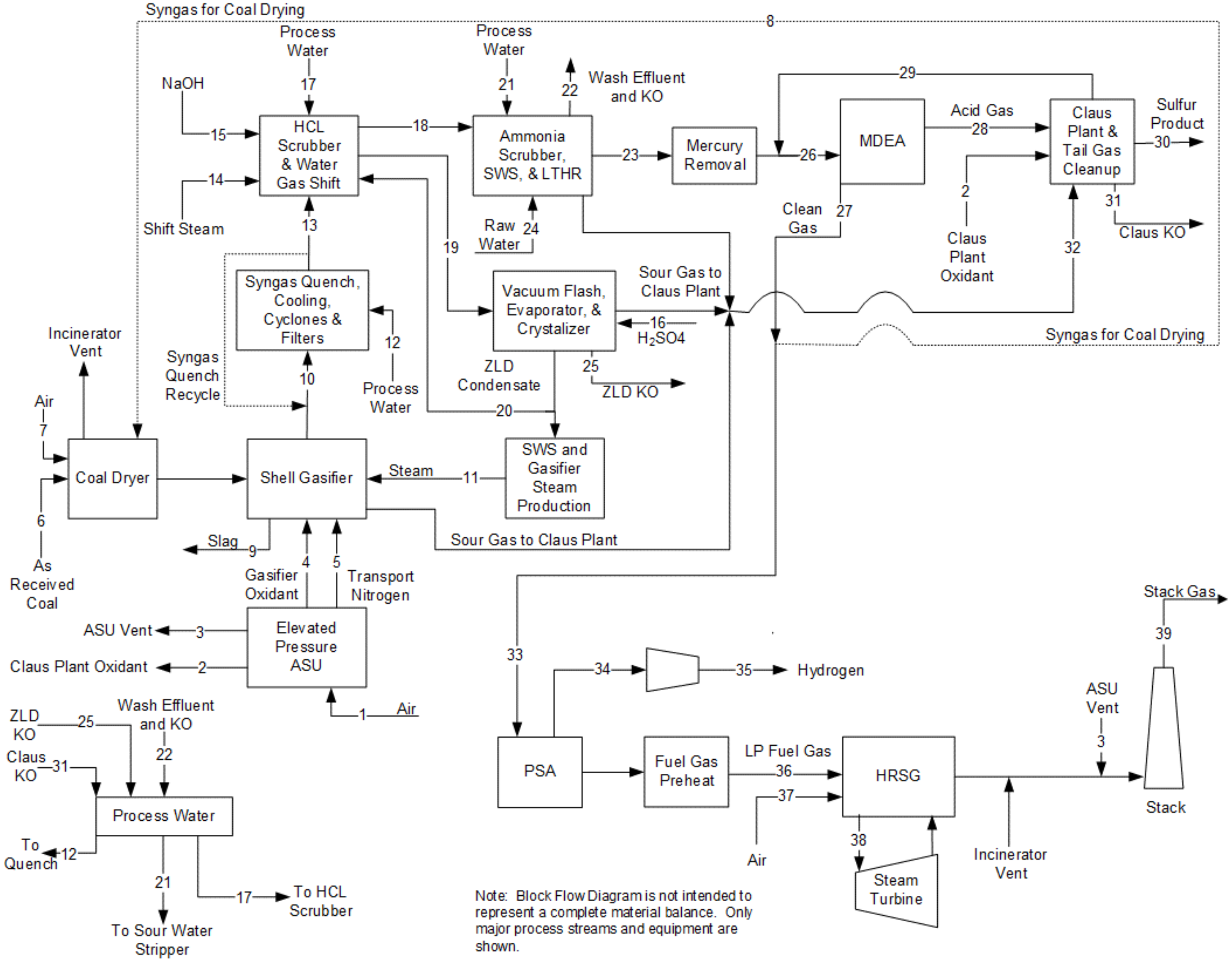
CapExp Period	D/E	IRROE/ Econ. Life	Debt Rate / Term	FCR	TASC/ TOC
3-yr	38/62	3.10%/30 yrs	5.15%/30 yrs	0.0586	1.070

- **Gasification cases will use similar financial assumptions with differences in construction period and TASC/TOC:**

CapExp Period	D/E	IRROE/ Econ. Life	Debt Rate / Term	FCR	TASC/ TOC
5-yr	38/62	3.10%/30 yrs	5.15%/30 yrs	0.0586	1.116

Case 4: Gasifier w/o CCS

BFD



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Case 4: Gasifier w/o CCS

Carbon/Sulfur Balance & Emissions

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal		Stack Gas	
Air (CO_2)		CO_2 Product	
		Slag	
		H2 Product	
Total		**Total**	

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal		Stack Gas	
		CO_2 Product	
		Elemental Sulfur	
Total		**Total**	

Pollutant	kg/GJ (lb/MMBtu)	tonne/yr (Ton/year)[A]
SO_2		
NOx		
Particulate		
Hg		
HCl		
CO_2		

[A] Calculations based on a 90 percent capacity factor

Case 4: Gasifier w/o CCS

Energy Balance

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal				
Air				
Raw Water Makeup				
Auxiliary Power				
TOTAL				
Misc. Process Steam				
Slag				
Stack Gas				
Sulfur				
Motor Losses and Design Allowances				
Hydrogen Product				
Cooling Tower Load[A]				
CO_2 Product Stream				
Blowdown Streams				
Ambient Losses[B]				
Power				
TOTAL				
Unaccounted Energy[C]				

[A] Includes condenser, AGR, and Miscellaneous cooling loads
[B] Ambient losses include all losses to the environment through radiation, convection, etc. sources of these losses include the combustor, reheater, superheater, and transformers
[C] By difference

Case 4: Gasifier w/o CCS

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					
Slurry Water					
Gasifier Water					
Quench					
HCl Scrubber					
NH_3 Scrubber					
Gasifier Steam					
Condenser Makeup					
BFW Makeup					
Gasifier Steam					
Shift Steam					
Cooling Tower					
BFW Blowdown					
ASU Knockout					
Total					

Case 4: Gasifier w/o CCS

Performance Tables

Performance Summary	
Steam Turbine Power, MWe	
Total Gross Power, MWe	
Air Separation Unit Main Air Compressor, kWe Air Separation Unit Booster Compressor, kWe Nitrogen Compressors, kWe CO_2 Compression, kWe Acid Gas Removal, kWe Balance of Plant, kWe	
Total Auxiliaries, MWe	
Net Power, MWe	
Hydrogen Production, kg/hr (lb/hr)	
CO_2 Capture, %	
HHV Effective Thermal Efficiency (%)[A] HHV Cold Gas Efficiency, %[B]	
LHV Effective Thermal Efficiency (%)[A] LHV Cold Gas Efficiency, %[B]	
Steam Turbine Cycle Efficiency, % Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	
Condenser Duty, GJ/hr (10^6 Btu/hr) AGR Cooling Duty, GJ/hr (10^6 Btu/hr) As-Received Coal Feed, kg/hr (lb/hr) HHV Thermal Input, kWt LHV Thermal Input, kWt Raw Water Withdrawal, m^3/min (gpm) Raw Water Consumption, m^3/min (gpm) O_2:Coal	

[A] ETE = (Hydrogen Heating Value + Net Power) / Fuel Heating Value
[B] CGE = Hydrogen Heating Value / Fuel Heating Value

Power Summary
Steam Turbine Power, MWe
Total Gross Power, kWe
Acid Gas Removal, kWe Air Blower, kWe Air Separation Unit Auxiliaries, kWe Air Separation Unit Main Air Compressor, kWe Air Separation Unit Booster Compressor, kWe Ammonia Wash Pumps, kWe Circulating Water Pumps, kWe Claus Plant TG Recycle Compressor, kWe Claus Plant/TGTU Auxiliaries, kWe CO_2 Compression, kWe Coal Dryer Air Compressor, kWe Coal Handling, kWe Coal Milling, kWe Condensate Pumps, kWe Cooling Tower Fans, kWe Feedwater Pumps, kWe Gasifier Water Pump, kWe Ground Water Pumps, kWe Hydrogen Compressor, kWe Miscellaneous Balance of Plant[A], kWe Nitrogen Compressors, kWe Oxygen Pump, kWe Quench Water Pump, kWe Shift Steam Pump, kWe Slag Handling, kWe Slag Reclaim Water Recycle Pump, kWe Slurry Water Pump, kWe Sour Gas Compressors, kWe Sour Water Recycle Pumps, kWe Steam Turbine Auxiliaries, kWe Syngas Recycle Compressor, kWe Syngas Scrubber Pumps, kWe Process Water Treatment Auxiliaries, kWe Transformer Losses, kWe
Total Auxiliaries, MWe
Net Power, MWe

[A] Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Schedule

Deliverable	Date
Design Basis	Complete
Simulation & Performance Assessment	Complete
Cost Analyses	Presently ongoing
Internal Draft Report	June 2021
Peer Review	July 2021
Public Final Report	August 2021

References

[1] NETL, "QGESS: Process Modeling Design Parameters," Pittsburgh, PA, 2019.

[2] NETL, "QGESS: Specification for Selected Feedstocks," Pittsburgh, PA, 2019.

[3] NETL, "Comprehensive Analysis of Coal and Biomass Conversion to Jet Fuel: Oxygen Blown, Transport Reactor Integrated Gasifier (TRIG) and Fischer-Tropsch (F-T) Catalyst Configurations," Pittsburgh, PA, 2014.

[4] CCST, "Biomethane in California Common Carrier Pipelines: Assessing Heating Value and Maximum Siloxane Specifications," June 2018

[5] NETL, "Assessment of Hydrogen Production with CO_2 Capture Volume 1: Baseline State-of-the-Art Plants," November, 2011

[6] NREL, [H2A: Hydrogen Analysis Production Models]

[7] NETL, "Fuel Prices for Selected Feedstocks in NETL Studies," Pittsburgh, PA, 2019.

[8] NETL, "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance: Revision 4 Report," Pittsburgh, PA, 2019.

[9] NETL, "Natural Gas-Based Coproduction of Power and Hydrogen with CCS – Draft," July 2020

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Legal

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NATIONAL ENERGY TECHNOLOGY LABORATORY

Questions/Comments?

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