

Cost and Performance Impact of Dry and Hybrid Cooling on Fossil Energy Power Systems

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ACRONYMS AND ABBREVIATIONS

ACC	Air-cooled condenser	ISO	International Organization for Standardization
ACHE	Air-cooled heat exchanger	ISO	Independent system operator
ACI	Activated carbon injection	ITD	Initial temperature difference
Ar	Argon	kJ/kg	Kilojoules per kilogram
Aspen	Aspen Plus®	KO	Knockout
B&V	Black & Veatch	kW, kWe	Kilowatt electric
BACT	Best available control technology	LAER	Lowest Achievable Emission Rate
BFW	Boiler feed water	lb	Pound
Btu/lb	British thermal units per pound	lb/hr	Pounds per hour
CCF	Capital charge factor	lb/MWh	Pounds per megawatt hour
CCS	Carbon capture and storage	LHV	Lower heating value
CH ₄ S	Mercaptan	LNB	Low NO _x burner
CL	Closed loop	LP	Low pressure
CO ₂	Carbon dioxide	MATS	Mercury and Air Toxics Standards
COE	Cost of electricity	MESA	Mission Execution and Strategic Analysis
CT	Combustion turbine	mi	Mile(s)
CTG	Combustion turbine generator	MJ	Megajoule
CW	Cooling water	MMBtu	Million British thermal units
d.b.	Dry bulb	MMBtu/hr	Million British thermal units per hour
DLN	Dry low NO _x	MPa	Megapascal
DOE	Department of Energy	MW, MWe	Megawatt electric
DSI	Dry sorbent injection	MWh	Megawatt-hour
EGU	Electric utility steam generating unit	N/A	Not applicable
ELG	Effluent limitation guideline	N ₂	Nitrogen
EPA	Environmental Protection Agency	NERC	North American Electric Reliability Council
FGD	Flue gas desulfurization	NETL	National Energy Technology Laboratory
ft	Foot, Feet	NGCC	Natural gas combined cycle
GADS	Generating Availability Data System	NO	Nitrogen monoxide
GJ	Gigajoule	NO _x	Oxides of nitrogen
gal/MWh	Gallons per megawatt hour	NSPS	New Source Performance Standards
gpm	Gallons per minute	NSR	New Source Review
h, hr	Hour	O&M	Operation and maintenance
H ₂ O	Water	O ₂	Oxygen
H ₂ S	Hydrogen sulfide	OFA	Overfire air
HCl	Hydrochloric acid	PC	Pulverized coal
Hg	Mercury	PM	Particulate matter
HHV	Higher heating value		
HRSG	Heat recovery steam generator		

POTW	Publicly owned treatment works
ppm	Parts per million
ppmvd	Parts per million by volume, dry basis
ppmwd	Parts per million by weight, dry basis
PSD	Prevention of significant deterioration
PSFM	Power Systems Financial Model
psia	Pound per square inch absolute
QGEISS	Quality Guidelines for Energy System Studies
R.H.	Relative humidity
scf	Standard cubic feet
scm	Standard cubic meter
SCR	Selective catalytic reduction
SO ₂	Sulfur dioxide
SO ₃	Sulfur trioxide
STG	Steam turbine generator
TOC	Total overnight cost
TPC	Total plant cost
T&S	Transportation & storage
U.S.	United States
USD	U.S. dollars
\$MM	Millions of dollars
°C	Degrees Celsius
°F	Degrees Fahrenheit

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EXECUTIVE SUMMARY

A critical component in any power plant containing a steam-based Rankine cycle is the cooling system, which rejects the remaining low-grade heat in the steam turbine exhaust into the atmosphere. This report evaluates the cost and performance impact of conventional and alternative plant cooling technologies on supercritical pulverized coal (PC) and natural gas combined cycle (NGCC) systems, with and without 90% CO₂ capture. The technologies considered are a traditional wet, recirculating cooling tower; a dry, air cooled condenser system that does not use water for cooling as in the wet recirculating system; and a hybrid system that incorporates both the wet recirculating system as well as an air cooled condenser.

Each of the configurations in this study was designed assuming a generic set of International Organization for Standardization (ISO) ambient conditions (59 °F dry bulb, 60% relative humidity) corresponding to a generic Midwestern plant location. To assess the impact of seasonal variations on plant and cooling system performance (including water consumption), each system was also evaluated against typical Midwest U.S., ISO summer conditions (85 °F dry bulb, 53% to 84% relative humidity) and winter conditions (20 °F dry bulb, 63% to 74% relative humidity). In addition to ambient atmospheric conditions, the effect of elevation was also considered: cost and performance impact based on both sea level and high (5,280 feet) elevation was assessed.

It should be noted that the dry cooling configurations required an additional air cooled heat exchanger, beyond the main air cooled condenser in the Rankine cycle, to deal with miscellaneous plant cooling water needs as part of the design, which introduced added cost to these systems. Integration of lower purity process cooling water with high-purity low pressure steam would contaminate the steam cycle loop, requiring additional water treatment. Therefore, cases eliminating evaporative cooling were designed using auxiliary air cooled heat exchanger bays as the means of rejecting miscellaneous process heat (not the low pressure steam turbine waste heat) to the atmosphere.

The primary findings from the report follow:

1. For PC systems, the negative impact on net power generation and system efficiency due to high ambient temperature is most pronounced in those cases with dry cooling. This is caused by differences in the cycle-side condenser conditions (saturation temperature and pressure) that can be achieved by wet and dry cooling systems. The minimum theoretical condenser temperature in cases with dry cooling is the atmospheric dry bulb temperature, whereas the minimum in cases with evaporative cooling is the atmospheric wet bulb temperature. Since the wet bulb temperature (a function of the dry bulb temperature and relative humidity) is always less than the dry bulb temperature,

those cases with evaporative cooling can achieve lower condenser temperatures (and therefore pressures) than the corresponding dry cooling cases. The lower steam turbine backpressure increases net power generation and system efficiency.

2. It follows that for a given dry bulb temperature, the net power and efficiency of PC and NGCC systems with evaporative cooling decrease with higher levels of relative humidity (higher wet bulb temperatures), while systems with dry cooling are unaffected.
3. PC systems with carbon capture and storage (CCS) exhibit significant decreases in net power and efficiency with dry cooling, relative to the evaporative cooling case, due to the high cooling water temperature provided to the CO₂ capture system. Among the PC cases, this configuration is the most sensitive to increasing temperature.
4. For NGCC systems (both with and without CO₂ capture), net power and efficiency decrease significantly with increasing temperature, as the fixed-volume combustion turbine is the primary power producer and is sensitive to changes in ambient air density. The impact of high temperature on combustion turbine performance has a greater impact than the cooling technology in use (regardless of wet or dry). Similarly, the reduction in power generation and efficiency when switching from wet to dry cooling is less prominent for NGCC systems than observed for PC, because the steam-based Rankine cycle output is a smaller percentage of the total power produced in NGCC.
5. Dry cooling eliminates evaporative water losses for all PC and NGCC cases.
6. Dry cooling results in significant reductions in raw water withdrawal for all PC and NGCC cases (nearly eliminated for NGCC cases).
7. Process water discharge is increased for all PC and NGCC dry cooling cases, due to the loss of internal recycle.
8. The capital cost and cost of electricity estimate differences between wet and dry cooling reflected in this study may not be extended to PC or NGCC power plants in general, as the performance and cost for each of the systems is site- and ambient conditions-specific. Although this study suggests only a nominal cost increase for replacing wet evaporative cooling towers with dry cooling systems, this is a consequence of the ambient conditions assumed to size the equipment, and for which performance was estimated.

All dry cooling equipment costs in this study were based on operation at ISO ambient conditions because it was desired to generate cost and performance

estimates for both wet and dry cooling systems using a common set of assumptions. While that objective was achieved, the dry cooling cost estimates were based on ambient conditions which do not reflect those which would be considered a typical fit for dry cooling technology.

Plants may utilize dry cooling systems due to permitting requirements or limited water availability, which are more common in the western United States. For those western U.S. locations, cooling system design may be based on higher ambient temperatures. Higher design ambient conditions would result in a larger cooling system size, resulting in higher auxiliary loads (adversely affecting net power and efficiency) and increased capital costs. Therefore, a more accurate representation of the true cost of employing dry cooling systems on pulverized coal units would select ambient conditions more typical of the western United States (which is likely to be hotter than those assumed in this study).

Future work that expands on the results presented in this study is expected to include:

- A study examining the implications of dry cooling under design conditions representative of locations where dry cooling is most needed and likely to be deployed (arid, higher ambient temperatures).
- Incorporation of technology required to comply with EPA's effluent limitation guideline standards for all relevant wastewater discharge streams, which were not addressed in the present study.

1 INTRODUCTION

Throughout the existing United States power plant fleet, wet evaporative cooling is a major method for rejecting low-grade heat from power plant systems to the surrounding atmosphere. Over half of the cooling systems operating at large-scale generating facilities employ wet evaporative cooling. [1] The availability of local water sources, combined with the proven ability to provide a reliable, effective source of cooling to critical power plant systems, often make wet evaporative cooling an attractive technology option. Wet evaporative cooling systems also provide options for new plant developers and operators of existing plants to comply with federal environmental regulations [2] [3] by including these systems in new plant designs, or replacing existing once-through cooling systems, to minimize the impact on local wildlife from cooling water intake structures.

However, sites faced with limited water availability, high water acquisition costs, or concerns from the local community may not view wet evaporative cooling systems as a preferred option. In addition to these factors, a recognition of the inherent high water consumption from the use of wet evaporative cooling has driven the development of alternative power plant cooling concepts. These concepts can be broadly classified into the following commercially-available types:

- Direct dry (air-cooled condenser [ACC])
- Indirect dry (air-cooled heat exchanger [ACHE])
- Hybrid (water conservation), e.g. wet/dry parallel
- Hybrid (plume abatement)

Approximately 5 percent of the operating cooling systems installed at large-scale generating facilities employ a form of alternative cooling with the majority being the direct dry type. Indicating a potential trend in the construction of alternative cooling technologies, of the seventeen newly constructed (or currently under construction) power generating facility cooling systems, seven are direct dry types. [1]

This report examines the impacts that various ambient conditions have on the performance of pulverized coal (PC) and natural gas combined cycle (NGCC) power plants employing a range of alternative power plant cooling configurations designed for ISO/Midwest conditions. The relative differences in greenfield capital costs are also assessed. The report considers twelve plant arrangements that include either a 1) wet evaporative cooling arrangement, 2) hybrid wet/dry parallel cooling arrangement, or 3) direct dry ACC arrangement with auxiliary ACHEs (for amine CO₂ capture process cooling duty) to achieve entirely dry cooling. Each plant arrangement is evaluated both with and without 90% amine-based CO₂ removal. A matrix of the plant arrangements

evaluated is provided in Exhibit 1-1. Included in the matrix are the ambient conditions under which the plant performance was evaluated.

Many of the trends observed in the results can be explained by understanding the phenomena underlying wet and dry cooling systems. Consider a system in which unsaturated air is exposed to liquid water under adiabatic conditions (no heat is given up to, or received from, the surroundings). Since the air is not saturated, a water concentration gradient (driving force) is established between water and air, and evaporation will occur, increasing humidity. Since the operation is adiabatic, heat of evaporation cannot be supplied externally, and therefore must be provided by cooling of air or water, or both.

If the water temperature is approximately equal to that of the air, evaporation will lower the water temperature slightly. However when the water temperature becomes cooler than air, sensible heat will be transferred from the air, back to the water. Eventually an equilibrium will be reached at a temperature where the loss of heat from the water (through evaporation) is exactly balanced by sensible heat passing from air back to water. Under these conditions, water temperature will be constant, and this is the wet bulb temperature.

Power plant cooling systems are an inherent acknowledgement that it is more economical to cool and reuse heated condenser discharge water than to discard it. In wet evaporative systems, cooling is accomplished by bringing warm cooling water into contact with unsaturated air, such that the air is humidified and the water is brought approximately to the wet-bulb temperature. Since the system is not truly adiabatic (heat transfer also occurs with the surroundings through radiation), cooling water temperature can never actually achieve wet bulb. However, wet bulb temperature is the theoretical minimum cooling water temperature in systems with wet evaporative cooling.

Unlike wet systems, dry cooling systems do not depend on the evaporation of water to discharge heat, but instead rely on convective heat transfer across a surface that separates the cooling water from air. Therefore, the theoretical minimum cooling water temperature that can be achieved in those cases with dry cooling systems is the dry bulb temperature. Since wet bulb temperature for all cases in this study is less than dry bulb, those cases with wet evaporative systems can achieve lower cooling water temperature than the corresponding dry cooling cases. Lower cooling water temperature in the condenser allows for lower LP steam turbine backpressure, which tends to increase net

power generation and system efficiency. Therefore, the wet evaporative system cases in this study generally have higher efficiency than the dry cooling cases.

Exhibit 1-1 Case descriptions

Site Conditions ^{A,B}		Unit Cycle	Steam Cycle	Combustion Turbine	Boiler Technology	Cooling System ^a	CO ₂ Separation
0 ft Elevation 14.696 psia ^b & 5280 ft Elevation 12.1 psia ^c	<u>Midwestern ISO^b</u> 59°F dry bulb 60% R.H. <u>July Average High^c</u> 85°F dry bulb 53, 69, & 84% R.H. <u>January Average Low^c</u> 20°F dry bulb 63, 70, & 74% R.H.	PC	3500/1100/1100	N/A	SC PC	Wet Evaporative Tower	No
		PC	3500/1100/1100	N/A	SC PC	Wet Evaporative Tower	Yes
		PC	3500/1100/1100	N/A	SC PC	Hybrid Wet/Dry Parallel	No
		PC	3500/1100/1100	N/A	SC PC	Hybrid Wet/Dry Parallel	Yes
		PC	3500/1100/1100	N/A	SC PC	Air Cooled Condenser (ACC)	No
		PC	3500/1100/1100	N/A	SC PC	Air Cooled Condenser (ACC)	Yes
		NGCC	2400/1050/1050	2 x State-of-the-art 2013 F-Class	HRSB	Wet Evaporative Tower	No
		NGCC	2400/1050/1050	2 x State-of-the-art 2013 F-Class	HRSB	Wet Evaporative Tower	Yes
		NGCC	2400/1050/1050	2 x State-of-the-art 2013 F-Class	HRSB	Hybrid Wet/Dry Parallel	No
		NGCC	2400/1050/1050	2 x State-of-the-art 2013 F-Class	HRSB	Hybrid Wet/Dry Parallel	Yes
		NGCC	2400/1050/1050	2 x State-of-the-art 2013 F-Class	HRSB	Air Cooled Condenser (ACC)	No
		NGCC	2400/1050/1050	2 x State-of-the-art 2013 F-Class	HRSB	Air Cooled Condenser (ACC)	Yes

^AAverage July high and January low temperatures for Pittsburgh, PA, <https://weather.com/weather/monthly/l/USPA1290:1:US>

^BJuly and January relative humidity data for Pittsburgh, PA, <https://www.currentresults.com/Weather/US/humidity-city-annual.php>

^a Cooling system, in this context, refers to the method by which the energy remaining in the low pressure steam turbine exhaust is rejected to the atmosphere. It is noted that for the cases utilizing exclusively dry cooling, this same system is also used to condense the low pressure steam turbine exhaust. Throughout this report, the term “cooling system” will be used to refer to the method by which the waste heat in the low pressure steam turbine exhaust is rejected to the atmosphere.

^b Ambient and site conditions at which all cases (including system performance, and cooling systems) were designed and costed at

^c “Off design” ambient conditions used as sensitivity parameters to evaluate performance. No attempt was made to optimize equipment at these off design conditions. The systems designed and optimized for ISO ambient conditions was exercised at off design ambient conditions to evaluate trends in plant cooling and system performance.

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 provided 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 obtaining reference cooling system costs from Black & Veatch (B&V) and scaling balance-of-plant systems from other relevant NETL studies. [4] Ultimately, a cost of electricity (COE) 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 plant configurations, as well as environmental targets and cost assumptions used in the study.

2.1 SITE CHARACTERISTICS

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

Exhibit 2-1 Site characteristics

Parameter	Value
Location	Greenfield, Midwestern U.S.
Topography	Level
Size (Pulverized Coal), acres	300
Size (Natural Gas Combined Cycle), acres	100
Transportation	Rail or Highway
Ash Disposal	Off-Site
Water	50% Municipal and 50% Ground Water

Exhibit 2-2 Design site ambient conditions^d

Parameter	Value
Elevation, (ft)	0
Barometric Pressure, MPa (psia)	0.101 (14.696)
Ambient Dry Bulb Temperature, °C (°F)	15 (59)
Ambient Wet Bulb Temperature, °C (°F)	10.8 (51.5)
Ambient Relative Humidity, %	60
Cooling Water Temperature, °C (°F)	See Section 2.7
Air composition based on published psychrometric data, mass %	
Ar	0.0128
CO ₂	0.0005
H ₂ O	0.0062
N ₂	0.7506
O ₂	0.2300
Total	1.0000

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

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 combustion turbines (CTs) in the NGCC cases 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
- Noise regulations – Impact on site and surrounding area

^d As stated in the footnote for Exhibit 1-1 above, this is the set of ambient conditions used to design and optimize all power plant generating and cooling equipment. Alternate “off design” ambient conditions were also used as sensitivity parameters to determine trends in cooling and performance.

- Other localized environmental concerns
- Weather delays

2.2 COAL CHARACTERISTICS

The design coal in the PC plant configurations is Illinois No. 6 with characteristics presented in Exhibit 2-3. The coal properties are from the Quality Guidelines for Energy System Studies (QGESS) document “Detailed Coal Specifications.” [5]

The Power Systems Financial Model (PSFM) was used to derive the capital charge factors (CCFs) for this report. [6] The PSFM requires that all cost inputs have a consistent cost year basis. Because the capital and operating cost estimates are in June 2011 dollars, the fuel costs must also be in June 2011 dollars.

Assumed fuel price is \$2.78/GJ (\$2.94/MMBtu) for Illinois No. 6 coal, on a higher heating value (HHV) basis, delivered to the Midwest, and in 2011 U.S. dollars (USD).^e

Exhibit 2-3 Design coal

Rank	Bituminous	
Seam	Illinois No. 6 (Herrin)	
Source	Old Ben Mine	
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, Btu/lb (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

^e As specified in the November 2012 QGESS document on “Fuel Prices for Selected Feedstocks in NETL Studies.” [23]

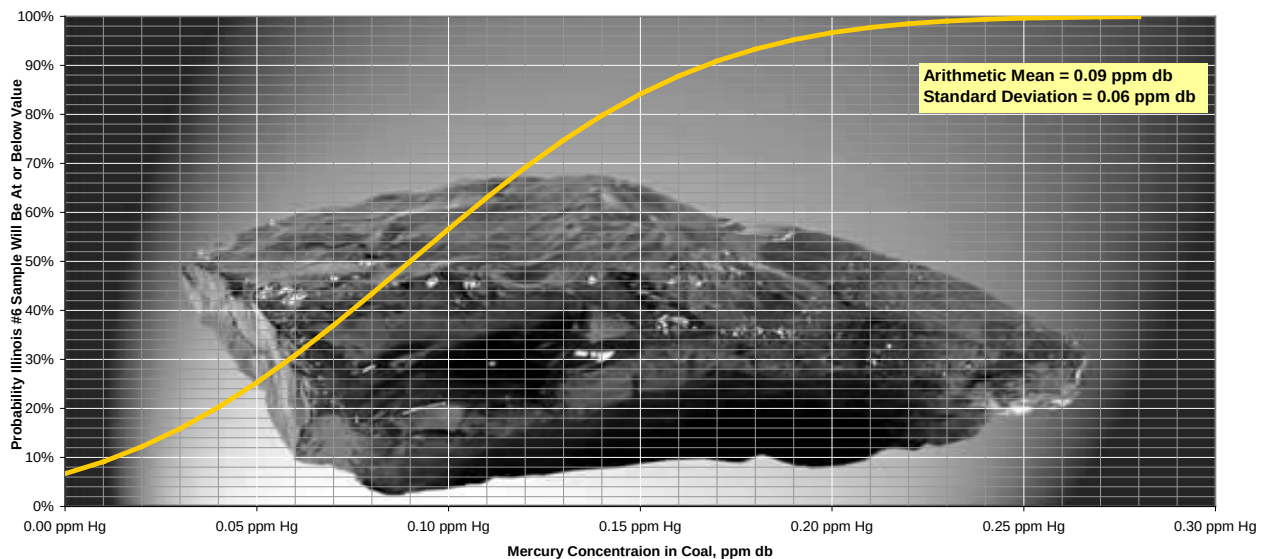
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen ^B	6.88	7.75
Total	100.00	100.00

^AThe proximate analysis assumes sulfur as volatile matter.

^BBy difference

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. [7] Hence, as illustrated in Exhibit 2-4, 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 for all PC cases, which corresponds to the mean plus one standard deviation and encompasses about 84 percent of the samples. It was further assumed that all of the coal Hg enters the gas phase and none leaves with the bottom ash. [8]

Exhibit 2-4 Probability distribution of mercury concentration in the Illinois No. 6 coal



Source: NETL

2.3 NATURAL GAS CHARACTERISTICS

Natural gas is utilized as the fuel in the NGCC plant configurations and its composition is presented in Exhibit 2-5. The natural gas properties are from the QGESS document

"Specification for Selected Feedstocks" [9] with the addition of methanethiol (mercaptan). [10]

Assumed fuel price is \$5.81/GJ (\$6.13/MMBtu) for natural gas, on an HHV basis, delivered to the Midwest, and in 2011 USD.^f

^f As specified in the November 2012 QGESS document on "Fuel Prices for Selected Feedstocks in NETL Studies." [23]

Exhibit 2-5 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
n-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	100.00
	LHV	HHV
kJ/kg (Btu/lb)	47,454 (20,410)	52,581 (22,600)
MJ/scm (Btu/scf)	34.71 (932)	38.46 (1,032)

^AThe sulfur content of natural gas is primarily composed of added mercaptan (methanethiol, CH₄S) with trace levels of H₂S. [10]

Note: Fuel composition is normalized and heating values are calculated.

2.4 ENVIRONMENTAL 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 Mercury and Air Toxics Standards (MATS) for PC technologies. [11], [12], [13]
- 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 PC and NGCC technologies. [13], [14]

The regulations divide the coal types into low rank and non-low rank based on their heating value. Coals with an HHV of greater than 8,300 Btu per pound (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 12,900 Btu/lb, is considered a non-low rank coal.

The emission limits imposed by MATS and NSPS that apply to each technology in this report are provided in Exhibit 2-6.

Exhibit 2-6 MATS and NSPS emission limits for PM, HCl, SO₂, NO_x, and Hg

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

These new regulations apply to PC and NGCC technologies that began construction after May 3, 2011. Furthermore, these regulations state that [13], [15]

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 megawatts electric (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, etc.; 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.

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 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed for coal $\geq 8,300$ 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 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 (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. [14]

In addition to federal regulations, state and local jurisdictions can impose even more stringent regulations on a new facility. However, since each new plant has unique environmental requirements, it was necessary to apply some judgment in setting the environmental targets for this report.

2.4.1 Pulverized Coal

Exhibit 2-7 provides the emissions limits for PC plants as well as a summary of the control technology utilized to satisfy the limits.

Exhibit 2-7 Environmental targets for PC cases

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 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. [16]

It was assumed that low NO_x burners and staged overfire air (OFA) would limit NO_x emissions to 0.5 lb/MMBtu and that selective catalytic reduction (SCR) technology

would be 83-85 percent efficient. By adjusting the ammonia flow rate in the SCR, the NO_x emissions limits were 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 flue gas desulfurization (FGD) removal efficiencies greater than 99 percent, but based on NSPS requirements, such high removal efficiency is not necessary.

The fabric filter was assumed to be capable of achieving a PM removal 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 sulfur trioxide (SO₃) on Hg capture due to the high sulfur content of the coal in this study.

2.4.2 Natural Gas Combined Cycle

Exhibit 2-8 provides the emissions limits for NGCC plants as well as a summary of the control technology utilized to satisfy the limits.

Exhibit 2-8 Environmental targets for NGCC cases

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 1.0 ppmvd NO_x emissions (referenced to 15 percent oxygen [O₂]) through the use of a dry low NO_x (DLN) burner in the combustion turbine generator (CTG)—the DLN burners are a low NO_x design and reduce the emissions to about 9 ppmvd [17] (assumed to be approximately 98 percent nitrogen monoxide (NO) and referenced to 15 percent O₂)—and an SCR. [18]

While a state-of-the-art 2013 F-class CT alone produces NO_x emissions below the limit shown in Exhibit 2-8, an SCR was included to ensure the plant met EPA's PSD program by installing BACT. The SCR system is designed for 90 percent NO 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. [10] 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 CH₄S was the sole contributor of sulfur to the natural gas. The CH₄S concentration of the natural gas is provided in Exhibit 2-5 as 5.75×10^{-6} mol% (7.06×10^{-4} lb-CH₄S/MMBtu).

If the natural gas contained 1.00 gr-S/100 scf, the SO₂ emissions for the non-capture case would be 0.018 lb/MWh-gross. The CO₂ capture system removes virtually all SO₂ from the flue gas.

The pipeline natural gas was assumed to contain no PM, Hg, or HCl, resulting in zero emissions.

2.4.3 Carbon Dioxide

EPA proposed an NSPS on April 13, 2012, for emissions of CO₂ from new fossil fuel-fired EGUs. This rule was finalized on August 3, 2015 and sets the CO₂ emissions limits below that of current fossil fuel-fired EGUs without CO₂ capture.

The PC and NGCC cases both assume that all the combusted carbon in the fuel is converted to CO₂ in the flue gas. CO₂ is also generated from limestone in the FGD system. The CO₂ capture systems in this analysis are designed for 90 percent capture of the CO₂ entering the removal unit.

2.4.4 Effluent Limitation Guidelines

EPA issued updated effluent limitation guidelines (ELGs) and standards for the steam electric power generation point source category in November 2015, to strengthen controls on wastewater discharges. [19] Wastewater streams most impacted by the update include FGD wastewater, fly ash and bottom ash transport (sluicing) water, combustion residual leachates, flue gas Hg control wastewater, and nonchemical metal cleaning wastewater.

EPA issued another update to the ELGs in September 2017 that extended the compliance deadlines for wet FGD wastewater and bottom ash transport water of existing plants. [20] However, greenfield plants are still required to meet the more stringent compliance deadlines set forth by the November 2015 ELG update.

For the plant configurations considered in this study, FGD wastewater discharged by the PC plant arrangement is the only wastewater stream that is applicable to ELG regulations. Meeting the updated, more stringent ELG limits was not an objective of this study, so plant configurations do not consider treatment options suggested by the 2015 rule.

2.5 CAPACITY FACTOR

The North American Electric Reliability Council (NERC) Generating Availability Data System [21] (GADS) provides information on existing plants (e.g. Generating Analysis Reports, Generating Availability Reports, Generating Unit Statistical Brochure, Historical Availability Statistics). An analysis of existing plant capacity factor data for PC and NGCC plants was conducted as part of the NETL Cost and Performance Baseline for Fossil Energy Plants. [4] The outcome of the analysis was an assumed capacity factor for both PC and NGCC cases, both with and without CO₂ capture, of 85 percent. This assumption is used for this study as well.

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. In plant configurations including a wet evaporative cooling tower, internal recycle water available from various sources like boiler feedwater (BFW) blowdown and condensate from flue gas (in CO₂ capture cases) was applied to offset the water demand. In configurations using exclusively dry cooling technologies, these streams are left as process discharges. Further discussion is provided in Section 2.8. 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. Water evaporated from the wet recirculating cooling tower is an example of consumption, and accounts for the most significant portion of total water consumption for the cases examined in this study.

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, BFW makeup, ash handling makeup, and FGD system makeup. 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.

In cases which included a wet evaporative cooling tower, BFW blowdown was assumed to be treated and recycled to the wet evaporative cooling tower. The cooling tower blowdown was assumed to be treated and 90 percent returned to the water source with the balance sent to the ash ponds for evaporation.

Among the plant configurations in this study, the largest consumer of raw water is the cooling tower makeup in plants including a wet evaporative cooling systems. In these

cases, all process blowdown streams were assumed to be treated and recycled to the cooling tower. The design ambient wet bulb temperature of 51.5°F (Exhibit 2-1 and Exhibit 2-2) was used to achieve a cooling water temperature of 60°F using an approach of 8.5°F under the design ambient conditions. The design cooling water range was assumed to be 20°F. For the off-design ambient conditions (high elevation, a range of relative humidities, and “hot” summer conditions as well as “cold” winter conditions), the cooling water temperatures ranged from 55.0°F for the low temperature, low relative humidity ambient case (20°F d.b., 63% R.H.) to 84.2°F for the high temperature, high relative humidity ambient case (85°F d.b., 84% R.H.). The wet cooling tower evaporative losses, blowdown, and makeup rate were modeled for each of the off-design ambient conditions presented in Section 2.7 using Thermoflex (Version 26), a nonproprietary, commercially available software package developed by Thermoflow, Inc.

2.7 OFF-DESIGN PERFORMANCE ESTIMATING METHODOLOGY

The overall performance of fixed size power plants at any given point in time is influenced by the ambient conditions. Fluctuations in ambient conditions occur on an hourly, daily, and seasonal basis throughout the lifetime of a power plant, resulting in a nearly constant state of off-design operation. The performance of the plant cooling circuit is among the systems most influenced by changes in ambient conditions. In turn, the performance of critical plant systems supported by the cooling circuit are influenced to a large degree as well. This study sought to quantify key plant performance metrics for each of the twelve plant types described in Exhibit 1-1 under different ambient dry bulb temperatures, relative humidities, and pressures to observe the influence that fluctuating ambient conditions have on the performance of plants with different cooling arrangements.

The general methodology for quantifying changes in performance for each of the fixed size power plants presented in Exhibit 1-1 was to:

1. Establish the plant sizing basis for each of the plant configurations under the design ambient (ISO) conditions shown in Exhibit 2-2.
 - o Coal feed rates of 395,053 lb/hr and 495,578 lb/hr from cases B12A and B12B of the NETL Cost and Performance Baseline for Fossil Energy Plants [4] were used as the sizing basis for the PC cases without and with 90% CO₂ capture, respectively.
 - o Two 2013 F-class CTGs with an individual ISO rating of 211 MW when firing natural gas were used as the sizing basis for each of the NGCC cases.
2. Obtain reference off-design performance information for each of the three cooling systems listed in Exhibit 1-1.

- o The system sizing parameters are given in Exhibit 2-9 and represent those for a reference 630 MWe-net NGCC plant without CO₂ capture.
- o The percentage of the condenser duty split between the wet evaporative cooling tower and ACC was applied only to the hybrid wet/dry parallel configuration. The initial temperature difference (ITD) design parameter was used to size the ACC in the hybrid wet/dry parallel and ACC configurations.

Block flow diagrams for each cooling system are shown in Exhibit 2-10, Exhibit 2-11, and Exhibit 2-12.

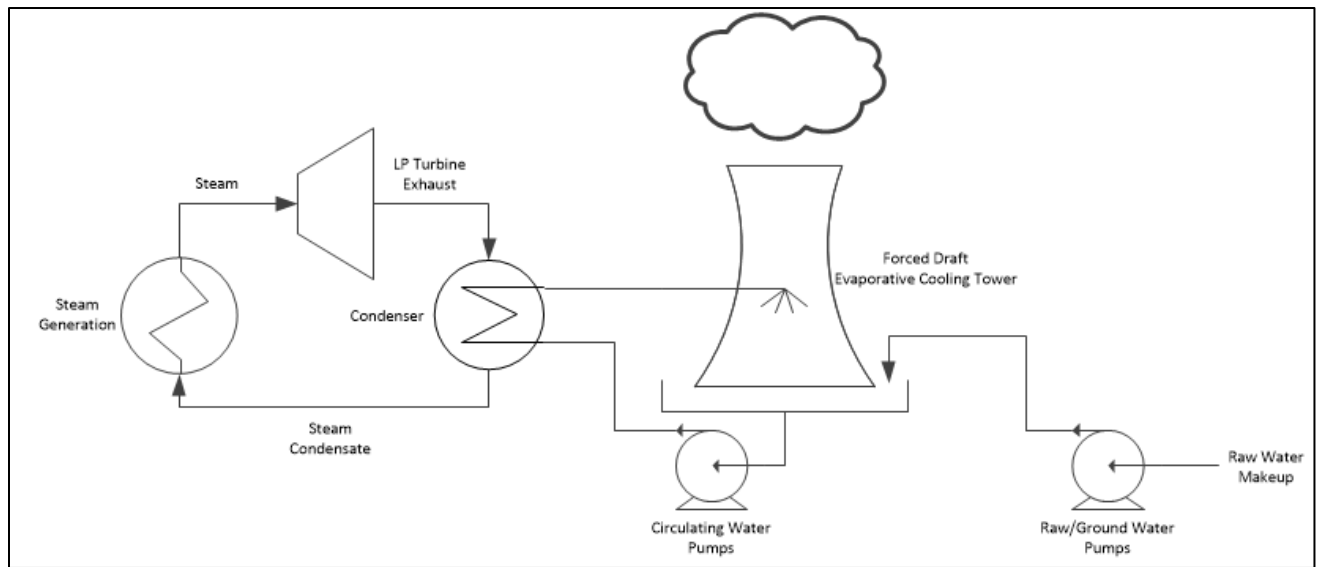
Exhibit 2-9 Condenser system design parameters

Design parameter	Value
Condenser duty, (MMBtu/hr)	1,215
LP turbine exhaust flow, (lb/hr)	1,282,290
LP turbine exhaust pressure, (psia)	0.9823
LP turbine exhaust steam quality	0.9146
CW supply temp. to condenser, (°F)	60
CW supply temp. from condenser, (°F)	80
Duty split, (%) ^A	50/50
Initial temperature difference (ITD), (°F) ^B	42.1

^AThe duty split design parameter specifies the proportions of the condenser duty shared between the wet evaporative and ACC components of the hybrid wet/dry parallel arrangement at the design ambient conditions.

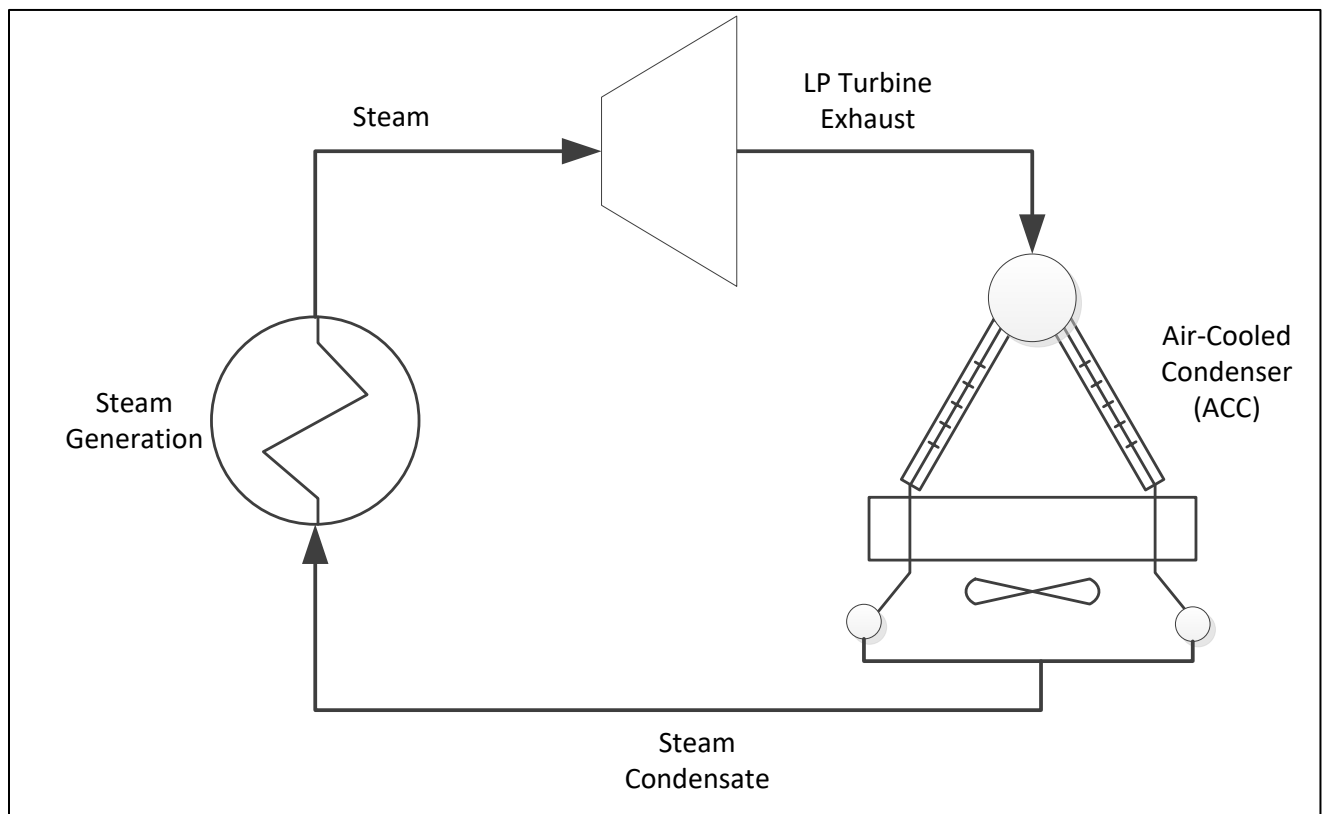
^BThe ITD is the difference between the temperature of the LP steam entering the ACC and the dry bulb air temperature at design ambient temperature (59°F). The LP turbine exhaust temperature at the specified pressure (0.9823 psia) and quality (0.9146) is 101.1°F resulting in an ITD of 42.1°F = 101.1°F - 59°F.

Exhibit 2-10 Wet evaporative system block flow diagram

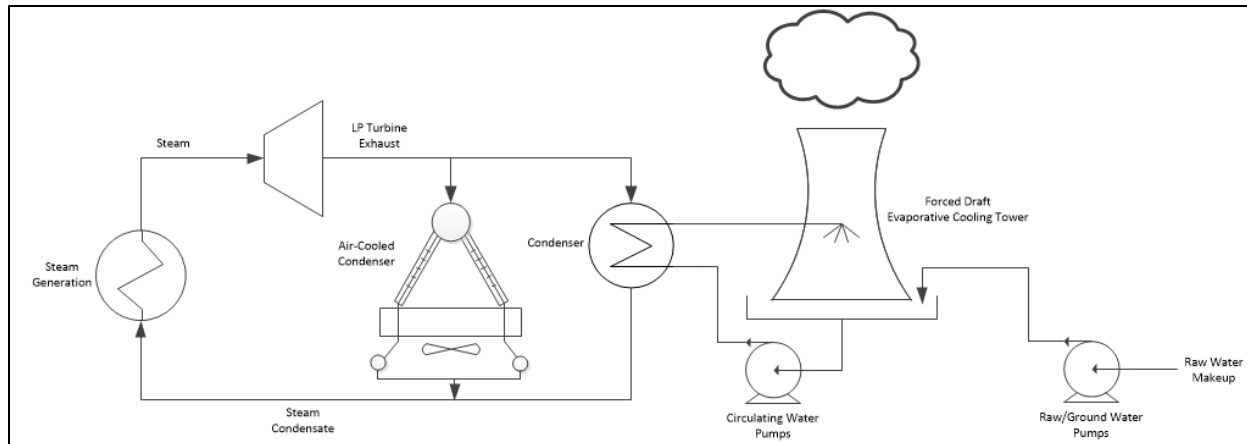


Source: NETL

Exhibit 2-11 ACC block flow diagram



Source: NETL

Exhibit 2-12 Hybrid wet/dry parallel block flow diagram

Source: NETL

3. Obtain a range of off-design performance information for the Shell Cansolv CO₂ removal process while maintaining a 90 percent CO₂ capture efficiency at various cooling water supply temperatures.
 - o The information was used to observe the impact of fluctuating ambient conditions on the CO₂ removal process when dry cooling technologies (e.g. ACHE bays) are utilized for process cooling loads, in addition to an ACC, to eliminate wet evaporative cooling entirely.
 - o A spreadsheet ACHE model was developed to estimate the cooling water temperature and corresponding operating point of the Cansolv system under each study dry bulb temperature.

Further discussion on the elimination of evaporative cooling is provided in Section 2.8.

4. Incorporate the off-design information obtained for the cooling systems, Shell Cansolv process, and ACHE bays into process models representing each of the plant types listed in Exhibit 1-1 to generate plant-level, off-design performance results for the range of ambient conditions and air compositions shown in Exhibit 2-13.

Exhibit 2-13 Ambient condition sensitivities

Air composition based on published psychrometric data, mass %														
Pressure, psia	14.696							12.1						
T _{d.b.} (°F)/R.H.(%)	59/60	85/53	85/69	85/84	20/63	20/70	20/74	59/60	85/53	85/69	85/84	20/63	20/70	20/74
Ar	0.0128	0.0127	0.0127	0.0126	0.0129	0.0129	0.0129	0.0128	0.0127	0.0126	0.0125	0.0129	0.0129	0.0129
CO ₂	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
H ₂ O	0.0062	0.0135	0.0177	0.0216	0.0014	0.0015	0.0016	0.0077	0.0165	0.0215	0.0262	0.0016	0.0018	0.0019
N ₂	0.7506	0.7450	0.7419	0.7389	0.7542	0.7541	0.7540	0.7494	0.7428	0.7390	0.7354	0.7540	0.7538	0.7537
O ₂	0.2300	0.2283	0.2273	0.2264	0.2311	0.2311	0.2310	0.2296	0.2276	0.2264	0.2253	0.2310	0.2310	0.2310
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

2.8 ELIMINATION OF EVAPORATIVE COOLING

An objective of this study was to develop performance and cost information for PC and NGCC plants without the use of wet evaporative cooling. For these plant configurations, cooling for the plant was supplied entirely by dry cooling technologies consisting of an ACC and ACHE bays. A significant portion of the plant cooling load is associated with the steam cycle condenser. Condenser cooling loads account for approximately 95 and 98 percent of the overall cooling load for PC and NGCC plants without CO₂ capture, respectively. The inclusion of CO₂ capture decreases this proportion to approximately 47 and 37 percent, respectively, due to the addition of the cooling duty required for the Cansolv CO₂ capture system. Condenser cooling loads are supplied by an ACC as part of the overall strategy to eliminate wet evaporative cooling.

The remaining non-condenser cooling loads are associated with miscellaneous equipment items such as lube oil coolers, turbine generators, boiler feed pumps, and the cooling demand from the Cansolv process and CO₂ compression train in plants with CO₂ capture. Heat generated by these sources is typically removed by a closed loop (CL) auxiliary cooling water (CW) system where it is ultimately rejected in the wet evaporative cooling tower in plants employing such systems. The elimination of the wet evaporative cooling tower in favor of dry cooling technologies necessitates that the heat carried by the CL auxiliary CW system be rejected elsewhere.

Integrating a plant's CL auxiliary CW system with the steam cycle heat rejection system is not feasible for a power plant with an ACC. The design of an ACC is such that low pressure (LP) turbine exhaust steam is sent directly from the LP turbine section to a large diameter steam distribution header and is condensed in finned tube downcomers by the removal of latent heat. In contrast, the CL auxiliary CW system must reject sensible heat from the CW in non-condensing fashion, thereby requiring a different hydraulic design. In addition, integration of lower purity process cooling water with high-purity LP steam would contaminate the steam cycle loop, requiring additional water treatment. Therefore, cases eliminating evaporative cooling were designed using ACHE bays as the means of rejecting miscellaneous process heat to the atmosphere.

Exhibit 2-14 summarizes the type of cooling technology used in each of the cases in this study.

Exhibit 2-14 Cooling technology by load type

		Cooling Load Type		
		Condenser System	Misc. ^A	Cansolv System
w/o CO ₂ Capture	PC	Wet Evaporative		
		Hybrid Wet/Dry Parallel	Wet Evaporative	
		ACC	ACHE	
	NGCC	Wet Evaporative		
		Hybrid Wet/Dry Parallel	Wet Evaporative	
		ACC	ACHE	
w/ CO ₂ Capture	PC	Wet Evaporative		
		Hybrid Wet/Dry Parallel	Wet Evaporative	
		ACC	ACHE	
	NGCC	Wet Evaporative		
		Hybrid Wet/Dry Parallel	Wet Evaporative	
		ACC	ACHE	

^AMisc. cooling loads include those from lube oil coolers, turbine generators, boiler feed pumps, etc., and total 100 MMBtu/hr for all PC cases and 25 MMBtu/hr for all NGCC cases.

2.9 COST ESTIMATING METHODOLOGY

Screening-level, factored capital cost estimates were obtained from B&V for a wet evaporative, hybrid wet/dry parallel, and ACC cooling system. Each were sized for a reference 630 MWe-net NGCC plant without CO₂ capture. In addition to the condenser systems, a screening-level, factored capital cost estimate for a reference ACHE system was also obtained from B&V. The basis for the ACHE estimate was the required cooling duty for the Cansolv system under the design ambient conditions, shown in Exhibit 2-2, for an equivalently sized NGCC system. Each estimate was based on budgetary quotes obtained from vendors. The scope of the condenser system estimates included the following:

- Fiberglass reinforced plastic cooling tower
- 2 x 50 percent circulating water pumps
- Single-speed cooling tower fans (two-speed used when developing the performance curves).
- Single-speed ACC fans (variable speed used when developing the performance curves)

- No plume abatement
- Spread footing foundations
- Rail/highway access
- Makeup water quality is 50 percent city and 50 percent groundwater
- Distance between condenser and cooling tower: 250 feet
- Distance from steam turbine generator (STG) exhaust to ACC: 100 feet
- Site considered to be Seismic Zone 1, relatively level, free from hazardous materials, archeological artifacts, or excessive rock
- Soil conditions considered adequate for spread footing foundations
- Soil bearing capability assumed adequate such that piling is not needed to support the foundation loads

The scope of the ACHE estimate included the following:

- ACHE equipment cost (68 bays total)
- Spread footing foundations
- Craft labor wages consistent with Merit Shop rates for Midwest locations
- Closed water loop piping (250 ft buried)
- 2 x 50 percent circulating water pumps

Both sets of estimates considered a greenfield Midwestern site location.

Bare erected costs were obtained on a 2017 USD basis. The bare erected costs for the condensing and ACHE systems were adjusted to June 2011 dollars using the Chemical Engineering Plant Cost Index (CEPCI) to maintain consistency with the balance of plant cost estimates. The costs were then scaled for each of the twelve plant configurations shown in Exhibit 1-1 per the NETL QGESS methodology. [22] Engineering, procurement, and construction fees, and project contingencies were included prior to incorporating these adjusted costs into the overall plant-level, greenfield total overnight cost (TOC) estimates for each plant. Additionally, operation and maintenance (O&M) cost estimates for each configuration were developed. A COE for each plant configuration was developed and is reported, along with the TOC results, in Section 3.1.6. The COE developed for each plant configuration reflects only the operation of the plant at the design ambient conditions and does not account for periods of off-design operation throughout the operating life of the plant.

3 RESULTS

3.1 PERFORMANCE

The performance analysis results are shown for different ambient dry bulb temperature and relative humidity (R.H.) values for a key plant performance parameter for either a PC or NGCC plant at either the design ISO ambient pressure (14.696 psia) or low ambient pressure (12.1 psia). The design ambient condition for both the NGCC and PC plants of 59°F and 60% R.H. is annotated on the ISO ambient pressure charts for reference.

3.1.1 Low Pressure (LP) Turbine Backpressure

A key performance parameter that is influenced by both the cooling system design and ambient conditions is the exhaust pressure of the LP steam turbine, also known as the LP turbine backpressure. Under a given set of ambient conditions, the LP turbine backpressure is an indicator of the performance of the condenser system. A reduced LP turbine backpressure indicates that lower cooling medium temperatures are available to the condenser system. This produces a lower condenser temperature and pressure. Low turbine backpressures also indicate that the steam cycle power output is being maximized. Exhibit 3-1 shows the LP turbine backpressure at ISO ambient pressure (14.696 psia) and varying ambient temperatures for the PC plant configurations considered. The following observations can be made:

- The highest LP turbine backpressures are observed at a dry bulb temperature of 85°F, indicating a reduction in performance of each condenser system at this high temperature relative to the design conditions.
- Ambient R.H. only impacts the LP turbine backpressure for the plant arrangements that include wet evaporative cooling. This is apparent at 85°F d.b. At higher values of R.H., the ability of the ambient air to retain additional moisture is reduced, thereby reducing the degree to which heat can be rejected via evaporative cooling, resulting in warmer cooling water being supplied to the condenser. The result is a higher LP turbine backpressure. Plant arrangements including an ACC are not influenced by R.H. because evaporative cooling does not occur.
- The inclusion of an evaporative cooling tower, either as part of an exclusively wet evaporative cooling system, or as a wet/dry hybrid cooling system, improves the cooling effectiveness of the heat rejection system at high ambient temperatures. The benefit comes from the ability of the wet evaporative cooling tower to approach the ambient wet bulb temperature, which is lower than the ambient dry bulb temperature.

- The increase in the LP turbine backpressure as the dry bulb temperature rises from the design conditions to 85°F, 84% R.H. is 0.9 and 1.2 psia for the wet evaporative and ACC configurations, respectively. This indicates that the performance of the ACC is more sensitive to increases in the dry bulb temperature due to the lack of evaporative cooling.
- The turbine backpressure did not decrease significantly for any of the cooling arrangements at the lower 20°F d.b. temperature conditions. For the plant arrangements employing wet evaporative cooling, this is a result of operating the wet cooling tower in a “winter operation” mode to prevent icing by maintaining a cooling tower basin temperature of 55°F. For the plant arrangement employing a sole ACC, individual fans are shut off to limit the turbine backpressure to prevent the lower performance limitations of the LP turbine from being exceeded.

Exhibit 3-1 LP turbine backpressure (PC cases at ISO ambient pressure [14.696 psia])

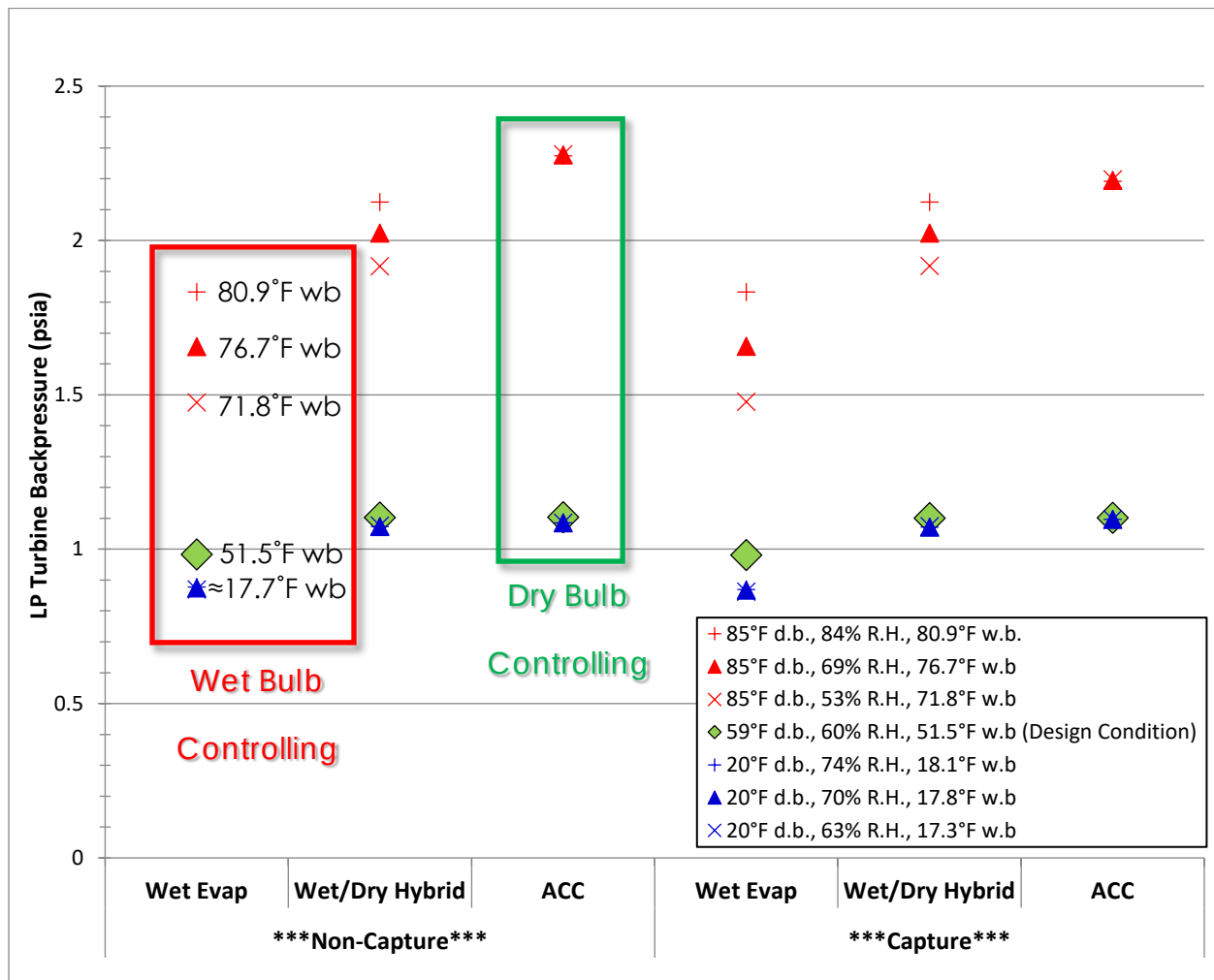


Exhibit 3-2 quantifies the impact that a reduced ambient pressure has on the LP turbine backpressures for the NGCC plants without CO₂ capture at each of the temperature and R.H. conditions. The primary effect is a reduction in the LP turbine backpressure (relative to the sea level case) for each configuration at the high temperature condition. This is a result of a derating of the CT at a lower ambient pressure where the mass flow rate through the CT main air compressor is reduced due to the lower air density. In turn, this leads to less mass flow through the heat recovery steam generator (HRSG) and an overall lower condenser duty. For a fixed condenser size, lower condenser duties result in lower LP turbine backpressures. Exhibit 3-3 shows a similar effect for the NGCC configurations with CO₂ capture.

Exhibit 3-2 LP turbine backpressure (NGCC cases without CO₂ Capture)

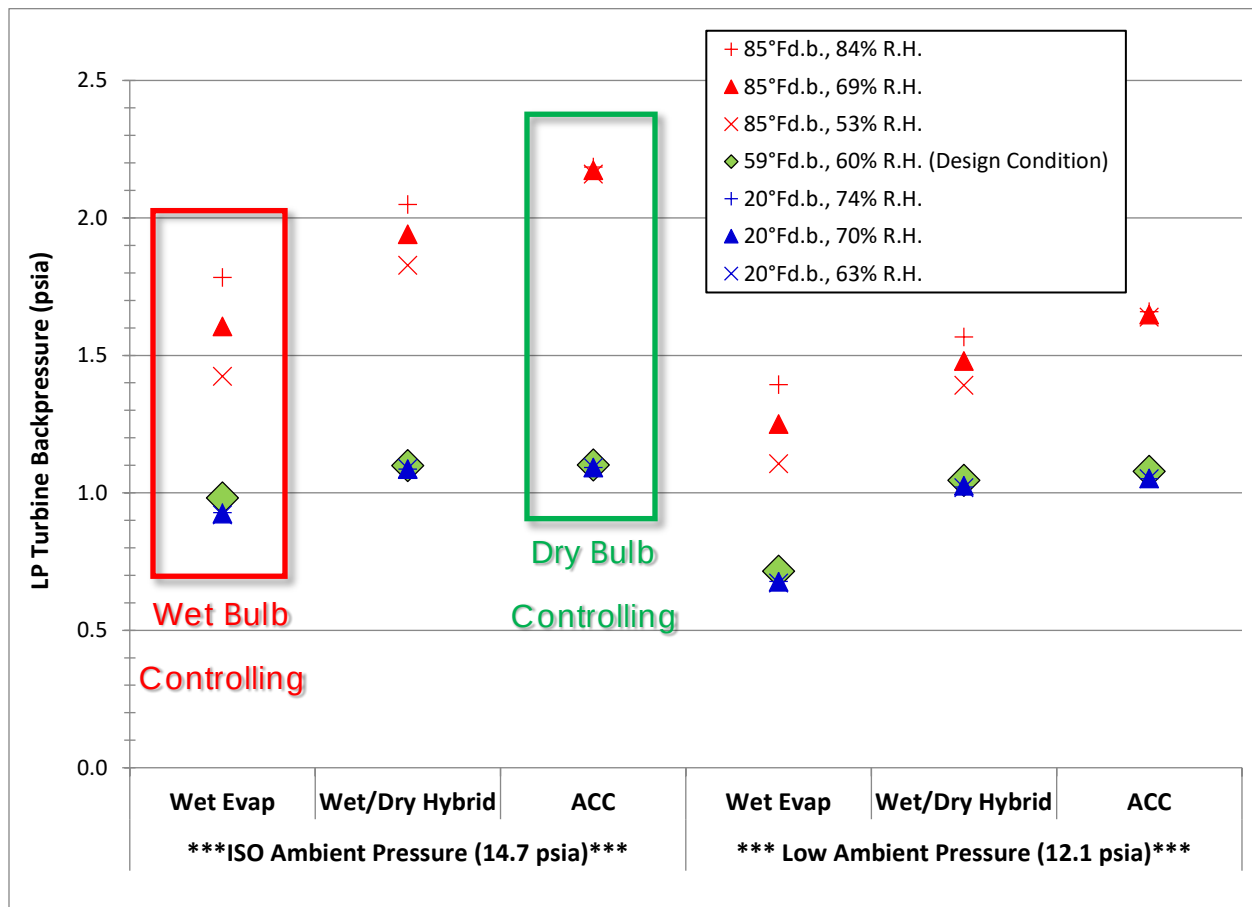
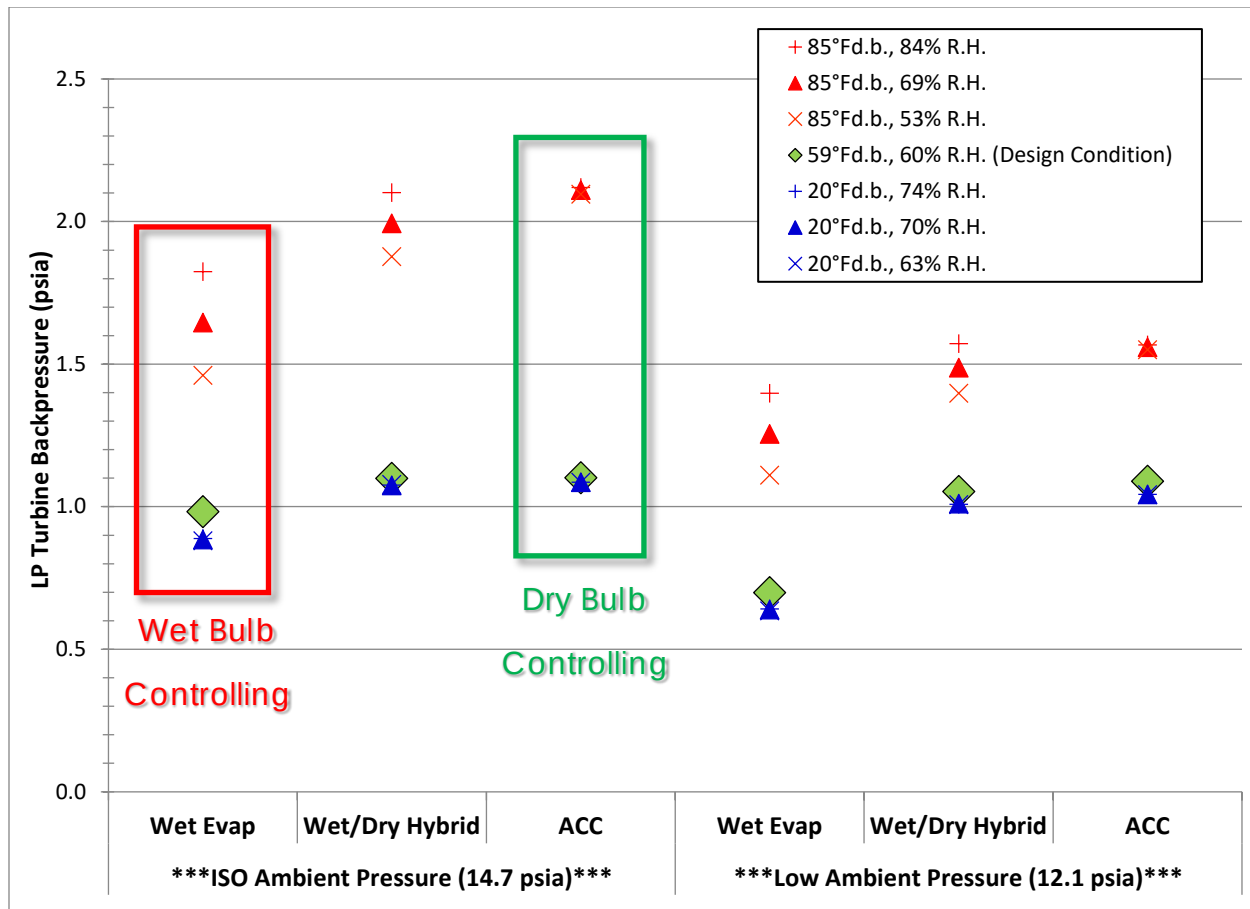


Exhibit 3-3 LP turbine backpressure (NGCC cases with CO₂ Capture)

3.1.2 Net Power

Exhibit 3-4 shows the net plant power for the PC configurations at the ISO ambient pressure 14.696 psia. The following observations can be made from these results:

- As noted in Section 3.1.1, the inclusion of an evaporative cooling tower (either as part of a wet/dry hybrid system, or total wet evaporative cooling) improves the effectiveness of the condensing system at high ambient temperatures since it enables the cooling water temperature to approach the ambient wet bulb temperature, which is lower than the ambient dry bulb temperature.
 - For the non-capture PC configuration with exclusively wet evaporative cooling, the design plant output of 547 MWe-net (ISO conditions) is reduced to 532 MWe-net, or 2.7 percent, at the upper extreme ambient R.H. condition at 85°F d.b. Comparatively, for the non-capture PC configuration utilizing only an ACC, the design plant output of 547 MWe-net is reduced to 528 MWe-net, or 3.5 percent. This indicates that the

performance of the ACC is more sensitive to increases in the dry bulb temperature due to the lack of evaporative cooling.

- The design net power output for the PC configuration with CO₂ capture utilizing only wet evaporative cooling is 548 MWe-net. Changing the cooling system to an entirely dry arrangement reduces the design output to 521 MWe-net (at ISO conditions), or by 4.9 percent. The reduction in net power is primarily due to three factors:
 - o The substitution of wet evaporative cooling with ACHE bays to provide process cooling for the Cansolv system results in warmer cooling water temperatures available to the Cansolv system. These warmer temperatures reduce solvent stripping ability, requiring higher solvent circulation rates to maintain 90 percent CO₂ capture efficiency.
 - o Additional steam is diverted from the steam cycle to compensate for the reduced performance of the Cansolv system. This results in an increased derate of the steam cycle.
 - o The inclusion of a large number of ACHE bays increases the parasitic load of the plant.
- At 85°F d.b., the net power output for the PC configuration with CO₂ capture and utilizing an ACC is reduced from its design net output of 521 MWe-net (ISO conditions) to 505 MWe-net, or 3.3 percent. The reduction is due to increases in the auxiliary load of the Cansolv system due to higher cooling water temperatures available from the ACHE at 85°F d.b., increases in cooling system fan power at 85°F d.b., and increased steam extraction due to the reduced performance of the Cansolv system at 85°F d.b.
- Conversely, at 20°F d.b., the net output for the PC configuration with CO₂ capture and utilizing an ACC is increased from its design net output of 521 MWe-net to 538 MWe-net, or 3.2 percent. The increase is due to reductions in the auxiliary load of the Cansolv system due to lower cooling water temperatures available from the ACHE at 20°F d.b., reductions in cooling system fan power at 20°F d.b., and decreased steam extraction due to the improved performance of the Cansolv system at 20°F d.b.

As explained earlier, the effect of temperature on power generated by pulverized coal units with evaporative cooling systems stands out, due to the impact on the minimum cooling water temperature that can be achieved. In Exhibit 3-4, the wet cooled case without CCS follows this trend: as dry bulb temperature and relative humidity increase, net power steadily declines. This same trend would be expected to continue for the wet

cooled case with CCS, however Exhibit 3-4 indicates that this decrease is much smaller than it is for the non-capture case. This is because a large fraction of the intermediate pressure steam is extracted and used for CO₂ capture solvent regeneration, which dampens the negative generation impact.

Exhibit 3-4 Net power (PC cases at ISO ambient pressure [14.696 psia])

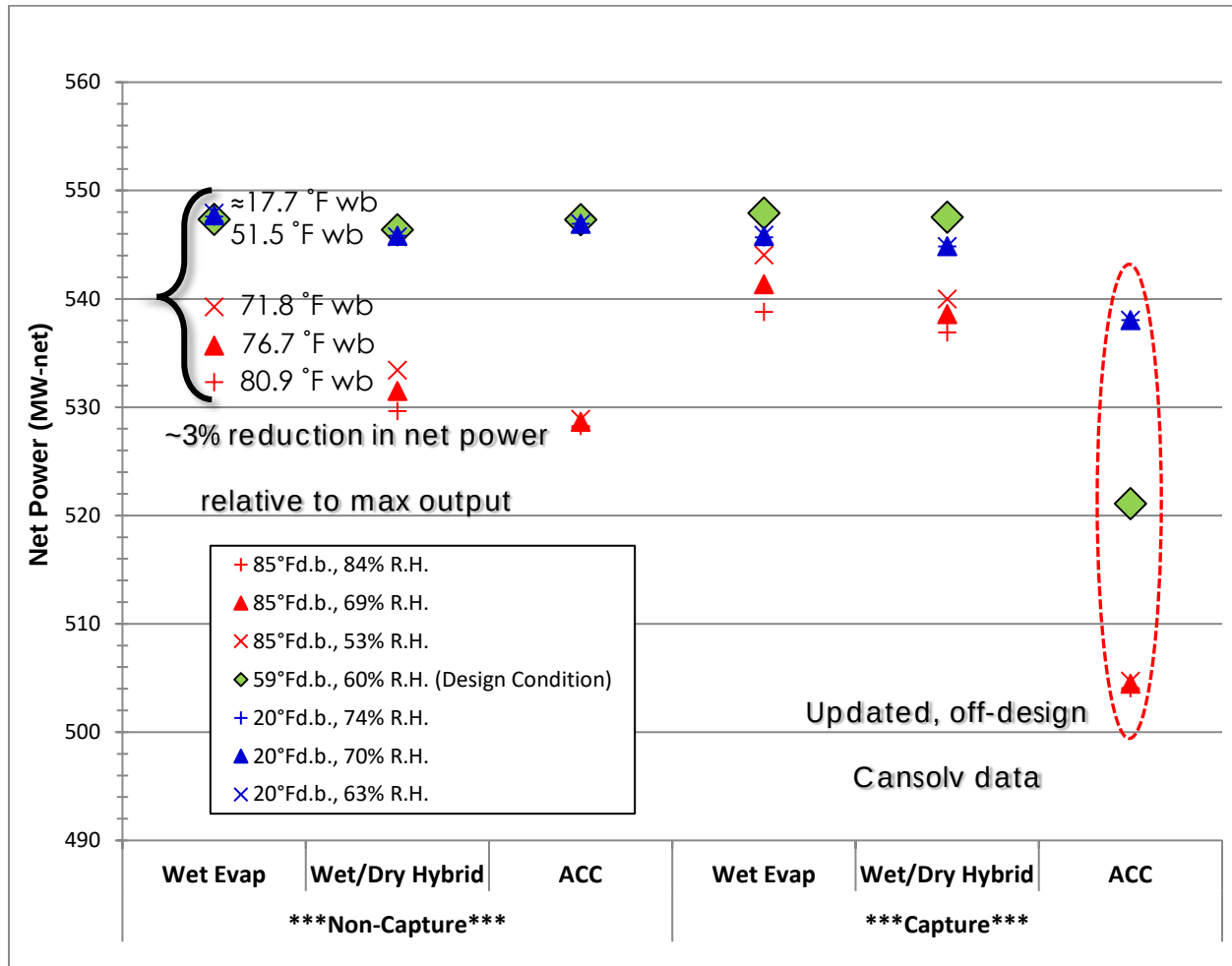


Exhibit 3-5 shows the net plant power for the NGCC configurations at ISO ambient pressure. The following observations can be made from these results:

- Both increases and decreases to net power, relative to the design point, are observed for each NGCC configuration at low- and high-temperature conditions, respectively. This trend is observed for the following reasons:
 - The increases to the net output at 20°F d.b. can be largely attributed to increases in the CT output due to increases in ambient air density and CT throughput.

- Increases in ambient air density result in an increased mass flow through the CT main air compressor.⁹
 - As shown in Exhibit 3-2 and Exhibit 3-3, the LP turbine backpressure is not significantly reduced at this temperature.
- o Conversely, decreases to the net output at 85°F d.b. can be attributed to both the derating of the CT, and increased LP turbine backpressures.
- For the non-capture NGCC configuration with exclusively wet evaporative cooling, the design plant output of 628 MWe-net is reduced to 591 MWe-net (5.9 percent) at 85°F dry bulb, 53% relative humidity. Comparatively, for the non-capture NGCC configuration utilizing strictly dry cooling, the design plant output of 628 MWe-net is reduced to 586 MWe-net (6.7 percent) at 85°F dry bulb, 53% relative humidity.
 - o At higher dry bulb temperatures, a greater (but still small) drop in plant output is experienced by plants utilizing dry cooling technology than plants utilizing wet cooling technology due to the lack of evaporative cooling in the dry cooling configurations. Evaporative cooling towers introduce an additional cooling benefit due to their ability to approach the wet bulb temperature, whereas ACCs and ACHEs are only able to approach the relatively higher dry bulb temperature for each set of ambient conditions.
- The design net power output for the NGCC configuration with CO₂ capture utilizing only wet evaporative cooling is 558 MWe-net. Changing the cooling system to an entirely dry arrangement reduces the design output to 550 MWe-net, or by 1.4 percent. The reduction in net power is due to the same three factors mentioned for the PC cases at ISO ambient pressure in Exhibit 3-4.

⁹ No vendor input was obtained regarding exceeding the ISO power output rating of the CT at off-design ambient conditions.

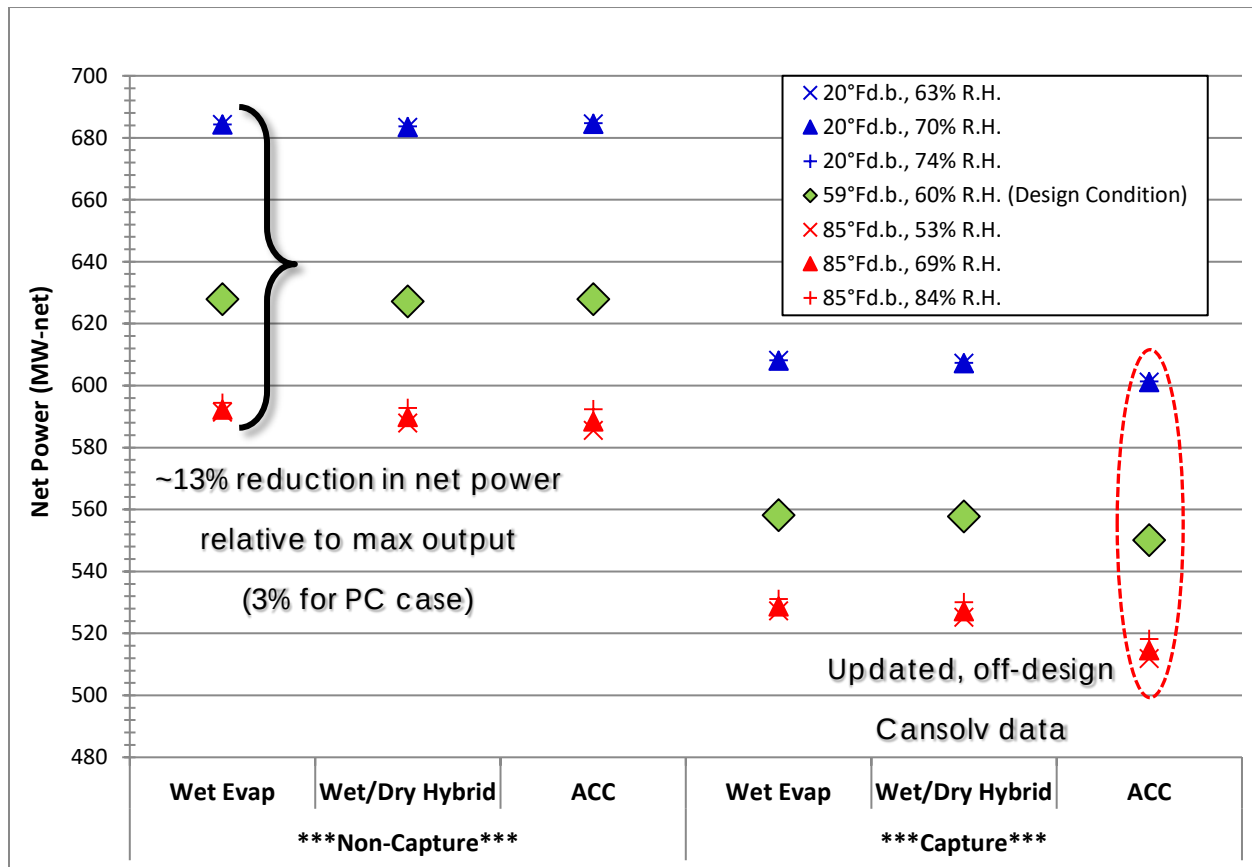
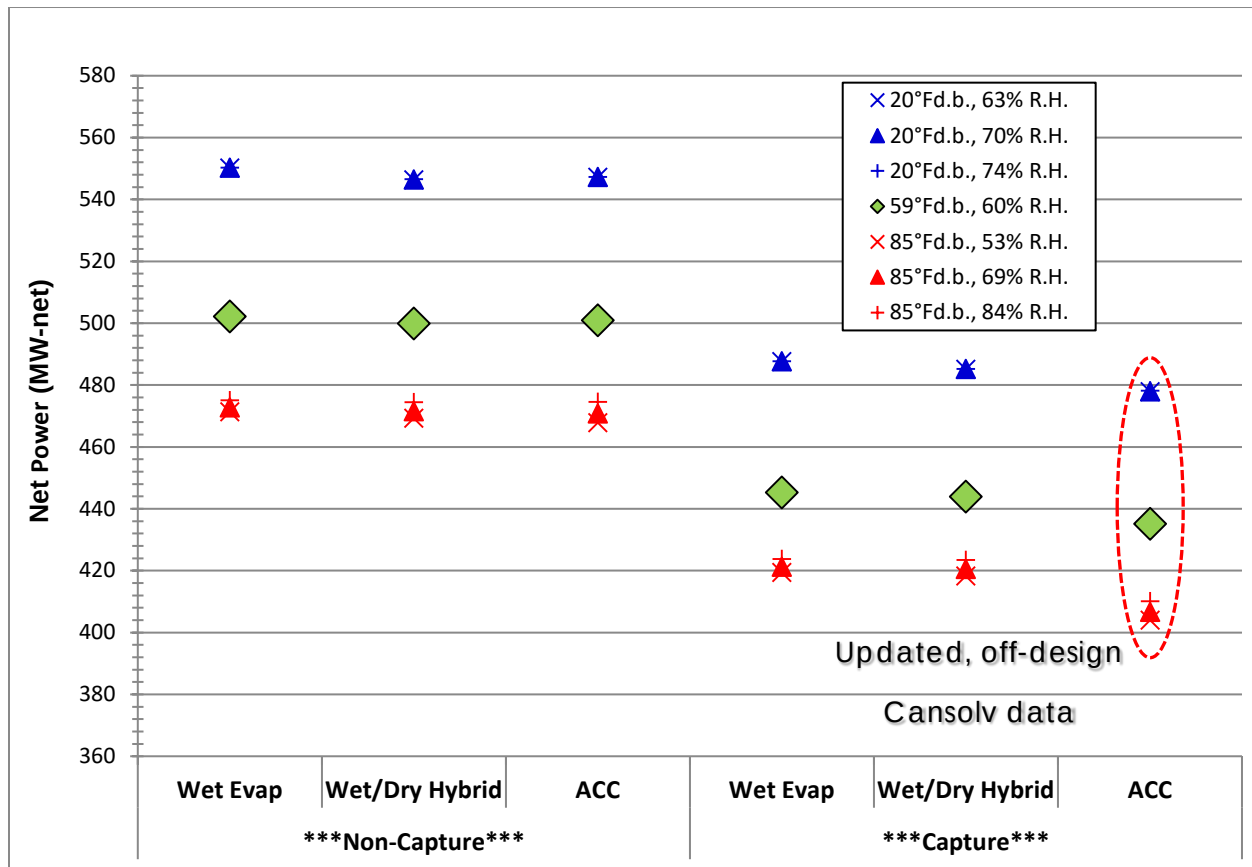
Exhibit 3-5 Net power (NGCC cases at ISO ambient pressure [14.696 psia])

Exhibit 3-6 quantifies the net plant output of the NGCC configurations at each of the temperature and R.H. conditions at low ambient pressure. The observations made from Exhibit 3-5 are largely consistent with the primary difference being an overall reduction in net power output due to a derate of the CT.

No appreciable change in net plant output was observed for the PC plants under low ambient conditions.

Exhibit 3-6 Net power (NGCC cases at low ambient pressure [12.1 psia])

3.1.3 Net Plant Efficiency

Exhibit 3-7 shows the net plant efficiencies for the PC plant configurations under the various ambient conditions at ISO ambient pressure. The trends in efficiencies largely correspond to the observations made for the LP turbine backpressure and net power. The following observations can be made:

- The net plant efficiency for all PC configurations is lowered at 85°F d.b. Those configurations including a wet evaporative cooling tower exclusively, or as part of a wet/dry hybrid configuration, see additional decreases in efficiency at high relative humidity due to the reduced effectiveness of evaporative cooling.
- For the non-capture PC configuration with exclusively wet evaporative cooling, the design net plant efficiency of 40.5 percent is reduced to 39.4 percent, or 1.1 percentage points, at the high temperature and high ambient relative humidity condition at 85°F d.b. Comparatively, for the non-capture PC configuration utilizing only an ACC, the design net plant efficiency of 40.5 percent is reduced to 39.1 percent, or 1.4 percentage points.

- o At higher dry bulb temperatures, a greater drop in net plant efficiency is experienced by plants utilizing dry cooling technology than plants utilizing wet cooling technology due to the lack of evaporative cooling in the dry cooling configurations. Evaporative cooling towers introduce an additional cooling benefit due to their ability to approach the wet bulb temperature, whereas ACCs and ACHEs are only able to approach the higher dry bulb temperature for each set of ambient conditions.
- For the PC capture configuration with exclusively wet evaporative cooling, the design net plant efficiency of 32.3 percent is reduced to 31.8 percent, or 0.5 percentage points, at the upper extreme ambient R.H. condition at 85°F d.b. Comparatively, for the capture PC configuration utilizing only an ACC, the design net plant efficiency of 30.8 percent is reduced to 29.8 percent, or 1.0 percentage point. The reason for the greater decrease in net plant efficiency at higher d.b. temperatures for the dry cooling arrangement is primarily due to the impact of dry cooling on the performance of the Cansolv system. The reduction in net plant efficiency is primarily due to these three factors:
 - o The substitution of wet evaporative cooling with ACHE bays to provide process cooling for the Cansolv system results in warmer cooling water temperatures available to the Cansolv system. Consequently, the auxiliary loads of the Cansolv system are increased in order to maintain the design 90 percent CO₂ capture efficiency, which reduces the efficiency of the plant.
 - o Additional steam is diverted from the steam cycle to compensate for the reduced performance of the Cansolv system. This results in an increased derate of the steam cycle, which leads to a reduction in plant efficiency.
 - o The inclusion of a large number of ACHE bays increases the parasitic load of the plant, which reduces the net plant efficiency.
- At ISO design conditions, changing the cooling configuration of a PC plant with CO₂ capture from an exclusively wet evaporative cooling arrangement to an ACC with ACHE bays decreases the design net plant efficiency from 32.3 percent to 30.8 percent. This drop can be attributed to the same three factors listed in the previous observation, above.

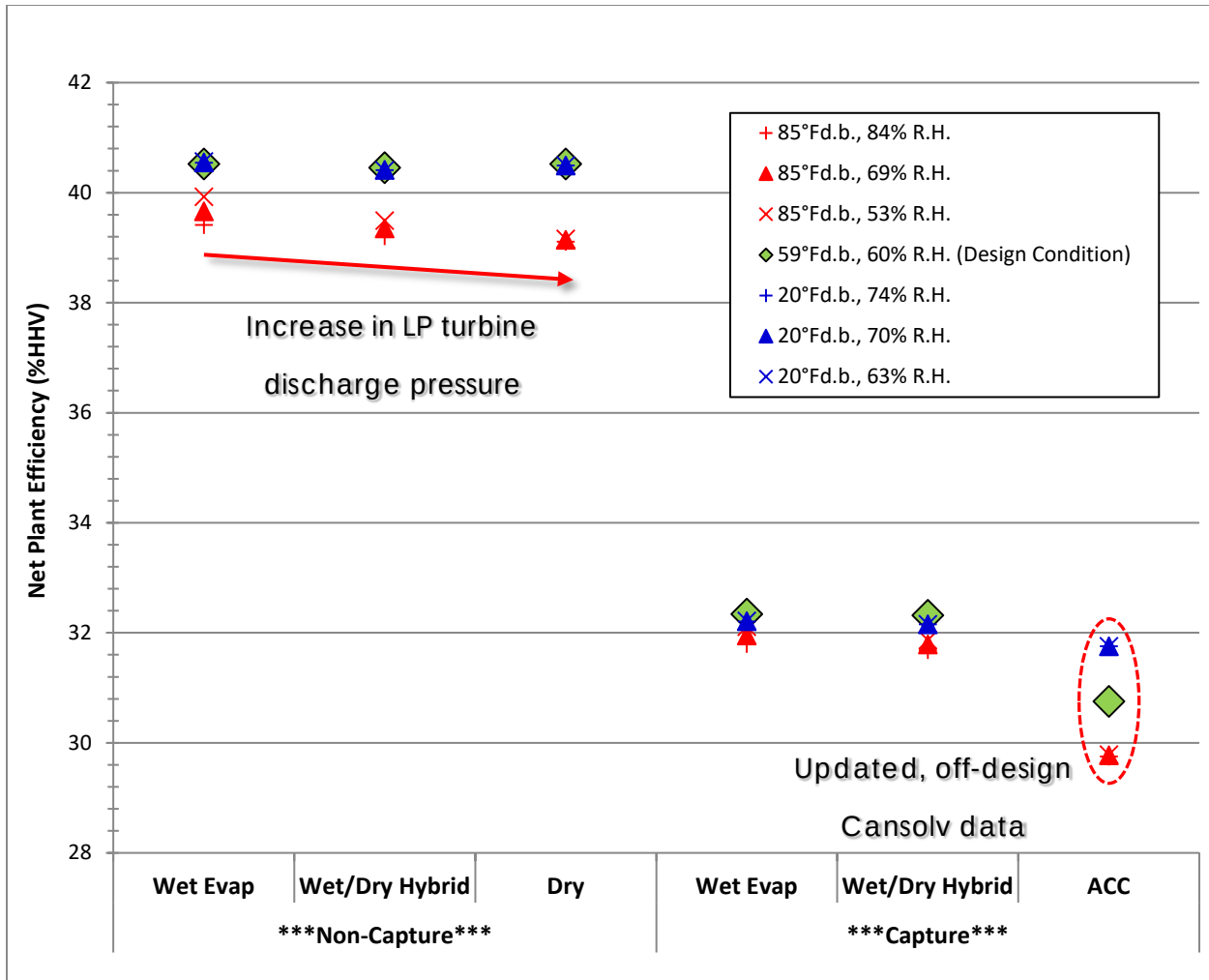
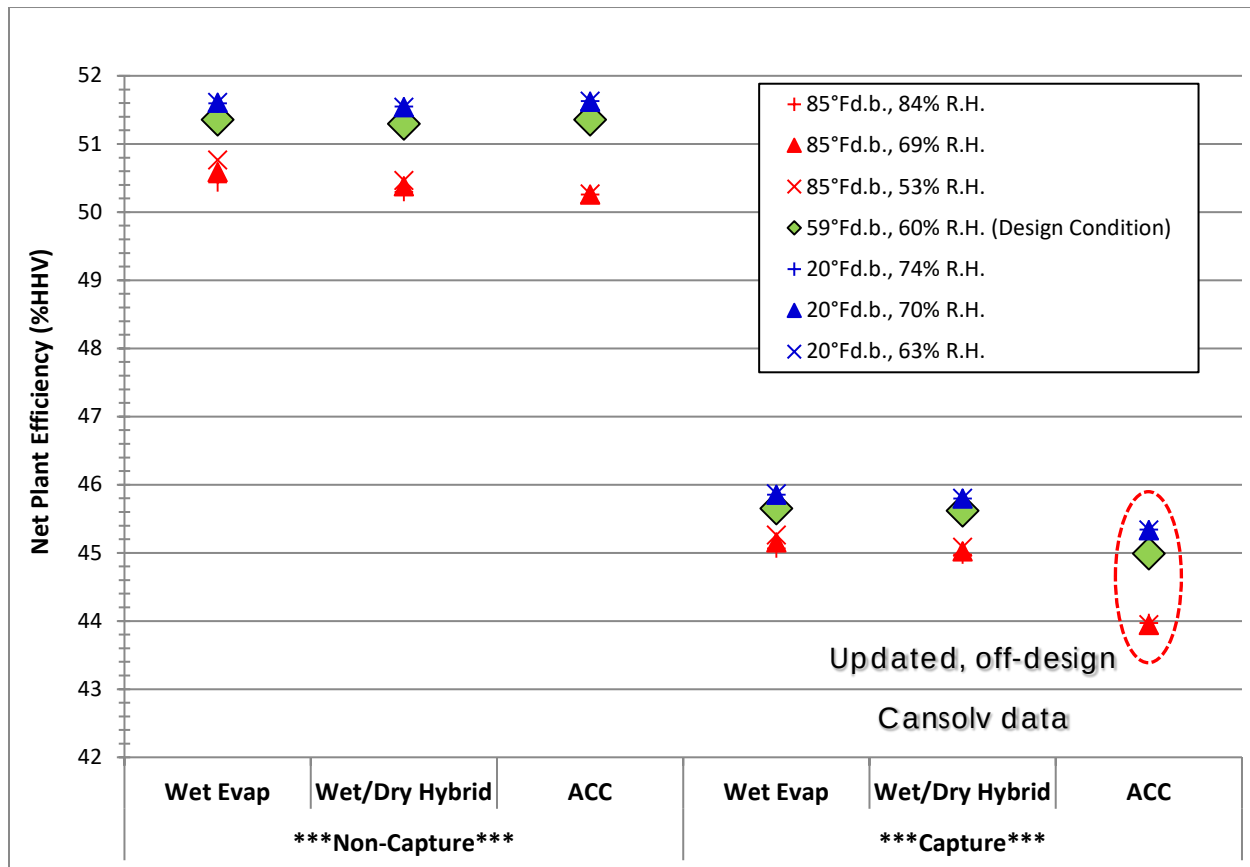
Exhibit 3-7 Net plant efficiency (PC cases at ISO ambient pressure [14.696 psia])

Exhibit 3-8 shows the net plant efficiencies for the NGCC plant configurations under the various ambient conditions at ISO ambient pressure. The trends in efficiencies largely correspond to the observations made for the LP turbine backpressure and net power. The following additional observation can be made:

- An increase above the design net plant efficiency of approximately 0.2 to 0.5 percentage points results at 20°F d.b. for all NGCC configurations. This increase is attributed to the greater power output of the CT at 20°F d.b. (due to increased density of air at lower temperature), as illustrated in Exhibit 3-5.

Exhibit 3-8 Net plant efficiency (NGCC cases at ISO ambient pressure [14.696 psia])

3.1.4 Evaporative Losses

Evaporative losses from the use of wet evaporative cooling are quantified for both PC and NGCC plant configurations at the ISO ambient pressure under the various ambient temperature and relative humidity combinations in Exhibit 3-9 and Exhibit 3-10. No significant variations in these results were observed at the low ambient pressure. The results are normalized by net plant output at the respective ambient condition. The following observations can be made:

- Regardless of the plant type, evaporative losses are greatest at 85°F d.b. and 53 percent R.H. This reflects the natural property of air to be able to retain more water at higher dry bulb temperatures and lower R.H. values. Thus, evaporation from the wet evaporative cooling towers is greatest.
- Evaporative losses are eliminated from the cases employing an ACC as the sole condenser technology in combination with the use of ACHE bays to achieve entirely dry cooling.
- For PC and NGCC cases without CO₂ capture, switching to a wet/dry hybrid parallel cooling arrangement reduces evaporative losses by approximately 50

percent at the design conditions. However, in cases with CO₂ capture, this reduction is only 23 and 24 percent for PC and NGCC plants, respectively. The difference in reduction is the result of the significant amount of non-condenser loads (primarily the CO₂ capture plant) that are still serviced by wet evaporative cooling in the wet/dry hybrid parallel arrangement.

- For PC and NGCC cases with a wet evaporative cooling tower and CO₂ capture, evaporative losses are significantly higher than those cases without capture. This is primarily due to the significant reduction in net power production for cases with CCS, and to a lesser degree, an increase in cooling water usage.

Exhibit 3-9 Evaporative losses (PC cases at ISO ambient pressure [14.696 psia])

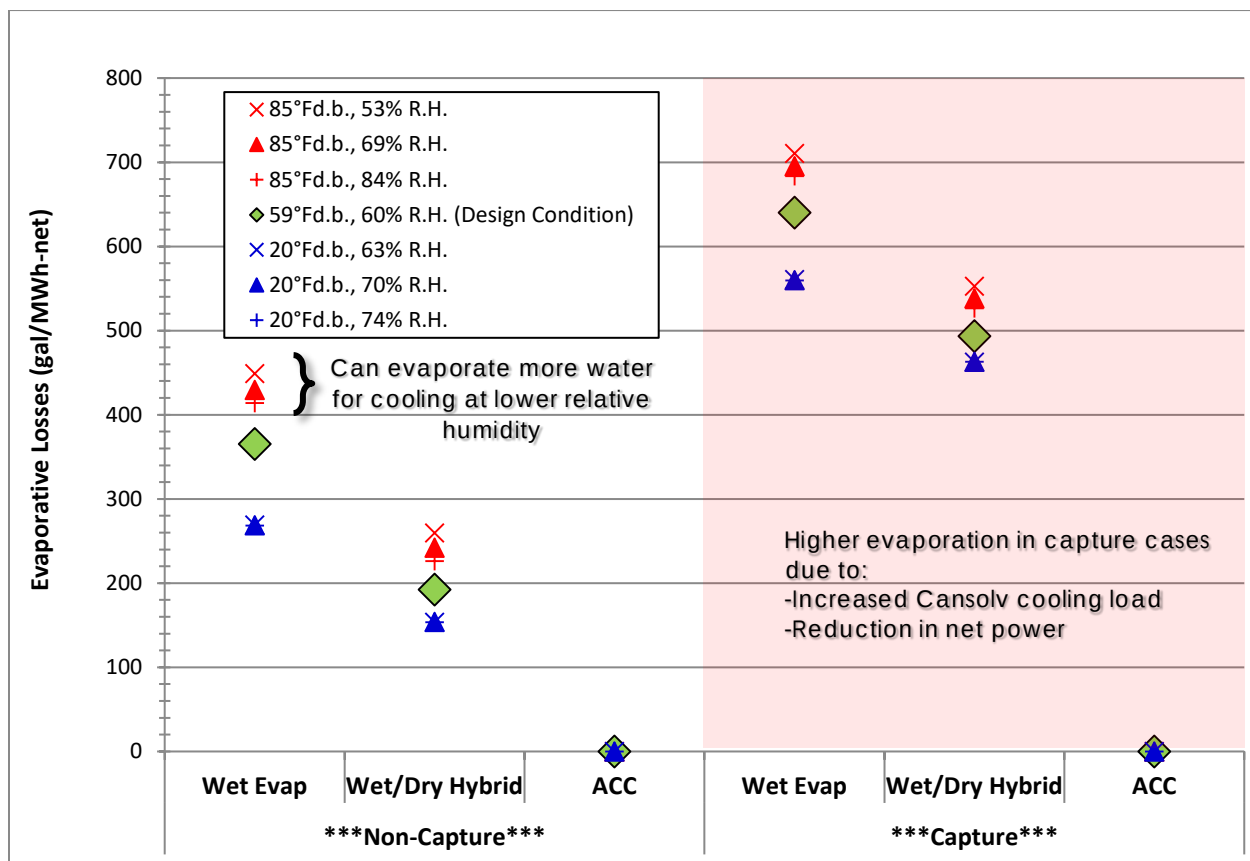
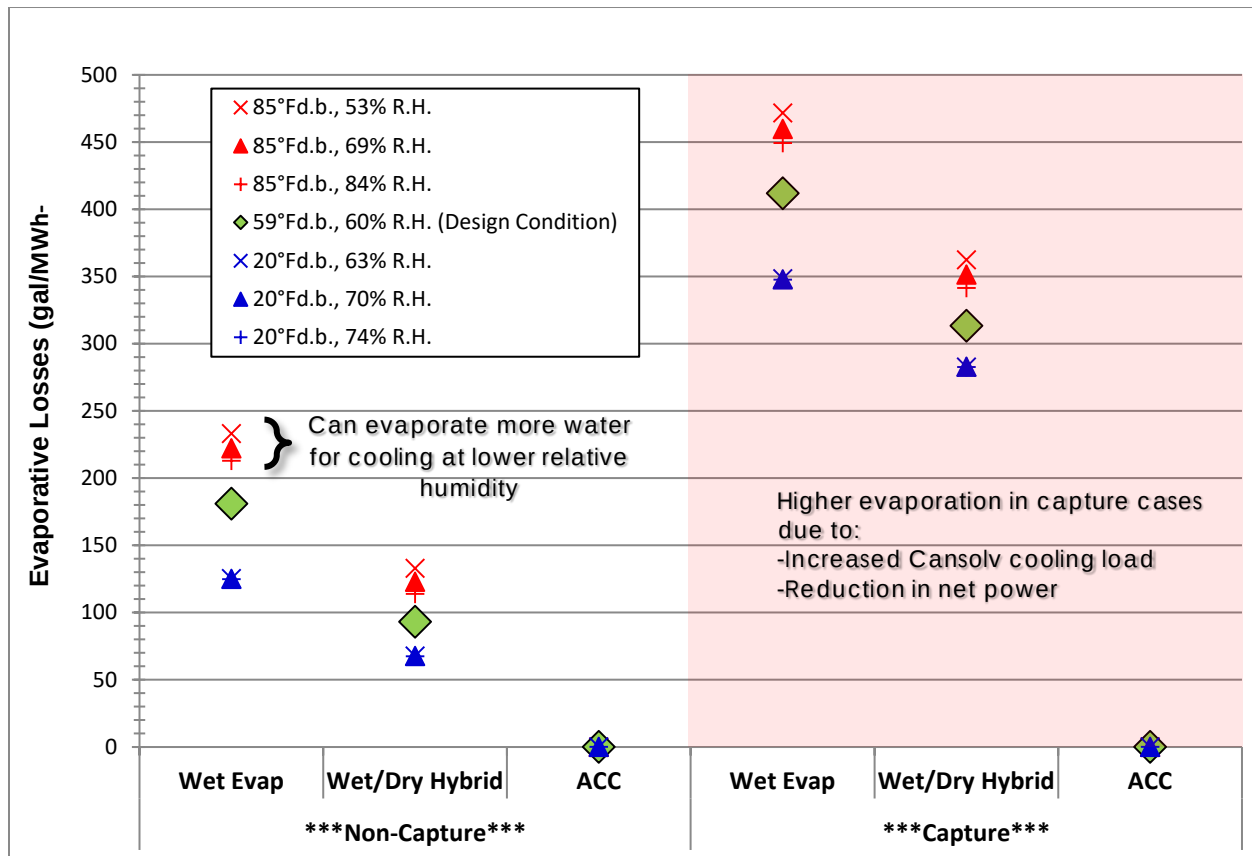


Exhibit 3-10 Evaporative losses (NGCC cases at ISO ambient pressure [14.696 psia])

3.1.5 Raw Water Withdrawal

Raw water withdrawal is quantified for both PC and NGCC plant configurations at ISO elevation under the various ambient temperature and relative humidity combinations in Exhibit 3-11 and Exhibit 3-12. A significant driver of raw water withdrawal is to supply raw water makeup to the wet evaporative cooling tower to offset evaporative losses. Consequently, the observations seen correspond with those made in Section 3.1.4. However, the following additional observations can be made:

- Despite eliminating wet evaporative cooling in the PC plants with an ACC, approximately 2 gpm/MW-net of raw water withdrawal is still required to satisfy the water demands from other process areas. These process areas include:
 - o FGD water makeup (PC cases only)
 - o Steam cycle makeup
 - o Cansolv system makeup (CO₂ capture cases only)

Exhibit 3-11 Raw water withdrawal (PC cases at ISO ambient pressure [14.696 psia])

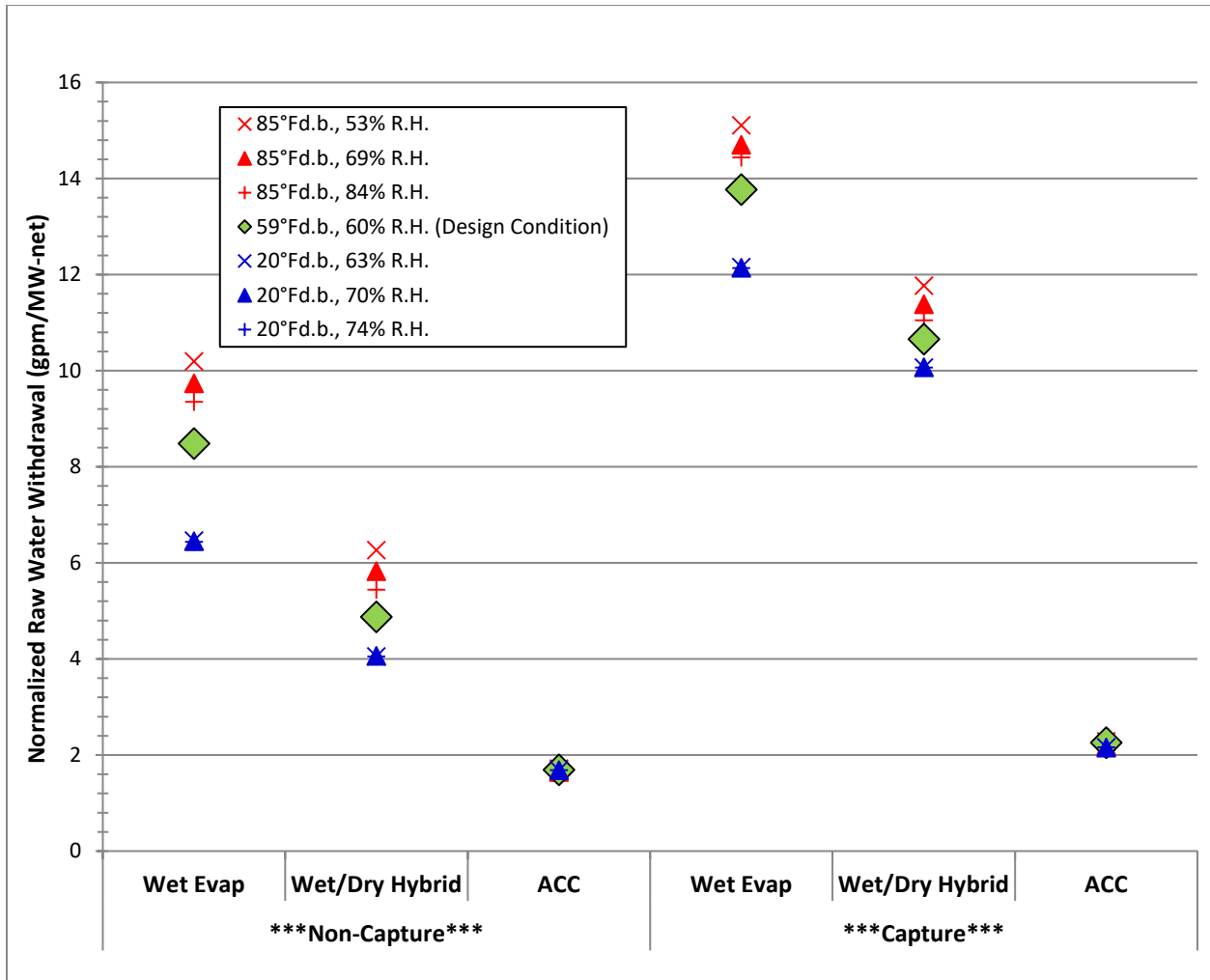
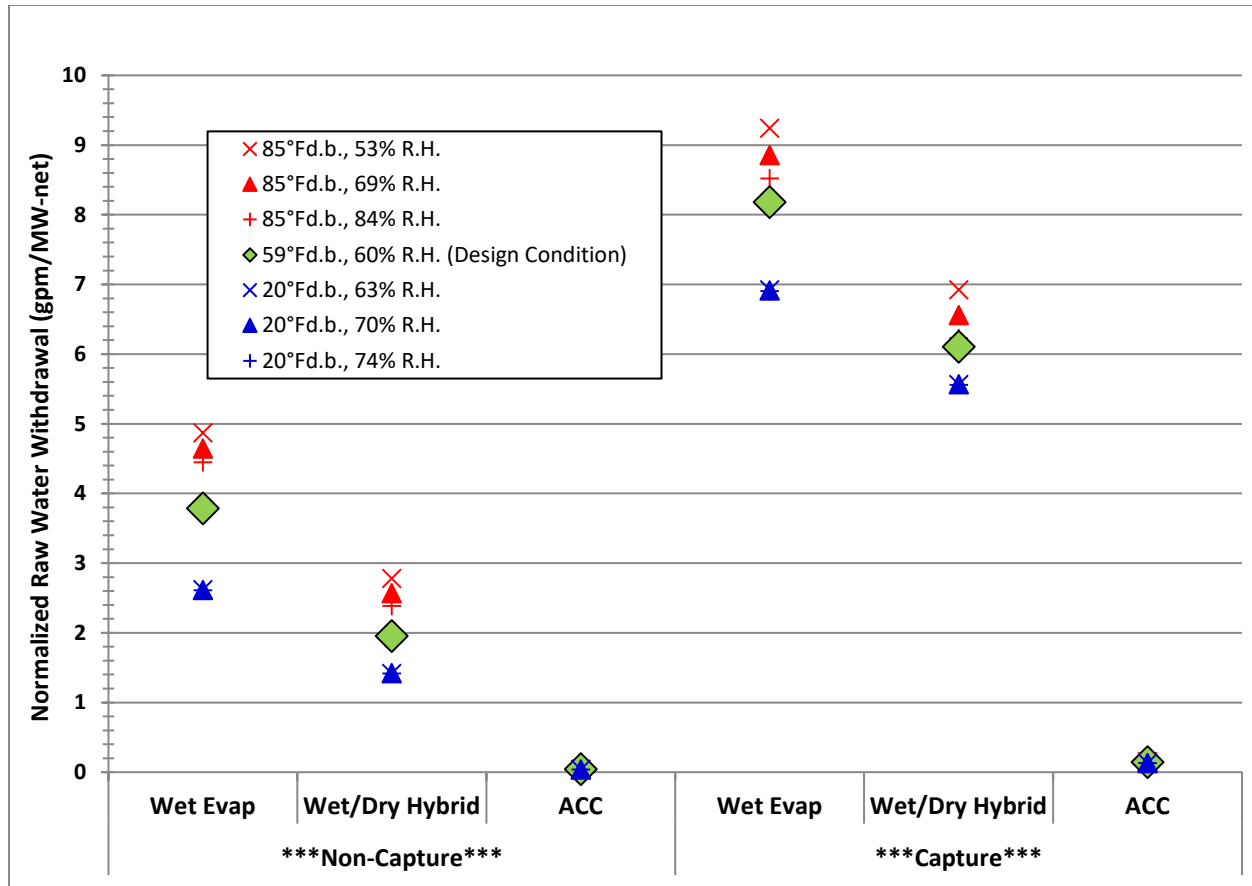


Exhibit 3-12 Raw water withdrawal (NGCC cases at ISO ambient pressure [14.696 psia])

3.1.6 Process Water Discharge

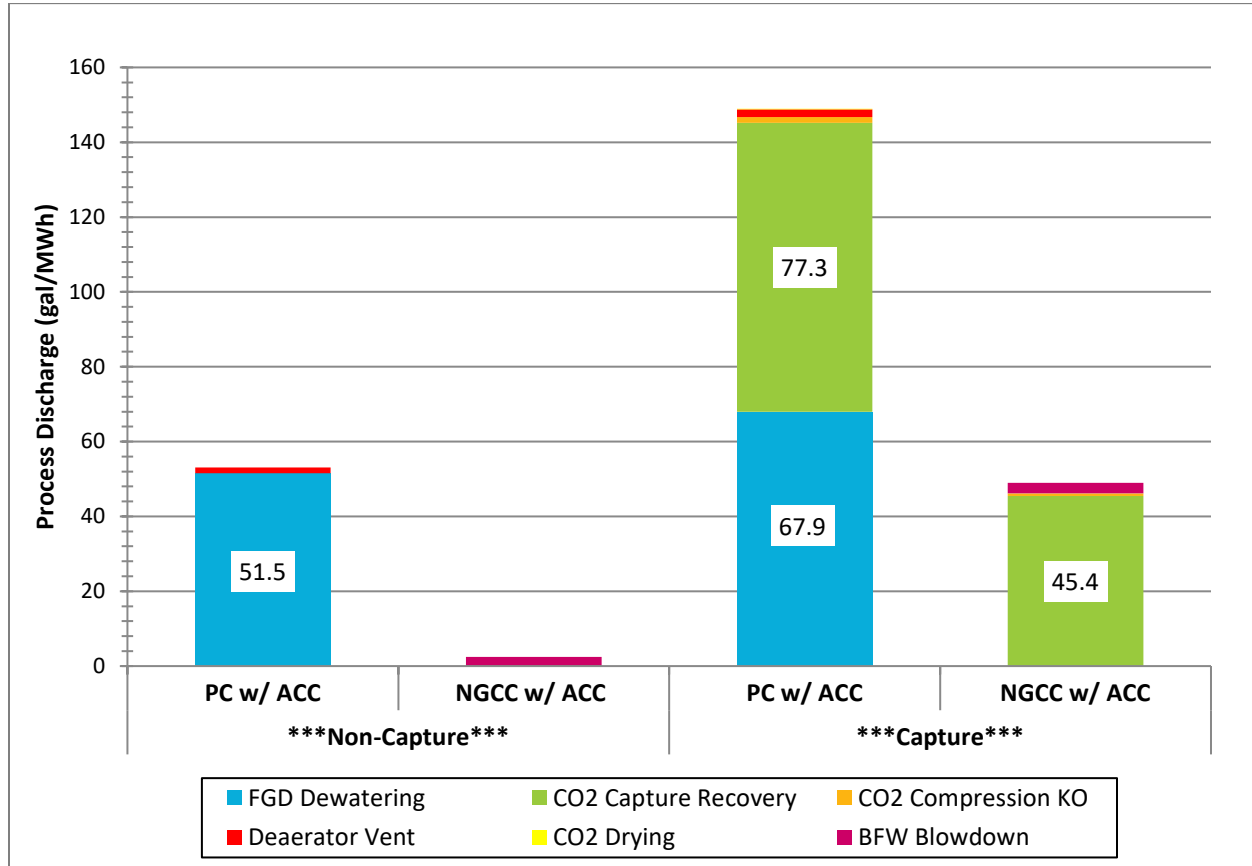
In both PC and NGCC plant configurations, process water streams are produced by the following process steps:

- Cooling the flue gas in the Cansolv prescrubber prior to entering the absorber tower (CO₂ capture cases only)
- Interstage compression cooling of separated CO₂ (CO₂ capture cases only)
- FGD product dewatering (PC cases only)

These streams are retained as internal recycle streams and sent to the wet evaporative cooling tower to partially offset the raw water withdrawal required to meet the demand of the tower. However, in cases that have eliminated wet evaporative cooling in favor of dry cooling technologies, these streams must be utilized elsewhere, treated, or disposed. This study considers these streams to be process discharge streams. However, further study is needed to assess options for handling these discharge streams and the potential impact of the ELG regulation mentioned in Section 2.4.4. Exhibit 3-13 shows

the additional process discharges by source for the PC and NGCC plant configurations that have eliminated wet evaporative cooling.

Exhibit 3-13 Process water discharge in dry cooling plant configurations



3.2 Cost

Greenfield cost estimates were developed for each of the twelve plant configurations shown in Exhibit 1-1. The following sections present the cost results and allow for a comparative analysis of the relative cost differences between plant configurations that employ different alternative cooling technologies. Each of the metrics reported in the following sections reflect only the design ambient conditions for the plants presented in Exhibit 2-2. No cost adjustments have been made to account for off-design performance of the plants from varying ambient conditions throughout the operating life of the plant. Additionally, this study did not seek to optimize the size and cost of the cooling systems by evaluating the performance and cost tradeoffs at different design ambient conditions.

3.2.1 Cooling System Costs

Exhibit 3-14 and Exhibit 3-15 show the costs of several key accounts that are impacted by the type of plant cooling system configuration for the PC and NGCC plant arrangements, respectively. All costs are reported in June 2011 U.S dollars.

Exhibit 3-14 PC plant cooling system costs (1,000\$ [%TPC])

Parameter	Without CO ₂ Capture			With CO ₂ Capture		
	Wet Evaporative	Wet/Dry Hybrid	ACC	Wet Evaporative	Wet/Dry Hybrid	ACC
Surface Condenser & Auxiliaries	3,498 [0.3]	2,228 [0.2]	-	3,303 [0.2]	2,097 [0.1]	-
Air-Cooled Condenser	-	18,800 [1.7]	32,285 [3.0]	-	22,821 [1.2]	35,891 [1.8]
Wet Evaporative Cooling Tower	24,004 [2.2]	14,081 [1.3]	-	35,263 [1.8]	12,429 [0.7]	-
Circulating Water Pumps	1,379 [0.1]	1,052 [0.1]	143 [0.0]	1,937 [0.1]	879 [0.0]	1,246 [0.1]
Circulating Water System Auxiliaries	738 [0.1]	738 [0.1]	-	1,432 [0.1]	928 [0.0]	-
Circulating Water Piping	1,906 [0.2]	1,462 [0.1]	1,167 [0.1]	2,595 [0.1]	1,289 [0.1]	10,178 [0.5]
Make-up Water System	632 [0.1]	445 [0.0]	-	879 [0.0]	754 [0.0]	-
Component Cooling Water System	1,069 [0.1]	1,069 [0.1]	5,711 [0.5]	1,478 [0.1]	1,478 [0.1]	91,082 [4.6]
Total Cooling System	33,226 [3.0]	39,876 [3.7]	39,305 [3.6]	46,888 [2.5]	42,677 [2.2]	138,396 [7.0]
Total Plant Cost (TPC)	1,090,087	1,090,499	1,078,443	1,913,249	1,903,627	1,988,068

Exhibit 3-15 NGCC cooling system costs (1,000\$ [%TPC])

Parameter	Without CO ₂ Capture			With CO ₂ Capture		
	Wet Evaporative	Wet/Dry Hybrid	ACC	Wet Evaporative	Wet/Dry Hybrid	ACC
Condenser & Auxiliaries	2,543 [0.6]	1,610 [0.4]	-	1,832 [0.2]	1,160 [0.1]	-
Air-Cooled Condenser	-	11,970 [2.8]	20,560 [5.0]	-	8,624 [1.0]	14,261 [1.6]
Cooling Towers	15,959 [3.7]	9,398 [2.2]	-	22,231 [2.7]	13,082 [1.6]	-
Circulating Water Pumps	867 [0.2]	662 [0.2]	52 [0.0]	1,214 [0.1]	926 [0.1]	892 [0.1]
Circulating Water System Auxiliaries	732 [0.2]	765 [0.2]	-	968 [0.1]	968 [0.1]	-
Circulating Water Piping	1,326 [0.3]	1,016 [0.2]	426 [0.1]	1,755 [0.2]	1,344 [0.2]	7,287 [0.8]
Make-up Water System	438 [0.1]	308 [0.1]	-	647 [0.1]	408 [0.0]	-
Component Cooling Water System	886 [0.2]	925 [0.2]	1,476 [0.4]	1,173 [0.1]	1,635 [0.2]	73,566 [8.3]
Total Cooling System	22,751 [5.3]	26,654 [6.2]	22,515 [5.4]	29,819 [3.6]	28,146 [3.4]	96,005 [10.9]
Total Plant Cost (TPC)	430,198	430,510	414,559	834,916	828,550	883,156

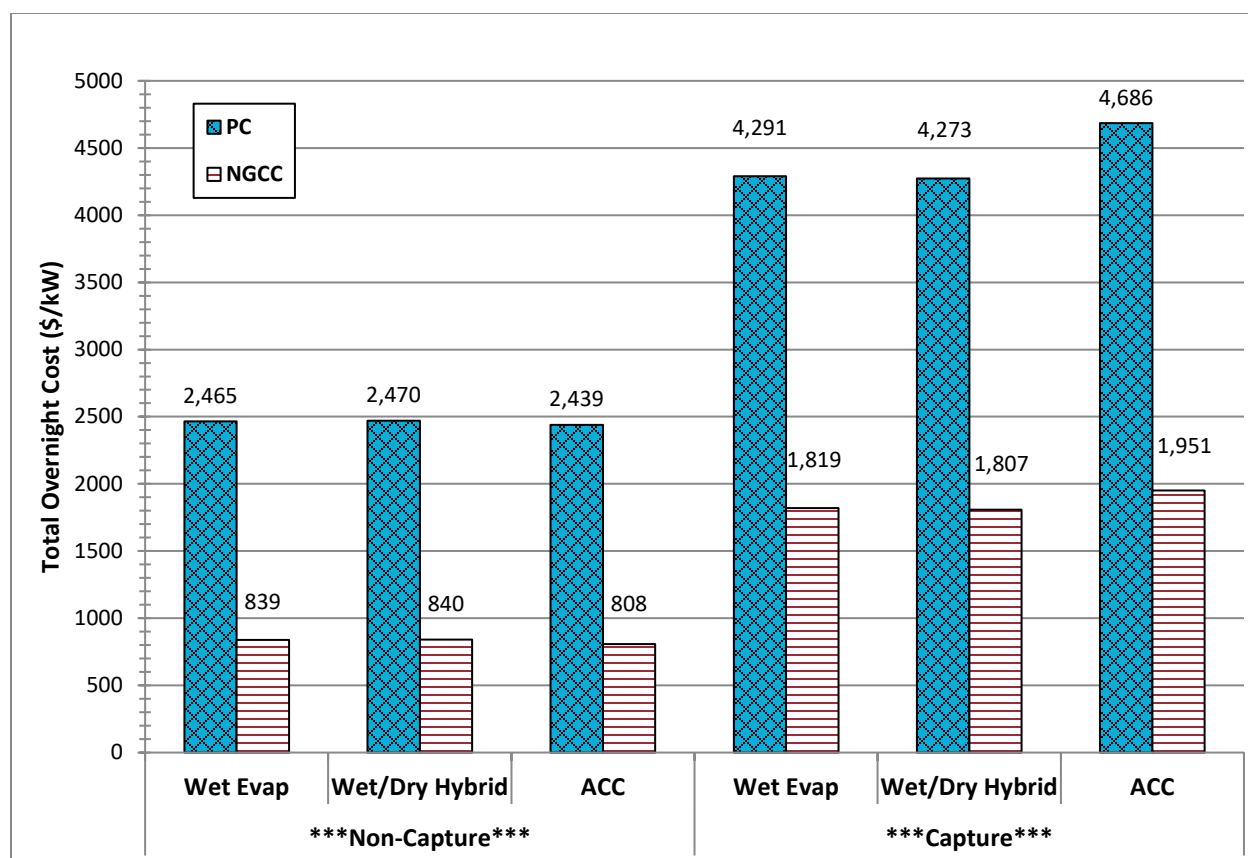
For non-capture plants using an entirely wet cooling arrangement, 83 and 81 percent of the total cooling system cost are attributed to the surface condenser and auxiliaries and cooling towers for both PC and NGCC plants, respectively. Incorporating dry cooling technologies, as part of a wet/dry hybrid or entirely dry arrangement, introduces additional capital costs. However, these additional costs are partially offset by the reduction in, or elimination of, costs associated with the wet evaporative cooling system, such as the surface condenser, evaporative cooling towers, make-up water system, and costs associated with the circulating water pumps, auxiliaries, and piping.

For plants with CO₂ capture, the addition of the ACHE bays introduces a significant cost. In both the PC and NGCC plant configurations, the capital cost of the ACHE bays is included in the component cooling water system account. This cost account is \$91MM and \$74MM, or 66 and 77 percent of the total cooling system cost for the PC and NGCC plant configurations, respectively.

3.2.2 Total Overnight Cost

The TOC for each of the twelve plant configurations is shown below in Exhibit 3-16. Replacing wet evaporative cooling with an entirely dry system (air cooled heat exchanger and air cooled condenser) results in a slight reduction in TOC from \$2,465 to \$2,439/kW, or 1 percent for the non-capture PC plant, and from \$839 to \$808/kW, or 3.7 percent for the non-capture NGCC plant. Although this result suggests only a nominal cost increase for replacing wet cooling with dry, it should be noted that the selection of ISO ambient conditions as the cooling system design point may be the primary reason for this relative cost reduction. Designing for high ambient conditions is often the methodology chosen for real world applications. Higher design ambient conditions would lead to larger cooling system sizes, which may eliminate the relative cost reduction seen here. Water-constrained areas of the country where entirely dry cooling could be needed the most, such as the western United States, are also likely to be the hottest, and this could result in larger cost increases for systems that include dry cooling.

Replacing wet evaporative cooling with an entirely dry system (air cooled heat exchanger and air cooled condenser) results in a total overnight cost increase of 9.2 percent for the PC plant with CO₂ capture, (\$4,291 to \$4,686/kW), and 7.3 percent for the NGCC plant with CO₂ capture (\$1,819 to \$1,951/kW). This increase can be attributed to the costs incurred for the ACHE bays to supply dry process cooling to the Cansolv system and the reduction in net plant efficiency, as shown in Sections 3.2.1 and 3.1.3, respectively.

Exhibit 3-16 Total overnight cost (\$/kW)

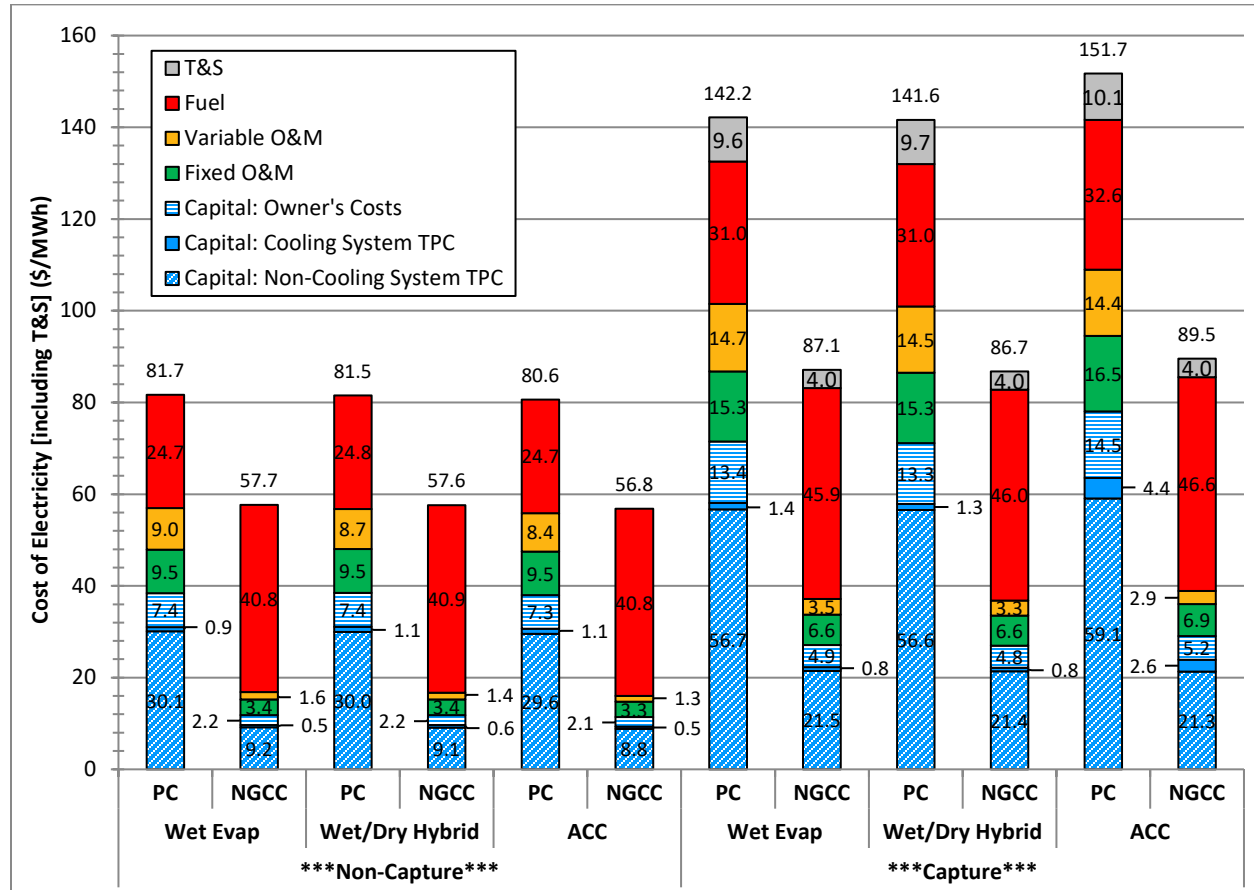
3.2.3 Cost of Electricity

The COE for each of the twelve plant configurations is shown below in Exhibit 3-17. The COE is broken down into several cost components, including capital costs, fixed O&M costs, variable O&M costs, fuel costs, and CO₂ transportation and storage (T&S) costs. The capital cost component is further divided into cooling system capital (TPC) costs, non-cooling system capital (TPC) costs, and owner's costs. Cooling system capital costs refer to the costs of several key accounts that are impacted by the type of plant cooling system configuration, such as the evaporative cooling tower, ACC, and ACHE. Exhibit 3-14 and Exhibit 3-15, in Section 3.2.1, provide a comprehensive list of the cooling system capital costs for the PC plants and NGCC plants, respectively.

The observations from these results correspond to those seen in Section 3.2.2. Eliminating wet evaporative cooling by replacement with an ACC and ACHE results in a slight reduction in COE from \$81.7 to \$80.6/MWh, or 1.3 percent for the PC plant configuration without CO₂ capture, and from \$57.7 to \$56.8/MWh, or 1.6 percent for the NGCC configuration without CO₂ capture. As was noted in Section 3.2.2, this result is expected to be impacted by the selection of higher ambient design conditions.

Eliminating wet evaporative cooling by replacement with an ACC and ACHE results in an increase in COE from \$142.2 to \$151.7/MWh, or 6.7 percent for the PC plant configuration with CO₂ capture, and \$87.1 to \$89.5/MWh, or 2.8 percent for the NGCC configuration with CO₂ capture. This increase can be attributed to the costs incurred for the ACHE bays to supply dry process cooling to the Cansolv system along with the reduction in net plant efficiency, as shown in Sections 3.2.1 and 3.1.3, respectively.

Exhibit 3-17 Cost of electricity (\$/MWh)



4 CONCLUSIONS

The objective of this study was to examine the impacts that various off-design, location-specific ambient conditions have on the performance of PC and NGCC plants employing alternative power plant cooling arrangements. The relative differences in plant level capital costs were also assessed. It is important to note that the relative performance and cost differences for each of the plant configurations reflect only cooling systems which have been designed for ISO conditions so that a consistent design philosophy is maintained throughout the entire plant. In real world applications, plant developers may opt to design cooling systems for high ambient temperatures scenarios, thus affecting the performance of a particular cooling system at different ambient conditions, as well as its cost. With this in mind, the primary findings from this report include:

- The LP turbine backpressure is a key performance parameter impacted by changes in ambient conditions. For each plant configuration assessed:
 - o High ambient dry bulb temperatures cause a reduction in the effectiveness of the steam cycle condensing system and a higher LP turbine backpressure than at design ambient conditions.
 - o However, low ambient temperatures do not significantly impact the LP turbine backpressure due to pressure and temperature limitations of the LP turbine and wet cooling tower (when included), respectively.
- Relative humidity affects the degree to which the LP turbine backpressure is impacted for plants employing wet evaporative cooling technologies, because the theoretical cooling limit is the wet bulb temperature. Plants employing exclusively dry cooling are not impacted by changes in relative humidity because of the lack of evaporative cooling.
 - o For PC plants with a wet evaporative cooling system at an ambient pressure of 14.696 psia and temperature of 85°F d.b., an increase in relative humidity from 53 (71.8 °F wet bulb) to 84 (80.9 °F wet bulb) percent increases the LP turbine backpressure from 1.5 to 1.8 psia.
 - o Similarly, for NGCC plants with a wet evaporative cooling system at an ambient pressure of 14.696 psia and temperature of 85°F d.b., an increase in R.H. from 53 (71.8 °F wet bulb) to 84 (80.9 °F wet bulb) percent increases the LP turbine backpressure from 1.4 to 1.8 psia.
- A reduction in ambient pressure leads to a reduction in the LP turbine backpressure for NGCC cases. This is most evident at 85°F d.b.
 - o Combustion turbine derating occurs at a lower ambient pressure where the mass flow rate through the combustion turbine main air compressor is

reduced due to the lower air density. In turn, this leads to less mass flow through the heat recovery steam generator (HRSG) and an overall lower condenser duty which enables the condenser to achieve a lower LP turbine backpressure.

- PC plants without CO₂ capture experience reduced net power outputs at high ambient temperature due to the reduced effectiveness of the condensing system. Additionally, plant configurations employing exclusively dry cooling are impacted more than plant configurations that include wet evaporative cooling.
 - o For a PC configuration with wet evaporative cooling, the power output is reduced from its design of 547 to 532 MWe-net at 85°F d.b., 84% R.H., or 2.7 percent.
 - o For a PC configuration with exclusively dry cooling, the power output is reduced from its design of 547 to 528 MWe-net at 85°F d.b., 84% R.H., or 3.5 percent.
- NGCC plants without CO₂ capture also experience reduced net power outputs at high ambient temperature due to the reduced effectiveness of the condensing system. However, the derating of the combustion turbine at high temperature compounds this effect.
 - o For an NGCC configuration with wet evaporative cooling, the design power output is reduced from 628 to 591 MWe-net at 85°F d.b., 53% R.H., or 5.9 percent.
 - o For an NGCC configuration with exclusively dry cooling, the design power output is reduced from 628 to 586 MWe-net at 85°F d.b., 53% R.H., or 6.7 percent.
- The inclusion of exclusively dry cooling in lieu of wet evaporative cooling, for both PC and NGCC plants with CO₂ capture, results in a reduction in the design net plant output.
 - o The design net output is reduced from 548 to 521 MWe-net (4.9 percent) and 558 to 550 MWe-net (1.4 percent) for PC and NGCC plants, respectively.
 - o Reductions in the design net output are the result of the following:
 - Increases in auxiliary loads and LP steam requirements of the Cansolv system to compensate for higher cooling water temperatures supplied by ACHEs.
 - The addition of auxiliary loads associated with the ACHE bays needed to provide process cooling to the Cansolv system.

- Evaporative losses are eliminated from all PC and NGCC plant configurations employing entirely dry cooling. However, raw water withdrawal is still required by several plant systems in dry cooling configurations.
 - o Raw water withdrawal is reduced from 8.5 to 1.7 gpm/MW-net, or 80 percent for a PC plant without CO₂ capture. The remaining withdrawal is needed for FGD and steam cycle makeup.
 - o Raw water withdrawal is reduced from 3.8 to less than 0.1 gpm/MWe-net, or 99 percent for an NGCC plant without CO₂ capture. The remaining withdrawal is needed for steam cycle makeup.
- The elimination of wet evaporative cooling results in a significant amount of process water discharge streams which may have otherwise been retained as internal recycle streams to a wet evaporative cooling tower.
 - o Additional process discharge streams totaling 51.5 and 146.7 gal/MWh for PC plants without and with CO₂ capture, respectively, are produced. The sources of these streams are the FGD dewatering, CO₂ capture, and CO₂ compression processes.
 - o Additional process discharge streams totaling 46.1 gal/MWh for an NGCC plant with CO₂ capture is produced from the CO₂ capture and compression processes.
- The greenfield COE for PC and NGCC plants only reflects plant configurations designed and continually operated at ISO conditions. The COE results do not capture the cost implications of varying plant performance at different ambient conditions throughout the plant lifetime. Accordingly, a comparison of the greenfield COE under these constraints follows:
 - o The COE is reduced from \$81.7 to \$80.6/MWh by including entirely dry cooling in lieu of wet evaporative cooling in PC plants without CO₂ capture.
 - o The COE is increased from \$142.2 to \$151.7/MWh by including entirely dry cooling in lieu of wet evaporative cooling in PC plants with CO₂ capture.
 - o The COE is reduced from \$57.7 to \$56.8/MWh by including entirely dry cooling in lieu of wet evaporative cooling in NGCC plants without CO₂ capture.
 - o The COE is increased from \$87.1 to \$89.5/MWh by including entirely dry cooling in lieu of wet evaporative cooling in NGCC plants with CO₂ capture.

5 FUTURE WORK

5.1 ELG IMPLICATIONS

Additional plant systems required to meet EPA's ELG regulations were not included in the plant configurations assessed in this study. Effluent streams most impacted by the ELGs include FGD wastewater, fly ash and bottom ash transport (sluicing) water, combustion residual leachates, flue gas Hg control wastewater, and nonchemical metal cleaning wastewater. For greenfield power plants, the inclusion of zero liquids discharge (ZLD) systems are necessary to meet the regulations and are expected to impact the performance and cost of these plants. Additional study is needed to better understand the implications of including such systems in plants employing alternative cooling technologies.

Additionally, this study has shown that the elimination of wet evaporative cooling results in a significant amount of water which must be either disposed, treated, or utilized elsewhere. Further study is needed to determine if the additional process water discharges are affected by the ELG regulations, and what options are available for treating, disposing, or utilizing these streams.

5.2 HIGH TEMPERATURE LOCATION

The decision drivers behind which type of cooling system plant developers opt to incorporate into new plant designs are complex and numerous. Factors such as upfront investment, long term economics, system performance, operational flexibility, water usage objectives, available space, local concerns, and permitting can have varying degrees of influence in the ultimate decision. In this study, a Midwest site location with relatively low design and site temperatures was considered. An alternative site with higher average ambient temperatures would reflect a water constrained location, which may prioritize lowering water usage while at the same time, necessitate designing equipment for higher temperature operation. Study at a high average temperature location will provide additional perspective on the performance and cost tradeoffs between wet evaporative and dry cooling technologies which are likely to be different than those observed in this study.

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