NATIONAL ENERGY TECHNOLOGY LABORATORY

COST AND PERFORMANCE OF RETROFITTING NGCC UNITS FOR CARBON CAPTURE – REVISION 3

May 31, 2023

DOE/NETL-2023/3848

Disclaimer

Tommy Schmitt[1,2]*: Methodology, Software, Formal Analysis, Writing – Original Draft, Writing – Review & Editing*; ***Sally Homsy***[1,2]*: Software Validation, Writing – Review & Editing, Supervision;* ***Hari Mantripragada***[1,2]*: Writing – Review & Editing;* ***Mark Woods***[1,2]*: Writing – Review & Editing, Supervision;* ***Hannah Hoffman***[1,2]*: Writing – Review & Editing;* ***Travis Shultz***[1]*: Conceptualization, Writing – Review & Editing;* ***Timothy Fout***[1]*: Conceptualization, Writing – Review & Editing;* ***Gregory Hackett***[1]**: Writing – Review & Editing*

[1]National Energy Technology Laboratory
[2]National Energy Technology Laboratory Support Contractor
*Corresponding contact: Gregory.Hackett@netl.doe.gov

Suggested Citation:
NETL, "Cost and Performance of Retrofitting NGCC Units for Carbon Capture – Revision 3," National Energy Technology Laboratory, May 31, 2023.

This page intentionally left blank.

TABLE OF CONTENTS

LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

A#	Cost account number
AGR	Acid gas removal
Ar	Argon
Aspen	Aspen Plus®
BAU	Business as usual
BEC	Bare erected cost
BOP	Balance of plant
Btu	British thermal unit
C_2H_6	Ethane
C_3H_8	Propane
C_4H_{10}	n-Butane
CCS	Carbon capture and storage
CF	Capacity factor
CH_4	Methane
CH_4S	Methanethiol
Circ.	Circulating
CO_2	Carbon dioxide
COE	Cost of electricity
CRF	Capital recovery factor
DOE	Department of Energy
Eng'g CM, H.O. & Fee	Engineering, Construction Management, Home Office, & Fees
FEBRev4a	Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity – Revision 4a
FO	Fuel oil
ft	Foot
GHG	Greenhouse gas
GJ	Gigajoule
gpm	Gallons per minute
GT	Gas turbine
H_2O	Water
H_2S	Hydrogen sulfide
HHV	Higher heating value
h, hr	Hour
HRSG	Heat recovery steam generator
HVAC	Heating, ventilating, and air conditioning
I&C	Instrumentation and control
IEA	International Energy Agency
IOU	Investor-owned utility
IP	Intermediate pressure
kg	Kilogram
kJ	Kilojoules
kW, kWe	Kilowatt electric
kWh	Kilowatt-hour
kWt	Kilowatt thermal
lb	Pound
LCOE	Levelized cost of electricity
LHV	Lower heating value
LP	Low pressure
m	Meter
m^3/min	Cubic meter per minute
MJ/scm	Megajoule per standard cubic meter
MMBtu	Million British thermal units (also shown as 10^6 Btu)
MPa	Megapascal
MPC	Makeup power cost
MW, MWe	Megawatt electric
MWh	Megawatt-hour
N/A	Not available/applicable
N_2	Nitrogen
NETL	National Energy Technology Laboratory
NG	Natural gas
NGCC	Natural gas combined cycle
O_2	Oxygen
O&M	Operation and maintenance
PC	Pulverized coal
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PSP	Projected sales price
QGESS	Quality Guidelines for Energy System Studies
RDF	Retrofit difficulty factor
RET	Retrofit
SC	Supercritical
scf	Standard cubic foot
SCR	Selective catalytic reduction
SOA	State-of-the-art
ST	Steam turbine

T&S	Transport and storage	U.S.	United States
TASC	Total as-spent cost	y, yr	Year
TOC	Total overnight cost	°C	Degrees Celsius
tonne	Metric ton (1000 kg)	°F	Degrees Fahrenheit
TPC	Total plant cost		

EXECUTIVE SUMMARY

The purpose of this study is to present the cost and performance of retrofitting natural gas combined cycle (NGCC) power plants with commercial, state-of-the-art (SOA), solvent-based post-combustion carbon capture. The cases presented in this report are analogous to greenfield cases reported in the National Energy Technology Laboratory's (NETL) "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity – Revision 4a", hereafter referred to as FEBRev4a. [1] Cases are developed for NGCC plants with SOA F-frame and H-frame turbines with the case designations being listed in Exhibit ES-1. For the retrofit (brownfield) cases, it is assumed that the existing plant has been fully paid off, and the only capital outlay required is that for the capture process and associated modifications to the existing plant. The post-combustion carbon dioxide (CO_2) capture system performance and costs are based on data from quotes; details can be found in FEBRev4a. The naming convention used follows previous naming conventions presented in FEBRev4a. For retrofit cases, the "-BR" designation represents that the base plant without capture (B31A or B32A) has now been retrofitted (R) with capture (B).

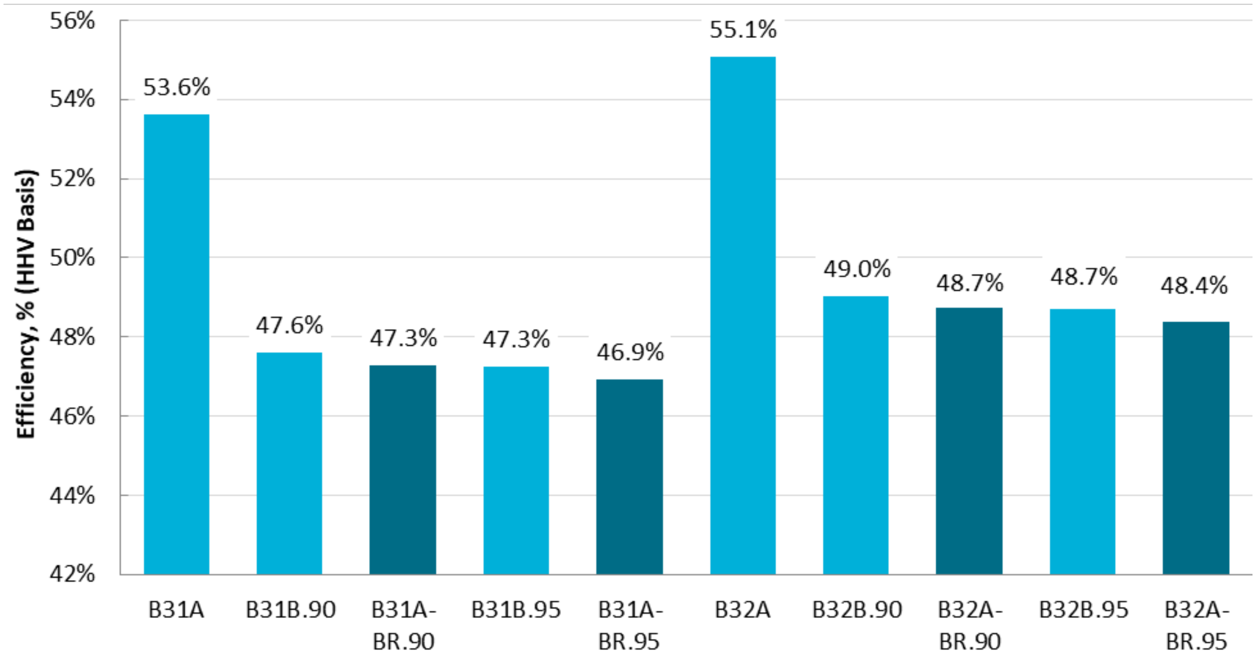
Exhibit ES-1. Case descriptions

Case[A]	Plant Type	Steam Cycle, psig/°F/°F	Combustion Turbine	CO_2 Separation	Capture Rate	Plant Type
B31A	F-frame NGCC	2378/1085/1084	2× State-of-the-art 2017 F-frame	N/A	N/A	Greenfield
B31B.90				Shell's CANSOLV Process	90%	Greenfield
B31B.95					95%	Greenfield
B31A-BR.90					90%	Brownfield
B31A-BR.95					95%	Brownfield
B32A	H-frame NGCC	2668/1085/1044	2× State-of-the-art 2017 H-frame	N/A	N/A	Greenfield
B32B.90				Shell's CANSOLV Process	90%	Greenfield
B32B.95					95%	Greenfield
B32A-BR.90					90%	Brownfield
B32A-BR.95					95%	Brownfield

[A]All plants in this report are assumed to be located at a generic plant site in the midwestern United States

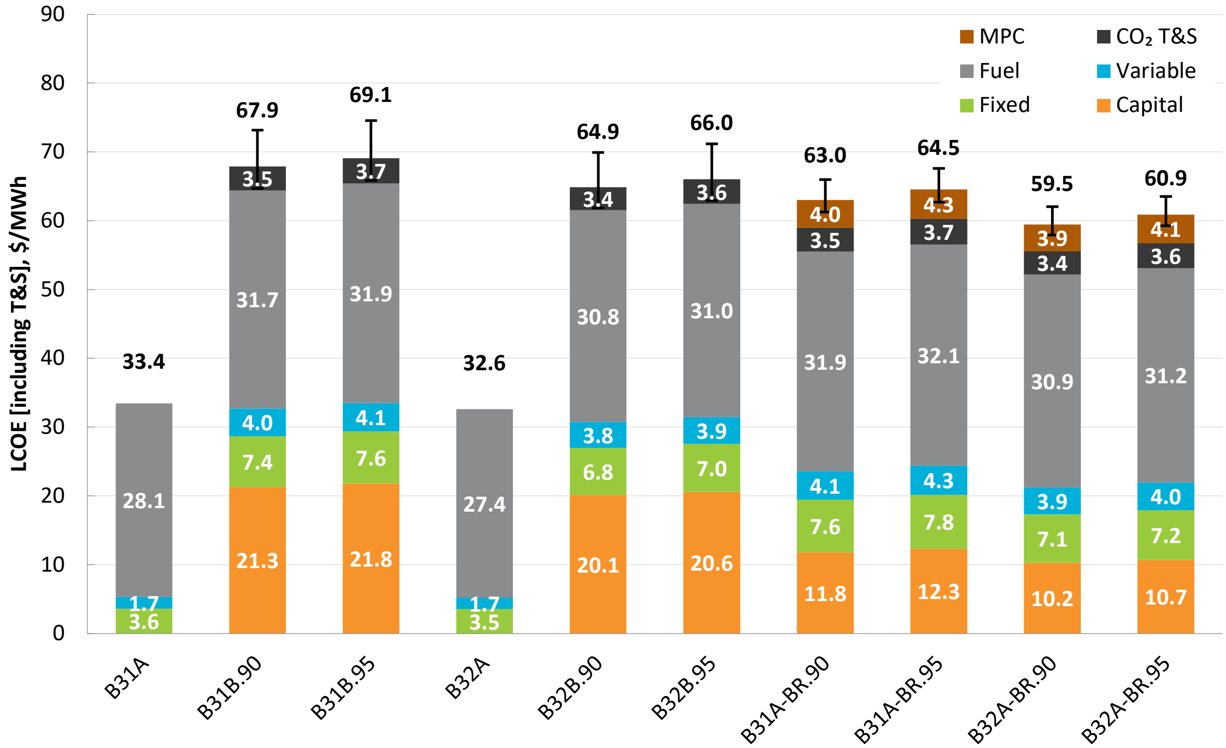
The net plant efficiencies, based on the higher heating value (HHV), for NGCC plants with and without CO_2 capture for each turbine type are illustrated in Exhibit ES-2. The lightly colored efficiencies represent those associated with greenfield cases while the darker colored efficiencies represent the brownfield cases. The capture system performance for a given turbine size is identical between the greenfield and retrofit cases aside from an off-design performance derate due to extracting steam prior to the low-pressure steam turbine. For the greenfield cases, the low-pressure steam turbine section is sized to account for the upstream steam extraction and does not experience an off-design performance derate. The balance of plant performance remains consistent with the greenfield assumptions.

Exhibit ES-2. Net plant efficiency summary (HHV basis)



The levelized cost of electricity (LCOE) for retrofitting the NGCC plants with CO_2 capture for each turbine type is illustrated in Exhibit ES-3. The estimated LCOE values for the non-capture cases (assuming the existing plant is fully paid off) are also included in the chart for comparison. When comparing H-frame turbines to F-frame turbines in NGCC applications, overall plant efficiency increases while plant output also increases, decreasing LCOE, which is consistent with changes resulting from the economies of scale. The annual fuel cost makes up the largest portion of the annual operating costs. The total annual fuel cost remains the same for each turbine type before and after retrofit, but the cost per MWh increases after retrofitting due to the decrease in net power generation. Note that the 30-year levelized natural gas price was assumed to be $4.42/MMBtu as specified in "QGESS: Fuel Prices for Selected Feedstocks in NETL Studies" for natural gas delivered to large, combined cycle plants operating at high capacity factors in the Midwest. [2]

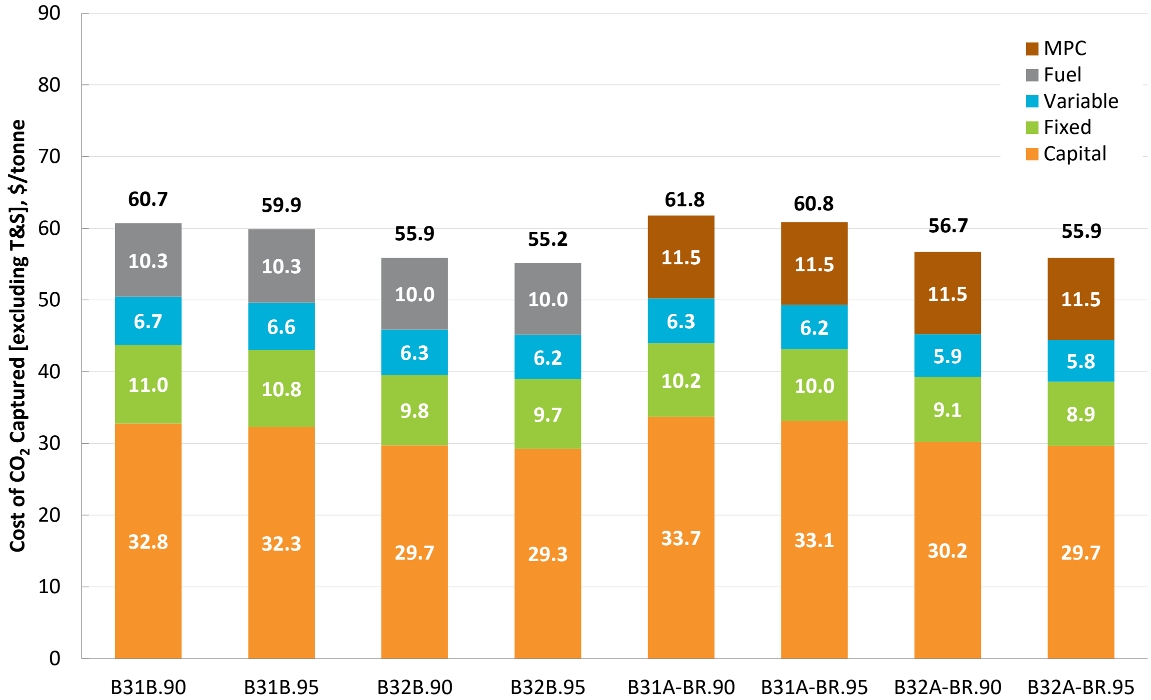
Exhibit ES-3. Summary of Levelized Cost of Electricity (LCOE)



Note: All costs are in real 2018 dollars and calculated at 85% capacity factor. Cases B31A and B32A in this chart do not include capital costs, as to represent the plant prior to retrofit (i.e., capital costs are paid off)

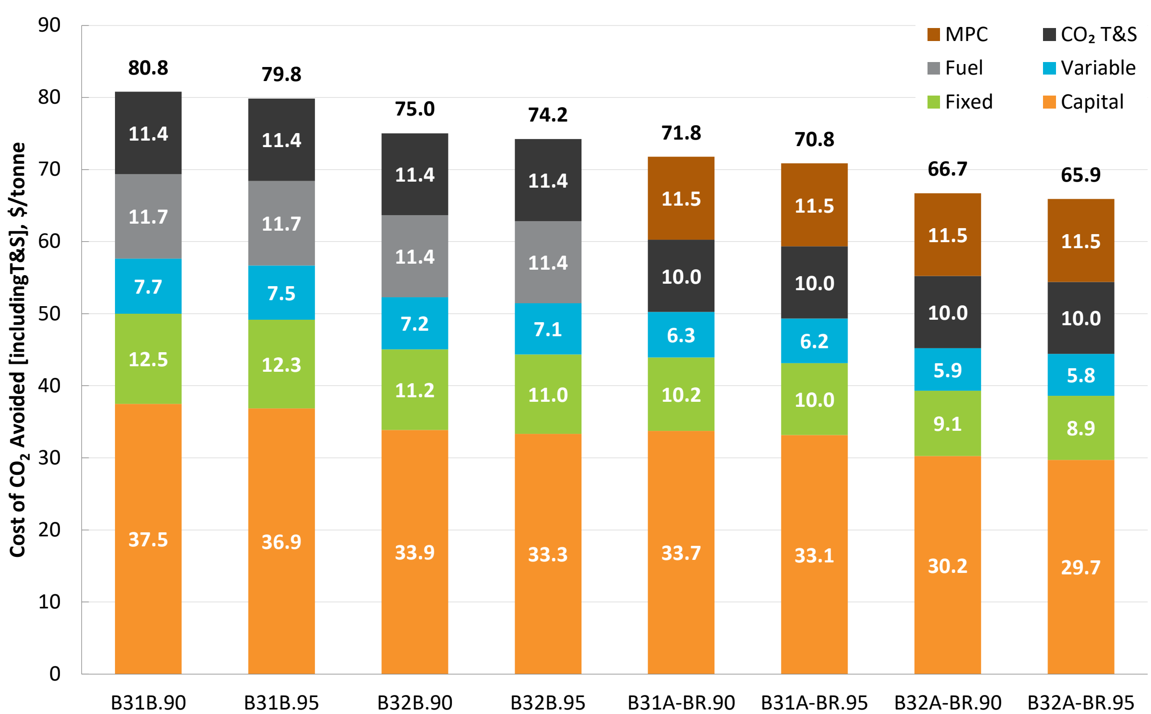
The cost of CO_2 captured, and the cost of CO_2 avoided are shown in Exhibit ES-4 and Exhibit ES-5 for each case. These parameters are explained in detail in Section 4.3, but it should be noted the calculation for greenfield and retrofit applications differs. As the turbine design improves (increases in efficiency), the cost of CO_2 captured and cost of CO_2 avoided decrease. The inclusion of higher capture rates does not have a significant impact on the cost of CO_2 captured or avoided, indicating that the incremental cost of achieving higher capture rates is offset by the additional CO_2 captured.

Exhibit ES-4. Summary cost of CO_2 captured



Note: All costs are in real 2018 dollars and calculated at 85% capacity factor. B31A is used as a reference for all F-frame retrofit case calculations. B32A is used as a reference for all H-frame retrofit case calculations.

Exhibit ES-5. Summary cost of CO_2 avoided



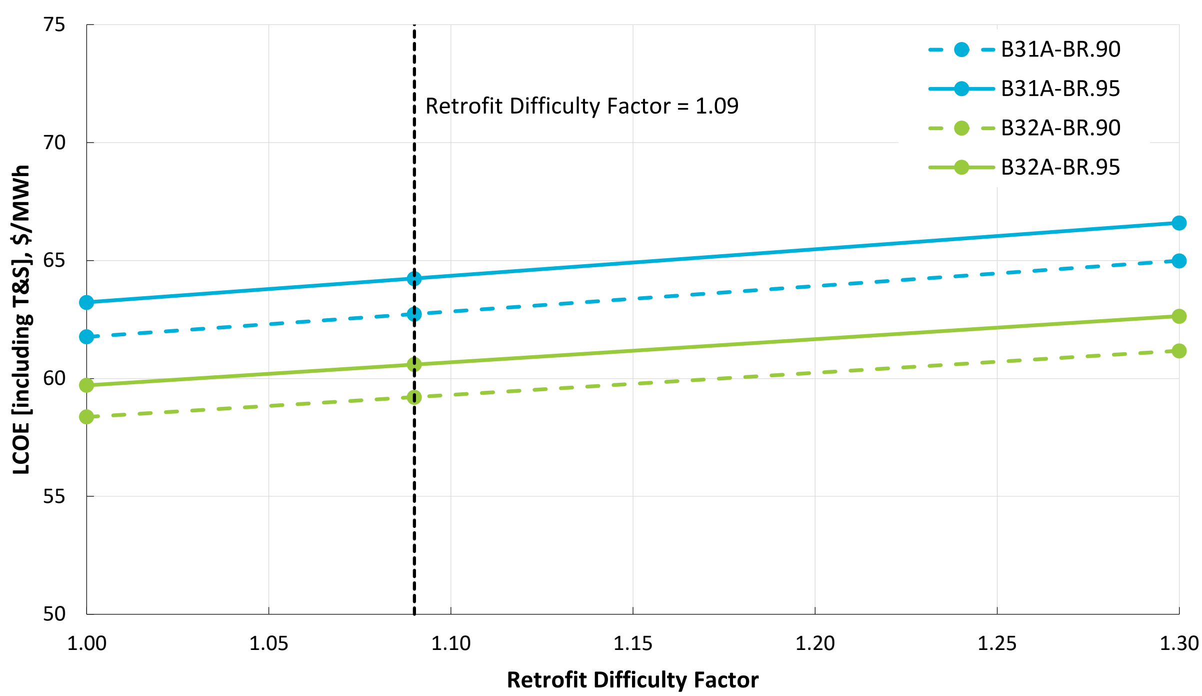
Note: All costs are in real 2018 dollars and calculated at 85% capacity factor. B31A is used as a reference for all F-frame retrofit case calculations. B32A is used as a reference for all H-frame retrofit case calculations.

CO_2 emissions from current SOA F-frame turbines and H-frame turbines in non-capture NGCC configurations for cases B31A and B32A are estimated at 741 lb/MWh$_{gross}$ and 723 lb/MWh$_{gross}$, respectively. The modeled capture systems were designed for 90 and 95 percent CO_2 capture from the flue gas. This results in a CO_2 emission rate ranging 40–80 lb/MWh$_{gross}$ in F-frame cases and 39–78 lb/MWh$_{gross}$ in H-frame cases.

Retrofit systems are subject to a cost premium relative to equivalent greenfield installations due to design, construction, and tie-in constraints imposed by the existing plant layout and operation. A retrofit difficulty factor (RDF) of 1.09 is used to account for this cost premium; capital costs are estimated by multiplying the RDF by the total plant cost (TPC) of an equivalent greenfield installation. A more detailed approach to estimating the total retrofit cost premium for brownfield projects would be to apply an RDF to each line item of an equivalent greenfield system. These values range 1.0–1.3 as outlined in the Quality Guidelines for Energy System Studies (QGESS) for retrofit applications. [3] However, this requires more detailed knowledge of the plant layout. The RDF of 1.09 used in this report represents the weighted average of the QGESS recommended account-level retrofit difficulty factors for an NGCC plant retrofit with post combustion capture. This indicates that $100 of installed greenfield equipment costs $109 if installed as a retrofit for the configurations presented in this report. The retrofit premium estimated by either the detailed or simplified method is within the expected accuracy (-15 percent/+25 percent for an AACE International Class 4 cost estimate) of the reference NGCC plants considered.

The sensitivity of the LCOE to the single RDF was calculated and is shown in Exhibit ES-6. An RDF of 1.3 increases the overall LCOE by $2.8–3.5/MWh versus cases without a premium (RDF=1.0).

Exhibit ES-6. Sensitivity of LCOE to retrofit difficulty factor (RDF)



Note: All costs are in real 2018 dollars and calculated at 85% capacity factor

The conclusions of this study apply only to this level of conceptual design and economic analysis. Further analysis is needed for costing actual retrofit plant designs. Site and plant design-specific considerations (seismic conditions, water quality, local labor costs, local environmental regulations, etc.) are not included in this analysis. A more detailed analysis should explore scenarios where the existing capital costs are not zero at the time of retrofitting. In addition, the plant performance of today's SOA F-class or H-class NGCC plants may or may not reflect the plant performance of existing NGCC plants that are candidates for capture retrofit. A more detailed analysis should also identify the combustion turbine types and vintages that represent sunk assets existing in the current fleet and apply today's SOA capture system performance and cost as a retrofit to further refine the cost of capture. Finally, this study does not consider any upgrades or maintenance (outside of typical maintenance costs included in operation and maintenance) that may be necessary to extend the life of the plant such that it remains online for the 30-year duration estimated for the LCOE.

CO_2 CAPTURE RATES ABOVE 95 PERCENT

Commercial-scale demonstration of solvent-based post-combustion CO_2 capture systems at power generation facilities (specifically pulverized coal [PC] plants) has shown the ability to capture 90 percent of the CO_2 in the flue gas stream. Moreover, field-testing of post-combustion CO_2 capture technology as well as vendor and industry feedback on projects currently in the planning stages (including front-end engineering and design projects sponsored by the Department of Energy [DOE]) indicates that capture rates as high as 95 percent are feasible for both coal- and natural gas-fueled electricity generating units. Given the breadth of publicly available information supporting the capability for post-combustion capture systems to remove greater than 90 percent of the CO_2 in the treated stream, cases for 90 percent and 95 percent capture on NGCC are presented in the main body of this report.

It should be emphasized that technology suppliers (as reflected in vendor-supplied information provided to DOE that included cost and performance estimates for >95 percent carbon capture and storage [97 percent for NGCC and 99 percent for PC] study cases) as well as subject matter experts acknowledge and support that solvent-based post-combustion CO_2 capture technologies are capable of achieving CO_2 removal rates beyond 95 percent on low-purity streams representative of fossil-fueled combustion. Although techno-economic analyses of deep decarbonization (≥ 99 percent) of combustion flue gas have been published by others, the relatively limited experience with design and operation of capture systems that can routinely, reliably, and economically achieve very high removal rates requires further study. Techno-economic analysis of the higher capture rate (97 percent for NGCC) is included as Appendix A.

1 INTRODUCTION

This analysis is an evaluation of the cost and performance associated with retrofitting natural gas combined cycle (NGCC) plants for carbon capture and storage (CCS). The analysis is based on two previous National Energy Technology Laboratory (NETL) studies:

- **Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity – Revision 4a, October 2022.** [1]

  This report presents techno-economic assessment results for greenfield NGCC plants, with state-of-the-art (SOA) F-frame and H-frame turbines, with and without CCS. Among other modifications, updated performance and costs based on a 2021 vendor quote for the capture system are reported in this revision of the report. **Hereafter, this report is referenced as FEBRev4a.**

- **Cost and Performance of Retrofitting NGCC Units for Carbon Capture – Revision 2, December 2020.** [4]

  This report represents the most recent study of NGCC units retrofit with carbon capture and is based on a prior revision (Revision 4) of FEBRev4a. This report was compiled for internal use only.

NGCC models were developed for greenfield cases in FEBRev4a using Aspen Plus® (Aspen) v10. [1] These models were modified to include case switching features for retrofit parameters, primarily consisting of a steam turbine derate, as outlined in Section 3. The derate is due to the off-design performance of the low-pressure (LP) section of the steam turbine. The reason for this is the lower inlet steam flow rate due to the extraction of steam for the capture system reboiler between the LP and intermediate-pressure (IP) sections of the turbine.

The NGCC cases included in this study were based on two gas turbine designs: F-frame (7FA.05) and H-frame (7HA.02). Each turbine was modeled in three greenfield configurations—without carbon dioxide (CO_2) capture and with 90 and 95 percent CO_2 capture—and two retrofit (brownfield) configurations-with 90 and 95 percent CO_2 capture. The case designations are listed in Exhibit 1-1. Each case was modeled as a 2×2×1 power system (two gas turbines, two heat recovery steam generators [HRSG], and one steam turbine). The naming convention used follows previous naming conventions presented in FEBRev4a. For retrofit cases, the "-BR" designation represents that the base plant without capture (B31A or B32A) has now been retrofitted (R) with capture (B).

Exhibit 1-1. Case descriptions

Case[A]	Plant Type	Steam Cycle, psig/°F/°F	Combustion Turbine	CO_2 Separation	Capture Rate	Plant Type
B31A	F-frame NGCC	2378/1085/1084	2× State-of-the-art 2017 F-Class	N/A	N/A	Greenfield
B31B.90				Shell's CANSOLV Process	90%	Greenfield
B31B.95					95%	Greenfield
B31A-BR.90					90%	Brownfield
B31A-BR.95					95%	Brownfield
B32A	H-frame NGCC	2668/1085/1044	2× State-of-the-art 2017 H-Class	N/A	N/A	Greenfield
B32B.90				Shell's CANSOLV Process	90%	Greenfield
B32B.95					95%	Greenfield
B32A-BR.90					90%	Brownfield
B32A-BR.95					95%	Brownfield

[A]All plants in this report are assumed to be located at a generic plant site in the midwestern United States

Cost estimates were developed for each turbine configuration as greenfield installations. In addition, the cost of retrofitting the non-capture case for each turbine type to include 90 and 95 percent capture was estimated. The greenfield cost estimation methodology (including contingencies, owners' costs, capital recovery factors [CRF], and levelized cost of electricity [LCOE] equations) is described in the NETL Quality Guidelines for Energy System Studies (QGESS) report "Cost Estimation Methodology for NETL Assessments of Power Plant Performance." [5] The capital and operating and maintenance (O&M) costs for greenfield cases are presented in FEBRev4a. For the retrofit cases, it is assumed that the existing plant has been fully paid off, and the only capital outlay required is that for the capture process and associated modifications to the existing plant (excluding life-extension costs). Otherwise, costs were scaled as needed using the methodology specified for NGCC plants in "QGESS: Capital Cost Scaling Methodology: Revision 4 Report." [6] The 30-year levelized natural gas price was assumed to be $4.42/MMBtu as specified in "QGESS: Fuel Prices for Selected Feedstocks in NETL Studies" for natural gas delivered to large, combined cycle plants operating at high capacity factors in the Midwest. [2] The costs of CO_2 transport and storage (T&S) are specified in "QGESS: Carbon Dioxide Transport and Storage Costs in NETL Studies." [7] The cost premiums associated with retrofitting an existing plant are specified in "QGESS: Carbon Capture Retrofit Studies." [3] Owners' costs (which are added to the total plant cost [TPC] to calculate the total overnight cost [TOC]) for the retrofitted cases were calculated based only on the additional retrofitted equipment and capital charges and the increase in consumables and other O&M above existing plant values.

1.1 CO_2 CAPTURE RATES ABOVE 95 PERCENT

Commercial-scale demonstration of solvent-based post-combustion CO_2 capture systems at power generation facilities (specifically pulverized coal [PC] plants) has shown the ability to capture 90 percent of the CO_2 in the flue gas stream. Moreover, field-testing of post-combustion CO_2 capture technology as well as vendor and industry feedback on projects currently in the planning stages (including front-end engineering and design projects sponsored by the Department of Energy [DOE]) indicates that capture rates as high as 95 percent are feasible for both coal- and natural gas-fueled electricity generating units. Given the breadth of publicly available information supporting the capability for post-combustion capture systems to remove greater than 90 percent of the CO_2 in the treated stream, cases for 90 percent and 95 percent capture on NGCC are presented in the main body of this report.

It should be emphasized that technology suppliers (as reflected in vendor-supplied information provided to DOE that included cost and performance estimates for > 95 percent CCS [97 percent for NGCC and 99 percent for PC] study cases) as well as subject matter experts acknowledge and support that solvent-based post-combustion CO_2 capture technologies are capable of achieving CO_2 removal rates beyond 95 percent on low-purity streams representative of fossil-fueled combustion. Although techno-economic analyses of deep decarbonization (≥ 99 percent) of combustion flue gas have been published by others, the relatively limited experience with design and operation of capture systems that can routinely, reliably, and economically achieve very high removal rates requires further study. Techno-economic analysis of the higher capture rate (97 percent for NGCC) is included as Appendix A.

2 GENERAL EVALUATION BASIS

The design criteria are identical to those used in FEBRev4a. All plants in this study are assumed to be located at a generic plant site in the midwestern United States, with site characteristics and ambient conditions as summarized in Exhibit 2-1. The ambient conditions are the same as International Organization for Standardization conditions. An 85 percent capacity factor was selected for all cases. More detailed design criteria for the present study are outlined in the "Quality Guidelines for Energy System Studies (QGESS): Process Modeling Design Parameters". [8] The natural gas composition is specified in "QGESS: Specification for Selected Feedstocks" and is summarized in Exhibit 2-2. [9]

Exhibit 2-1. Site characteristics

Parameter	Value
Location	Midwestern U.S.
Topography	Level
Size, acres	100
Transportation	Rail or Highway
Water	50% Municipal and 50% Ground Water
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 International Organization for Standardization cases

Exhibit 2-2. Natural gas composition

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	$5.75\text{x}10^{-6}$	
	Total	**100.0**	
	LHV	**HHV**	
kJ/kg (Btu/lb)	47,201 (20,293)	52,295 (22,483)	
MJ/scm (Btu/scf)	34.52 (927)	38.25 (1,027)	

[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

3 PERFORMANCE ESTIMATES

Steady state models for each case were developed using Aspen v10. The turbine model specifications are presented in Exhibit 3-1. Since NGCC net power output is determined by the turbine type and configuration selected, the natural gas flow differs between F-frame and H-frame cases but remains constant in relation to the combustion turbine size (i.e., capture and non-capture cases have the same natural gas flow rate). In comparison to the previous report, [4] the most notable adjustments made were to reflect current post-combustion capture technology information as outlined in a 2021 vendor quote. The addition of post-combustion capture reduces the quantity of steam available to generate power in the LP turbine section as well as increases the cooling water required and overall water usage.

The retrofit case performance for each turbine type was assumed to be identical to the greenfield capture case performance except for an off-design efficiency penalty applied to the steam turbine due to the throttled steam extraction upstream from the existing plant LP turbine stage resulting in operation at a significantly reduced flow relative to the full design flow. This causes a derate not only based on lower power production from decreased flow to the steam turbine, but also an additional derate due to an efficiency penalty caused by off-design flow to the steam turbine.

The additional off-design efficiency penalty is a function of the percentage of steam extracted from the IP-LP crossover and is, therefore, a function of the capture system reboiler duty. The off-design steam turbine derate was calculated using data from the Lucquiaud et al. study, which was verified against published data from the International Energy Agency (IEA) greenhouse gas (GHG) study involving a collaboration between Alstom Power, Mitsui Babcock, Fluor, and Imperial College. [10, 11, 12] For 90 percent capture cases, the steam turbine derate was based on the ratio of the Lucquiaud et al.-reported steam turbine gross output for a throttled LP turbine due to CCS retrofit to the steam turbine gross output of a greenfield plant with CCS. The derate for higher capture cases was then scaled based on the linear relationship, reported by Lucquiaud et al., of steam turbine efficiency to the percent of steam extracted for a throttled LP turbine. This methodology remains consistent with previous iterations of this report for 90 percent capture, with slight adjustments for higher capture rates based on the assumption that greater steam extraction at higher capture rates will lead to increased off-design efficiency penalties in the LP section of the steam turbine. The resulting derates range 2.05–2.15 percent gross power in the steam turbine section for 90–95 percent capture from an NGCC system.

The linear relationship of the off design derate can be approximated by:

$$\text{Steam turbine gross power derate} = 0.0187 * \frac{A}{B} + 0.0018$$

for capture rates between 90 and 95 percent, where:

A = Steam flow rate extracted prior to the LP steam turbine for the desired capture rate, lb/h

B = Steam flow rate extracted prior to the LP steam turbine for the reference 90 percent capture case, lb/h

The resulting value is then applied as a fractional decrease in the steam turbine gross power.

Exhibit 3-1. Turbine model specifications

Case Turbine	Technology		Steam Cycle, psig/°F/°F	Efficiency (% HHV/LHV)	2×GT (MWe)	ST (MWe)[A]	Gross (MWe)	Aux (MWe)	Net (MWe)
1 SOA Based on F-frame	B31A	w/o CO_2 capture	2378/1085/1084	53.6/59.4	477	263	740	14	727
	B31B.90	w/CO_2 capture		47.6/52.7	477	215	692	47	645
	B31B.95	w/CO_2 capture		47.3/52.4	477	212	690	49	640
	B31A-BR.90	w/CO_2 capture retrofit		47.3/52.4	477	211	688	47	641
	B31A-BR.95	w/CO_2 capture retrofit		46.9/52.0	477	208	685	49	636
2 SOA Based on H-frame	B32A	w/o CO_2 capture	2668/1085/1044	55.1/61.0	686	324	1,009	17	992
	B32B.90	w/CO_2 capture		49.0/54.3	686	260	945	62	883
	B32B.95	w/CO_2 capture		48.7/54.0	686	256	942	65	877
	B32A-BR.90	w/CO_2 capture retrofit		48.7/54.0	686	255	940	62	878
	B32A-BR.95	w/CO_2 capture retrofit		48.4/53.6	686	251	936	65	872

[A] Steam turbine value includes derate for off-design LP operation

The models include Shell's CANSOLV solvent-based chemical absorption process for CO_2 capture as outlined and applied to NGCC cases in FEBRev4a. The performance results are listed in Exhibit 3-2 and Exhibit 3-3 for each turbine type and retrofit application.

The performance of the greenfield and retrofit applications is nearly identical except for the addition of the LP steam turbine off-design efficiency penalty. This efficiency penalty reduces power generation in the steam turbine by about 4–5 MWe (about 2 percent of the steam turbine gross power output or less than 1 percent of net power). Overall steam cycle efficiency is reduced by about 1.0 percentage point in retrofit applications and HHV net plant efficiency is reduced by about 0.3 percentage points. The raw water withdrawal and consumption, shown in Exhibit 3-2 and Exhibit 3-3, remain constant between cases of similar turbine type but appear to increase in retrofit applications due to the reduction in net power causing the normalized water usage to increase.

Exhibit 3-2. F-frame NGCC plant performance summary

Case	7FA.05 Without Capture (B31A)	7FA.05 with 90% Capture (B31B.90)	7FA.05 with 95% Capture (B31B.95)	7FA.05 Retrofitted with 90% Capture (B31A-BR.90)	7FA.05 Retrofitted with 95% Capture (B31A-BR.95)
Plant Output					
Gas Turbine Power, MWe	477	477	477	477	477
Steam Turbine Power, MWe	263	215	212	211	208
Total, MWe	**740**	**692**	**690**	**688**	**685**
Auxiliary Load					
Circulating Water Pumps, kWe	2,820	4,340	4,360	4,340	4,360
Combustion Turbine Auxiliaries, kWe	1,020	1,020	1,020	1,020	1,020
Condensate Pumps, kWe	150	170	170	170	170
Cooling Tower Fans, kWe	1,460	2,240	2,260	2,240	2,260
CO_2 Capture/Removal Auxiliaries, kWe	–	13,600	14,400	13,600	14,400
CO_2 Compression, kWe	–	17,900	18,900	17,900	18,900
Feedwater Pumps, kWe	4,830	4,830	4,830	4,830	4,830
Ground Water Pumps, kWe	260	400	410	400	410
Miscellaneous Balance of Plant[A], kWe	570	570	570	570	570
SCR, kWe	2	2	2	2	2
Steam Turbine Auxiliaries, kWe	200	200	200	200	200
Transformer Losses, kWe	2,250	2,220	2,220	2,210	2,200
Total Auxiliaries, MWe	**14**	**47**	**49**	**47**	**49**
Net Plant Power, MWe	**727**	**645**	**640**	**641**	**636**
Plant Performance					
HHV Net Plant Efficiency, %	53.6%	47.6%	47.3%	47.3%	46.9%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,714 (6,363)	7,563 (7,169)	7,617 (7,220)	7,615 (7,218)	7,671 (7,270)

Case	7FA.05 Without Capture (B31A)	7FA.05 with 90% Capture (B31B.90)	7FA.05 with 95% Capture (B31B.95)	7FA.05 Retrofitted with 90% Capture (B31A-BR.90)	7FA.05 Retrofitted with 95% Capture (B31A-BR.95)
Plant Performance (continued)					
HHV Combustion Turbine Efficiency, %	35.2%	35.2%	35.2%	35.2%	35.2%
LHV Net Plant Efficiency, %	59.4%	52.7%	52.4%	52.4%	52.0%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,060 (5,743)	6,827 (6,470)	6,875 (6,516)	6,873 (6,515)	6,924 (6,562)
LHV Combustion Turbine Efficiency, %	39.0%	39.0%	39.0%	39.0%	39.0%
Steam Turbine Cycle Efficiency, %	39.7%	46.9%	47.5%	45.9%	46.5%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	9,074 (8,601)	7,678 (7,277)	7,586 (7,190)	7,838 (7,429)	7,750 (7,345)
CO_2 Capture Rate, %	0%	90%	95%	90%	95%
Condenser Duty, GJ/h (MMBtu/h)	1,406 (1,332)	860 (815)	830 (787)	860 (815)	830 (787)
AGR Cooling Duty, GJ/h (MMBtu/h)	0 (0)	1,194 (1,132)	1,232 (1,167)	1,194 (1,132)	1,232 (1,167)
Natural Gas Feed Flow, kg/h (lb/h)	93,272 (205,630)	93,272 (205,630)	93,272 (205,630)	93,272 (205,630)	93,272 (205,630)
HHV Thermal Input, kWt	1,354,905	1,354,905	1,354,905	1,354,905	1,354,905
LHV Thermal Input, kWt	1,222,936	1,222,936	1,222,936	1,222,936	1,222,936
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.015 (4.0)	0.026 (6.9)	0.027 (7.0)	0.026 (7.0)	0.027 (7.1)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.012 (3.1)	0.017 (4.6)	0.018 (4.7)	0.018 (4.6)	0.018 (4.7)

Note: Values shown are for total 2×2×1 system

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

Exhibit 3-3. H-frame NGCC plant performance summary

Case	7HA.02 Without Capture (B32A)	7HA.02 with 90% Capture (B32B.90)	7HA.02 with 95% Capture (B32B.95)	7HA.02 Retrofitted with 90% Capture (B32A-BR.90)	7HA.02 Retrofitted with 95% Capture (B32A-BR.95)
Plant Output					
Gas Turbine Power, MWe	686	686	686	686	686
Steam Turbine Power, MWe	324	260	256	255	251
Total, MWe	**1,009**	**945**	**942**	**940**	**936**
Auxiliary Load					
Circulating Water Pumps, kWe	3,510	5,530	5,570	5,530	5,570
Combustion Turbine Auxiliaries, kWe	1,320	1,320	1,320	1,320	1,320
Condensate Pumps, kWe	180	200	200	200	200
Cooling Tower Fans, kWe	1,810	2,860	2,880	2,860	2,880
CO_2 Capture/Removal Auxiliaries, kWe	–	18,000	19,200	18,000	19,200
CO_2 Compression, kWe	–	23,810	25,130	23,810	25,130
Feedwater Pumps, kWe	5,760	5,760	5,760	5,760	5,760
Ground Water Pumps, kWe	330	520	520	520	520
Miscellaneous Balance of Plant[A], kWe	710	710	710	710	710
SCR, kWe	3	3	3	3	3
Steam Turbine Auxiliaries, kWe	230	230	230	230	230
Transformer Losses, kWe	3,070	3,020	3,020	3,010	3,000
Total Auxiliaries, MWe	**17**	**62**	**65**	**62**	**65**
Net Plant Power, MWe	**992**	**883**	**877**	**878**	**872**
Plant Performance					
HHV Net Plant Efficiency, %	55.1%	49.0%	48.7%	48.7%	48.4%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,537 (6,196)	7,342 (6,959)	7,393 (7,007)	7,387 (7,001)	7,439 (7,051)
HHV Combustion Turbine Efficiency, %	38.0%	38.0%	38.0%	38.0%	38.0%

Case	7HA.02 Without Capture (B32A)	7HA.02 with 90% Capture (B32B.90)	7HA.02 with 95% Capture (B32B.95)	7HA.02 Retrofitted with 90% Capture (B32A-BR.90)	7HA.02 Retrofitted with 95% Capture (B32A-BR.95)
Plant Performance (continued)					
LHV Net Plant Efficiency, %	61.0%	54.3%	54.0%	54.0%	53.6%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	5,900 (5,592)	6,627 (6,281)	6,672 (6,324)	6,667 (6,319)	6,714 (6,364)
LHV Combustion Turbine Efficiency, %	42.2%	42.2%	42.2%	42.2%	42.2%
Steam Turbine Cycle Efficiency, %	39.1%	46.7%	47.3%	45.7%	46.3%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	9,213 (8,732)	7,713 (7,311)	7,609 (7,212)	7,877 (7,466)	7,776 (7,370)
CO_2 Capture Rate, %	0%	90%	95%	90%	95%
Condenser Duty, GJ/h (MMBtu/h)	1,757 (1,666)	1,031 (978)	992 (940)	1,031 (978)	992 (940)
AGR Cooling Duty, GJ/h (MMBtu/h)	0 (0)	1,587 (1,505)	1,638 (1,552)	1,587 (1,505)	1,638 (1,552)
Natural Gas Feed Flow, kg/h (lb/h)	124,025 (273,429)	124,025 (273,429)	124,025 (273,429)	124,025 (273,429)	124,025 (273,429)
HHV Thermal Input, kWt	1,801,631	1,801,631	1,801,631	1,801,631	1,801,631
LHV Thermal Input, kWt	1,626,150	1,626,150	1,626,150	1,626,150	1,626,150
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.014 (3.6)	0.024 (6.4)	0.025 (6.5)	0.025 (6.5)	0.025 (6.6)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.011 (2.8)	0.016 (4.2)	0.016 (4.3)	0.016 (4.3)	0.016 (4.3)

Note: Values shown are for total 2×2×1 system

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

4 COST ESTIMATES

Detailed cost estimates (including capital and operation and maintenance [O&M] costs) were developed for greenfield installations in FEBRev4a. Those costs were used as the basis for scaling all the cost estimates in this study. The greenfield cost estimation methodology, including CRF and LCOE equations, is described in "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance." [5] The owner/developer is assumed to be an investor-owned utility (IOU). All NGCC plants are assumed to have financial structures consistent with three-year capital expenditure periods and thirty-year operational periods.

Costs are scaled as needed using the methodology specified for NGCC plants in "QGESS: Capital Cost Scaling Methodology: Revision 4 Report." [6] The 30-year levelized natural gas cost is assumed to be $4.42/MMBtu as specified in "QGESS: Fuel Prices for Selected Feedstocks in NETL Studies" [2] for natural gas delivered to large combined cycle plants operating at high capacity factors in the Midwest. The costs of T&S are assumed to be $10 per tonne of CO_2 as specified in "QGESS: Carbon Dioxide Transport and Storage Costs in NETL Studies." [7] The costs of retrofitting are estimated using the methodology outlined in the "QGESS: Carbon Capture Retrofit." [3] All costs are presented in real 2018 dollars.

To avoid capital cost estimation bias due to the number of processing trains considered, all cases assume that the flue gas can be processed in a single capture system process train. Future development of capture systems may prove that multiple trains are required for the flue gas flow rates considered, but that information was not available from the vendor. Different configurations of the advanced amine CCS process and equipment could be considered for operational flexibility at additional cost, but these options were not considered in the present study. The cost curves herein are representative costs based on cost models validated with recent vendor input. Since there have been no designs of this size constructed to date, these costs incorporate near-term projections for the deployment of carbon capture, utilization, and storage technology in the utility sector.

The vendor data provided suggested that the flue gas flow rate available from the F-frame NGCC case would be able to be processed in a single train without issue. The flue gas flow rate available from the H-frame NGCC case was approximately 20 percent higher than the data provided by the vendor; however, the vendor did not specifically exclude this flow rate as too large for a single train, nor provide a maximum flow rate for single train processing. Therefore, it was assumed that a single train could be applied for H-frame cases. Typical scaling outlined in the capital cost scaling QGESS [6] was applied to the F-frame capture system vendor-quoted costs to achieve estimated costs for an NGCC H-frame capture system.

4.1 GREENFIELD COST ESTIMATES

The TPC estimates include the bare erected costs (BEC) for the equipment; engineering, construction management, home office & fees (Engineering CM, H.O. & Fee); and project and process. Owners' costs are added to the TPC resulting in the TOC. Additionally, financing costs are estimated by applying a factor to the TOC value to calculate total as-spent costs (TASC). [5, 6] The annual O&M costs are calculated using model results to determine consumable quantities.

The greenfield cost estimates summaries (including capital and O&M) are listed in Exhibit 4-1 and Exhibit 4-2 for each turbine type. Additional details can be found in FEBRev4a.

Exhibit 4-1. Summary cost estimate data for F-frame greenfield cases

Case	B31A	B31B.90	B31B.95
Turbine	7FA.05	7FA.05	7FA.05
Capture Rate	0%	90%	95%
Bare Erected Cost by Account, $/1000			
A3 – Feedwater & Misc. BOP Systems	66,159	78,523	78,722
A5 – Flue Gas Cleanup	0	294,169	305,145
A6 – Combustion Turbine and Accessories	82,353	82,353	82,353
A7 – HRSG, Ducting & Stack	83,482	79,769	79,656
A8 – Steam Turbine & Accessories	69,836	59,667	59,077
A9 – Cooling Water System	28,207	36,639	36,789
A11 – Accessory Electric Plant	29,946	50,215	51,131
A12 – Instrumentation & Controls	14,169	16,594	16,690
A13 – Improvements to Site	19,332	20,008	19,972
A14 – Building & Structures	14,087	13,289	13,232
Total BEC, $/1000	**407,571**	**731,225**	**742,768**
Engineering CM, H.O.& Fee, $/1000	81,514	146,245	148,554
Process Contingencies, $/1000	0	45,859	47,658
Project Contingencies, $/1000	77,908	163,719	166,823
TPC, $/1000	**566,994**	**1,087,048**	**1,105,803**
TPC, $/kW	**780**	**1,686**	**1,727**
TOC, $/1000	**691,670**	**1,321,288**	**1,343,987**
TOC, $/kW	**952**	**2,049**	**2,099**
TASC, $/1000	**755,751**	**1,443,701**	**1,468,503**
TASC, $/kW	**1,040**	**2,239**	**2,293**
First-Year Fuel Cost (100% CF), $/1000	179,012	179,012	179,012
First-Year Fixed O&M Cost, $/1000	19,467	35,539	36,092
First-Year Variable O&M Cost (100% CF), $/1000	10,854	22,782	23,228
First-Year Total O&M (100% CF), $/1000	**209,332**	**237,333**	**238,332**

Note: All costs are in real 2018 dollars

Exhibit 4-2. Summary cost estimate data for H-frame greenfield cases

Case	B32A	B32B.90	B32B.95
Turbine	7HA.02	7HA.02	7HA.02
Capture Rate	0%	90%	95%
Bare Erected Cost by Account, $/1000			
A3 – Feedwater & Misc. BOP Systems	82,401	97,785	98,031
A5 – Gas Cleanup & Piping	0	348,712	361,860
A6 – Combustion Turbine and Accessories	159,892	159,892	159,892
A7 – HRSG, Ducting & Stack	127,656	122,240	122,061
A8 – Steam Turbine Generator	76,023	64,027	63,342
A9 – Cooling Water System	32,281	42,582	42,765
A11 – Accessory Electric Plant	37,066	61,614	62,779
A12 – Instrumentation & Controls	14,807	17,433	17,540
A13 – Improvements to Site	22,295	23,090	23,050
A14 – Building & Structures	16,029	15,060	14,993
Total BEC, $/1000	**568,450**	**952,434**	**966,313**
Engineering CM, H.O.& Fee, $/1000	113,690	190,487	193,263
Process Contingencies, $/1000	0	54,711	56,880
Project Contingencies, $/1000	107,880	209,774	213,506
TPC, $/1000	**790,020**	**1,407,406**	**1,429,961**
TPC, $/kW	**796**	**1,593**	**1,630**
TOC, $/1000	**962,719**	**1,710,262**	**1,737,565**
TOC, $/kW	**970**	**1,936**	**1,980**
TASC, $/1000	**1,051,912**	**1,868,712**	**1,898,546**
TASC, $/kW	**1,060**	**2,115**	**2,164**
First-Year Fuel Cost (100% CF), $/1000	238,034	238,034	238,034
First-Year Fixed O&M Cost, $/1000	26,046	44,989	45,655
First-Year Variable O&M Cost (100% CF), $/1000	14,690	29,556	30,116
First-Year Total O&M (100% CF), $/1000	**278,770**	**312,579**	**313,805**

Note: All costs are in 2018 dollars

4.2 RETROFIT COST ESTIMATES

Retrofit factors provided in the carbon capture retrofit QGESS are applied to greenfield estimates to determine retrofit costs for adding a capture system. [3] The first step in determining the retrofit costs is to determine the greenfield equivalent cost of the retrofit equipment. Standard cost scaling techniques are used to estimate the cost of the new equipment, using the FEBRev4a costs for each turbine type as the reference costs. The greenfield equivalent costs for the retrofit equipment that are added to the non-capture plant designs for each turbine type are shown in Exhibit 4-3.

Exhibit 4-3. Summary greenfield equivalent costs of the retrofit equipment

Case	B31A-BR.90	B31A-BR.95	B32A-BR.90	B32A-BR.95
Turbine	7FA.05	7FA.05	7HA.02	7HA.02
Capture Rate	90%	95%	90%	95%
Bare Erected Cost by Account, $/1000				
A3 – Feedwater & Misc. BOP Systems	12,364	12,562	15,384	15,630
A5 – Gas Cleanup & Piping	294,169	305,145	348,712	361,860
A6 – Combustion Turbine and Accessories	0	0	0	0
A7 – HRSG, Ducting & Stack	0	0	0	0
A8 – Steam Turbine Generator	7,417	7,703	9,138	9,490
A9 – Cooling Water System	8,432	8,582	10,302	10,484
A11 – Accessory Electric Plant	21,428	22,407	26,190	27,444
A12 – Instrumentation & Controls	2,424	2,520	2,626	2,733
A13 – Improvements to Site	676	640	795	755
A14 – Building & Structures	226	230	280	285
Total BEC, $/1000	**347,137**	**359,790**	**413,426**	**428,681**
Engineering CM, H.O.& Fee, $/1000	69,427	71,958	82,685	85,736
Process Contingencies, $/1000	45,250	47,050	54,081	56,250
Project Contingencies, $/1000	89,987	93,293	107,151	111,132
Greenfield equivalent TPC, $/1000	**551,801**	**572,091**	**657,343**	**681,799**
Greenfield equivalent TPC, $/kW	**861**	**900**	**749**	**782**

Note: All costs are in 2018 dollars

Typical TPC includes summing BEC; engineering, construction management, home office expenses and fees; and process and project contingencies. However, for retrofit applications, there is an increased difficulty associated with adding units after construction of the base plant, which can introduce additional costs. A retrofit difficulty factor (RDF) of 1.09 is used to account for this cost premium; the retrofit TPC is estimated by multiplying the RDF by the greenfield equivalent TPC. [3]

Owners' costs were calculated for only the additional equipment and O&M costs required for CO_2 capture and added to the TPC to obtain the TOC.

Line-item RDF applicable to NGCC plant designs are listed in Exhibit 4-4. While this study did not apply RDFs on an account line-item basis, if a given study has specific knowledge of an existing plant layout and restrictions, individual line-item factors should be applied to better reflect the difficulty of executing a retrofit at the specific plant. In cases such as this study, where generic plant locations and layouts are assumed with no space constraints, applying a RDF at the TPC level will represent an averaged increase in cost, equivalent to applying the 1.09 RDF to each account line item. The equipment and material retrofit factors are the cost premium addressing minor differences in equipment specifications, layout, duct routing, and items where additional complexity is likely to be encountered. Labor productivity adjustments account for productivity losses associated with working on an existing operating plant site, in potentially highly congested areas, and with modifications and tie-ins to existing equipment and/or systems. The RDF range 1.00–1.30 and are multiplied by the greenfield equivalent equipment, material, and labor costs for each cost account to estimate retrofit cost premiums. The accounts in Exhibit 4-4 have been modified from the QGESS to align with cost accounts reported in FEBRev4a.

Exhibit 4-4. Retrofit scope adjustment factors

Retrofit Scope Adjustment					
Cost Category		Equipment/Material		Labor Productivity	
		Low	High	Low	High
3	FEEDWATER & MISC. BOP SYSTEMS				
3.1	Feedwater System	1.00	1.00	1.00	1.00
3.2	Water Makeup & Pretreating	1.00	1.05	1.05	1.25
3.3	Other Feedwater Subsystems	1.00	1.00	1.00	1.00
3.4	Service Water Systems	1.00	1.05	1.05	1.25
3.5	Other Boiler Plant Systems	1.00	1.00	1.00	1.00
3.6	FO Supply System & Natural Gas	1.00	1.00	1.00	1.00
3.7	Waste Treatment Equipment	1.00	1.05	1.05	1.25
3.9	Misc. Equip. (Cranes, Air Comp., Comm.)	1.00	1.05	1.05	1.25
5	CO_2 REMOVAL & COMPRESSION				
5.1	CO_2 Removal System	1.00	1.05	1.00	1.15
5.4	CO_2 Compression & Drying	1.00	1.00	1.00	1.15
6	COMBUSTION TURBINE/ACCESSORIES				
6.1	Combustion Turbine Generator	1.00	1.00	1.00	1.00
6.3	Combustion Turbine Accessories	1.00	1.00	1.00	1.00
6.4	Compressed Air Piping	1.00	1.00	1.00	1.00
6.5	Combustion Turbine Foundations	1.00	1.00	1.00	1.00
7	HRSG, DUCTING & STACK				
7.1	Heat Recovery Steam Generator	1.00	1.00	1.00	1.00
7.2	HRSG Accessories	1.00	1.00	1.00	1.00
7.3	Ductwork	1.00	1.10	1.05	1.20
7.4	Stack	1.00	1.25	1.00	1.30
7.5	Duct & Stack Foundations	1.00	1.10	1.00	1.25
8	STEAM TURBINE GENERATOR				
8.1	Steam Turbine Generator & Accessories	1.00	1.00	1.00	1.00
8.2	Turbine Plant Auxiliaries	1.00	1.00	1.00	1.00
8.3	Condenser & Auxiliaries	1.00	1.00	1.00	1.00
8.4	Steam Piping	1.00	1.10	1.05	1.25
8.5	Turbine Generator Foundations	1.00	1.00	1.00	1.00
9	COOLING WATER SYSTEM				
9.1	Cooling Towers	1.00	1.05	1.00	1.15
9.2	Circulating Water Pumps	1.00	1.05	1.00	1.15

Retrofit Scope Adjustment					
Cost Category		Equipment/Material		Labor Productivity	
		Low	High	Low	High
9.3	Circ. Water System Auxiliaries	1.00	1.05	1.00	1.15
9.4	Circ. Water Piping	1.00	1.10	1.00	1.15
9.5	Make-up Water System	1.00	1.10	1.00	1.15
9.6	Component Cooling Water System	1.00	1.05	1.00	1.15
9.7	Circ. Water System Foundations & Structures	1.00	1.10	1.00	1.15
11	**ACCESSORY ELECTRIC PLANT**				
11.1	Generator Equipment	1.00	1.00	1.00	1.00
11.2	Station Service Equipment	1.00	1.05	1.00	1.15
11.3	Switchgear & Motor Control	1.00	1.05	1.00	1.15
11.4	Conduit & Cable Tray	1.00	1.10	1.00	1.15
11.5	Wire & Cable	1.00	1.10	1.00	1.15
11.6	Protective Equipment	1.00	1.05	1.00	1.15
11.7	Standby Equipment	1.00	1.05	1.00	1.15
11.8	Main Power Transformers	1.00	1.05	1.00	1.15
11.9	Electrical Foundations	1.00	1.10	1.00	1.15
12	**INSTRUMENTATION & CONTROL**				
12.1	NGCC Control Equipment	1.00	1.00	1.00	1.00
12.2	Combustion Turbine Control	1.00	1.00	1.00	1.00
12.3	Steam Turbine Control	1.00	1.00	1.00	1.00
12.4	Other Major Component Control	1.00	1.00	1.00	1.00
12.5	Signal Processing Equipment	1.00	1.00	1.00	1.00
12.6	Control Boards, Panels & Racks	1.00	1.05	1.00	1.15
12.7	Distributed Control System Equipment	1.00	1.05	1.10	1.30
12.8	Instrument Wiring & Tubing	1.00	1.05	1.05	1.20
12.9	Other I&C Equipment	1.00	1.05	1.05	1.20
13	**IMPROVEMENTS TO SITE**				
13.1	Site Preparation	1.00	1.05	1.00	1.20
13.2	Site Improvements	1.00	1.05	1.00	1.20
13.3	Site Facilities	1.00	1.05	1.00	1.20
14	**BUILDINGS & STRUCTURES**				
14.1	Combustion Turbine Area	1.00	1.00	1.00	1.00
14.3	Steam Turbine Building	1.00	1.00	1.00	1.00
14.4	Administration Building	1.00	1.00	1.00	1.00
14.5	Circulation Water Pumphouse	1.00	1.05	1.00	1.15
14.6	Water Treatment Buildings	1.00	1.05	1.05	1.25
14.7	Machine Shop	1.00	1.00	1.00	1.00
14.8	Warehouse	1.00	1.00	1.00	1.00
14.9	Other Buildings & Structures	1.00	1.05	1.00	1.15

Retrofit Scope Adjustment					
Cost Category		Equipment/Material		Labor Productivity	
		Low	High	Low	High
14.10	Waste Treating Building & Structures	1.00	1.05	1.05	1.25

The carbon capture retrofit QGESS states that the weighted average of these factors assuming high retrofit difficulty is 1.09, which was applied to the generic plant layout. [4] This simplified approach assumes that $100 of installed greenfield equipment tends to cost $109 if installed as a retrofit in NGCC applications. This approach also lends itself to a simple sensitivity analysis on a single retrofit factor that bounds the retrofit impact. The sensitivity analysis results are presented in Section 5.

Exhibit 4-5 summarizes the total capital and O&M costs for cases B31A-BR.90, B31A-BR.95, B32A-BR.90, and B32A-BR.95. The total annual O&M costs after retrofitting were estimated based on the performance parameters presented in Section 3.

Exhibit 4-5. Summary costs of the retrofit equipment

Case	B31A-BR.90	B31A-BR.95	B32A-BR.90	B32A-BR.95
Turbine	7FA.05	7FA.05	7HA.02	7HA.02
Capture Rate	90%	95%	90%	95%
Bare Erected Cost by Account				
Greenfield equivalent TPC, $/1000	**551,801**	**572,091**	**657,343**	**681,799**
Greenfield equivalent TPC, $/kW	**861**	**900**	**749**	**782**
RDF	**1.09**	**1.09**	**1.09**	**1.09**
TPC w/ RDF, $/1000	**601,463**	**623,579**	**716,504**	**743,161**
TPC w/RDF, $/kW	**939**	**981**	**816**	**852**
TOC w/ RDF, $/1000	**727,657**	**754,405**	**866,916**	**899,161**
TOC w/ RDF, $/kW	**1,136**	**1,186**	**987**	**1,031**
TASC w/ RDF, $/1000	**795,072**	**824,298**	**947,233**	**982,466**
TASC w/ RDF, $/kW	**1,241**	**1,296**	**1,079**	**1,127**
First-Year Fuel Cost (100% CF), $/1000	179,012	179,012	238,034	238,034
First-Year Fixed O&M Cost, $/1000	36,475	37,074	46,168	46,889
First-Year Variable O&M Cost (100% CF), $/1000	23,208	23,674	30,092	30,678
First-Year Total O&M (100% CF), $/1000	**238,695**	**239,760**	**314,294**	**315,601**

Note: All costs are in real 2018 dollars

4.3 LEVELIZED COST OF ELECTRICITY AND OTHER METRICS

The primary cost metric used in this study is LCOE, which is the revenue required to meet all capital and operational costs per net MWh levelized over the lifetime of the power plant. Since these are retrofit systems, it is assumed that the existing plant has been fully paid off, no additional costs are necessary for plant life extension, and the only capital outlay required is for the CCS process, which includes the removal technology process equipment, a CO_2 compression train, and any modification to the existing plant required to accommodate the retrofitted technology (e.g. additional cooling tower capacity to support the CCS process requirements and additional steam piping). Existing NGCC plant fuel costs and fixed and variable O&M, as well as additional labor, maintenance and consumables required by the retrofit are included in the LCOE calculations. The owner/developer is assumed to be an IOU, and the CO_2 capture retrofit was assumed to have financial structures consistent with a three-year capital expenditure period and a thirty-year operational period. This is consistent with the greenfield NGCC cases in FEBRev4a. The retrofit cost results for each case are listed in Exhibit 4-6. As the size of the turbine increases, the LCOE decreases, which is consistent with improvements in efficiency and typical economies of scale. The cost of CO_2 captured and the cost of CO_2 avoided are also included in the table. Upon retrofitting the NGCC plant with CCS, a derate in the net plant electrical output will be incurred due to the auxiliary electric load required to run the CCS system, as well as steam extraction from the steam cycle to satisfy the CCS reboiler duty, rather than produce power in the LP steam turbine section. It is recognized that this difference in power production from before retrofit to after retrofit constitutes a power makeup that will need to be financially accounted for within the electricity distribution system. This study assumes that the retrofitted plant needs to account for this charge and does so by including a makeup power cost (MPC) in the retrofitted plants' LCOE. A charge for the makeup capacity needed to match the original plant net generation is added to the LCOE at an assumed projected sales price (PSP) for electricity of $30/MWh. This $30/MWh price is based on the approximate average Midcontinent Independent System Operator Market price with near 10 percent renewable penetration. [13] The MPC is also included in the calculation of the cost of CO_2 captured and the cost of CO_2 avoided.

Exhibit 4-6. Summary LCOE of the retrofit cases

Case	B31A-BR.90	B31A-BR.95	B32A-BR.90	B32A-BR.95
Turbine	7FA.05	7FA.05	7HA.02	7HA.02
Capture Rate	90%	95%	90%	95%
LCOE, Total [Including T&S]	59.0	60.2	55.6	56.7
LCOE, Total [Including T&S and MPC]	63.0	64.5	59.5	60.9
Capital, $/MWh	11.8	12.3	10.2	10.7
Fixed, $/MWh	7.6	7.8	7.1	7.2
Variable, $/MWh	4.1	4.3	3.9	4.0
Fuel, $/MWh	31.9	32.1	30.9	31.2
CO_2 T&S, $/MWh	3.5	3.7	3.4	3.6
Makeup power cost @ PSP = $30/MWh, $/MWh	4.0	4.3	3.9	4.1
Cost of CO_2 Captured [Excluding T&S], $/tonne CO_2	61.8	60.8	56.7	55.9
Cost of CO_2 Avoided [Including T&S], $/tonne CO_2	71.8	70.8	66.7	65.9

Note: All costs are in real 2018 dollars and calculated at 85% capacity factor.

The cost of CO_2 captured is the price at which the revenue generated by selling the recovered CO_2 equals the costs of recovering it. The costs of recovering the CO_2 include capital expenditures, fixed and variable O&M increases, fuel cost changes, and makeup power charges.

For retrofit cases, the equation for calculating the cost of CO_2 captured is

$$\text{Cost of CO}_2\text{ Captured} = \frac{\left[\text{PSP}\left(\frac{\$}{\text{MWh}}\right)*\text{lost MWh}\left(\frac{\text{MWH}}{\text{yr}}@\text{CF}\right)+\text{CRF}*\text{Incremental TOC}\left(\frac{\$}{\text{yr}}\right)+\text{Incremental O\&M}\left(\frac{\$}{\text{yr}}@\text{CF}\right)\right]}{\text{CO}_2\text{ Captured}\left(\frac{\text{tonne}}{\text{yr}}@\text{CF}\right)}$$

where:

PSP = Projected sales price of electricity, \$/MWh

Lost MWh = MWh_{BAU} - MWh_{RET}

MWh_{BAU} = Annual net generation for non-capture/business as usual, MWh/yr

MWh_{RET} = Annual net generation for after retrofit, MWh/yr

BAU = Business as usual (i.e., existing plant)

RET = After retrofit

CF = Capacity factor

CCF = Capital recovery factor

TOC = Total overnight cost

Incremental O&M costs associated with retrofit, \$/yr
= (Fixed O&M + Variable O&M + Fuel)$_{BAU}$ - (Fixed O&M + Variable O&M + Fuel)$_{RET}$

The cost of CO_2 avoided is the cost of reducing emissions at which the penalty for not reducing the emissions is equal to the costs. If the price of allowances or fines for emissions are higher than this value, then there is an economic incentive for adding the capture system. The costs of recovering the CO_2 include capital expenditures, fixed and variable O&M increases, fuel cost changes, T&S, and makeup power charges.

For retrofit cases, the equation for calculating the cost of CO_2 avoided is

$$\text{Cost of CO}_2\text{ Avoided} = \frac{PSP\left(\frac{\$}{\text{MWh}}\right)*\text{lost MWh}\left(\frac{\text{MWh}}{\text{yr}}@\text{CF}\right)+\text{CRF}*\text{Incremental TOC}\left(\frac{\$}{\text{yr}}\right)+\text{Incremental O\&M}\left(\frac{\$}{\text{yr}}@\text{CF}\right)+\text{T\&S Costs}\left(\frac{\$}{\text{yr}}@\text{CF}\right)}{\left(\text{MWh}_{\text{BAU}}\left(\frac{\text{MWh}}{\text{yr}}@\text{CF}\right)*\text{CO}_2\text{Emissions}_{\text{BAU}}\left(\frac{\text{tonne}}{\text{MWh}_{\text{BAU}}}\right)-\text{MWh}_{\text{RET}}\left(\frac{\text{MWh}}{\text{yr}}@\text{CF}\right)*\text{CO}_2\text{Emissions}_{\text{RET}}\left(\frac{\text{tonne}}{\text{MWh}_{\text{RET}}}\right)\right)}$$

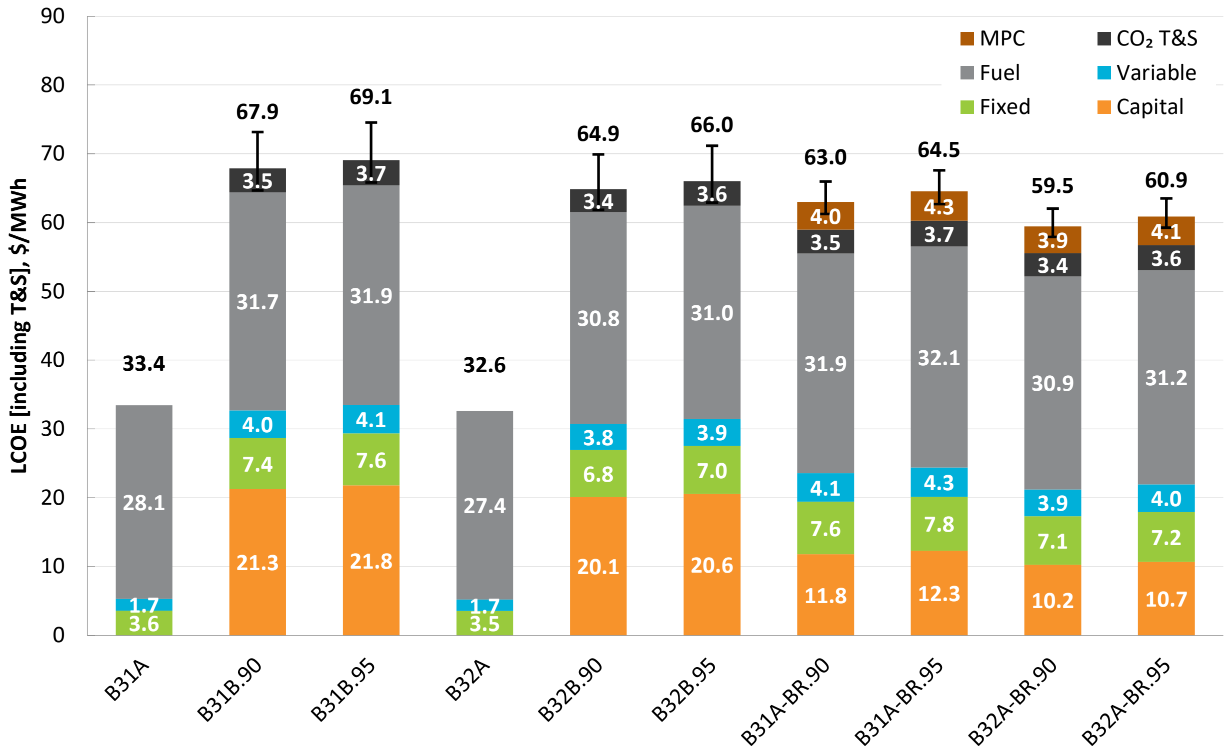
where:

Incremental O&M costs associated with retrofit, \$/yr
= (Fixed O&M + Variable O&M + Fuel)$_{BAU}$ - (Fixed O&M + Variable O&M + Fuel)$_{RET}$

5 SUMMARY COMPARISON

The LCOE for both turbine types, retrofit with CCS, is illustrated in Exhibit 5-1. The estimated LCOE values for the non-capture cases (assuming the existing plant is fully paid off) are included in the chart for comparison. Greenfield applications were also added for comparison, but represent different cost assumptions than the other cases, as previously noted. As the size of the turbine increases, the LCOE decreases, which is consistent with improvements in efficiency and typical economies of scale. The annual fuel costs make up the largest portion of the annual operating costs. The total annual fuel cost remains the same for each turbine type before and after retrofit, but the cost per MWh increases due to the decrease in net power generation after retrofit.

Exhibit 5-1. Summary LCOE



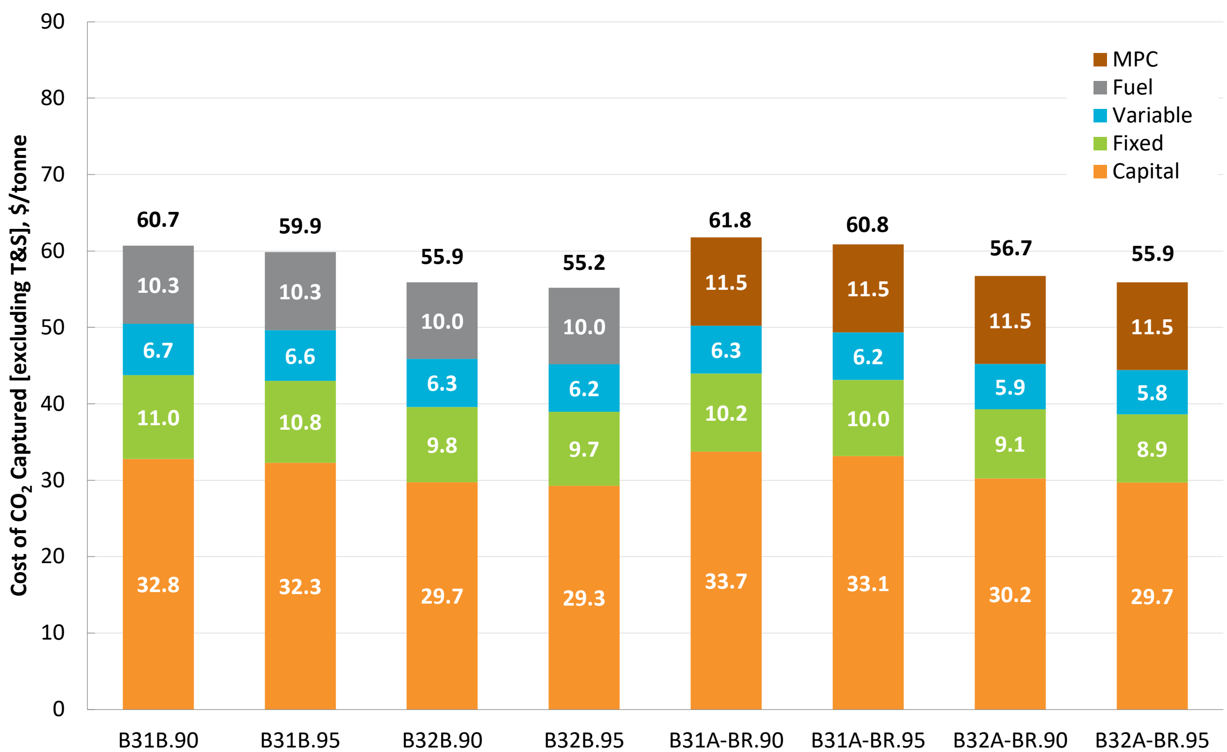
Note: All costs are in real 2018 dollars and calculated at 85% capacity factor. Capital costs for cases B31A and B32A are assumed to be paid off

CO_2 capture from power plants can be incentivized by selling the separated CO_2 product at a price greater than the cost of capturing CO_2. To match the previous economic attractiveness or profitability of the plant, the cost of CO_2 captured for the retrofit case must cover the amortized cost of the new retrofitted equipment, the additional O&M costs associated with the CO_2 capture process, and the lost opportunity cost associated with the derate in electrical generation capacity. The costs for CO_2 T&S are excluded from the cost of capture when the CO_2 is sold at the plant gate. The lost opportunity cost is due to the electricity sales that are forfeited due to the auxiliary load of the capture system and the reduced steam turbine output when steam is extracted to regenerate the capture solvent.

The lost opportunity cost is the portion of the CO_2 capture costs that covers the previous revenue from derated electrical generation sold at the PSP of electricity, with some built-in profit above the previous existing plant's marginal LCOE. For this analysis, a PSP of electricity of $30/MWh is assumed. [13]

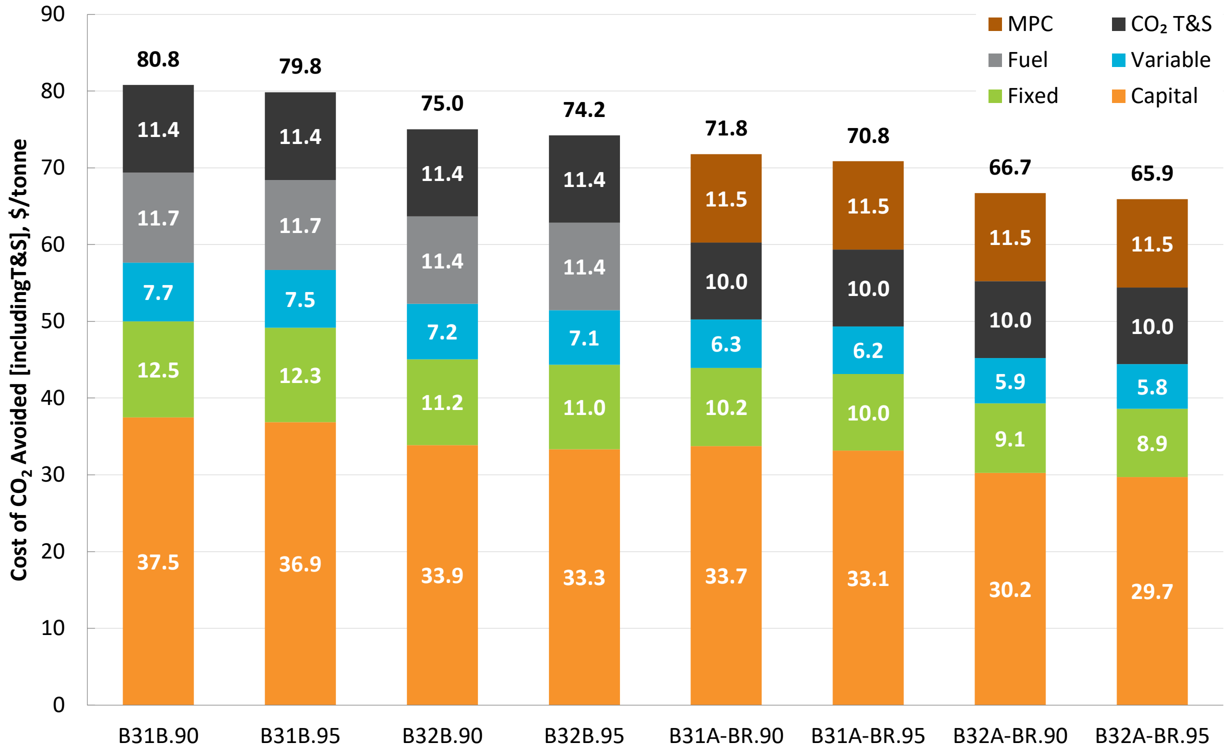
The cost of CO_2 captured/avoided for retrofit cases is shown in Exhibit 5-2 and Exhibit 5-3. These parameters are explained in more detail in Section 4.3. The reference case for each calculated value is the matching turbine non-capture case. As the turbine design increases in size, the costs per unit of CO_2 captured decreases. Increasing the capture rate for a given turbine size has a negligible impact on the cost of CO_2 captured/avoided. The increase in the CO_2 capture rate offsets the associated increase in capital costs and reduced power generation. Greenfield costs for CO_2 captured/avoided are included for comparison; however, the method for calculating the costs is slightly different in greenfield and retrofit applications so a direct comparison may not be appropriate.

Exhibit 5-2. Summary cost of CO_2 captured



Note: All costs are in real 2018 dollars and calculated at 85% capacity factor. B31A is used as a reference for all F-frame retrofit case calculations. B32A is used as a reference for all H-frame retrofit case calculations.

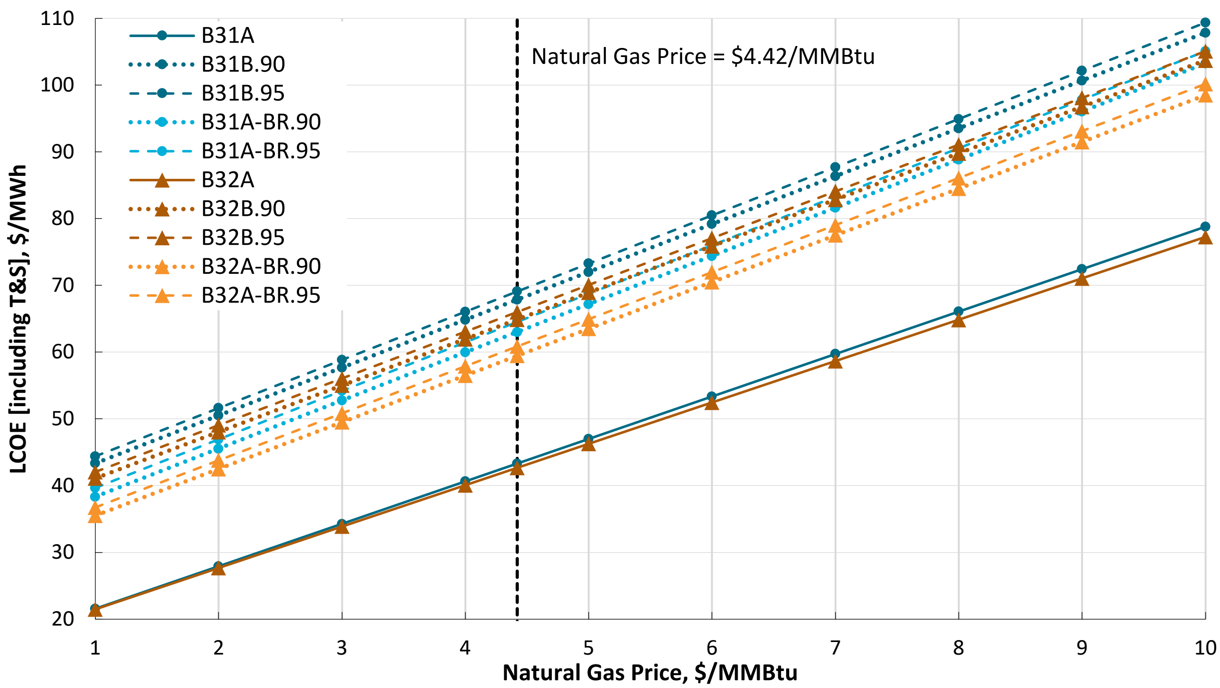
Exhibit 5-3. Summary cost of CO_2 avoided



Note: All costs are in real 2018 dollars and calculated at 85% capacity factor. B31A is used as a reference for all F-frame retrofit case calculations. B32A is used as a reference for all H-frame retrofit case calculations.

The sensitivity of the LCOE values to the price of natural gas is shown in Exhibit 5-4. The values at the $4.42/MMBtu price assumed for this study are along the vertical line shown in the chart. As the natural gas price increases, the LCOE values increase. The non-capture cases (not assuming the existing plant is fully paid off—greenfield installation) are slightly less sensitive than the capture cases. A natural gas price change of $1.00, on average, results in an increase in LCOE for non-capture cases of $6.28/MWh and for capture cases of $7.11/MWh. The impact of the price on the LCOE is approximately the same for all turbine designs because the annual fuel costs are a similar proportion of the LCOE values (approximately 50 percent of the retrofitted capture case values and 65 percent of the non-capture cases). Retrofit cases are slightly more sensitive to natural gas price (on a $/MWh basis) when compared to greenfield capture cases since the fuel portion of the LCOE for retrofit cases is slightly higher.

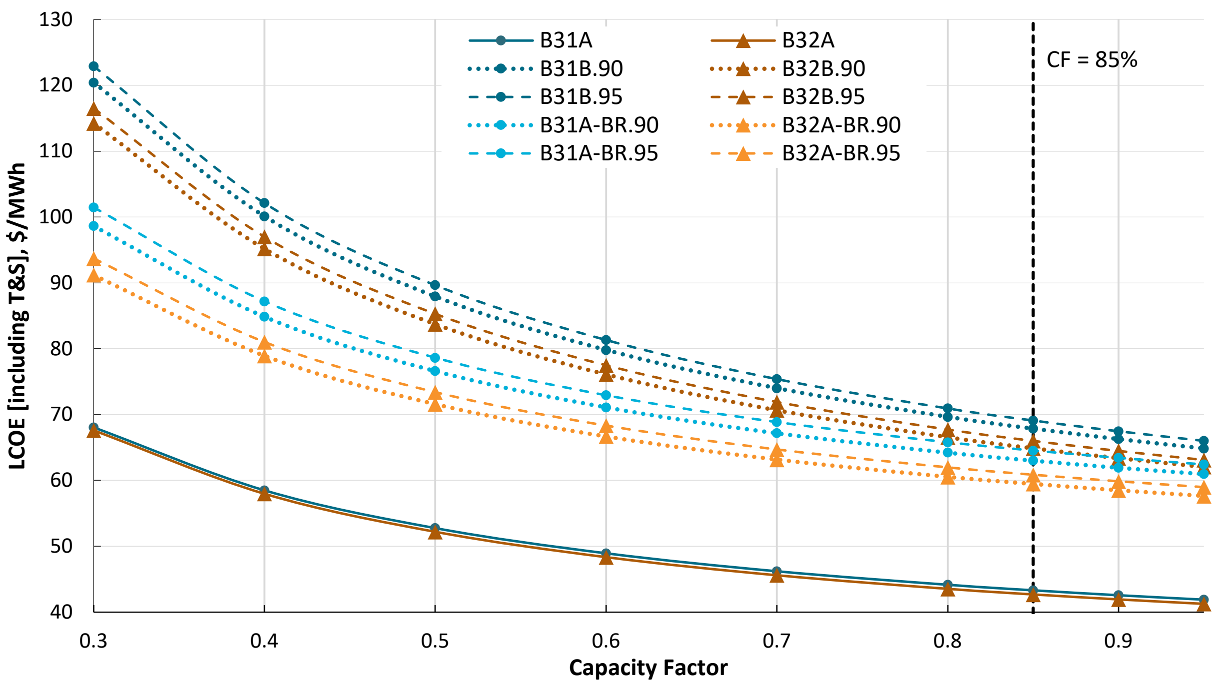
Exhibit 5-4. Sensitivity of LCOE to natural gas price



Note: All costs are in real 2018 dollars and calculated at 85% capacity factor

The sensitivity of the LCOE values to capacity factor is shown in Exhibit 5-5. The values at the 85 percent capacity factor assumed for this study are along the vertical line shown in the chart. As the capacity factor increases, the LCOE values decrease. The annual fuel cost is directly proportional to the annual electricity generated, so changes in the capacity factor do not impact the fuel portion of the LCOE. The fixed charges and the retrofitted capital annual charges are higher for the retrofitted capture cases, so the LCOE values for those cases increase more than the non-capture case LCOE values at lower capacity factors. The retrofitted capital annual charges are lower than greenfield capital annual charges, so the LCOE values for retrofit cases increase significantly less than the greenfield capture case LCOE values at lower capacity factors. The calculations were made with the assumption that no addition or reduction in equipment, operating, maintenance and support labor, or capital would be needed to operate at higher or lower capacity factors. The capacity factor has a smaller impact as the turbine designs (efficiencies) improve, and the base LCOE decreases.

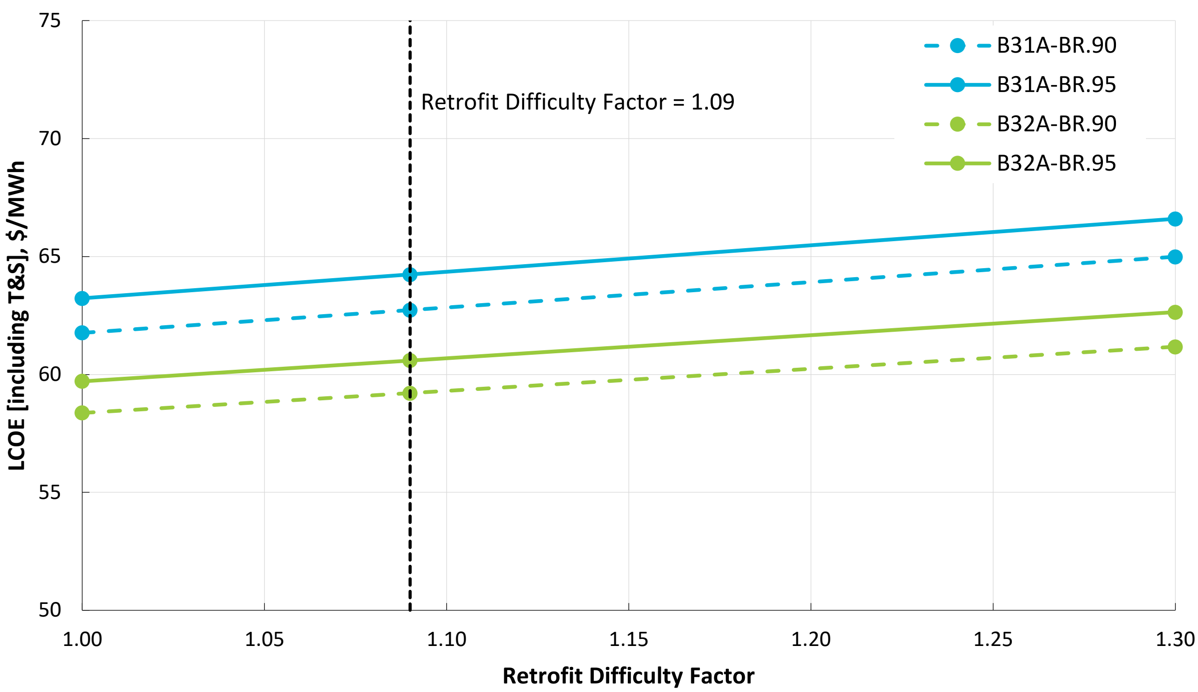
Exhibit 5-5. Sensitivity of LCOE to capacity factor



Note: All costs are in real 2018 dollars

The cost estimates in this study utilize an RDF of 1.09 applied at the TPC level to estimate retrofit cost premiums. The sensitivity of the LCOE to this single retrofit difficulty cost factor was calculated and is illustrated in Exhibit 5-6. The simplified approach generates LCOE values approximately equal to the detailed estimates and bounds the edges of the more detailed estimate. The assumed RDF of 1.09 (as indicated by the vertical line on the graph) indicates that $100 of installed greenfield equipment tends to cost $109 if installed as a retrofit. The retrofit premium estimated by either the detailed or simplified method is within the expected accuracy (-15 percent/+25 percent for an AACE International Class 4 cost estimate) of reference NGCC plants considered. It is important to note that the retrofit premium is highly site specific, which is why it is presented as a range, and that extreme site conditions or plant configurations could render such a retrofit unfeasible. The range presented here is meant to represent a typical retrofit as an evaluation tool, rather than to replace the detailed engineering and design required for such a project. For both F-frame and H-frame cases, the marginal increase in LCOE over the entire range of RDFs is less than $4/MWh.

Exhibit 5-6. Sensitivity of LCOE to retrofit difficulty factor (RDF)



Note: All costs are in real 2018 dollars and calculated at 85% capacity factor

6 CONCLUSION AND FUTURE WORK

The purpose of this revision is to align this report with the most recent revision of FEBRev4a. [1] The primary update to the NGCC power plants in FEBRev4a was an update to the CCS system cost and performance. Additionally, a higher CO_2 capture rate (95 percent) was included. In comparison to the previous revision of this report, non-capture LCOE remained constant when assuming the base plant is fully paid off (zero capital costs). For retrofit cases with 90 percent capture, LCOE reduced by 10 percent ($70.5/MWh versus $63.0/MWh for F-frame NGCC and $66.2/MWh versus $59.5/MWh H-frame NGCC), the cost of CO_2 captured reduced by 34 percent, and the cost of CO_2 avoided reduced by 41 percent in both F- and H-frame cases. This report shows that increasing the CO_2 capture rate from 90 to 95 percent in retrofit applications increases the LCOE by 2 percent. The increase from 90 to 95 percent CO_2 capture has a negligible impact on both the cost of CO_2 captured and avoided.

The study conclusions apply only to this level of conceptual design and economic analysis. Further analysis is needed to establish the influence of different retrofit scenarios on the cost of CO_2 captured and the LCOE. The following future work is recommended:

- Considering scenarios where the base plant is not fully paid off, or where the retrofit capture plant is owned and operated independently.
- The plant performance of today's SOA F-class or H-class NGCC plants may or may not reflect the plant performance of existing NGCC plants that are candidates for capture retrofit. A more detailed analysis should identify the combustion turbine types and vintages that represent the existing fleet and apply today's SOA capture system performance and cost as a retrofit to further refine the cost of capture.
- Accounting for the impact of possible costs associated with improvements necessary for plant life extension to maximize the utility of installing a new CCS system.
- Different configurations of the CCS process and equipment could be considered for operational flexibility at additional cost.
- Considering the influence of site-specific costs on LCOE and the cost of CO_2 captured, such as the need for longer flue gas ducting, air cooling, and dedicated cooling systems and package boilers for steam generation.

REFERENCES

[1] NETL, "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity," DOE/NETL, Pittsburgh, PA, 2022.

[2] NETL, "Quality Guidelines for Energy System Studies: Fuel Prices for Selected Feedstocks in NETL Studies," DOE/NETL, Pittsburgh, PA, 2019.

[3] NETL, "Quality Guidelines for Energy System Studies: Carbon Capture Retrofit Studies," DOE/NETL, Pittsburgh, PA, 2019.

[4] NETL, "Cost and Performance of Retrofitting Existing NGCC Units for Carbon Capture - Revision 2," DOE/NETL, Pittsburgh, PA, 2020.

[5] NETL, "Quality Guidelines for Energy System Studies: Cost Estimation Methodology for NETL Assessments of Power Plant Performance. DOE/NETL-2011/1455," DOE/NETL, Pittsburgh, PA, 2019.

[6] NETL, "Quality Guidelines for Energy System Studies: Capital Cost Scaling Methodology: Revision 4 Report," DOE/NETL, Pittsburgh, PA, 2019.

[7] NETL, "Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs in NETL Studies," DOE/NETL, Pittsburgh, PA, 2019.

[8] NETL, "Quality Guidelines for Energy System Studies: Process Modeling Design Parameters," DOE/NETL, Pittsburgh, PA, 2019.

[9] NETL, "Quality Guidelines for Energy System Studies: Specification for Selected Feedstocks," DOE/NETL, Pittsburgh, PA, 2012.

[10] M. Lucquiaud and J. Gibbins, "Retrofitting CO2 Capture Ready Fossil Plants with Post-combustion Capture Part 1: Requirements for Supercritical Pulverized Coal Plants Using Solvent-based Flue Gas Scrubbing," *Proceedings of the Institution of Mechanical Engineers, Part A: Journal of Power and Energy. Mechanical Engineering Dept, Imperial College London,* vol. 223, pp. 213-226, January 2009.

[11] International Energy Agency Greenhouse Gas (IEA GHG), "Improvement in Power Generation with Post-combustion Capture of CO2. Report Number PH4/33," 2004. [Online]. Available: http://www.canadiancleanpowercoalition.com/pdf/AS5%20-%20PH4-33%20post%20combustion.pdf. [Accessed 28 July 2011].

[12] NETL, "Post-Combustion Capture Retrofit Study Update, DOE/NETL-341/130104," DOE/NETL, Pittsburgh, PA, January 2013.

[13] Potomac Economics, "2019 State of the Market Report for the MISO Electricity Markets," Potomac Economics, 2020.

[14] Environmental Protection Agency, "40 CFR Part 60 - Carbon Pollution Emissions Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule Vol. 80 No. 205," 23 October 2015. [Online]. Available: https://www.gpo.gov/fdsys/pkg/FR-2015-10-23/pdf/2015-22842.pdf. [Accessed 9 October 2018].

APPENDIX A: 97 PERCENT CAPTURE CASES

Commercial-scale demonstration of solvent-based post-combustion carbon dioxide (CO_2) capture systems at power generation facilities (specifically pulverized coal [PC] plants) has shown the ability to capture 90 percent of the CO_2 in the flue gas stream. Moreover, field-testing of post-combustion CO_2 capture technology as well as vendor and industry feedback on projects currently in the planning stages (including front-end engineering and design projects sponsored by the Department of Energy [DOE]) indicates that capture rates as high as 95 percent are feasible for both coal- and natural gas-fueled electricity generating units. Given the breadth of publicly available information supporting the capability for post-combustion capture systems to remove greater than 90 percent of the CO_2 in the treated stream, cases for 90 percent and 95 percent capture on natural gas combined cycle (NGCC) are presented in the main body of this report.

It should be emphasized that technology suppliers (as reflected in vendor-supplied information provided to DOE that included cost and performance estimates for > 95 percent carbon capture and storage [97 percent for NGCC and 99 percent for PC] study cases) as well as subject matter experts acknowledge and support that solvent-based post-combustion CO_2 capture technologies are capable of achieving CO_2 removal rates beyond 95 percent on low-purity streams representative of fossil-fueled combustion. Although techno-economic analyses of deep decarbonization (≥ 99 percent) of combustion flue gas have been published by others, the relatively limited experience with design and operation of capture systems that can routinely, reliably, and economically achieve very high removal rates requires further study. Techno-economic analysis of the higher capture rate (97 percent for NGCC) is included in this appendix.

Exhibit A-1. F-frame NGCC plant performance summary

Case	7FA.05 Without Capture (B31A)	7FA.05 with 97% Capture (B31B.97)	7FA.05 Retrofitted with 97% Capture (B31A-BR.97)	7HA.02 Without Capture (B32A)	7HA.02 with 97% Capture (B32B.97)	7HA.02 Retrofitted with 97% Capture (B32A-BR.97)
Plant Output						
Gas Turbine Power, MWe	477	477	477	686	686	686
Steam Turbine Power, MWe	263	210	205	324	253	248
Total, MWe	**740**	**687**	**683**	**1,009**	**939**	**933**
Auxiliary Load						
Circulating Water Pumps, kWe	2,820	4,390	4,390	3,510	5,600	5,600
Combustion Turbine Auxiliaries, kWe	1,020	1,020	1,020	1,320	1,320	1,320
Condensate Pumps, kWe	150	170	170	180	200	200
Cooling Tower Fans, kWe	1,460	2,270	2,270	1,810	2,890	2,890
CO_2 Capture/Removal Auxiliaries, kWe	–	15,200	15,200	–	20,200	20,200
CO_2 Compression, kWe	–	19,290	19,290	–	25,660	25,660
Feedwater Pumps, kWe	4,830	4,830	4,830	5,760	5,760	5,760
Ground Water Pumps, kWe	260	410	410	330	520	520
Miscellaneous Balance of Plant[A], kWe	570	570	570	710	710	710
SCR, kWe	2	2	2	3	3	3
Steam Turbine Auxiliaries, kWe	200	200	200	230	230	230
Transformer Losses, kWe	2,250	2,210	2,200	3,070	3,020	3,000
Total Auxiliaries, MWe	**14**	**51**	**51**	**17**	**66**	**66**
Net Plant Power, MWe	**727**	**637**	**632**	**992**	**873**	**867**
Plant Performance						
HHV Net Plant Efficiency, %	53.6%	47.0%	46.7%	55.1%	48.4%	48.1%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,714 (6,363)	7,659 (7,260)	7,716 (7,313)	6,537 (6,196)	7,433 (7,045)	7,482 (7,091)
HHV Combustion Turbine Efficiency, %	35.2%	35.2%	35.2%	38.0%	38.0%	38.0%

Case	7FA.05 Without Capture (B31A)	7FA.05 with 97% Capture (B31B.97)	7FA.05 Retrofitted with 97% Capture (B31A-BR.97)	7HA.02 Without Capture (B32A)	7HA.02 with 97% Capture (B32B.97)	7HA.02 Retrofitted with 97% Capture (B32A-BR.97)
LHV Net Plant Efficiency, %	59.4%	52.1%	51.7%	61.0%	53.7%	53.3%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,060 (5,743)	6,913 (6,552)	6,964 (6,601)	5,900 (5,592)	6,709 (6,359)	6,753 (6,401)
LHV Combustion Turbine Efficiency, %	39.0%	39.0%	39.0%	42.2%	42.2%	42.2%
Steam Turbine Cycle Efficiency, %	39.7%	48.0%	47.0%	39.1%	47.9%	46.8%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	9,074 (8,601)	7,495 (7,104)	7,666 (7,266)	9,213 (8,732)	7,514 (7,121)	7,687 (7,285)
CO_2 Capture Rate, %	0%	97%	97%	0%	97%	97%
Condenser Duty, GJ/h (MMBtu/h)	1,406 (1,332)	803 (761)	803 (761)	1,757 (1,666)	955 (906)	955 (906)
AGR Cooling Duty, GJ/h (MMBtu/h)	0 (0)	1,268 (1,201)	1,268 (1,201)	0 (0)	1,686 (1,598)	1,686 (1,598)
Natural Gas Feed Flow, kg/h (lb/h)	93,272 (205,630)	93,272 (205,630)	93,272 (205,630)	124,025 (273,429)	124,025 (273,429)	124,025 (273,429)
HHV Thermal Input, kWt	1,354,905	1,354,905	1,354,905	1,801,631	1,801,631	1,801,631
LHV Thermal Input, kWt	1,222,936	1,222,936	1,222,936	1,626,150	1,626,150	1,626,150
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.015 (4.0)	0.027 (7.1)	0.027 (7.2)	0.014 (3.6)	0.025 (6.6)	0.025 (6.7)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.012 (3.1)	0.018 (4.8)	0.018 (4.8)	0.011 (2.8)	0.017 (4.4)	0.017 (4.4)

Note: Values shown are for total 2×2×1 system
[A] Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Exhibit A-2. Summary cost estimate data for F-frame greenfield cases

Case	B31A	B31B.97	B32A	B32B.97
Turbine	7FA.05	7FA.05	7HA.02	7HA.02
Capture Rate	0%	97%	0%	97%
Bare Erected Cost by Account, $/1000				
A3 – Feedwater & Misc. BOP Systems	66,159	78,645	82,401	97,937
A5 – Flue Gas Cleanup	0	311,908	0	369,925
A6 – Combustion Turbine and Accessories	82,353	82,353	159,892	159,892
A7 – HRSG, Ducting & Stack	83,482	79,623	127,656	121,983
A8 – Steam Turbine & Accessories	69,836	58,563	76,023	62,715
A9 – Cooling Water System	28,207	36,908	32,281	42,910
A11 – Accessory Electric Plant	29,946	51,715	37,066	63,454
A12 – Instrumentation & Controls	14,169	16,751	14,807	17,603
A13 – Improvements to Site	19,332	19,941	22,295	23,014
A14 – Building & Structures	14,087	13,184	16,029	14,931
Total BEC, $/1000	407,571	749,592	568,450	974,365
Engineering CM, H.O.& Fee, $/1000	81,514	149,918	113,690	194,873
Process Contingencies, $/1000	0	48,810	0	58,255
Project Contingencies, $/1000	77,908	168,680	107,880	215,705
TPC, $/1000	566,994	1,117,000	790,020	1,443,198
TPC, $/kW	780	1,754	796	1,654
TOC, $/1000	691,670	1,357,546	962,719	1,753,601
TOC, $/kW	952	2,132	970	2,010
TASC, $/1000	755,751	1,483,319	1,051,912	1,916,067
TASC, $/kW	1,040	2,329	1,060	2,196
First-Year Fuel Cost (100% CF), $/1000	179,012	179,012	238,034	238,034
First-Year Fixed O&M Cost, $/1000	19,467	36,422	26,046	46,045
First-Year Variable O&M Cost (100% CF), $/1000	10,854	23,528	14,690	30,494
First-Year Total O&M (100% CF), $/1000	209,332	238,962	278,770	314,573

Note: All costs are in real 2018 dollar

Exhibit A-3. Summary costs of retrofit

Case	B31A-BR.97	B32A-BR.97
Turbine	7FA.05	7HA.02
Capture Rate	97%	97%
Bare Erected Cost by Account, $/1000		
A3 – Feedwater & Misc. BOP Systems	12,486	15,536
A5 – Gas Cleanup & Piping	311,908	369,925
A6 – Combustion Turbine and Accessories	0	0
A7 – HRSG, Ducting & Stack	0	0
A8 – Steam Turbine Generator	7,958	9,804
A9 – Cooling Water System	8,701	10,629
A11 – Accessory Electric Plant	23,046	28,198
A12 – Instrumentation & Controls	2,582	2,796
A13 – Improvements to Site	610	719
A14 – Building & Structures	233	289
Total BEC, $/1000	367,524	437,897
Engineering CM, H.O.& Fee, $/1000	73,505	87,579
Process Contingencies, $/1000	48,201	57,625
Project Contingencies, $/1000	95,315	113,542
Greenfield equivalent TPC, $/1000	584,545	696,643
Greenfield equivalent TPC, $/kW	925	804
Retrofit Difficulty Factor (RDF)	1.09	1.09
TPC w/ RDF, $/1000	637,154	759,341
TPC w/RDF, $/kW	1,008	876
TOC w/ RDF, $/1000	770,830	918,744
TOC w/ RDF, $/kW	1,219	1,060
TASC w/ RDF, $/1000	842,245	1,003,863
TASC w/ RDF, $/kW	1,332	1,158
First-Year Fuel Cost (100% CF), $/1000	179,012	238,034
First-Year Fixed O&M Cost, $/1000	37,441	47,327
First-Year Variable O&M Cost (100% CF), $/1000	23,991	31,077
First-Year Total O&M (100% CF), $/1000	**240,444**	**316,438**

Note: All costs are in 2018 dollars

Exhibit A-4. Summary LCOE of the retrofit cases

Case	B31A-BR.97	B32A-BR.97
Turbine	7FA.05	7HA.02
Capture Rate	97%	97%
LCOE, Total [Including T&S]	61.1	57.5
LCOE, Total [Including T&S and MPC]	65.6	61.8
Capital, $/MWh	12.7	11.0
Fixed, $/MWh	8.0	7.3
Variable, $/MWh	4.3	4.1
Fuel, $/MWh	32.3	31.3
CO_2 T&S, $/MWh	3.8	3.7
Makeup power cost @ PSP = $30/MWh, $/MWh	4.5	4.3
Cost of CO_2 Captured [Excluding T&S], $/tonne CO_2	61.1	56.2
Cost of CO_2 Avoided [Including T&S], $/tonne CO_2	71.1	66.2

Note: All costs are in real 2018 dollars, 85% capacity factor.

APPENDIX B: COST ESTIMATE DETAILS

Capital and O&M cost tables for the following cases are listed below.

Case B31A-BR.90, 7FA.05 Turbines retrofitted with 90% Capture Rate

Case B31A-BR.95, 7FA.05 Turbines retrofitted with 95% Capture Rate

Case B31A-BR.97, 7FA.05 Turbines retrofitted with 97% Capture Rate

Case B32A-BR.90, 7HA.02 Turbines retrofitted with 90% Capture Rate

Case B32A-BR.95, 7HA.02 Turbines retrofitted with 95% Capture Rate

Case B32A-BR.97, 7HA.02 Turbines retrofitted with 97% Capture Rate

Exhibit B-1. B31A-BR.90 capital costs

Case:		B31A-BR.90	– 2x1 CT NGCC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		641					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
	3					Feedwater & Miscellaneous BOP Systems					
3.1	Feedwater System	$1	$2	$1	$0	$4	$1	$0	$1	$5	$0
3.2	Water Makeup & Pretreating	$1,339	$134	$759	$0	$2,231	$446	$0	$535	$3,213	$5
3.3	Other Feedwater Subsystems	$1	$0	$0	$0	$1	$0	$0	$0	$1	$0
3.4	Service Water Systems	$406	$775	$2,511	$0	$3,693	$739	$0	$886	$5,318	$8
3.7	Waste Water Treatment Equipment	$3,990	$0	$2,445	$0	$6,435	$1,287	$0	$1,544	$9,266	$14
	Subtotal	**$5,736**	**$912**	**$5,716**	**$0**	**$12,364**	**$2,473**	**$0**	**$2,967**	**$17,804**	**$28**
	5					Flue Gas Cleanup					
5.1	CANSOLV Carbon Dioxide (CO_2) Removal System	$101,663	$48,103	$101,017	$0	$250,783	$50,157	$45,141	$69,216	$415,297	$648
5.4	Carbon Dioxide (CO_2) Compression & Drying	$26,989	$4,049	$11,197	$0	$42,234	$8,447	$0	$10,136	$60,817	$95
5.5	Carbon Dioxide (CO_2) Compressor Aftercooler	$224	$36	$96	$0	$356	$71	$0	$85	$513	$1
5.12	Gas Cleanup Foundations	$0	$382	$413	$0	$795	$159	$0	$191	$1,145	$2
	Subtotal	**$128,877**	**$52,570**	**$112,723**	**$0**	**$294,169**	**$58,834**	**$45,141**	**$79,629**	**$477,772**	**$746**
	8					Steam Turbine & Accessories					
8.4	Steam Piping	$5,278	$0	$2,139	$0	$7,417	$1,483	$0	$1,335	$10,236	$16
	Subtotal	**$5,278**	**$0**	**$2,139**	**$0**	**$7,417**	**$1,483**	**$0**	**$1,335**	**$10,236**	**$16**
	9					Cooling Water System					
9.1	Cooling Towers	$2,942	$0	$872	$0	$3,814	$763	$0	$687	$5,264	$8
9.2	Circulating Water Pumps	$389	$0	$27	$0	$416	$83	$0	$75	$574	$1
9.3	Circulating Water System Auxiliaries	$1,920	$0	$253	$0	$2,173	$435	$0	$391	$2,999	$5
9.4	Circulating Water Piping	$0	$684	$619	$0	$1,303	$261	$0	$235	$1,798	$3
9.5	Make-up Water System	$55	$0	$71	$0	$126	$25	$0	$23	$174	$0
9.6	Component Cooling Water System	$101	$0	$77	$0	$178	$36	$0	$32	$246	$0
9.7	Circulating Water System Foundations	$0	$158	$263	$0	$421	$84	$0	$101	$606	$1
	Subtotal	**$5,407**	**$842**	**$2,183**	**$0**	**$8,432**	**$1,686**	**$0**	**$1,543**	**$11,661**	**$18**
	11					Accessory Electric Plant					
11.2	Station Service Equipment	$3,621	$0	$311	$0	$3,932	$786	$0	$708	$5,426	$8
11.3	Switchgear & Motor Control	$5,171	$0	$897	$0	$6,068	$1,214	$0	$1,092	$8,373	$13
11.4	Conduit & Cable Tray	$0	$1,249	$3,601	$0	$4,850	$970	$0	$873	$6,693	$10
11.5	Wire & Cable	$0	$1,865	$3,334	$0	$5,200	$1,040	$0	$936	$7,175	$11
11.6	Protective Equipment	$308	$0	$1,070	$0	$1,379	$276	$0	$248	$1,902	$3
	Subtotal	**$9,100**	**$3,115**	**$9,213**	**$0**	**$21,428**	**$4,286**	**$0**	**$3,857**	**$29,571**	**$46**
	12					Instrumentation & Control					
12.1	Natural Gas Combined Cycle Control Equipment	$36	$0	$23	$0	$60	$12	$0	$11	$82	$0

Case:		B31A-BR.90	– 2x1 CT NGCC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		641					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
12.3	Steam Turbine Control Equipment	$58	$0	$37	$0	$95	$19	$0	$17	$132	$0
12.4	Other Major Component Control Equipment	$99	$0	$63	$0	$163	$33	$8	$30	$234	$0
12.5	Signal Processing Equipment	$82	$0	$3	$0	$84	$17	$0	$15	$116	$0
12.6	Control Boards, Panels & Racks	$22	$0	$13	$0	$35	$7	$2	$7	$50	$0
12.7	Distributed Control System Equipment	$1,216	$0	$38	$0	$1,254	$251	$63	$235	$1,803	$3
12.8	Instrument Wiring & Tubing	$100	$80	$322	$0	$502	$100	$25	$94	$722	$1
12.9	Other Instrumentation & Controls Equipment	$70	$0	$161	$0	$231	$46	$12	$43	$332	$1
	Subtotal	**$1,683**	**$80**	**$661**	**$0**	**$2,424**	**$485**	**$109**	**$453**	**$3,471**	**$5**
	13					**Improvements to Site**					
13.1	Site Preparation	$0	$19	$399	$0	$417	$83	$0	$100	$601	$1
13.2	Site Improvements	$0	$59	$81	$0	$140	$28	$0	$34	$202	$0
13.3	Site Facilities	$58	$0	$61	$0	$119	$24	$0	$28	$171	$0
	Subtotal	**$58**	**$78**	**$540**	**$0**	**$676**	**$135**	**$0**	**$162**	**$974**	**$2**
	14					**Buildings & Structures**					
14.5	Circulation Water Pumphouse	$0	$24	$12	$0	$35	$7	$0	$6	$49	$0
14.6	Water Treatment Buildings	$0	$100	$91	$0	$191	$38	$0	$34	$263	$0
	Subtotal	**$0**	**$124**	**$102**	**$0**	**$226**	**$45**	**$0**	**$41**	**$312**	**$0**
	Pre-Retrofit Difficulty Factor Total	**$156,139**	**$57,720**	**$133,277**	**$0**	**$347,137**	**$69,427**	**$45,250**	**$89,987**	**$551,801**	**$861**
	Retrofit Adjusted Total									**$601,463**	**$939**

Exhibit B-2. B31A-BR.90 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$2,986	$5
1 Month Maintenance Materials	$617	$1
1 Month Non-fuel Consumables	$406	$1
1 Month Waste Disposal	$7	$0
25% of 1 Months Fuel Cost at 100% CF	$0	$0
2% of TPC	$12,029	$19
Total	**$16,045**	**$25**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$682	$1
0.5% of TPC (spare parts)	$3,007	$5
Total	**$3,689**	**$6**
Other Costs		
Initial Cost for Catalyst and Chemicals	$0	$0
Land	$0	$0
Other Owner's Costs	$90,219	$141
Financing Costs	$16,240	$25
Total Overnight Costs (TOC)	**$727,657**	**$1,136**
TASC Multiplier (IOU, 33 year)	1.093	
Total As-Spent Cost (TASC)	**$795,072**	**$1,241**

Exhibit B-3. B31A-BR.90 O&M costs

Case:	**B31A-BR.90**	**– 2x1 CT NGCC w/ CO_2 Capture**			**Cost Base:**	**Dec 2018**
Plant Size (MW, net):	**641**	**Heat Rate-net (Btu/kWh):**		**7,218**	**Capacity Factor (%):**	**85**
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:		1.0
Operating Labor Burden:		30.00	**% of base**	Operator:		3.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		1.0
				Total:		**6.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$2,776,628	$4.33
Maintenance Labor:					$8,502,838	$13.27
Administrative & Support Labor:					$2,819,867	$4.40
Property Taxes and Insurance:					$22,375,890	$34.93
Total:					**$36,475,223**	**$56.95**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$12,754,257	$2.67
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	3,216	$1.90	$0	$1,895,852	$0.40
Makeup and Waste Water Treatment Chemicals (ton):	0	9.6	$550	$0	$1,634,796	$0.34
Ammonia (19 wt%, ton):	0	3.50	$300	$0	$325,533	$0.07
SCR Catalyst (ft³):	5,649	3.10	$150	$847,299	$144,041	$0.03
CO_2 Capture System Chemicals[A]:	Proprietary				$1,969,571	$0.41
Triethylene Glycol (gal):	w/equip.	442	$6.80	$0	$931,690	$0.20
Subtotal:				**$847,299**	**$6,901,483**	**$1.45**
Waste Disposal						
SCR Catalyst (ft³):	0	3.10	$2.50	$0	$2,401	$0.00
Triethylene Glycol (gal):	0	442	$0.35	$0	$47,955	$0.01
Thermal Reclaimer Unit Waste (ton):	0	1.751	$38.0	$0	$20,643	$0.00
Subtotal:				**$0**	**$70,998**	**$0.01**
Variable Operating Costs Total:				**$847,299**	**$19,726,739**	**$4.14**
Fuel Cost						
Natural Gas (MMBtu):	0	110,955	$4.42	$0	$152,160,133	$31.90
Total:				**$0**	**$152,160,133**	**$31.90**

[A]CO_2 Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit B-4. B31A-BR.95 capital costs

Case:		B31A-BR.95	– 2x1 CT NGCC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		636					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
	3					**Feedwater & Miscellaneous BOP Systems**					
3.1	Feedwater System	$1	$2	$1	$0	$4	$1	$0	$1	$5	$0
3.2	Water Makeup & Pretreating	$1,363	$136	$773	$0	$2,272	$454	$0	$545	$3,272	$5
3.3	Other Feedwater Subsystems	$1	$0	$0	$0	$1	$0	$0	$0	$1	$0
3.4	Service Water Systems	$414	$790	$2,557	$0	$3,761	$752	$0	$903	$5,416	$9
3.7	Waste Water Treatment Equipment	$4,045	$0	$2,479	$0	$6,524	$1,305	$0	$1,566	$9,395	$15
	Subtotal	**$5,824**	**$928**	**$5,810**	**$0**	**$12,562**	**$2,512**	**$0**	**$3,015**	**$18,089**	**$28**
	5					**Flue Gas Cleanup**					
5.1	CANSOLV Carbon Dioxide (CO_2) Removal System	$106,145	$49,875	$104,737	$0	$260,757	$52,151	$46,936	$71,969	$431,813	$679
5.4	Carbon Dioxide (CO_2) Compression & Drying	$27,597	$4,140	$11,449	$0	$43,186	$8,637	$0	$10,365	$62,188	$98
5.5	Carbon Dioxide (CO_2) Compressor Aftercooler	$235	$37	$101	$0	$372	$74	$0	$89	$536	$1
5.12	Gas Cleanup Foundations	$0	$399	$431	$0	$830	$166	$0	$199	$1,195	$2
	Subtotal	**$133,977**	**$54,451**	**$116,717**	**$0**	**$305,145**	**$61,029**	**$46,936**	**$82,622**	**$495,733**	**$780**
	8					**Steam Turbine & Accessories**					
8.4	Steam Piping	$5,481	$0	$2,221	$0	$7,703	$1,541	$0	$1,387	$10,630	$17
	Subtotal	**$5,481**	**$0**	**$2,221**	**$0**	**$7,703**	**$1,541**	**$0**	**$1,387**	**$10,630**	**$17**
	9					**Cooling Water System**					
9.1	Cooling Towers	$2,996	$0	$889	$0	$3,885	$777	$0	$699	$5,361	$8
9.2	Circulating Water Pumps	$396	$0	$27	$0	$423	$85	$0	$76	$584	$1
9.3	Circulating Water System Auxiliaries	$1,953	$0	$258	$0	$2,211	$442	$0	$398	$3,051	$5
9.4	Circulating Water Piping	$0	$696	$630	$0	$1,326	$265	$0	$239	$1,830	$3
9.5	Make-up Water System	$56	$0	$72	$0	$128	$26	$0	$23	$177	$0
9.6	Component Cooling Water System	$103	$0	$79	$0	$181	$36	$0	$33	$250	$0
9.7	Circulating Water System Foundations	$0	$161	$267	$0	$428	$86	$0	$103	$617	$1
	Subtotal	**$5,503**	**$857**	**$2,222**	**$0**	**$8,582**	**$1,716**	**$0**	**$1,570**	**$11,869**	**$19**
	11					**Accessory Electric Plant**					
11.2	Station Service Equipment	$3,784	$0	$325	$0	$4,108	$822	$0	$740	$5,670	$9
11.3	Switchgear & Motor Control	$5,403	$0	$937	$0	$6,340	$1,268	$0	$1,141	$8,749	$14
11.4	Conduit & Cable Tray	$0	$1,306	$3,762	$0	$5,068	$1,014	$0	$912	$6,994	$11
11.5	Wire & Cable	$0	$1,949	$3,484	$0	$5,433	$1,087	$0	$978	$7,497	$12
11.6	Protective Equipment	$326	$0	$1,132	$0	$1,458	$292	$0	$262	$2,012	$3
	Subtotal	**$9,512**	**$3,255**	**$9,640**	**$0**	**$22,407**	**$4,481**	**$0**	**$4,033**	**$30,922**	**$49**
	12					**Instrumentation & Control**					
12.1	Natural Gas Combined Cycle Control Equipment	$38	$0	$24	$0	$62	$12	$0	$11	$85	$0

Case:		B31A-BR.95	– 2x1 CT NGCC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		636					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
12.3	Steam Turbine Control Equipment	$60	$0	$39	$0	$99	$20	$0	$18	$136	$0
12.4	Other Major Component Control Equipment	$103	$0	$66	$0	$169	$34	$8	$32	$243	$0
12.5	Signal Processing Equipment	$84	$0	$3	$0	$87	$17	$0	$16	$120	$0
12.6	Control Boards, Panels & Racks	$22	$0	$14	$0	$36	$7	$2	$7	$52	$0
12.7	Distributed Control System Equipment	$1,265	$0	$40	$0	$1,305	$261	$65	$245	$1,876	$3
12.8	Instrument Wiring & Tubing	$105	$84	$335	$0	$523	$105	$26	$98	$751	$1
12.9	Other Instrumentation & Controls Equipment	$73	$0	$168	$0	$240	$48	$12	$45	$345	$1
	Subtotal	**$1,750**	**$84**	**$687**	**$0**	**$2,520**	**$504**	**$114**	**$471**	**$3,609**	**$6**
	13					**Improvements to Site**					
13.1	Site Preparation	$0	$18	$377	$0	$395	$79	$0	$95	$569	$1
13.2	Site Improvements	$0	$56	$76	$0	$133	$27	$0	$32	$191	$0
13.3	Site Facilities	$55	$0	$58	$0	$112	$22	$0	$27	$162	$0
	Subtotal	**$55**	**$74**	**$512**	**$0**	**$640**	**$128**	**$0**	**$154**	**$922**	**$1**
	14					**Buildings & Structures**					
14.5	Circulation Water Pumphouse	$0	$24	$12	$0	$36	$7	$0	$6	$50	$0
14.6	Water Treatment Buildings	$0	$102	$92	$0	$194	$39	$0	$35	$268	$0
	Subtotal	**$0**	**$126**	**$104**	**$0**	**$230**	**$46**	**$0**	**$41**	**$318**	**$0**
	Pre-Retrofit Difficulty Factor Total	**$162,103**	**$59,774**	**$137,914**	**$0**	**$359,790**	**$71,958**	**$47,050**	**$93,293**	**$572,091**	**$900**
	Retrofit Adjusted Total									**$623,579**	**$981**

Exhibit B-5. B31A-BR.95 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$3,083	$5
1 Month Maintenance Materials	$639	$1
1 Month Non-fuel Consumables	$422	$1
1 Month Waste Disposal	$7	$0
25% of 1 Months Fuel Cost at 100% CF	$0	$0
2% of TPC	$12,472	$20
Total	**$16,623**	**$26**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$711	$1
0.5% of TPC (spare parts)	$3,118	$5
Total	**$3,829**	**$6**
Other Costs		
Initial Cost for Catalyst and Chemicals	$0	$0
Land	$0	$0
Other Owner's Costs	$93,537	$147
Financing Costs	$16,837	$26
Total Overnight Costs (TOC)	**$754,405**	**$1,186**
TASC Multiplier (IOU, 33 year)	1.093	
Total As-Spent Cost (TASC)	**$824,298**	**$1,296**

Exhibit B-6. B31A-BR.95 O&M costs

Case:	**B31A-BR.95**	**– 2x1 CT NGCC w/ CO_2 Capture**			**Cost Base:**	**Dec 2018**
Plant Size (MW, net):	**636**	**Heat Rate-net (Btu/kWh):**		**7,270**	**Capacity Factor (%):**	**85**
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:	1.0	
Operating Labor Burden:		30.00	**% of base**	Operator:	3.3	
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	**6.3**	
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$2,776,628	$4.37
Maintenance Labor:					$8,657,045	$13.61
Administrative & Support Labor:					$2,858,418	$4.50
Property Taxes and Insurance:					$22,781,697	$35.83
Total:					**$37,073,788**	**$58.30**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$12,985,567	$2.74
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	3,216	$1.90	$0	$1,908,434	$0.40
Makeup and Waste Water Treatment Chemicals (ton):	0	9.6	$550	$0	$1,645,645	$0.35
Ammonia (19 wt%, ton):	0	3.50	$300	$0	$325,651	$0.07
SCR Catalyst (ft^3):	5,649	3.10	$150	$847,299	$144,041	$0.03
CO_2 Capture System Chemicals[A]:	Proprietary				$2,055,608	$0.43
Triethylene Glycol (gal):	w/equip.	442	$6.80	$0	$983,451	$0.21
Subtotal:				**$847,299**	**$7,062,830**	**$1.49**
Waste Disposal						
SCR Catalyst (ft^3):	0	3.10	$2.50	$0	$2,401	$0.00
Triethylene Glycol (gal):	0	442	$0.35	$0	$50,619	$0.01
Thermal Reclaimer Unit Waste (ton):	0	1.751	$38.0	$0	$21,582	$0.00
Subtotal:				**$0**	**$74,602**	**$0.02**
Variable Operating Costs Total:				**$847,299**	**$20,123,000**	**$4.25**
Fuel Cost						
Natural Gas (MMBtu):	0	110,955	$4.42	$0	$152,160,133	$32.14
Total:				**$0**	**$152,160,133**	**$32.14**

[A]CO_2 Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit B-7. B31A-BR.97 capital costs

Case:		B31A-BR.97	– 2x1 CT NGCC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		632					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
	3					Feedwater & Miscellaneous BOP Systems					
3.1	Feedwater System	$1	$2	$1	$0	$4	$1	$0	$1	$5	$0
3.2	Water Makeup & Pretreating	$1,383	$138	$784	$0	$2,305	$461	$0	$553	$3,319	$5
3.3	Other Feedwater Subsystems	$1	$0	$0	$0	$1	$0	$0	$0	$1	$0
3.4	Service Water Systems	$420	$801	$2,594	$0	$3,815	$763	$0	$916	$5,493	$9
3.7	Waste Water Treatment Equipment	$3,944	$0	$2,417	$0	$6,361	$1,272	$0	$1,527	$9,160	$14
	Subtotal	**$5,748**	**$942**	**$5,796**	**$0**	**$12,486**	**$2,497**	**$0**	**$2,996**	**$17,980**	**$28**
	5					Flue Gas Cleanup					
5.1	CANSOLV Carbon Dioxide (CO_2) Removal System	$108,714	$51,104	$107,319	$0	$267,137	$53,427	$48,085	$73,730	$442,378	$700
5.4	Carbon Dioxide (CO_2) Compression & Drying	$27,829	$4,175	$11,545	$0	$43,549	$8,710	$0	$10,452	$62,711	$99
5.5	Carbon Dioxide (CO_2) Compressor Aftercooler	$239	$38	$102	$0	$379	$76	$0	$91	$546	$1
5.12	Gas Cleanup Foundations	$0	$405	$438	$0	$844	$169	$0	$202	$1,215	$2
	Subtotal	**$136,782**	**$55,722**	**$119,404**	**$0**	**$311,908**	**$62,382**	**$48,085**	**$84,475**	**$506,850**	**$802**
	8					Steam Turbine & Accessories					
8.4	Steam Piping	$5,663	$0	$2,295	$0	$7,958	$1,592	$0	$1,432	$10,981	$17
	Subtotal	**$5,663**	**$0**	**$2,295**	**$0**	**$7,958**	**$1,592**	**$0**	**$1,432**	**$10,981**	**$17**
	9					Cooling Water System					
9.1	Cooling Towers	$3,039	$0	$902	$0	$3,940	$788	$0	$709	$5,438	$9
9.2	Circulating Water Pumps	$402	$0	$27	$0	$429	$86	$0	$77	$592	$1
9.3	Circulating Water System Auxiliaries	$1,979	$0	$261	$0	$2,240	$448	$0	$403	$3,091	$5
9.4	Circulating Water Piping	$0	$705	$639	$0	$1,344	$269	$0	$242	$1,855	$3
9.5	Make-up Water System	$57	$0	$73	$0	$130	$26	$0	$23	$180	$0
9.6	Component Cooling Water System	$104	$0	$80	$0	$184	$37	$0	$33	$254	$0
9.7	Circulating Water System Foundations	$0	$163	$271	$0	$434	$87	$0	$104	$625	$1
	Subtotal	**$5,580**	**$868**	**$2,253**	**$0**	**$8,701**	**$1,740**	**$0**	**$1,592**	**$12,034**	**$19**
	11					Accessory Electric Plant					
11.2	Station Service Equipment	$3,890	$0	$334	$0	$4,224	$845	$0	$760	$5,828	$9
11.3	Switchgear & Motor Control	$5,554	$0	$964	$0	$6,518	$1,304	$0	$1,173	$8,994	$14
11.4	Conduit & Cable Tray	$0	$1,342	$3,868	$0	$5,210	$1,042	$0	$938	$7,190	$11
11.5	Wire & Cable	$0	$2,004	$3,581	$0	$5,585	$1,117	$0	$1,005	$7,707	$12
11.6	Protective Equipment	$338	$0	$1,173	$0	$1,510	$302	$0	$272	$2,084	$3
	Subtotal	**$9,781**	**$3,346**	**$9,919**	**$0**	**$23,046**	**$4,609**	**$0**	**$4,148**	**$31,804**	**$50**
	12					Instrumentation & Control					
12.1	Natural Gas Combined Cycle Control Equipment	$38	$0	$25	$0	$63	$13	$0	$11	$87	$0

Case:		B31A-BR.97	– 2x1 CT NGCC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		632					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
12.3	Steam Turbine Control Equipment	$61	$0	$39	$0	$101	$20	$0	$18	$139	$0
12.4	Other Major Component Control Equipment	$106	$0	$68	$0	$173	$35	$9	$33	$249	$0
12.5	Signal Processing Equipment	$86	$0	$3	$0	$89	$18	$0	$16	$122	$0
12.6	Control Boards, Panels & Racks	$23	$0	$14	$0	$37	$7	$2	$7	$53	$0
12.7	Distributed Control System Equipment	$1,297	$0	$41	$0	$1,337	$267	$67	$251	$1,923	$3
12.8	Instrument Wiring & Tubing	$107	$86	$343	$0	$536	$107	$27	$100	$770	$1
12.9	Other Instrumentation & Controls Equipment	$74	$0	$172	$0	$246	$49	$12	$46	$354	$1
	Subtotal	**$1,793**	**$86**	**$704**	**$0**	**$2,582**	**$516**	**$116**	**$482**	**$3,697**	**$6**
13	**Improvements to Site**										
13.1	Site Preparation	$0	$17	$359	$0	$376	$75	$0	$90	$542	$1
13.2	Site Improvements	$0	$54	$73	$0	$126	$25	$0	$30	$182	$0
13.3	Site Facilities	$52	$0	$55	$0	$107	$21	$0	$26	$154	$0
	Subtotal	**$52**	**$70**	**$487**	**$0**	**$610**	**$122**	**$0**	**$146**	**$878**	**$1**
14	**Buildings & Structures**										
14.5	Circulation Water Pumphouse	$0	$24	$12	$0	$37	$7	$0	$7	$50	$0
14.6	Water Treatment Buildings	$0	$103	$94	$0	$197	$39	$0	$35	$272	$0
	Subtotal	**$0**	**$128**	**$106**	**$0**	**$233**	**$47**	**$0**	**$42**	**$322**	**$1**
	Pre-Retrofit Difficulty Factor Total	**$165,399**	**$61,162**	**$140,964**	**$0**	**$367,524**	**$73,505**	**$48,201**	**$95,315**	**$584,545**	**$925**
	Retrofit Adjusted Total									**$637,154**	**$1,008**

Exhibit B-8. B31A-BR.97 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$3,142	$5
1 Month Maintenance Materials	$653	$1
1 Month Non-fuel Consumables	$434	$1
1 Month Waste Disposal	$8	$0
25% of 1 Months Fuel Cost at 100% CF	$0	$0
2% of TPC	$12,743	$20
Total	**$16,980**	**$27**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$734	$1
0.5% of TPC (spare parts)	$3,186	$5
Total	**$3,920**	**$6**
Other Costs		
Initial Cost for Catalyst and Chemicals	$0	$0
Land	$0	$0
Other Owner's Costs	$95,573	$151
Financing Costs	$17,203	$27
Total Overnight Costs (TOC)	**$770,830**	**$1,219**
TASC Multiplier (IOU, 33 year)	1.093	
Total As-Spent Cost (TASC)	**$842,245**	**$1,332**

Exhibit B-9. B31A-BR.97 O&M costs

Case:	**B31A-BR.97**	**– 2x1 CT NGCC w/ CO_2 Capture**			**Cost Base:**	**Dec 2018**
Plant Size (MW, net):	**632**	**Heat Rate-net (Btu/kWh):**		**7,313**	**Capacity Factor (%):**	**85**
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:		1.0
Operating Labor Burden:		30.00	**% of base**	Operator:		3.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		1.0
				Total:		**6.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$2,776,628	$4.39
Maintenance Labor:					$8,751,694	$13.84
Administrative & Support Labor:					$2,882,080	$4.56
Property Taxes and Insurance:					$23,030,773	$36.43
Total:					**$37,441,175**	**$59.23**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$13,127,541	$2.79
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	3,216	$1.90	$0	$1,918,423	$0.41
Makeup and Waste Water Treatment Chemicals (ton):	0	9.6	$550	$0	$1,654,259	$0.35
Ammonia (19 wt%, ton):	0	3.50	$300	$0	$325,528	$0.07
SCR Catalyst (ft^3):	5,649	3.10	$150	$847,299	$144,041	$0.03
CO_2 Capture System Chemicals[A]:	Proprietary				$2,142,137	$0.46
Triethylene Glycol (gal):	w/equip.	442	$6.80	$0	$1,004,155	$0.21
Subtotal:				**$847,299**	**$7,188,542**	**$1.53**
Waste Disposal						
SCR Catalyst (ft^3):	0	3.10	$2.50	$0	$2,401	$0.00
Triethylene Glycol (gal):	0	442	$0.35	$0	$51,684	$0.01
Thermal Reclaimer Unit Waste (ton):	0	1.751	$38.0	$0	$22,520	$0.00
Subtotal:				**$0**	**$76,605**	**$0.02**
Variable Operating Costs Total:				**$847,299**	**$20,392,688**	**$4.33**
Fuel Cost						
Natural Gas (MMBtu):	0	110,955	$4.42	$0	$152,160,133	$32.33
Total:				**$0**	**$152,160,133**	**$32.33**

[A]CO_2 Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit B-10. B32A-BR.90 capital costs

Case:		B32A-BR.90	– 2x1 CT NGCC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		878					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
	3	Feedwater & Miscellaneous BOP Systems									
3.1	Feedwater System	$1	$2	$1	$0	$5	$1	$0	$1	$7	$0
3.2	Water Makeup & Pretreating	$1,673	$167	$948	$0	$2,789	$558	$0	$669	$4,016	$5
3.3	Other Feedwater Subsystems	$1	$0	$0	$0	$1	$0	$0	$0	$2	$0
3.4	Service Water Systems	$508	$969	$3,139	$0	$4,616	$923	$0	$1,108	$6,648	$8
3.7	Waste Water Treatment Equipment	$4,942	$0	$3,029	$0	$7,972	$1,594	$0	$1,913	$11,479	$13
	Subtotal	**$7,126**	**$1,140**	**$7,118**	**$0**	**$15,384**	**$3,077**	**$0**	**$3,692**	**$22,152**	**$25**
	5	Flue Gas Cleanup									
5.1	CANSOLV Carbon Dioxide (CO_2) Removal System	$122,385	$57,227	$120,178	$0	$299,790	$59,958	$53,962	$82,742	$496,452	$565
5.4	Carbon Dioxide (CO_2) Compression & Drying	$30,338	$4,551	$12,586	$0	$47,475	$9,495	$0	$11,394	$68,364	$78
5.5	Carbon Dioxide (CO_2) Compressor Aftercooler	$284	$45	$122	$0	$451	$90	$0	$108	$649	$1
5.12	Gas Cleanup Foundations	$0	$479	$517	$0	$996	$199	$0	$239	$1,434	$2
	Subtotal	**$153,007**	**$62,302**	**$133,403**	**$0**	**$348,712**	**$69,742**	**$53,962**	**$94,483**	**$566,900**	**$646**
	8	Steam Turbine & Accessories									
8.4	Steam Piping	$6,503	$0	$2,635	$0	$9,138	$1,828	$0	$1,645	$12,611	$14
	Subtotal	**$6,503**	**$0**	**$2,635**	**$0**	**$9,138**	**$1,828**	**$0**	**$1,645**	**$12,611**	**$14**
	9	Cooling Water System									
9.1	Cooling Towers	$3,677	$0	$1,092	$0	$4,768	$954	$0	$858	$6,580	$7
9.2	Circulating Water Pumps	$485	$0	$33	$0	$517	$103	$0	$93	$714	$1
9.3	Circulating Water System Auxiliaries	$2,267	$0	$299	$0	$2,566	$513	$0	$462	$3,541	$4
9.4	Circulating Water Piping	$0	$828	$750	$0	$1,578	$316	$0	$284	$2,178	$2
9.5	Make-up Water System	$64	$0	$82	$0	$146	$29	$0	$26	$202	$0
9.6	Component Cooling Water System	$122	$0	$94	$0	$216	$43	$0	$39	$298	$0
9.7	Circulating Water System Foundations	$0	$192	$318	$0	$510	$102	$0	$122	$734	$1
	Subtotal	**$6,614**	**$1,020**	**$2,668**	**$0**	**$10,302**	**$2,060**	**$0**	**$1,885**	**$14,247**	**$16**
	11	Accessory Electric Plant									
11.2	Station Service Equipment	$4,391	$0	$377	$0	$4,768	$954	$0	$858	$6,580	$7
11.3	Switchgear & Motor Control	$6,270	$0	$1,088	$0	$7,358	$1,472	$0	$1,324	$10,154	$12
11.4	Conduit & Cable Tray	$0	$1,515	$4,367	$0	$5,882	$1,176	$0	$1,059	$8,117	$9
11.5	Wire & Cable	$0	$2,262	$4,043	$0	$6,305	$1,261	$0	$1,135	$8,701	$10
11.6	Protective Equipment	$420	$0	$1,457	$0	$1,877	$375	$0	$338	$2,590	$3
	Subtotal	**$11,081**	**$3,777**	**$11,332**	**$0**	**$26,190**	**$5,238**	**$0**	**$4,714**	**$36,143**	**$41**
	12	Instrumentation & Control									
12.1	Natural Gas Combined Cycle Control Equipment	$39	$0	$25	$0	$64	$13	$0	$11	$88	$0

Case:		B32A-BR.90	– 2x1 CT NGCC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		878					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
12.3	Steam Turbine Control Equipment	$62	$0	$40	$0	$102	$20	$0	$18	$141	$0
12.4	Other Major Component Control Equipment	$108	$0	$69	$0	$176	$35	$9	$33	$254	$0
12.5	Signal Processing Equipment	$87	$0	$3	$0	$90	$18	$0	$16	$124	$0
12.6	Control Boards, Panels & Racks	$23	$0	$14	$0	$38	$8	$2	$7	$54	$0
12.7	Distributed Control System Equipment	$1,319	$0	$41	$0	$1,361	$272	$68	$255	$1,956	$2
12.8	Instrument Wiring & Tubing	$109	$87	$349	$0	$545	$109	$27	$102	$784	$1
12.9	Other Instrumentation & Controls Equipment	$76	$0	$175	$0	$250	$50	$13	$47	$360	$0
	Subtotal	**$1,823**	**$87**	**$716**	**$0**	**$2,626**	**$525**	**$119**	**$490**	**$3,760**	**$4**
	13					**Improvements to Site**					
13.1	Site Preparation	$0	$22	$469	$0	$491	$98	$0	$118	$706	$1
13.2	Site Improvements	$0	$70	$95	$0	$165	$33	$0	$40	$237	$0
13.3	Site Facilities	$68	$0	$72	$0	$140	$28	$0	$33	$201	$0
	Subtotal	**$68**	**$92**	**$635**	**$0**	**$795**	**$159**	**$0**	**$191**	**$1,145**	**$1**
	14					**Buildings & Structures**					
14.5	Circulation Water Pumphouse	$0	$30	$15	$0	$45	$9	$0	$8	$62	$0
14.6	Water Treatment Buildings	$0	$123	$112	$0	$235	$47	$0	$42	$324	$0
	Subtotal	**$0**	**$153**	**$127**	**$0**	**$280**	**$56**	**$0**	**$50**	**$386**	**$0**
	Pre-Retrofit Difficulty Factor Total	**$186,222**	**$68,571**	**$158,633**	**$0**	**$413,426**	**$82,685**	**$54,081**	**$107,151**	**$657,343**	**$749**
	Retrofit Adjusted Total									**$716,504**	**$816**

Exhibit B-11. B32A-BR.90 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$3,488	$4
1 Month Maintenance Materials	$735	$1
1 Month Non-fuel Consumables	$540	$1
1 Month Waste Disposal	$9	$0
25% of 1 Months Fuel Cost at 100% CF	$0	$0
2% of TPC	$14,330	$16
Total	**$19,102**	**$22**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$907	$1
0.5% of TPC (spare parts)	$3,583	$4
Total	**$4,489**	**$5**
Other Costs		
Initial Cost for Catalyst and Chemicals	$0	$0
Land	$0	$0
Other Owner's Costs	$107,476	$122
Financing Costs	$19,346	$22
Total Overnight Costs (TOC)	**$866,916**	**$987**
TASC Multiplier (IOU, 33 year)	1.093	
Total As-Spent Cost (TASC)	**$947,233**	**$1,079**

Exhibit B-12. B32A-BR.90 O&M costs

Case:	B32A-BR.90	– 2x1 CT NGCC w/ CO_2 Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	**878**	**Heat Rate-net (Btu/kWh):**		**7,001**	**Capacity Factor (%):**	**85**
			Operating & Maintenance Labor			
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:		1.0
Operating Labor Burden:		30.00	**% of base**	Operator:		3.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		1.0
				Total:		**6.3**
			Fixed Operating Costs			
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$2,776,628	$3.16
Maintenance Labor:					$10,999,957	$12.53
Administrative & Support Labor:					$3,444,146	$3.92
Property Taxes and Insurance:					$28,947,255	$32.97
Total:					**$46,167,986**	**$52.58**
			Variable Operating Costs			
					($)	**($/MWh-net)**
Maintenance Material:					$16,499,935	$2.52
			Consumables			
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	3,216	$1.90	$0	$2,416,896	$0.37
Makeup and Waste Water Treatment Chemicals (ton):	0	9.6	$550	$0	$2,084,093	$0.32
Ammonia (19 wt%, ton):	0	3.50	$300	$0	$432,821	$0.07
SCR Catalyst (ft^3):	5,649	3.10	$150	$1,129,110	$191,949	$0.03
CO_2 Capture System Chemicals[A]:			Proprietary		$2,619,004	$0.40
Triethylene Glycol (gal):	w/equip.	442	$6.80	$0	$1,238,900	$0.19
Subtotal:				**$1,129,110**	**$8,983,662**	**$1.37**
			Waste Disposal			
SCR Catalyst (ft^3):	0	3.10	$2.50	$0	$3,199	$0.00
Triethylene Glycol (gal):	0	442	$0.35	$0	$63,767	$0.01
Thermal Reclaimer Unit Waste (ton):	0	1.751	$38.0	$0	$27,450	$0.00
Subtotal:				**$0**	**$94,416**	**$0.01**
Variable Operating Costs Total:				**$1,129,110**	**$25,578,014**	**$3.91**
			Fuel Cost			
Natural Gas (MMBtu):	0	110,955	$4.42	$0	$202,328,910	$30.95
Total:				$0	**$202,328,910**	**$30.95**

[A]CO_2 Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit B-13. B32A-BR.95 capital costs

Case:		B32A-BR.95	– 2x1 CT NGCC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		872					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
	3	Feedwater & Miscellaneous BOP Systems									
3.1	Feedwater System	$1	$2	$1	$0	$5	$1	$0	$1	$7	$0
3.2	Water Makeup & Pretreating	$1,704	$170	$966	$0	$2,840	$568	$0	$682	$4,090	$5
3.3	Other Feedwater Subsystems	$1	$0	$0	$0	$1	$0	$0	$0	$2	$0
3.4	Service Water Systems	$517	$987	$3,197	$0	$4,701	$940	$0	$1,128	$6,770	$8
3.7	Waste Water Treatment Equipment	$5,011	$0	$3,071	$0	$8,082	$1,616	$0	$1,940	$11,638	$13
	Subtotal	**$7,234**	**$1,160**	**$7,235**	**$0**	**$15,630**	**$3,126**	**$0**	**$3,751**	**$22,507**	**$26**
	5	Flue Gas Cleanup									
5.1	CANSOLV Carbon Dioxide (CO_2) Removal System	$127,873	$59,335	$124,603	$0	$311,812	$62,362	$56,126	$86,060	$516,360	$592
5.4	Carbon Dioxide (CO_2) Compression & Drying	$31,017	$4,653	$12,868	$0	$48,537	$9,707	$0	$11,649	$69,893	$80
5.5	Carbon Dioxide (CO_2) Compressor Aftercooler	$297	$47	$127	$0	$472	$94	$0	$113	$679	$1
5.12	Gas Cleanup Foundations	$0	$500	$540	$0	$1,039	$208	$0	$249	$1,497	$2
	Subtotal	**$159,187**	**$64,534**	**$138,138**	**$0**	**$361,860**	**$72,372**	**$56,126**	**$98,072**	**$588,429**	**$675**
	8	Steam Turbine & Accessories									
8.4	Steam Piping	$6,754	$0	$2,737	$0	$9,490	$1,898	$0	$1,708	$13,097	$15
	Subtotal	**$6,754**	**$0**	**$2,737**	**$0**	**$9,490**	**$1,898**	**$0**	**$1,708**	**$13,097**	**$15**
	9	Cooling Water System									
9.1	Cooling Towers	$3,744	$0	$1,112	$0	$4,856	$971	$0	$874	$6,701	$8
9.2	Circulating Water Pumps	$493	$0	$33	$0	$527	$105	$0	$95	$727	$1
9.3	Circulating Water System Auxiliaries	$2,305	$0	$304	$0	$2,610	$522	$0	$470	$3,601	$4
9.4	Circulating Water Piping	$0	$843	$763	$0	$1,606	$321	$0	$289	$2,216	$3
9.5	Make-up Water System	$65	$0	$84	$0	$149	$30	$0	$27	$205	$0
9.6	Component Cooling Water System	$124	$0	$95	$0	$220	$44	$0	$40	$303	$0
9.7	Circulating Water System Foundations	$0	$195	$324	$0	$519	$104	$0	$124	$747	$1
	Subtotal	**$6,732**	**$1,037**	**$2,715**	**$0**	**$10,484**	**$2,097**	**$0**	**$1,918**	**$14,500**	**$17**
	11	Accessory Electric Plant									
11.2	Station Service Equipment	$4,597	$0	$394	$0	$4,992	$998	$0	$899	$6,889	$8
11.3	Switchgear & Motor Control	$6,564	$0	$1,139	$0	$7,703	$1,541	$0	$1,387	$10,630	$12
11.4	Conduit & Cable Tray	$0	$1,586	$4,571	$0	$6,158	$1,232	$0	$1,108	$8,497	$10
11.5	Wire & Cable	$0	$2,368	$4,233	$0	$6,601	$1,320	$0	$1,188	$9,109	$10
11.6	Protective Equipment	$445	$0	$1,545	$0	$1,990	$398	$0	$358	$2,747	$3
	Subtotal	**$11,606**	**$3,954**	**$11,883**	**$0**	**$27,444**	**$5,489**	**$0**	**$4,940**	**$37,872**	**$43**
	12	Instrumentation & Control									
12.1	Natural Gas Combined Cycle Control Equipment	$40	$0	$26	$0	$66	$13	$0	$12	$91	$0

Case:		B32A-BR.95	– 2x1 CT NGCC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		872					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
12.3	Steam Turbine Control Equipment	$64	$0	$41	$0	$106	$21	$0	$19	$146	$0
12.4	Other Major Component Control Equipment	$112	$0	$72	$0	$184	$37	$9	$34	$264	$0
12.5	Signal Processing Equipment	$90	$0	$3	$0	$93	$19	$0	$17	$128	$0
12.6	Control Boards, Panels & Racks	$24	$0	$15	$0	$39	$8	$2	$7	$57	$0
12.7	Distributed Control System Equipment	$1,374	$0	$43	$0	$1,417	$283	$71	$266	$2,037	$2
12.8	Instrument Wiring & Tubing	$114	$91	$363	$0	$568	$114	$28	$106	$816	$1
12.9	Other Instrumentation & Controls Equipment	$79	$0	$182	$0	$261	$52	$13	$49	$375	$0
	Subtotal	**$1,897**	**$91**	**$745**	**$0**	**$2,733**	**$547**	**$123**	**$510**	**$3,913**	**$4**
	13					**Improvements to Site**					
13.1	Site Preparation	$0	$21	$445	$0	$466	$93	$0	$112	$671	$1
13.2	Site Improvements	$0	$66	$90	$0	$157	$31	$0	$38	$225	$0
13.3	Site Facilities	$65	$0	$68	$0	$133	$27	$0	$32	$191	$0
	Subtotal	**$65**	**$87**	**$604**	**$0**	**$755**	**$151**	**$0**	**$181**	**$1,088**	**$1**
	14					**Buildings & Structures**					
14.5	Circulation Water Pumphouse	$0	$31	$15	$0	$46	$9	$0	$8	$63	$0
14.6	Water Treatment Buildings	$0	$125	$114	$0	$239	$48	$0	$43	$330	$0
	Subtotal	**$0**	**$156**	**$129**	**$0**	**$285**	**$57**	**$0**	**$51**	**$393**	**$0**
	Pre-Retrofit Difficulty Factor Total	**$193,475**	**$71,021**	**$164,186**	**$0**	**$428,681**	**$85,736**	**$56,250**	**$111,132**	**$681,799**	**$782**
	Retrofit Adjusted Total									**$743,161**	**$852**

Exhibit B-14. B32A-BR.95 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$3,604	$4
1 Month Maintenance Materials	$762	$1
1 Month Non-fuel Consumables	$561	$1
1 Month Waste Disposal	$10	$0
25% of 1 Months Fuel Cost at 100% CF	$0	$0
2% of TPC	$14,863	$17
Total	**$19,800**	**$23**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$945	$1
0.5% of TPC (spare parts)	$3,716	$4
Total	**$4,661**	**$5**
Other Costs		
Initial Cost for Catalyst and Chemicals	$0	$0
Land	$0	$0
Other Owner's Costs	$111,474	$128
Financing Costs	$20,065	$23
Total Overnight Costs (TOC)	**$899,161**	**$1,031**
TASC Multiplier (IOU, 33 year)	1.093	
Total As-Spent Cost (TASC)	**$982,466**	**$1,127**

Exhibit B-15. B32A-BR.95 O&M costs

Case:	**B32A-BR.95**	**– 2x1 CT NGCC w/ CO_2 Capture**			**Cost Base:**	**Dec 2018**
Plant Size (MW, net):	**872**	**Heat Rate-net (Btu/kWh):**		**7,051**	**Capacity Factor (%):**	**85**
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:	1.0	
Operating Labor Burden:		30.00	**% of base**	Operator:	3.3	
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	**6.3**	
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$2,776,628	$3.18
Maintenance Labor:					$11,185,819	$12.83
Administrative & Support Labor:					$3,490,612	$4.00
Property Taxes and Insurance:					$29,436,367	$33.76
Total:					**$46,889,426**	**$53.78**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$16,778,729	$2.58
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	3,216	$1.90	$0	$2,433,611	$0.37
Makeup and Waste Water Treatment Chemicals (ton):	0	9.6	$550	$0	$2,098,506	$0.32
Ammonia (19 wt%, ton):	0	3.50	$300	$0	$432,979	$0.07
SCR Catalyst (ft^3):	5,649	3.10	$150	$1,129,110	$191,949	$0.03
CO_2 Capture System Chemicals[A]:	Proprietary				$2,733,410	$0.42
Triethylene Glycol (gal):	w/equip.	442	$6.80	$0	$1,307,727	$0.20
Subtotal:				**$1,129,110**	**$9,198,183**	**$1.42**
Waste Disposal						
SCR Catalyst (ft^3):	0	3.10	$2.50	$0	$3,199	$0.00
Triethylene Glycol (gal):	0	442	$0.35	$0	$67,310	$0.01
Thermal Reclaimer Unit Waste (ton):	0	1.751	$38.0	$0	$28,699	$0.00
Subtotal:				**$0**	**$99,207**	**$0.02**
Variable Operating Costs Total:				**$1,129,110**	**$26,076,120**	**$4.02**
Fuel Cost						
Natural Gas (MMBtu):	0	110,955	$4.42	$0	$202,328,910	$31.17
Total:				$0	**$202,328,910**	**$31.17**

[A]CO_2 Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit B-16. B32A-BR.97 capital costs

Case:		B32A-BR.97	– 2x1 CT NGCC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		867					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
	3					**Feedwater & Miscellaneous BOP Systems**					
3.1	Feedwater System	$1	$2	$1	$0	$5	$1	$0	$1	$7	$0
3.2	Water Makeup & Pretreating	$1,728	$173	$979	$0	$2,881	$576	$0	$691	$4,148	$5
3.3	Other Feedwater Subsystems	$1	$0	$0	$0	$1	$0	$0	$0	$2	$0
3.4	Service Water Systems	$524	$1,001	$3,242	$0	$4,768	$954	$0	$1,144	$6,866	$8
3.7	Waste Water Treatment Equipment	$4,886	$0	$2,995	$0	$7,881	$1,576	$0	$1,891	$11,348	$13
	Subtotal	**$7,141**	**$1,177**	**$7,218**	**$0**	**$15,536**	**$3,107**	**$0**	**$3,728**	**$22,372**	**$26**
	5					**Flue Gas Cleanup**					
5.1	CANSOLV Carbon Dioxide (CO_2) Removal System	$130,962	$60,798	$127,675	$0	$319,434	$63,887	$57,498	$88,164	$528,983	$610
5.4	Carbon Dioxide (CO_2) Compression & Drying	$31,283	$4,693	$12,978	$0	$48,954	$9,791	$0	$11,749	$70,494	$81
5.5	Carbon Dioxide (CO_2) Compressor Aftercooler	$302	$48	$130	$0	$480	$96	$0	$115	$691	$1
5.12	Gas Cleanup Foundations	$0	$508	$549	$0	$1,057	$211	$0	$254	$1,522	$2
	Subtotal	**$162,547**	**$66,046**	**$141,331**	**$0**	**$369,925**	**$73,985**	**$57,498**	**$100,282**	**$601,690**	**$694**
	8					**Steam Turbine & Accessories**					
8.4	Steam Piping	$6,977	$0	$2,827	$0	$9,804	$1,961	$0	$1,765	$13,530	$16
	Subtotal	**$6,977**	**$0**	**$2,827**	**$0**	**$9,804**	**$1,961**	**$0**	**$1,765**	**$13,530**	**$16**
	9					**Cooling Water System**					
9.1	Cooling Towers	$3,797	$0	$1,128	$0	$4,925	$985	$0	$886	$6,796	$8
9.2	Circulating Water Pumps	$500	$0	$34	$0	$534	$107	$0	$96	$737	$1
9.3	Circulating Water System Auxiliaries	$2,336	$0	$308	$0	$2,644	$529	$0	$476	$3,649	$4
9.4	Circulating Water Piping	$0	$854	$773	$0	$1,627	$325	$0	$293	$2,246	$3
9.5	Make-up Water System	$66	$0	$85	$0	$151	$30	$0	$27	$208	$0
9.6	Component Cooling Water System	$126	$0	$97	$0	$222	$44	$0	$40	$307	$0
9.7	Circulating Water System Foundations	$0	$198	$328	$0	$526	$105	$0	$126	$757	$1
	Subtotal	**$6,825**	**$1,051**	**$2,753**	**$0**	**$10,629**	**$2,126**	**$0**	**$1,945**	**$14,700**	**$17**
	11					**Accessory Electric Plant**					
11.2	Station Service Equipment	$4,721	$0	$405	$0	$5,126	$1,025	$0	$923	$7,074	$8
11.3	Switchgear & Motor Control	$6,741	$0	$1,170	$0	$7,911	$1,582	$0	$1,424	$10,917	$13
11.4	Conduit & Cable Tray	$0	$1,629	$4,694	$0	$6,323	$1,265	$0	$1,138	$8,726	$10
11.5	Wire & Cable	$0	$2,432	$4,347	$0	$6,779	$1,356	$0	$1,220	$9,355	$11
11.6	Protective Equipment	$460	$0	$1,599	$0	$2,059	$412	$0	$371	$2,842	$3
	Subtotal	**$11,922**	**$4,061**	**$12,215**	**$0**	**$28,198**	**$5,640**	**$0**	**$5,076**	**$38,914**	**$45**
	12					**Instrumentation & Control**					
12.1	Natural Gas Combined Cycle Control Equipment	$41	$0	$26	$0	$67	$13	$0	$12	$93	$0

Case:		B32A-BR.97	– 2x1 CT NGCC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		867					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
12.3	Steam Turbine Control Equipment	$66	$0	$42	$0	$108	$22	$0	$19	$149	$0
12.4	Other Major Component Control Equipment	$115	$0	$73	$0	$188	$38	$9	$35	$270	$0
12.5	Signal Processing Equipment	$92	$0	$3	$0	$95	$19	$0	$17	$131	$0
12.6	Control Boards, Panels & Racks	$25	$0	$15	$0	$40	$8	$2	$8	$58	$0
12.7	Distributed Control System Equipment	$1,406	$0	$44	$0	$1,450	$290	$73	$272	$2,085	$2
12.8	Instrument Wiring & Tubing	$116	$93	$372	$0	$581	$116	$29	$109	$835	$1
12.9	Other Instrumentation & Controls Equipment	$81	$0	$186	$0	$267	$53	$13	$50	$384	$0
	Subtotal	**$1,941**	**$93**	**$762**	**$0**	**$2,796**	**$559**	**$126**	**$522**	**$4,004**	**$5**
	13					**Improvements to Site**					
13.1	Site Preparation	$0	$20	$424	$0	$444	$89	$0	$107	$639	$1
13.2	Site Improvements	$0	$63	$86	$0	$149	$30	$0	$36	$215	$0
13.3	Site Facilities	$62	$0	$65	$0	$126	$25	$0	$30	$182	$0
	Subtotal	**$62**	**$83**	**$575**	**$0**	**$719**	**$144**	**$0**	**$173**	**$1,036**	**$1**
	14					**Buildings & Structures**					
14.5	Circulation Water Pumphouse	$0	$31	$15	$0	$47	$9	$0	$8	$64	$0
14.6	Water Treatment Buildings	$0	$127	$115	$0	$242	$48	$0	$44	$334	$0
	Subtotal	**$0**	**$158**	**$131**	**$0**	**$289**	**$58**	**$0**	**$52**	**$398**	**$0**
	Pre-Retrofit Difficulty Factor Total	**$197,416**	**$72,669**	**$167,812**	**$0**	**$437,897**	**$87,579**	**$57,625**	**$113,542**	**$696,643**	**$804**
	Retrofit Adjusted Total									**$759,341**	**$876**

Exhibit B-17. B32A-BR.97 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$3,674	$4
1 Month Maintenance Materials	$779	$1
1 Month Non-fuel Consumables	$577	$1
1 Month Waste Disposal	$10	$0
25% of 1 Months Fuel Cost at 100% CF	$0	$0
2% of TPC	$15,187	$18
Total	**$20,227**	**$23**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$976	$1
0.5% of TPC (spare parts)	$3,797	$4
Total	**$4,772**	**$6**
Other Costs		
Initial Cost for Catalyst and Chemicals	$0	$0
Land	$0	$0
Other Owner's Costs	$113,901	$131
Financing Costs	$20,502	$24
Total Overnight Costs (TOC)	**$918,744**	**$1,060**
TASC Multiplier (IOU, 33 year)	1.093	
Total As-Spent Cost (TASC)	**$1,003,863**	**$1,158**

Exhibit B-18. B32A-BR.97 O&M costs

Case:	B32A-BR.97	– 2x1 CT NGCC w/ CO_2 Capture			Cost Base:	Dec 2018
Plant Size (MW, net):	867	Heat Rate-net (Btu/kWh):		7,091	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:		1.0
Operating Labor Burden:		30.00	**% of base**	Operator:		3.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		1.0
				Total:		**6.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$2,776,628	$3.20
Maintenance Labor:					$11,298,639	$13.03
Administrative & Support Labor:					$3,518,817	$4.06
Property Taxes and Insurance:					$29,733,260	$34.30
Total:					**$47,327,343**	**$54.59**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$16,947,958	$2.63
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	3,216	$1.90	$0	$2,446,871	$0.38
Makeup and Waste Water Treatment Chemicals (ton):	0	9.6	$550	$0	$2,109,940	$0.33
Ammonia (19 wt%, ton):	0	3.50	$300	$0	$432,815	$0.07
SCR Catalyst (ft^3):	5,649	3.10	$150	$1,129,110	$191,949	$0.03
CO_2 Capture System Chemicals[A]:	Proprietary				$2,848,471	$0.44
Triethylene Glycol (gal):	w/equip.	442	$6.80	$0	$1,335,259	$0.21
Subtotal:				**$1,129,110**	**$9,365,304**	**$1.45**
Waste Disposal						
SCR Catalyst (ft^3):	0	3.10	$2.50	$0	$3,199	$0.00
Triethylene Glycol (gal):	0	442	$0.35	$0	$68,727	$0.01
Thermal Reclaimer Unit Waste (ton):	0	1.751	$38.0	$0	$29,946	$0.00
Subtotal:				**$0**	**$101,872**	**$0.02**
Variable Operating Costs Total:				**$1,129,110**	**$26,415,133**	**$4.09**
Fuel Cost						
Natural Gas (MMBtu):	0	110,955	$4.42	$0	$202,328,910	$31.34
Total:				**$0**	**$202,328,910**	**$31.34**

[A]CO_2 Capture System Chemicals includes NaOH and CANSOLV Solvent

www.netl.doe.gov

Albany, OR • Anchorage, AK • Morgantown, WV • Pittsburgh, PA • Sugar Land, TX

(800) 553-7681

NATIONAL ENERGY TECHNOLOGY LABORATORY