NATIONAL ENERGY TECHNOLOGY LABORATORY

Current and Future Technologies for Gasification-Based Power Generation

Volume 2: A Pathway Study Focused on Carbon Capture Advanced Power Systems R&D Using Bituminous Coal

Revision 1
November 2010
(Original Issue Date November 2009)

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CURRENT AND FUTURE TECHNOLOGIES FOR GASIFICATION-BASED POWER GENERATION

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LIST OF ACRONYMS AND ABBREVIATIONS

AHT	Advanced Hydrogen Turbine
AST	Advanced Syngas Turbine
ASU	Air Separation Unit
BEC	Bare Erected Cost
CCF	Capital Charge Factor
CF	Capacity Factor
COE	Cost of Electricity
COS	Carbonyl Sulfide
DOE	Department of Energy
DSRP	Direct Sulfur Reduction Process
EPCC	Engineering, Procurement, and Construction Cost
FYC	First year variable operating costs
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
IGFC	Integrated Gasification Fuel Cell
ITM	Ion Transport Membrane
kW	kilowatt
kW-hr	kilowatt-hour
LF	Levelization factor
LHV	Lower Heating Value
MM	million
MW	megawatt
MWh	megawatt hour
NETL	National Energy Technology Laboratory
O&M	Operating and Maintenance
R&D	Research and Development
RAM	Reliability, Availability, and Maintainability
SOFC	Solid Oxide Fuel Cell
TASC	Total As-Spent Cost
TOC	Total Overnight Cost
TPC	Total Plant Cost
TRC	Total Required Capital
TS&M	Transportation, Storage, and Monitoring of CO_2
WGCU	Warm Gas Cleanup

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EXECUTIVE SUMMARY

The United States Department of Energy's (DOE) Strategic Center for Coal funds research and development (R&D) with the objective to improve the efficiency and reduce the cost of advanced power systems. In order to evaluate the benefits of on-going R&D, Noblis utilized their energy systems analysis capabilities and Aspen Plus computer simulation models to quantify the impact of successful federally-funded R&D on future power systems configurations.

This report represents Volume 2 of a two-volume Pathway Study in which a variety of process configurations that produce electric power from bituminous coal are analyzed. While Volume 1 [1] focuses on non-carbon capture process scenarios, Volume 2 addresses pre-combustion carbon capture scenarios. Each volume begins with a reference integrated gasification combined cycle (IGCC) plant using conventional technology, and a series of process modifications are made to represent commercialization of advanced technologies. Impacts of each technology on both process performance and cost are evaluated. In this manner, DOE can measure and prioritize the contribution of its R&D program to future power systems technology.

Advanced technologies within DOE's R&D program include:

- Three models of advanced hydrogen turbines (AHT)
- Dry coal feed pump
- Improved capacity factor resulting from equipment design and operating experience
- Warm gas cleanup (WGCU)
- Hydrogen membrane
- Ion transport membrane (ITM) for oxygen production
- Pressurized solid oxide fuel cell (SOFC)

Compared to non-capture technology, requirements for carbon capture impose both performance and cost penalties. The penalties are primarily the result of the parasitic energy and the capital cost of additional technology needed to separate CO_2 from process streams and compress the CO_2 to a pressure suitable for pipeline transport to a sequestration site. Advanced technology not only improves process performance and reduces the cost of electricity, but it also helps to reduce the incremental cost of carbon capture. Assuming R&D success in terms of performance and cost, the conceptual process configurations for each of these advanced technologies follow a pathway to an advanced IGCC plant with 90 % carbon capture that (1) is 9.6 percentage points greater in efficiency, and (2) reduces the 20-yr levelized cost of electricity (COE) by greater than 35 % relative to the reference carbon capture IGCC plant. An alternate pathway provided by an advanced integrated gasification fuel cell (IGFC) plant provides a high efficiency, near-100 % capture solution at a COE similar to that of the advanced IGCC.

Reference Plant Design Basis

The reference non-capture IGCC configuration from Volume 1 uses conventional technology from the year 2003 that features a single-stage slurry feed gasifier with radiant-only gas cooler followed by Selexol acid gas removal, a 7FA syngas turbine, and conventional three-pressure level steam cycle. Gasifier oxygen is provided by a cryogenic air separation unit (ASU). Process operation assumes a 75 % capacity factor.

In this Volume 2, to obtain the reference IGCC configuration with carbon capture the non-capture configuration is modified by: (1) converting sour syngas to hydrogen-rich fuel through water gas shift; (2) changing the acid gas removal section to conventional two-stage Selexol to accomplish CO_2 separation; (3) adding a CO_2 compression section, and (4) modifying the 7FA-based turbine to be powered by the hydrogen-rich fuel. The capacity factor is increased to 80 % to represent operating experience to date gained through DOE's Clean Coal Program as well as to account for improved reliability and availability expected to occur by the time that carbon capture cases are deployed. In the reference plant configuration, addition of carbon capture results in an efficiency reduction of 5 percentage points and a capital cost increase of $600/kW compared to its non-capture counterpart.

Process Improvements from Advanced Technologies

A series of conceptual process configurations with carbon capture that produce electric power from bituminous coal is analyzed to determine the potential performance improvements and cost reductions resulting from successful R&D of advanced technology. These process configurations are listed in Table ES-1. The white blocks represent existing, commercially available technologies while the colored blocks represent advanced emerging technologies. Each advanced technology is implemented and evaluated in a composite process in the order in which demonstration-readiness is anticipated. This allows assessment of the cumulative improvements in process performance and cost over time. The majority of the technologies are evaluated in the context of an IGCC plant. The single IGFC case represents an advanced process configuration that occurs later in the commercialization timeline, incorporating technologies that are of specific value to an IGFC plant.

Table ES-1. Carbon Capture Power System Technology Development

<table>
<tr><th>Case Title</th><th>Gas Turbine</th><th>Coal Feed System / Gasifier</th><th>Capacity Factor</th><th>Gas Clean Up</th><th>CO_2 Separation</th><th>Oxygen Production</th></tr>
<tr><td>Reference IGCC</td><td>7FA</td><td>Slurry Feed</td><td>80% CF</td><td colspan="2">2-Stage Selexol</td><td>Cryogenic</td></tr>
<tr><td>Adv "F" Turbine</td><td>Adv "F"</td><td></td><td></td><td colspan="2"></td><td rowspan="4">Air Separation Unit (ASU)</td></tr>
<tr><td>Coal Feed Pump</td><td></td><td rowspan="3">Coal Feed Pump</td><td></td><td colspan="2"></td></tr>
<tr><td>85% CF</td><td></td><td>85% CF</td><td colspan="2"></td></tr>
<tr><td>WGCU/Selexol</td><td></td><td></td><td>WGCU</td><td>Selexol</td></tr>
<tr><td>WGCU/H_2Membrane</td><td></td><td></td><td></td><td></td><td rowspan="4">High Temp Hydrogen Membrane</td><td></td></tr>
<tr><td>AHT-1 Turbine</td><td>AHT-1</td><td></td><td></td><td></td><td></td></tr>
<tr><td>ITM</td><td></td><td></td><td></td><td></td><td>ITM</td></tr>
<tr><td>AHT-2 Turbine</td><td>AHT-2</td><td></td><td></td><td></td><td></td></tr>
<tr><td>90% CF</td><td></td><td></td><td>90% CF</td><td></td><td></td><td></td></tr>
<tr><td>Advanced IGFC</td><td>Pressurized SOFC</td><td>Catalytic Gasifier</td><td>90% CF</td><td>WGCU</td><td>SOFC + Oxycom-bustion</td><td>Cryogenic ASU</td></tr>
</table>

Cost and Performance Impact of Advanced Technologies

See Appendix A for NETL's update to capital costs and COE. [1]

Table ES-2 summarizes the results of the analysis as each new technology is added to the pathway, highlighting the increase in efficiency and decrease in total plant cost (TPC) and 20-year levelized COE. The delta for each metric provides an estimate of the incremental benefits of successful R&D for each technology. Turbine advancements contribute 50 % of the efficiency improvement and 40 % of the reduction in COE. The combined benefits of WGCU and the hydrogen membrane contribute 40 % of the efficiency benefit and 30 % of the COE reduction. The remaining benefits are due to a combination of the coal feed pump, ITM, and research efforts to improve plant availability. Details on the contributions of each advanced technology are provided in the following paragraphs.

Table ES-2. Cumulative Cost and Performance Impact of R&D for Gasification-Based Power Generation

Case Title	Efficiency (% HHV)	Delta* Efficiency (% points)	TPC** ($/kW)	Delta* TPC** ($/kW)	20-yr Levelized COE (¢/kW-hr)	Delta* COE (¢/kW-hr)
Reference IGCC	30.4	0	2,718	0	11.48	0
Adv "F" Turbine	31.7	1.3	2,472	-246	10.64	-0.84
Coal Feed Pump	32.5	0.8	2,465	-7	10.54	-0.10
85% CF	32.5	0.0	2,465	0	10.14	-0.40
WGCU/Selexol	33.3	0.8	2,425	-40	10.00	-0.14
WGCU/H_2Membrane	36.2	2.9	2,047	-378	8.80	-1.20
AHT-1 Turbine	38.0	1.8	1,855	-192	8.14	-0.66
ITM	38.3	0.3	1,724	-131	7.74	-0.40
AHT-2 Turbine	40.0	1.7	1,683	-41	7.61	-0.13
90% CF	40.0	0.0	1,683	0	7.36	-0.25
IGCC Pathway		+9.6%pts (+32%)		-1,035 (-38%)		-4.12 (-36%)
Advanced IGFC	56.3	+26%pts +85%	1,759	-959 (-35%)	7.45	-4.03 (-35%)

* Delta shown is the incremental change as each new technology is added to previous case configuration
** TPC is reported in January 2007 dollars and excludes owner's costs

[1] NETL is updating the performance, cost, and costing methodology as part of Revision 2 of "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity." The estimated capital cost and COE for the configurations presented in this report using this new methodology are reported in Appendix A.

Advanced Turbines

Advanced turbines contribute 4.8 (1.3+1.8+1.7) percentage points to increased process efficiency due to the combination of (1) improved engine performance at increasingly higher pressure ratios and firing temperatures, (2) air integration that reduces auxiliary load of the main air compressor, and (3) increased turbine exit temperature, which improves heat recovery from the heat recovery steam generator (HRSG).

Advanced hydrogen turbines also significantly reduce total plant cost. Although the cost of the turbine itself increases due to increased size, TPC on a $/kW basis decreases because of increased net plant power. The advanced "F" turbine and the first generation (AHT-1)[2] turbine contribute significant COE reductions – a total of 15 (8.4+6.6) mills/kW-hr. To maintain a nominal 600 MW plant size (the basis of this study), there is a reduction from two process trains to a single process train for the next generation (AHT-2) turbine. The reverse economy of scale associated with the train reduction translates into a minor decrease (1.3 mills/kW-hr) in COE.

If instead two trains are utilized, resulting in a 1 GW capacity unit, the COE change associated with incorporation of the advanced turbine is 8.2 mills/kW-hr (an 11 % reduction). Table ES-2 reports the costs corresponding to the more conservative single-train, nominal 600 MW configuration.

Coal Feed Pump

The coal feed pump increases the gasifier cold gas efficiency by eliminating the need to evaporate water in a slurry-fed gasifier. This benefit is somewhat countered by a higher steam requirement for the water gas shift reaction than was needed with a slurry feed. The resulting efficiency benefit is 0.8 percentage points.

The minor change in cost of equipment, coupled with a small reduction in net power associated with the coal feed pump, results in a negligible impact on TPC and COE.

Warm Gas Cleanup and Hydrogen Membrane

Warm gas cleanup (with Selexol CO_2 capture) improves process efficiency over cold gas cleanup in the carbon capture scenario as the result of eliminating the sour water stripper reboiler duty. However, coupling warm gas cleanup with the hydrogen membrane contributes even more increase in process efficiency by eliminating the Selexol regeneration steam requirements and auxiliary power, and also by producing CO_2 at elevated pressure – reducing CO_2 compressor load.

The cost of warm gas desulfurization is projected to be less than single-stage Selexol, which partly accounts for the decrease in TPC of the WGCU+Selexol configuration. An even greater reduction in TPC results with the addition of a hydrogen membrane that replaces the second-stage Selexol absorber for CO_2 capture. Furthermore, the cost of CO_2 compression is much less

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[2] The pseudonyms AHT-1 and AHT-2 are used to represent technology that is presently under development within DOE's R&D program. While actual performance parameters are business-sensitive, the turbine parameters used in this study represent target performance.

in the WGCU+Membrane case than any of the previous carbon capture cases due to the higher pressure at which CO_2 is produced from the H_2 membrane. Finally, when the added net power generation (made possible by eliminating the sour water stripper and Selexol reboilers and reducing CO_2 compression parasitic losses) is divided into the already-reduced TPC, the cost of the WGCU+Membrane case decreases by $418/kW (40+378) relative to the cold gas cleanup configuration. The COE benefit follows suit, decreasing by 13.4 mills/kW-hr (1.4+12.0).

Ion Transport Membrane

The ITM does not contribute strongly to process performance; its primary benefit is decreased capital cost of oxygen production. The ITM is predicted to reduce TPC by $131/kW and the COE by 4.0 mills/kW-hr.

Reliability, Availability, and Maintainability (RAM)

Anticipated improvements in process RAM due to R&D in areas such as vessel refractories, improved sensors and advanced process controls are modeled as an increase in capacity factor. Although increased capacity factor does not influence either process efficiency or TPC, the added on-stream plant operation decreases COE by a total of 6.5 mills/kW-hr (4.0+2.5).

Pressurized Solid Oxide Fuel Cell

The pressurized solid oxide fuel cell case is capable of a process efficiency that approaches 60 %. The catalytic gasifier, with high methane content in the syngas, operates with a cold gas efficiency in excess of 90 %. Conversion of chemical energy within the fuel cell, as opposed to thermal and mechanical energy conversion in an IGCC process, enables the higher process efficiency obtained in the IGFC case.

Despite much higher process efficiency, higher capital costs of the IGFC process relative to IGCC result in a TPC and COE that are slightly greater than the most advanced IGCC configuration with carbon capture. However, the SOFC case results in nearly 100 % CO_2 removal compared to the 90 % capture of the IGCC.

Comparison to Non-Capture Scenarios

Figure ES-1 depicts the cumulative improvements in process efficiency, TPC, and COE as each technology is introduced for the carbon capture cases described in this study and the non-capture cases from Volume 1. The overall efficiency improvement for the IGCC non-capture pathway is 10.7 percentage points, slightly greater than the 9.6 percentage points achieved in the carbon capture cases. TPC (on a $/kW basis) and COE decrease by approximately 33 % in the non-capture IGCC cases, compared to 38 % and 36 % reduction in TPC and COE for the carbon capture cases, respectively.

The bottom of the shaded bars on the TPC and COE pathways illustrate the impact of the AHT-2 turbine if two turbine trains were built. That installation would exceed the nominal 600 MW plant size for this study, but the point serves to illustrate the effect of economy of scale on process economics.

While warm gas cleanup results in greater process efficiency improvement for the carbon capture scenario, its impact is especially pronounced in terms of TPC and COE. The cost differential between warm gas cleanup and cold gas cleanup is greater (resulting in more cost reduction) in the carbon capture scenario due to the additional Selexol absorber. In addition, the cost of CO_2 compression is much less in the WGCU+Membrane case than any of the previous carbon capture cases due to the higher pressure at which CO_2 is produced from the H_2 membrane. Finally, when the added net power generation (made possible by eliminating sour water stripper and Selexol reboiler duties and reduced CO_2 compression parasitic loss) is divided into the already-reduced TPC, the cost of the warm gas cleanup cases on a $/kW basis becomes $418/kW less than the cold gas cleanup carbon capture scenario, and COE decreases by more than 13 %. By comparison, warm gas cleanup in the non-capture scenario decreases TPC by $161/kW and COE by almost 7 %.

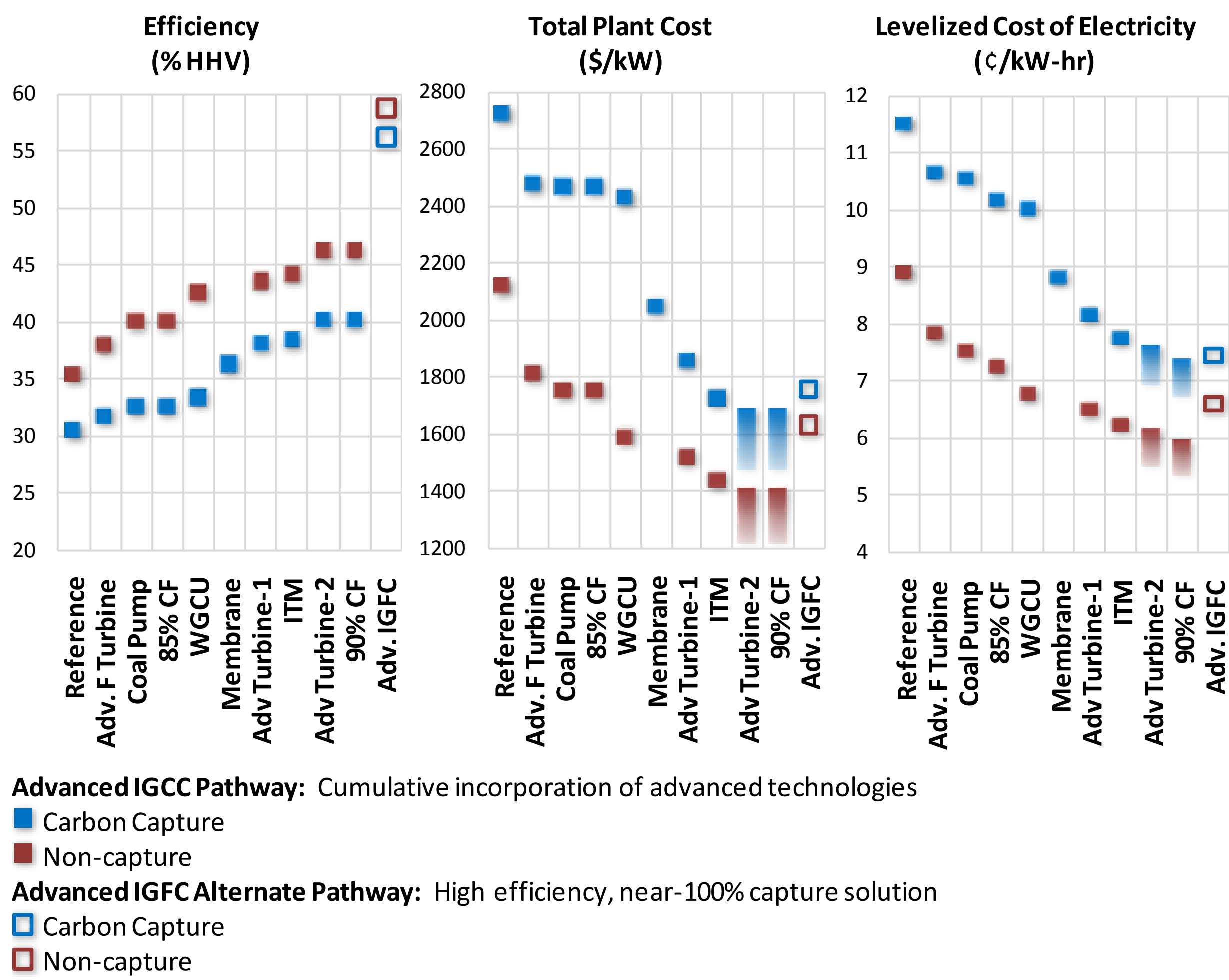

Figure ES-1. Non-Capture and Carbon Capture Pathway Results

The coal feed pump makes a greater contribution to process efficiency and cost improvement in the non-capture scenario (2.1 percentage point efficiency increase and 4 % reduction in COE) than in the carbon capture scenario (0.8 percentage point efficiency increase and 1 % COE reduction). The coal feed pump increases process efficiency by eliminating the need to evaporate water in a slurry-fed gasifier. In the non-capture scenario with cold gas cleanup, that moisture is condensed and most of the latent heat is unrecoverable because of the low condensation temperature. In the carbon capture scenario with cold gas cleanup, on the other hand, moisture is needed for water gas shift; so whether the moisture is provided by slurry water or addition of shift steam (following a dry feed gasifier), the coal feed pump doesn't have as much of an impact on process efficiency.

The ITM is seen to reduce TPC by relatively more in the carbon capture scenario ($131/kW) than in the non-capture scenario ($82/kW). With an increase in coal feed rate to generate hydrogen turbine fuel compared to syngas turbine fuel, the significance of the air separation unit increases. This is because, with increased oxygen demand in the carbon capture cases, the capital cost savings represented by the less-expensive ITM compared to cryogenic ASU has a greater impact on reducing cost.

COE in the non-capture SOFC case increases by 11 % over that of the most advanced non-capture IGCC technology; this is due to a higher TPC that, even despite much higher process efficiency, results in a COE that is greater than IGCC by 6.6 mills/kW-hr. In the carbon capture scenario the sequestration-ready CO_2 stream from the SOFC incurs minimal incremental capital cost. The resulting COE, aided by 56.3 % process efficiency, is just 0.9 mills/kW-hr (1 %) greater than the most advanced carbon capture IGCC configuration.

DOE's Carbon Capture Targets

DOE's advanced power generation program goals are to achieve 90 % carbon capture while maintaining less than 10 % increase in COE over a 2003 reference IGCC plant having no carbon capture. That reference plant is represented in Case 0 in Volume 1 of this Pathway Study. At 75 % capacity factor the COE of that plant is 9.3 ¢/kW-hr, so DOE's cost target for carbon capture is 10 % greater, or 10.2 ¢/kW-hr.

From Figure ES-1 above, DOE's carbon capture target should be met early in the pathway, specifically by the case with 85 % capacity factor. Other process features of that case include advanced "F" hydrogen turbine, dry feed gasifier, cryogenic ASU, and cold gas cleanup.

All subsequent technology advancements will help to exceed DOE's program goals. By achieving the ultimate, most advanced IGCC and IGFC technologies projected in Figure ES-1, DOE could realize a 20 % *reduction* in COE over the 2003 reference IGCC plant having no carbon capture. The enabling technologies to achieve that improvement include:

- Advanced hydrogen turbines
- Coal feed pump
- Improved RAM
- Warm gas cleanup
- Hydrogen membrane
- ITM
- Pressurized SOFC with catalytic gasifier

The technology pathway evaluated in this study covers a time span of about 18 years of technology development. Results of the analysis clearly indicate the importance of continued

R&D, large scale testing, and integrated deployment so that future coal-based power plants will be capable of generating clean power with greater reliability and at significantly lower cost.

Aside from improved process efficiencies and reduced costs of electricity for both non-capture and carbon capture power generation alike, these advanced technologies enable (1) production of high-value products such as hydrogen, (2) integration with solid oxide fuel cells, and (3) pre-combustion carbon capture projected at lower cost than post-combustion alternatives.

1. INTRODUCTION

The United States Department of Energy's (DOE) Strategic Center for Coal funds research and development (R&D) whose objective is to improve the efficiency and reduce the cost of advanced power systems. In order to evaluate the benefits of on-going R&D, Noblis utilized their energy systems analysis capabilities and Aspen Plus computer simulation models to quantify the impact of successful federally-funded R&D on future power systems configurations.

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The advanced technologies that are examined in this volume include:

- Three models of advanced hydrogen turbines (AHT)
- Coal feed pump
- Improved capacity factor resulting from equipment design and operating experience
- Warm gas cleanup (WGCU)
- Hydrogen membrane for H_2 separation
- Ion transport membrane (ITM) for oxygen production
- Pressurized solid oxide fuel cell (SOFC) with catalytic gasifier

Compared to non-capture technology, requirements for carbon capture impose both performance and cost penalties. The penalties are primarily the result of the parasitic energy and the capital cost of additional technology needed to separate CO_2 from process streams and compress the CO_2 to a pressure suitable for pipeline transport to a sequestration site. Section 4 of this report compares the pathways of non-capture versus carbon capture power generation. As will be shown, advanced technology not only improves process performance and reduces the cost of electricity but it also helps to reduce the incremental cost of carbon capture.

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2. PATHWAY STUDY BASIS

The design basis of NETL's Baseline Study [2] was adopted so that results from this pathway study would be consistent with established results. In general, all cases are based on a nominal plant size of 600 MW net power. A process flow diagram of the reference carbon capture case is provided in Figure 2-1. The process includes two 7FA hydrogen turbines and a steam cycle operating at 1,800 psig with 1,000 ^{o}F steam superheat and 1,000 ^{o}F steam reheat. The as-received Illinois #6 bituminous coal feed has a higher heating value of 13,126 Btu/lb (dry basis). Ultimate and proximate analyses of the coal are presented in Table 2-1.

Table 2-1. Bituminous Coal Analysis

Proximate Analysis
As-Received (wt %)

Moisture	11.12
Ash	9.70
Volatile Matter	34.99
Fixed Carbon	44.19

Ultimate Analysis
Dry Basis (wt %)

Ash	10.91
Carbon	71.72
Hydrogen	5.06
Nitrogen	1.41
Chlorine	0.33
Sulfur	2.82
Oxygen	7.75
Total	100.00
HHV (Btu/lb)	13,126

2.1 PROCESS DESCRIPTION

A cryogenic air separation unit (ASU) provides oxygen for the single-stage, slurry feed, oxygen-blown gasifier. The ASU is sized to provide sufficient oxygen to the gasifier, plus a small slipstream of oxygen used in the Claus furnace for acid gas treatment. Most of the N_2 by-product can be compressed and injected into the topping combustor of the hydrogen turbine; the exact amount is determined by the turbine power rating, which is regulated to 192 MW per unit.

Although the gasifier exceeds 2,400 ^{o}F during operation, the radiant gas cooler reduces exit raw gas temperature to 1,250 ^{o}F. The capacity of a single gasifier in the reference case is on the order of 2,200 tons/day coal.

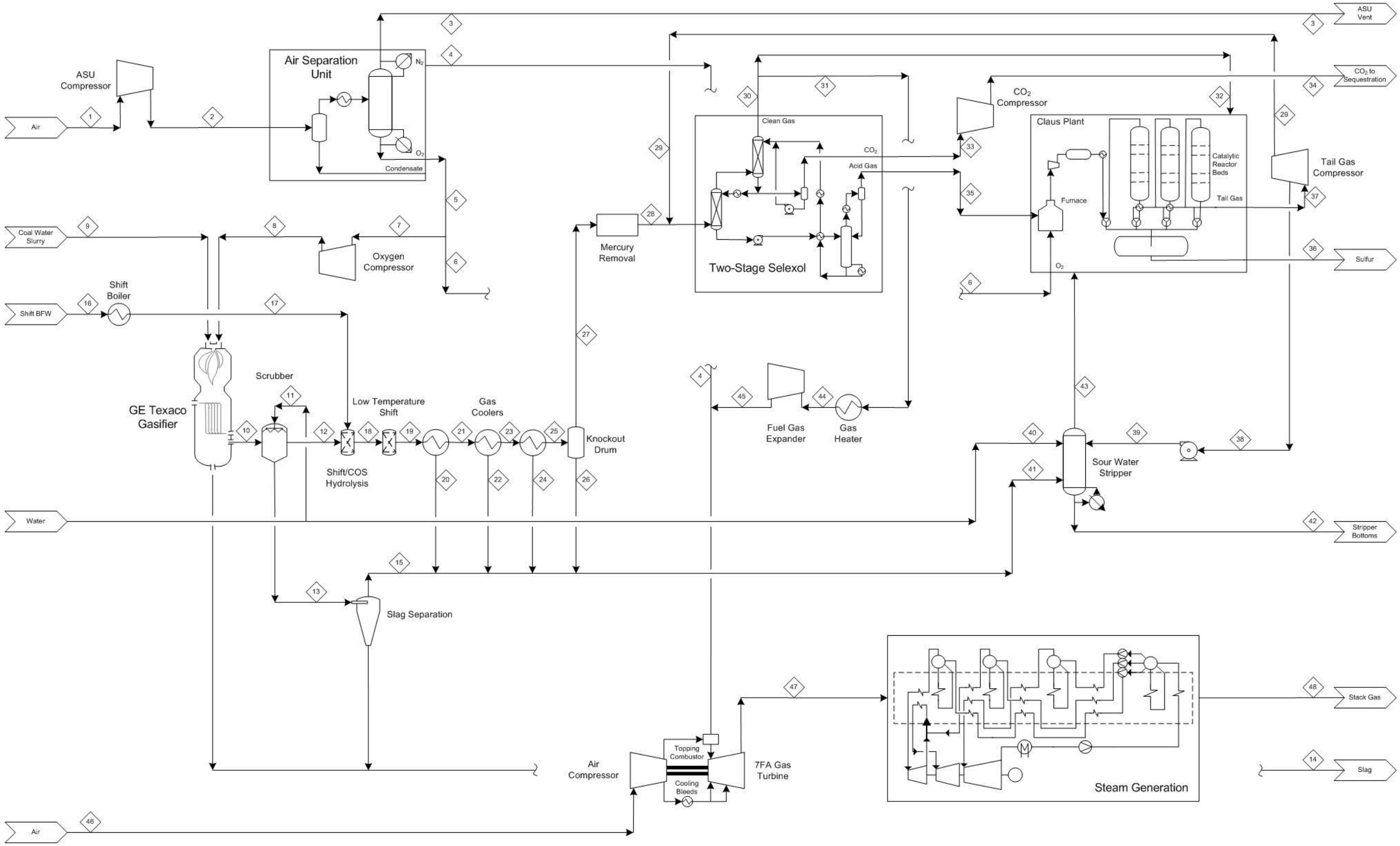

Figure 2-1. Process Flow Diagram of the Reference Carbon Capture Case

Exiting the gasifier, raw fuel gas is scrubbed with water to remove particulates. Water is separated from the slag, and flows to the sour water stripper for treatment. Raw fuel gas mixes with steam for COS hydrolysis and two-stage water gas shift. Heat recovered from the high temperature shift reactor is recovered to generate high pressure steam. Heat recovered from the low temperature gas shift is suitable for generating intermediate pressure steam. The feed rate of shift steam is regulated in order to shift CO in the raw fuel gas sufficient to meet 90 % carbon removal overall.

Following the shift reaction, the gas is cooled again; first to 315 ^{o}F to recover useful heat for low pressure steam generation, next to 235 ^{o}F to recover useful heat for the steam cycle deaerator, then finally to 100 ^{o}F for NH_3 removal. The cooling temperatures of 315 ^{o}F and 235 ^{o}F were selected based on reasonable temperature approaches to the steam cycle streams.

The fuel gas enters packed carbon bed absorbers to remove mercury, followed by a two-stage Selexol process that absorbs both CO_2 and H_2S from the fuel gas. H_2S is stripped from the solvent in the solvent regenerator and sent to the Claus plant. The CO_2 is compressed to 2,200 psig for transport to sequestration.

The Claus plant converts H_2S to elemental sulfur through a series of reactions. Sulfur is condensed, and tail gas is hydrogenated to convert residual SO_2 back into H_2S, which can be captured when the tail gas is recycled to the Selexol absorber. A small slipstream of clean fuel gas is used for reactant.

Clean fuel gas exits the Selexol absorber at nearly 700 psia, and is delivered to the topping combustor at 464.7 psia. Therefore, it can be expanded to recover excess pressure prior to entering the topping combustor; this expansion results in about 6 MWe of power generation.

Fuel gas is diluted with N_2 from the ASU; the hydrogen-rich mixture is burned in the topping combustor. Because of the high H_2 content, the fuel flowrate is regulated to maintain a turbine exit temperature of 1,050 ^{o}F. The net turbine power output is 192 MWe per unit [3].

All available process heat is collected for steam generation in the bottoming cycle. Superheated steam is expanded through three turbines, with reheat after the high pressure turbine. The steam cycle also provides heat to generate shift steam, acid gas removal (the Selexol solvent regenerator), the sour water stripper, and fuel gas reheating prior to the fuel gas expander.

2.2 ADVANCED TECHNOLOGY ASSUMPTIONS

In the absence of demonstration data, process performance and costs for unproven futuristic technologies are difficult to estimate. Engineering judgment and information provided by technology developers are used, when necessary, to derive reasonable estimates. In addition, performance and cost results are provided to technology developers for reasonableness review and comment. While every attempt is made to calculate objective and reasonable performance and cost results, the bottom-line accuracy is limited by the uncertainty of design information.

At the time that the cases were configured, the limitations and key assumptions were as follows.

Technology Advancement	Performance Limitations and Assumptions	Cost Limitations and Assumptions
Advanced H_2 Turbines	Turbine parameters are highly proprietary to technology developers, and detailed turbine simulation modeling is outside the scope of this study. Hydrogen turbine parameters are devised to a configuration that meets the turbine program goals of 3-5 percentage points above a 7FA turbine. Technology developers have performed system analyses using proprietary data and advanced modeling that predict their R&D efforts will exceed this goal. Performance uncertainty also exists due to limited commercial experience with hydrogen-fired turbines.	Turbine cost is scaled to the turbine power rating. There is no assumed premium for additional cost at elevated temperature or pressure. Increases in turbine power ratings result in plant-wide economies of scale resulting from increased net plant power production. For this reason, capital costs and COE are sensitive to the assumed turbine power rating increase and the scaling factors used on all plant equipment.
Coal Feed Pump	The coal feed pump is assumed to process as-received coal – without the need for coal drying. Demonstration to 1,000 psia pressure has been verified.	While there is considerable uncertainty regarding the cost of the coal feed pump, it is expected to be a relatively small capital cost which, when divided by the net plant power output to calculate on a $/kW basis, will have a minor impact on COE.
Warm Gas Cleanup	Extents of reaction and pressure drop through vessels are based on technology description by the developer. A demonstration scale unit has been running at the Eastman gasifier in Kingsport Tennessee but data from that demonstration has not yet been incorporated into this model. Reports on that demonstration plant indicate that the technology is performing well with very low exit concentrations of sulfur.	Technology developer's target costs are utilized in cost assessments. Installation costs, EPC costs and process and project contingencies are added as appropriate.
Hydrogen Membrane	The DOE/NETL Hydrogen and Clean Fuels Program 2015 target flux and temperatures are used in simulating performance. Commercialization of high temperature hydrogen membranes must surmount challenges of (1) manufacturing membranes with consistent high flux properties and long lifetimes, and (2) fabrication of the membrane units themselves with gas inlet and outlet interconnects.	2015 target membrane costs from the DOE/NETL Hydrogen and Clean Fuels Program are utilized in cost assessments. Installation costs, EPC costs, and process and project contingencies are added as appropriate.

Technology Advancement	Performance Limitations and Assumptions	Cost Limitations and Assumptions
Ion Transport Membrane	Technology developer's target operational parameters such as pressure and flux are utilized in process simulations. Very promising results have been obtained in the 5TPD oxygen demo unit that is operating at the Sparrows Point refinery in Maryland.	Technology developer's target costs are utilized in cost assessments. Installation costs, EPC costs and process and project contingencies are added as appropriate.
Reliability, Availability and Maintainability (RAM)	R&D in areas improving RAM may impact process performance; however, for this analysis, any changes in process efficiency are assumed to be negligible.	Improved RAM is modeled by increasing the capacity factor from 80% to 85% to 90%. This study does not specifically tie DOE-funded projects to capacity factor improvements. Capital costs associated with improved RAM are assumed to be negligible.
Solid Oxide Fuel Cell	The IGFC configuration includes the following: (1) an advanced pressurized SOFC meeting DOE/NETL Fuel Cell Program performance targets; (2) a conceptual catalytic gasifier that provides high methane content syngas, and (3) a pressurized oxycombustor that burns the hot spent anode fuel gas from the SOFC. Heat generated in the SOFC can be partially dissipated by internally reforming methane in the syngas. The catalytic gasifier is conceptual and is assumed to produce 17 mole % CH_4 by the potassium catalyzed methanation reaction. This is exothermic and helps to drive the endothermic gasification reaction. Great Point Energy is developing a catalytic gasifier that is based on the original Exxon process whereby the methanation reaction can provide enough heat for gasification so that oxygen is not required.	The fuel cell system total plant costs are assumed to be $700/kW (gross power from the fuel cell). Stack replacement frequency and cost are based on DOE/NETL Fuel Cell Program targets. The catalytic gasification costs are assumed to be based on the same reference costs as the non-catalytic gasification systems and scaled on coal throughput. Catalyst recovery costs are included.

2.3 ECONOMIC ANALYSIS

See Appendix A for NETL's update to capital costs and COE. [3]

Plant capital cost is estimated using cost algorithms based on literature and vendor supplied costs and capacities consistent with this level of conceptual scope definition and taking into consideration plant size, number of process trains, sparing philosophy, and as much equipment-specific design information as possible.

Operating and maintenance (O&M) costs include fixed labor costs as well as variable costs (that depend on capacity factor) including maintenance materials, water, chemicals, and waste disposal. Fuel cost is calculated separately from O&M based on coal feed rate and coal cost.

The cost of electricity calculation (described below) can be based directly on the capital charge factor. This study assumes a prescribed capital charge factor (17.5 %) typical of a higher-risk project undertaken by an investor-owned utility.

2.3.1 Capital Cost

The following Figure 2-2 illustrates the relationships between various elements of capital cost. Noblis correlations are used to estimate Bare Erected Cost (BEC) for each major section of the process plant. The BEC is estimated (in January 2007 dollars) using mass and energy balance information from Aspen Plus simulations of each case. For ease in comparing results, the organization of plant sections is consistent with the presentation used in NETL's Baseline Study. Each section's BEC represents the sum of major plant equipment within the section (including initial chemical and catalyst loadings), as well as materials and labor. Appropriate for a scoping study, BEC's are based on scaled estimates using best-available information collected from multiple sources for the cost correlations.

[3] NETL is updating the performance, cost, and costing methodology as part of Revision 2 of "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity." The estimated capital cost and COE for the configurations presented in this report using this new methodology are reported in Appendix A.

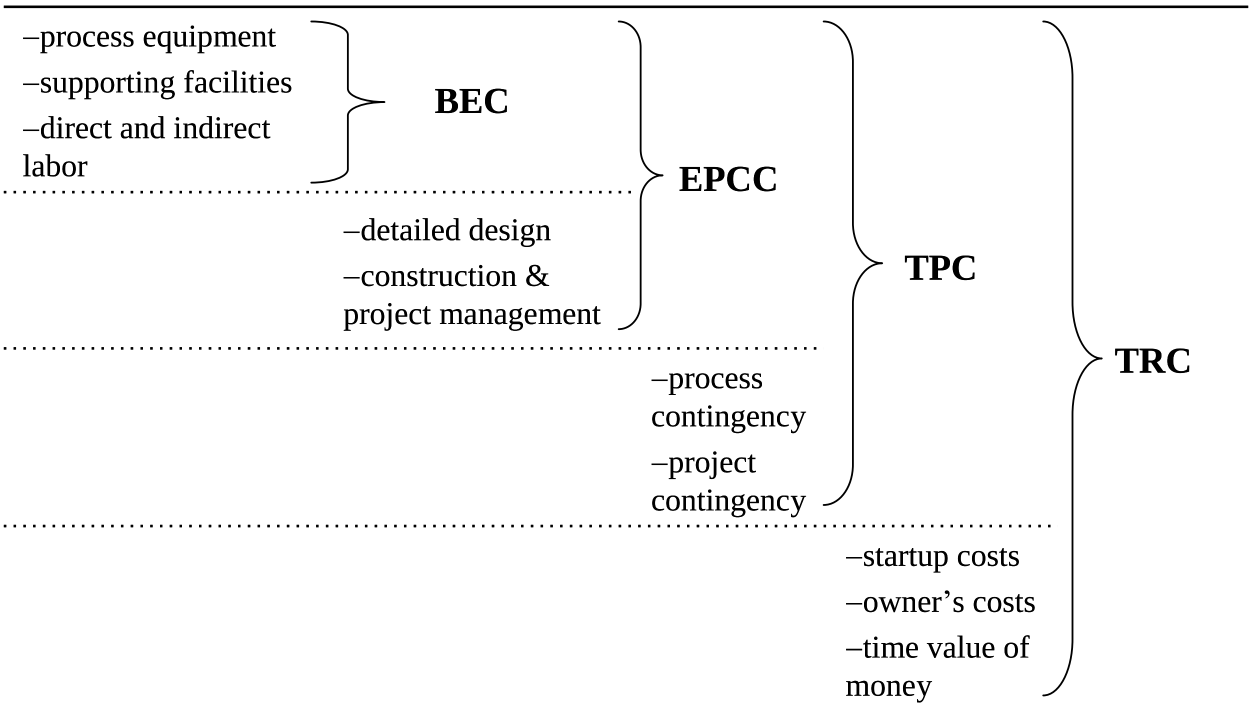

Figure 2-2. Elements of Capital Cost

The BEC is used as the basis for calculating detailed engineering and construction and project management fees. A 9 % charge is applied which, when added to the BEC, becomes the Engineering, Procurement, and Construction Cost (EPCC). The cost analyses in Chapter 3 of this report present the Total Plant Cost (TPC) at the process section level; however the capital cost contains additional process section detail for BEC, EPCC, and process and project contingencies.

For consistency, process and project contingencies used in NETL's Baseline Study form the basis for all major equipment in each plant section. Advanced technologies are assumed to embed cost uncertainty in the BEC; in this manner they retain the same level of contingency as conventional technologies in order not to put the advanced technologies at a disadvantage due to contingency. Contingency estimates are added to the EPCC to calculate the TPC.

Startup costs (assumed to be 2 % of EPCC), owner's costs (which might typically include a Technology Fee or licensing fee), and the time value of money are normally added to the TPC in order to obtain the Total Required Capital (TRC). For consistency with NETL's Baseline Study, owner's costs are omitted in this economic analysis because they are project-specific. Therefore, the reader should bear in mind that the financial results of this analysis (levelized cost of electricity and capital charge factor) do not include owner's costs.

2.3.2 O&M Cost

Labor represents a fixed operating cost, and is based on the number of operating laborers in the plant. The Baseline Study estimate for number of laborers, labor rates, burden, and administrative overhead is used as a basis. Administrative labor is estimated as an overhead rate (25 %) to the sum of operating and maintenance labor. An average labor rate of $33/hr is assumed – again consistent with that used in NETL's Baseline Study.

Table 2-2 identifies elements of variable operating cost that are included in the analysis. Consistent with the Baseline Study, no credit is taken for by-products from any process.

Table 2-2. Elements of Variable Operating Cost

Maintenance Materials
Water
Chemicals
Carbon (Hg removal)
COS Catalyst
Shift Catalyst
Claus Catalyst
Selexol Solvent
ZnO Sorbent
Membrane Replacement
Fuel Cell Stack Replacement
Spent Catalyst Waste Disposal
Ash Disposal

Fuel cost is calculated based on net power generation, heat rate, and fuel heating value. A coal cost of $42.11/ton ($1.80/MMBtu) is assumed, with an as-received heating value of 11,666 Btu/lb. For warm gas cleanup, costs of $14,000/ton for ZnO sorbent and $100/ton for trona are assumed[4]. The sorbent attrition rate is assumed to be 10-20 lb. per million lb. circulating sorbent.

[4] Warm gas cleanup chemical costs were verified by personal communication with Brian Turk, RTI.

2.3.3 Cost of Electricity

The current-dollar levelized cost of electricity can be calculated using the formula:

$$COE_P = ((CCF_P*TPC)+LF_{FP}*FYC_F+CF*(LF_{1P}*FYC_1+LF_{2P}*FYC_2+\ldots))/(CF*MWh)+TSM$$

Where:

COE_P = levelized cost of electricity over P years
CCF_P = capital charge factor levelized over P years
TPC = total plant cost
LF_{FP} = levelization factor over P years for fixed operating costs
FYC_F = first year fixed operating costs
CF = capacity factor
LF_{nP} = levelization factor over P years for category *n* variable operating cost element
FYC_n = first year variable operating costs for category *n* cost element
MWh = net annual power generation at 100% capacity factor
TSM = charge for CO_2 transportation, storage, and monitoring

The capital charge factor can be considered to be the rate at which capital costs are recovered during the lifetime of the project. It is a function of cost of capital and level of technology risk; as these factors increase, the capital charge factor also increases. For the purposes of this study, the investment scenario is considered to be an investor-owned utility (IOU) involved in higher-risk technology. Consistent with NETL's Baseline Study, the capital charge factor in this scenario is
17.5 %. Additional assumed financial parameters are itemized in Table 2-3.

Table 2-3. Discounted Cash Flow Analysis Parameters

Parameter	Value
Percentage Debt	45 %
Interest Rate	11.55 %
Repayment Term of Debt	15 years
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
Depreciation	20 years; 150 % DB
Working Capital	Zero
Plant Economic Life	30 years
Coal Escalation Factor	2.35 %
O&M Escalation Factors	1.87 %
EPC Escalation	0 %
Tax Holiday	0 years
Income Tax Rate	38 %
Investment Tax Credit	0 %
Duration of Construction	36 months

Individual levelization factors for the COE equation above can be calculated by:

$LF_{nP} = k * (1-k^P) / (a_P * (1-k))$

Where

$k = (1+e) / (1 + i)$

$a_P = (((1+i)^P – 1) / (i * (1+i)^P)$

e = annual escalation rate

i = annual discount rate

Consistent with NETL's Baseline Study, the 20-year O&M levelization factors for both fixed and variable costs are 1.1568 (presumes an escalation rate of 1.87 %). For coal, the 20-year levelization factor is 1.2022 (presumes an escalation rate of 2.35 %). Once again, all costs in this analysis are based on January 2007 dollars.

Finally, a CO_2 transmission, storage, and monitoring (TS&M) charge of 3.9 mills/kW-hr is applied to the COE to account for CO_2 sequestration.

3. ANALYSIS OF ADVANCED POWER PROCESS CONFIGURATIONS WITH CARBON CAPTURE

A series of process configurations with carbon capture that produce electric power from bituminous coal is analyzed to determine the potential performance improvements and cost reductions resulting from advanced technology. Starting with the reference IGCC plant with carbon capture, process modifications are simulated to represent commercialization of advanced technologies. These process configurations are listed in Table 3-1. The white blocks represent existing, commercially available technologies while the colored blocks represent advanced emerging technologies. Each advanced technology is implemented and evaluated in a composite process and in the order in which demonstration-readiness is anticipated. This allows assessment of the cumulative improvements in process performance and cost over time. The majority of the technologies are evaluated in the context of an IGCC plant. The pressurized SOFC case represents an advanced process configuration later in the demonstration timeline, incorporating some technologies that are of specific value to an integrated gasification fuel cell (IGFC) plant.

Table 3-1. Carbon Capture Power System Technology Development

Case Title	Gas Turbine	Coal Feed System / Gasifier	Capacity Factor	Gas Clean Up	CO_2 Separation	Oxygen Production
Reference IGCC	7FA	Slurry Feed	80% CF	2-Stage Selexol		Cryogenic
Adv "F" Turbine	Adv "F"					Air
Coal Feed Pump		Coal				Separation
85% CF		Feed	85% CF			Unit
WGCU/Selexol		Pump		WGCU	Selexol	(ASU)
WGCU/H_2Membrane					High	
AHT-1 Turbine	AHT-1				Temp	
ITM					Hydrogen	ITM
AHT-2 Turbine	AHT-2				Membrane	
90% CF			90% CF			
Advanced IGFC	Pressurized SOFC	Catalytic Gasifier	90% CF	WGCU	SOFC + Oxycom-bustion	Cryogenic ASU

3.1 CARBON CAPTURE REFERENCE PLANT

The process configurations used for both the capture and non-capture reference plants are based on state-of-the-art technology available in 2003 – the basis DOE used to establish its R&D program goals. The carbon capture reference plant is the same IGCC process as the non-capture reference plant from Volume 1 of this pathway study, except that the gas cleanup section has a sour shift to produce H_2-rich fuel and CO_2. The CO_2 is separated and compressed for pipeline transport to long-term storage; the H_2-rich fuel powers the hydrogen turbine. All IGCC carbon capture technologies in this study are based on 90 % capture of the carbon derived from coal.

Case Configuration: Slurry Feed Gasifier, Cryogenic ASU, Cold Gas Cleanup, 7FA Hydrogen Turbine, 80 % Capacity Factor

The carbon capture reference plant includes slurry feed gasifier, cryogenic air separation, cold gas cleanup, 7FA-based hydrogen turbine, CO_2 compression, and 80 % capacity factor. Water gas shift and CO_2 separation (achieved using 2-stage Selexol) are included as part of the gas cleanup section.

Figure 3-1 presents a block flow diagram of the process. Colored boxes in the illustration indicate process sections that are different from the non-capture reference process. The plant is configured with the following:

- Two trains of single-stage slurry feed gasifiers with radiant-only syngas coolers
- Two cryogenic air separation units
- Two trains of water quench and sour water gas shift/carbonyl sulfide (COS) hydrolysis
- Two trains of 2-stage Selexol acid gas removal
- Four trains of CO_2 compressors
- One train of sulfur recovery using conventional Claus technology
- Two trains of 7FA hydrogen turbines
- One HRSG
- One steam turbine bottoming cycle with high, intermediate, and low pressure (condensing) turbine sections; steam conditions are 1,800 psi and 1,000 ^oF for the high pressure turbine and 405 psi and 1,000 ^oF for the intermediate pressure turbine.

This IGCC plant produces a net 444 MW of power. Carbon utilization is 98 %, and overall efficiency is 30.4 % (HHV basis). Comparison with the non-capture reference plant in Table 3-2 illustrates the differences in process performance resulting from carbon capture. The same turbine size and power rating are assumed for syngas and hydrogen fuel.[5] The smaller heating value per mole of H_2 in hydrogen fuel compared to CO in syngas fuel results in a greater coal requirement for the carbon capture case; the additional heat recovery available due to this increased coal feed rate more than counters the shift steam requirement associated with the capture configuration, resulting in an increase in steam turbine power generation of 14 MW.

[5] Detailed models of hydrogen turbines were not developed for this study. As such, the power rating of each hydrogen turbine model is assumed to be the same as the corresponding syngas turbine.

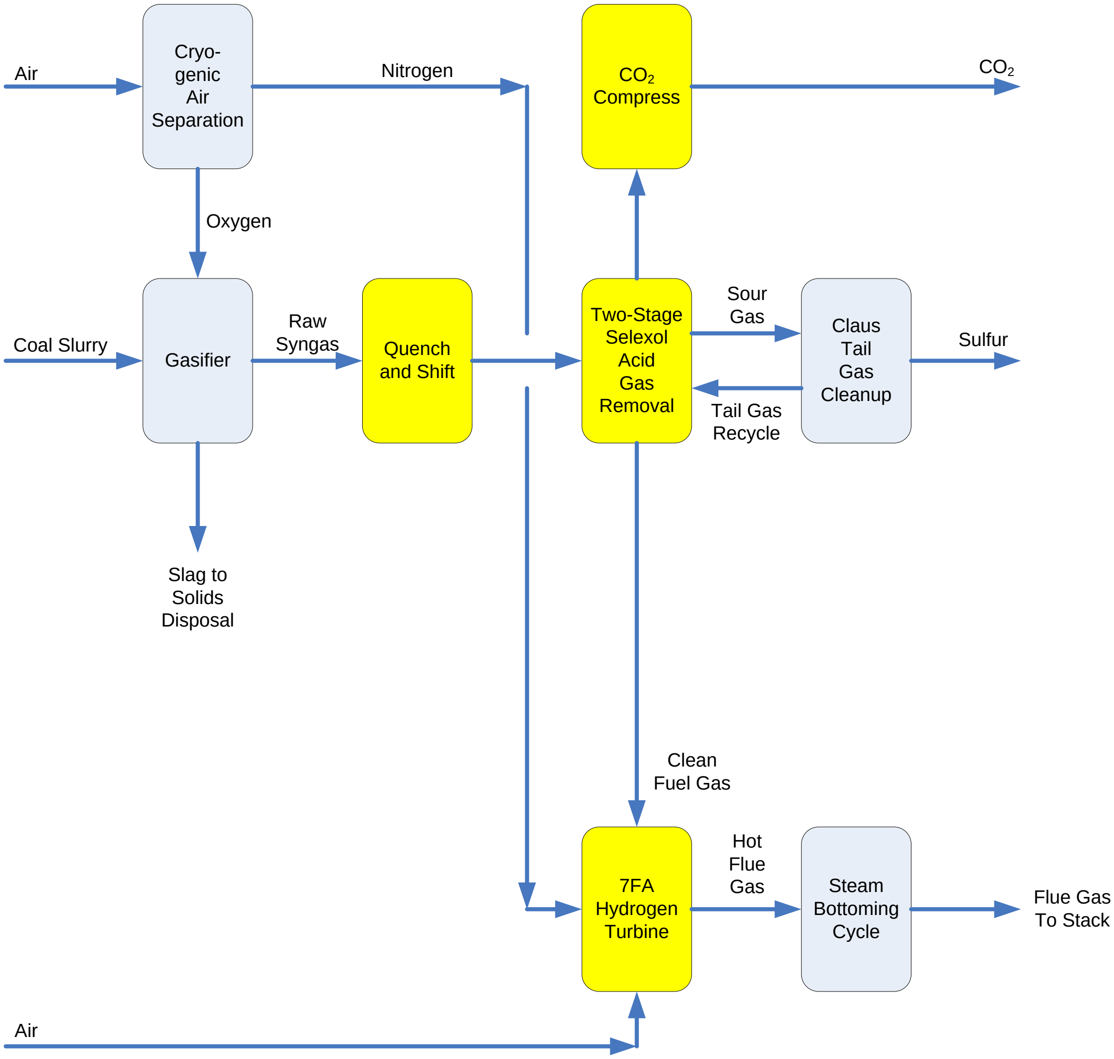

Figure 3-1. Carbon Capture Reference Plant Configuration

Auxiliary power use increases by 56 MW in the carbon capture case due to (1) increased plant size in general because of increased coal feed rate, (2) addition of CO_2 compressors, and (3) increased Selexol auxiliary power as the result of separating both H_2S and CO_2. In the reference plant, therefore, CO_2 capture imposes a 5.0 percentage point decrease in process efficiency from the non-capture case.

Table 3-2. Performance Impact of Carbon Capture in the Reference Plant

	Non-Capture Reference Plant	Carbon Capture Reference Plant
Gas Turbine Power (MWe)	384	384
Fuel Gas Expander (MWe)	6	6
Steam Turbine Power (MWe)	223	237
Total Power Produced (MWe)	614	627
Auxiliary Power Use (MWe)	-127	-183
Net Power (MWe)	487	444
As-Received Coal Feed (lb/hr)	402,581	426,544
Net Heat Rate (Btu/kW-hr)	9,649	11,214
Net Plant Efficiency (HHV)	35.4 %	30.4 %

Cost Analysis

See Appendix A for NETL's update to capital cost and COE.

Table 3-3 below compares the Total Plant Cost (TPC) for major sections of each process plant.

TPC increases by roughly between 2 to 5 % for most plant sections due to the increase in coal feed rate and therefore generally larger plant size in the carbon capture case. TPC on a $/kW basis, however, increases by a higher percentage (typically between 12 to 14 %) as the result of 43 MW less net power generation from the carbon capture case.

Gas cleanup section cost increases by a factor of about 2 due to (1) additional cost of water gas shift reactors (not used in the non-capture process), and (2) cost of the additional Selexol stage for CO_2 separation in the carbon capture case. The CO_2 compression section is an additional $94/kW cost to the carbon capture case that is not present in the non-capture plant. The cost of the hydrogen turbine is assumed to increase slightly in the carbon capture cases as the result of modifications required for H_2-rich fuel as opposed to syngas fuel.

Labor cost increases in the carbon capture case due to (1) slightly greater plant size resulting from increased coal feed rate, and (2) increased plant complexity from additional water gas shift, two-stage Selexol, and CO_2 compression sections.

Variable operating costs are calculated based on 80 % capacity factor. Results from the cost analysis indicate a TPC of $2,718/kW and a 20-year levelized COE of $0.1148/kW-hr based on January 2007 dollars. Compared to the non-capture plant, these represent a 29 % increase in both TPC ($/kW basis) and in COE due to CO_2 capture and storage.

Table 3-3. Reference Plant Capital and O&M Cost Comparison

	Non-Capture Reference Plant		Carbon Capture Reference Plant		Δ	
Capital Cost ($1,000)						
Plant Sections	**TPC**	**TPC $/kW**	**TPC**	**TPC $/kW**	**Δ TPC $/kW**	**% Δ**
1 Coal and Sorbent Handling	30,821	63	31,944	72	9	14
2 Coal and Sorbent Prep & Feed	48,980	101	50,928	115	14	14
3 Feedwater & Balance of Plant	35,077	72	36,260	82	10	14
4a Gasifier	236,212	485	241,531	544	59	12
4b Air Separation Unit	168,950	347	175,776	396	49	14
5a Gas Cleanup	112,389	231	206,045	464	233	101
5b CO_2 Removal & Compression	0	0	41,703	94	94	∞
6 Gas Turbine	105,058	215	116,181	262	47	22
7 HRSG	49,511	102	48,250	109	7	7
8 Steam Cycle and Turbines	54,310	112	56,734	128	16	14
9 Cooling Water System	24.233	50	25,010	56	6	12
10 Waste Solids Handling System	38,752	80	40,159	91	11	14
11 Accessory Electric Plant	66,529	137	73,922	167	30	22
12 Instrumentation & Control	23,178	48	25,730	58	10	21
13 Site Preparation	18,143	37	18,780	42	5	14
14 Buildings and Structures	16,314	34	16,931	38	4	12
Total	1,028,457	2,113	1,205,882	2,718	605	29
O&M Cost ($1,000/yr)						
Fixed Costs	**Total**		**Total**		**Δ**	**% Δ**
Labor	19,542		22,548		3,006	15
Variable Operating Costs*	**Total**		**Total**			
Maintenance Materials	19,593		21,569		1,976	10
Water	1,548		1,732		184	12
Chemicals	1,089		1,838		749	69
Waste Disposal	2,413		2,560		147	6
Total Variable Costs	24,642		27,698		3,056	12
Total O&M Cost	44,184		50,247		6,063	14
Fuel Cost*	59,402		62,938		3,536	6
Discounted Cash Flow Results, levelized						
Capital Cost ($/kW-hr)	0.0528		0.0679			29
Fixed O&M Cost ($/kW-hr)	0.0066		0.0084			27
Variable O&M Cost ($/kW-hr)	0.0084		0.0103			23
Fuel Cost ($/kW-hr)	0.0209		0.0243			16
TS&M Cost ($/kW-hr)	0		0.0039			∞
Levelized COE ($/kW-hr)	0.0887		0.1148			29

*Includes 80 % Capacity Factor

3.2 ADVANCED "F" FRAME HYDROGEN TURBINE

The advanced "F" hydrogen turbine produces more power, has a higher pressure ratio, and a higher firing temperature than the 7FA-based hydrogen turbine. Turbine performance is based on the carbon capture IGCC case in NETL's Baseline Study.

In non-capture cases, three benefits associated with the advanced "F" syngas turbine are (1) integration with the ASU reduces the auxiliary power load of the ASU (a portion of the air supply to the ASU is provided by the gas turbine), (2) the higher turbine firing temperature results in improved turbine performance, and (3) subsequently higher turbine exhaust temperature allows an increase in the steam superheat temperature from 1,000 ^{o}F to 1,050 ^{o}F.

In the carbon capture cases, these benefits are significantly diminished because (1) no air is extracted from the hydrogen turbine because there would not be sufficient flow through the turbine to meet both its power rating and operating temperature specifications, (2) turbine firing temperature is limited (due to the high moisture content in the turbine exhaust) by materials limitations, and (3) limited exhaust temperature of 1,050 ^{o}F provides a temperature differential for steam superheat temperature no higher than 1,000 ^{o}F.

Case Configuration: Slurry Feed Gasifier, Cryogenic ASU, Cold Gas Cleanup, Advanced "F" Frame Hydrogen Turbine, 80 % Capacity Factor

A block flow diagram of this case is presented in Figure 3-2. This two-train IGCC plant produces a net 539 MW of power. Overall efficiency is 31.7 % (HHV basis). Carbon utilization is 98 % and the capacity factor is 80 %. Performance resulting from the advanced "F" hydrogen turbine is compared against the 7FA turbine case in the following Table 3-4.

Table 3-4. Incremental Performance Improvement from Advanced "F" Hydrogen Turbine

	Carbon Capture Reference Plant	Advanced "F" Turbine
Gas Turbine Power (MWe)	384	464
Fuel Gas Expander (MWe)	6	7
Steam Turbine Power (MWe)	237	274
Total Power Produced (MWe)	627	745
Auxiliary Power Use (MWe)	-183	-206
Net Power (MWe)	444	539
As-Received Coal Feed (lb/hr)	426,544	496,865
Net Heat Rate (Btu/kW-hr)	11,214	10,755
Net Plant Efficiency (HHV)	30.4 %	31.7 %

The 7FA-based hydrogen turbine in the reference case is rated at 192 MW, while the advanced "F" turbine is rated at 232 MW. Because of the increased coal feed rate needed to power the higher-rated turbine, steam turbine power generation and auxiliary power use increase.

The increased power rating and pressure ratio of the advanced "F" hydrogen turbine result in a 1.3 percentage point efficiency improvement in the carbon capture cases. In the corresponding non-capture assessment, process efficiency increases by 2.5 percentage points. As discussed above, factors that limit performance efficiency improvement in this carbon capture case are: (1) the absence of air integration results in relatively greater ASU auxiliary load relative to coal feed rate, (2) steam turbine power increases by only 40 MW (as opposed to a 70 MW increase in the non-capture analysis) because of the limited turbine firing temperature that results in less sensible heat carried through the HRSG by the flue gas, and (3) lower steam superheat temperature that reduces the Carnot efficiency of the steam cycle below that achieved in the non-capture cases.

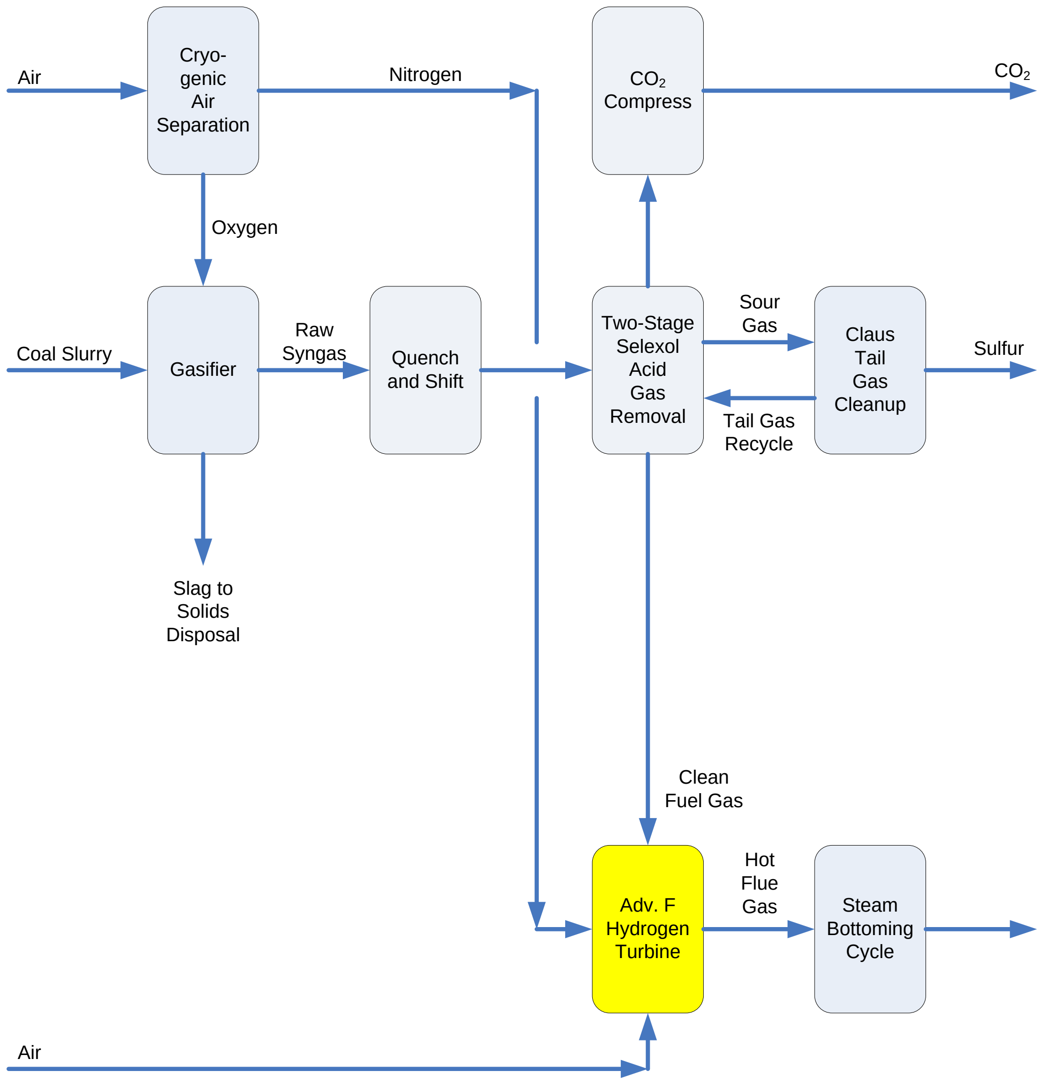

Figure 3-2. Advanced "F" Turbine Plant Configuration

Cost Analysis

See Appendix A for NETL's update to capital cost and COE.

Table 3-5 below compares capital and O&M costs with the carbon capture reference plant. The change in gas turbine drives the differences in capital costs between the reference plant and the case with advanced "F" hydrogen turbine. The advanced "F" turbine has a higher power rating, which increases coal flowrate to the process, and therefore larger equipment sizes throughout the plant; this is reflected in the higher TPC costs in the advanced "F" case. On a $/kW basis, however, the TPC of the advanced "F" turbine plant decreases by about 9 % because of increased net power output.

Table 3-5. Advanced "F" Turbine: Capital and O&M Cost Comparison

	Carbon Capture Reference Plant		Advanced "F" Turbine		Δ	
Capital Cost ($1,000)						
Plant Sections	**TPC**	**TPC $/kW**	**TPC**	**TPC $/kW**	**Δ TPC $/kW**	**% Δ**
1 Coal and Sorbent Handling	31,944	72	35,118	65	-7	-10
2 Coal and Sorbent Prep & Feed	50,928	115	56,449	105	-10	-9
3 Feedwater & Balance of Plant	36,260	82	38,079	71	-11	-13
4a Gasifier	241,531	544	266,942	495	-49	-9
4b Air Separation Unit	175,776	396	194,517	361	-35	-9
5a Gas Cleanup	206,045	464	230,927	428	-36	-8
5b CO_2 Removal & Compression	41,703	94	48,578	90	-4	-4
6 Gas Turbine	116,181	262	131,969	245	-17	-6
7 HRSG	48,250	109	53,454	99	-10	-9
8 Steam Cycle and Turbines	56,734	128	62,886	117	-11	-9
9 Cooling Water System	25,010	56	26,771	50	-6	-11
10 Waste Solids Handling System	40,159	91	44,115	82	-9	-10
11 Accessory Electric Plant	73,922	167	78,735	146	-21	-13
12 Instrumentation & Control	25,730	58	26,588	49	-9	-16
13 Site Preparation	18,780	42	19,241	36	-6	-14
14 Buildings and Structures	16,931	38	17,615	33	-5	-13
Total	1,205,882	2,718	1,331,986	2,472	-246	-9
O&M Cost ($1,000/yr)						
Fixed Costs	**Total**		**Total**		**Δ**	**% Δ**
Labor	22,548		25,555		7	0
Variable Operating Costs*	**Total**		**Total**			
Maintenance Materials	21,569		24,357		2,788	13
Water	1,732		1,885		153	9
Chemicals	1,838		2,115		277	15
Waste Disposal	2,560		2,965		405	16
Total Variable Costs	27,698		31,322		3,624	13
Total O&M Cost	50,247		56,877		6,630	13
Fuel Cost*	62,938		73,314		10,376	16
Discounted Cash Flow Results, levelized						
Capital Cost ($/kW-hr)	0.0679		0.0617			-9
Fixed O&M Cost ($/kW-hr)	0.0084		0.0078			-7
Variable O&M Cost ($/kW-hr)	0.0103		0.0096			-7
Fuel Cost ($/kW-hr)	0.0243		0.0233			-4
TS&M Cost ($/kW-hr)	0.0039		0.0039			0
Levelized COE ($/kW-hr)	0.1148		0.1064			-7

*Includes 80 % Capacity Factor

When the advanced "F" turbine is incorporated into the non-capture cases, TPC decreases by about 17 % (on a $/kW basis); the relative reduction in TPC is somewhat less for the carbon capture cases (9 %). Three primary reasons for this are (1) the cost of the main air compressor increases (rather than decreases) because there is no air integration in the advanced "F" turbine carbon capture case, (2) the bottom-line TPC is greater for the capture cases (because of greater coal throughput than the non-capture cases and also the additional cost for shift, two-stage Selexol, and CO_2 removal and compression) so the percentage decrease in TPC is more difficult to attain, and (3) the incremental net power generated in the carbon capture cases (95 MW) is less than the non-capture cases (150 MW) which results in less of a decrease in TPC on a $/kW basis. The advanced “F” hydrogen turbine in the carbon capture cases results in a smaller percentage decrease in TPC on a $/kW basis than in the non-capture cases.

Corresponding with the 9 % decrease in TPC (on a $/kW basis) from the carbon capture reference plant to the advanced “F” turbine plant, the COE decreases by about 7 % – from $0.1148/kW-hr to $0.1064/kW-hr. That result is based on 80 % capacity factor. The decrease in COE between the carbon capture cases is less than in the non-capture cases for all the same reasons as the TPC.

3.3 COAL FEED PUMP

The coal feed pump replaces the slurry feed system, delivering as-received coal to the gasifier which eliminates the energy required to evaporate slurry water in the gasifier thereby increasing cold gas efficiency of the gasifier.

Case Configuration: Coal Feed Pump, Cryogenic ASU, Cold Gas Cleanup, Advanced “F” Hydrogen Turbine, 80 % Capacity Factor

This process configuration, shown in Figure 3-3, is identical to that in Figure 3-2 except that as-received coal is delivered to the gasifier rather than coal slurry. Dry feed has the advantage of less energy consumed in the gasifier to evaporate water from the slurry, resulting in a greater portion of the coal feed converted to CO (rather than CO_2) in the raw syngas.

The raw syngas composition in this case has much less water than the previous case because of the dry feed. Due to the higher cold gas efficiency of the gasifier, less coal is needed in this case, so the molar flowrate of raw syngas is also less. The concentration of CO is much greater due to not having to oxidize as much carbon in the gasifier in order to evaporate slurry water. The absence of moisture from slurry water in the coal feed pump case also means that relatively more shift steam must be added.

Table 3-6 illustrates the primary differences in process performance resulting from slurry feed versus dry feed gasifier operation. Total power production is 45 MW less in the coal feed pump case because of less power recovered by the steam cycle – due primarily to (1) less heat recovered by the gasifier radiant cooler and syngas cooling section as the result of decreased coal throughput and less molar flow because there is less water in the syngas, and (2) additional shift steam generation due to the lack of water in the coal feed. Auxiliary power consumption relative to the coal feed rate is essentially constant; the reduction in ASU parasitic load correlates to the drop in coal feed rate. Overall, the net power generated in the coal feed pump case is 29 MW less than the slurry feed case, but the coal feed rate required to achieve the 232 MWe gas turbine rating is also significantly lower – resulting in an improved net plant efficiency from 31.7 % to 32.5 %.

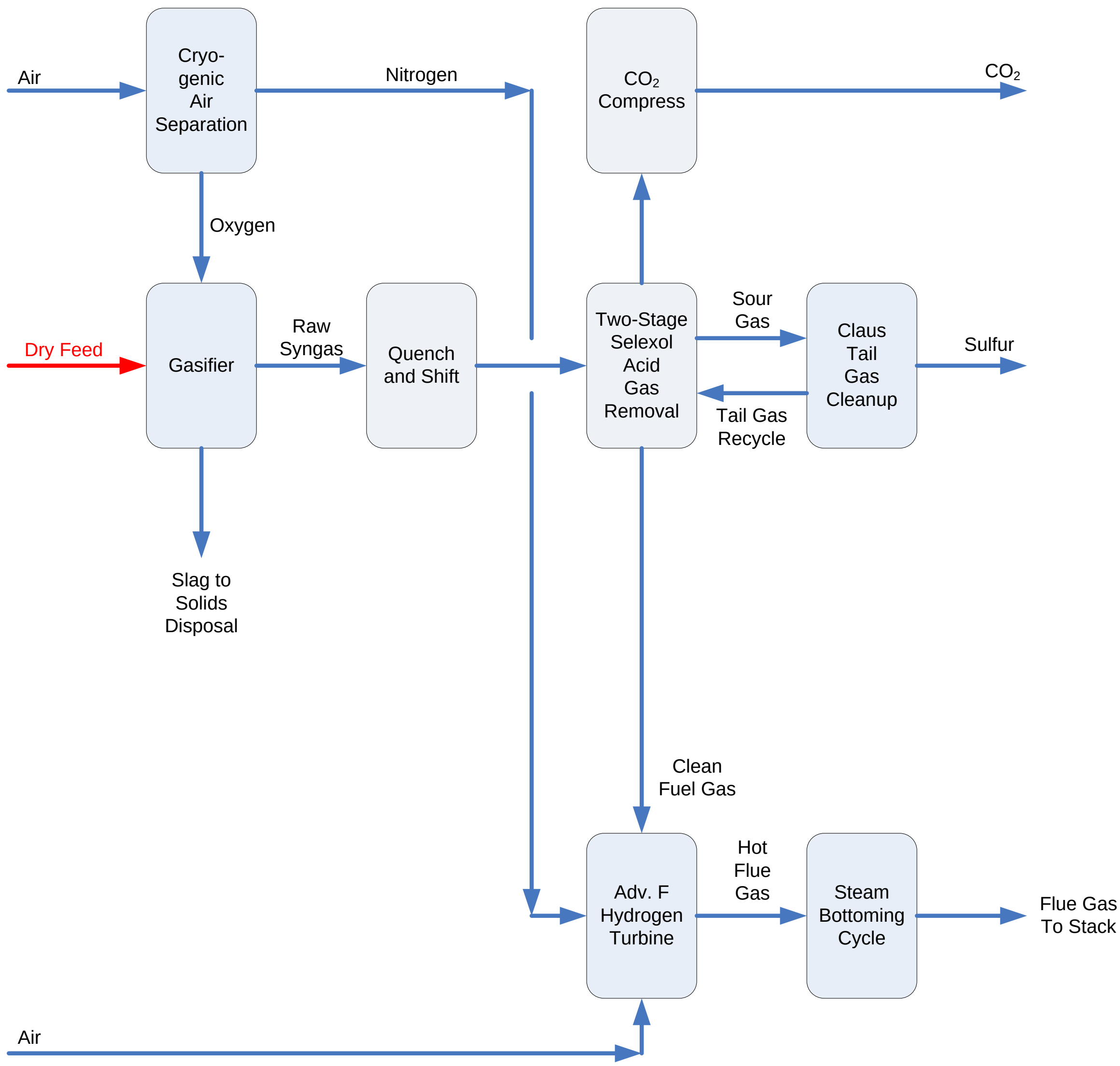

Figure 3-3. Coal Feed Pump Plant Configuration

Table 3-6. Incremental Performance Improvement from the Coal Feed Pump

	Advanced "F" Turbine	Coal Feed Pump
Gas Turbine Power (MWe)	464	464
Fuel Gas Expander (MWe)	7	7
Steam Turbine Power (MWe)	274	228
Total Power Produced (MWe)	744	699
Auxiliary Power Use (MWe)	-206	-189
Net Power (MWe)	539	510
As-Received Coal Feed (lb/hr)	496,865	459,257
Net Heat Rate (Btu/kW-hr)	10,755	10,497
Net Plant Efficiency (HHV)	31.7 %	32.5 %
Gasifier Cold Gas Efficiency	76.1 %	81.9 %

In the non-capture cases, the coal feed pump improves process efficiency by 2.1 percentage points. Compared to the 0.8 percentage point efficiency improvement for the carbon capture cases, the coal feed pump represents less of an improvement to the carbon capture cases because of the increase in shift steam that must be generated in the absence of slurry water.

Cost Analysis

See Appendix A for NETL's update to capital cost and COE.

Capital and O&M costs are compared with the slurry feed case results in Table 3-7. Total plant cost generally decreases in the coal feed pump case due to less coal feed rate, and therefore smaller equipment sizes. The cost per kilowatt remains about the same in most cost accounts, however, because of decreased power production.

The gas turbine and HRSG absolute costs do not change between cases because these remain the same size due to the fixed power output of the advanced "F" turbine; however, the costs on a $/kW basis increase for these plant sections in the coal feed pump case due to the decreased net power output.

The $74 MM reduction in TPC from the slurry feed case to the dry feed case is almost the same as the $80 MM reduction in the non-capture cases. However, decreased power production in the carbon capture cases results in only a $7/kW reduction in TPC compared to the $60/kW reduction in the non-capture cases. The capital cost advantage of the coal feed pump is not as great in the carbon capture scenario as it is in the non-capture scenario.

The slight change in TPC for the carbon capture coal feed pump case translates to a slight reduction in COE from $0.1064/kW-hr to $0.1054/kW-hr – a 1.0 % decrease in COE.

Table 3-7. Coal Feed Pump: Capital and O&M Cost Comparison

	Advanced "F" Turbine		Coal Feed Pump		Δ	
Capital Cost ($1,000)						
Plant Sections	**TPC**	**TPC $/kW**	**TPC**	**TPC $/kW**	**Δ TPC $/kW**	**% Δ**
1 Coal and Sorbent Handling	35,118	65	33,445	66	1	2
2 Coal and Sorbent Prep & Feed	56,449	105	55,442	109	4	4
3 Feedwater & Balance of Plant	38,079	71	34,231	67	-4	-6
4a Gasifier	266,942	495	247,284	485	-10	-2
4b Air Separation Unit	194,517	361	173,695	340	-21	-6
5a Gas Cleanup	230,927	428	226,119	443	15	4
5b CO_2 Removal & Compression	48,578	90	45,607	89	-1	-1
6 Gas Turbine	131,969	245	132,079	259	14	6
7 HRSG	53,454	99	53,439	105	6	6
8 Steam Cycle and Turbines	62,886	117	55,118	108	-9	-8
9 Cooling Water System	26,771	50	24,402	48	-2	-4
10 Waste Solids Handling System	44,115	82	39,732	78	-4	-5
11 Accessory Electric Plant	78,735	146	75,981	149	3	2
12 Instrumentation & Control	26,588	49	25,937	51	2	4
13 Site Preparation	19,241	36	18,958	37	1	3
14 Buildings and Structures	17,615	33	16,627	33	0	0
Total	1,331,986	2,472	1,258,097	2,465	-7	0
O&M Cost ($1,000/yr)						
Fixed Costs	**Total**		**Total**		**Δ**	**% Δ**
Labor	25,555		24,051		-1,504	-6
Variable Operating Costs*	**Total**		**Total**			
Maintenance Materials	24,357		23,273		-1,084	-4
Water	1,885		1,434		-451	-24
Chemicals	2,115		1,969		-146	-7
Waste Disposal	2,965		2,502		-463	-16
Total Variable Costs	31,322		29,179		-2,143	-7
Total O&M Cost	56,877		53,230		-3,647	-6
Fuel Cost*	73,314		67,765		-5,549	-8
Discounted Cash Flow Results, levelized						
Capital Cost ($/kW-hr)	0.0617		0.0616			0
Fixed O&M Cost ($/kW-hr)	0.0078		0.0078			0
Variable O&M Cost ($/kW-hr)	0.0096		0.0094			-2
Fuel Cost ($/kW-hr)	0.0233		0.0228			-2
TS&M Cost ($/kW-hr)	0.0039		0.0039			0
Levelized COE ($/kW-hr)	0.1064		0.1054			-1

*Includes 80 % Capacity Factor

3.4 INCREASED CAPACITY FACTOR TO 85 %

In this case, the process configuration and process performance remain the same as the previous case, but the capacity factor increases from 80 % to 85 %. The increased power production resulting from more time on-line reflects anticipated improvements in process reliability, availability, and maintainability (RAM) due to DOE-sponsored R&D in areas such as vessel refractories and improved sensors. In this analysis, it is assumed that these advancements add little additional capital or fixed O&M cost. The increased power production translates into additional revenue, which has a direct positive impact on the COE. Capital and O&M costs are compared in Table 3-8.

See Appendix A for NETL's update to capital cost and COE.

Table 3-8. 85 % Capacity Factor: Capital and O&M Cost Comparison

	Coal Feed Pump		85% Capacity Factor		Δ	
Capital Cost ($1,000)						
Plant Sections	**TPC**	**TPC $/kW**	**TPC**	**TPC $/kW**	**Δ TPC $/kW**	**% Δ**
1 Coal and Sorbent Handling	33,445	66	33,445	66	0	0
2 Coal and Sorbent Prep & Feed	55,442	109	55,442	109	0	0
3 Feedwater & Balance of Plant	34,231	67	34,231	67	0	0
4a Gasifier	247,284	485	247,284	485	0	0
4b Air Separation Unit	173,695	340	173,695	340	0	0
5a Gas Cleanup	226,119	443	226,119	443	0	0
5b CO_2 Removal & Compression	45,607	89	45,607	89	0	0
6 Gas Turbine	132,079	259	132,079	259	0	0
7 HRSG	53,439	105	53,439	105	0	0
8 Steam Cycle and Turbines	55,118	108	55,118	108	0	0
9 Cooling Water System	24,402	48	24,402	48	0	0
10 Waste Solids Handling System	39,732	78	39,732	78	0	0
11 Accessory Electric Plant	75,981	149	75,981	149	0	0
12 Instrumentation & Control	25,937	51	25,937	51	0	0
13 Site Preparation	18,958	37	18,958	37	0	0
14 Buildings and Structures	16,627	33	16,627	33	0	0
Total	1,258,097	2,465	1,258,097	2,465	0	0
O&M Cost ($1,000/yr)						
Fixed Costs	**Total**		**Total**		**Δ**	**% Δ**
Labor	24,051		24,051		0	0
Variable Operating Costs*	**Total**		**Total**			
Maintenance Materials	23,273		24,728		1,455	6
Water	1,434		1,524		90	6
Chemicals	1,969		2,092		123	6
Waste Disposal	2,502		2,659		157	6
Total Variable Costs	29,179		31,003		1,824	6
Total O&M Cost	53,230		55,054		1,824	3
Fuel Cost*	67,765		72,000		4,235	6
Discounted Cash Flow Results, levelized						
Capital Cost ($/kW-hr)	0.0616		0.0579			-6
Fixed O&M Cost ($/kW-hr)	0.0078		0.0073			-6
Variable O&M Cost ($/kW-hr)	0.0094		0.0094			0
Fuel Cost ($/kW-hr)	0.0228		0.0228			0
TS&M Cost ($/kW-hr)	0.0039		0.0039			0
Levelized COE ($/kW-hr)	0.1054		0.1014			-4

Capital cost is not affected by capacity factor, so the TPC is the same in both cases. The differences between cases lie in variable O&M costs and fuel cost, which increase by approximately 6 % as the result of increased annual hours of operation. However, the discounted cash flow spreads fixed costs over a greater amount of power production, more than compensating for these additional costs and resulting in an overall decrease in cost of electricity from \$0.1054/kW-hr to \$0.1014/kW-hr – a savings of about 4 % in cost of electricity resulting from increased capacity factor. On a percentage basis, this COE reduction is the same as the reduction for the corresponding non-capture analysis.

3.5 WARM GAS CLEANUP WITH SELEXOL CO_2 SEPARATION

In this case, the primary process improvement is that the cold gas ammonia scrub, mercury filter, Selexol H_2S removal, and Claus tail gas treatment processes are replaced with warm gas cleanup processes. A block flow diagram is presented in Figure 3-4. The warm gas transport desulfurization, direct sulfur reduction process (DSRP), novel ammonia removal, and mercury removal technologies are described in Volume 1 Section 3.6. When replacing the cold gas desulfurization section with warm gas desulfurization, the second-stage Selexol absorber is retained in order to separate CO_2 for sequestration.

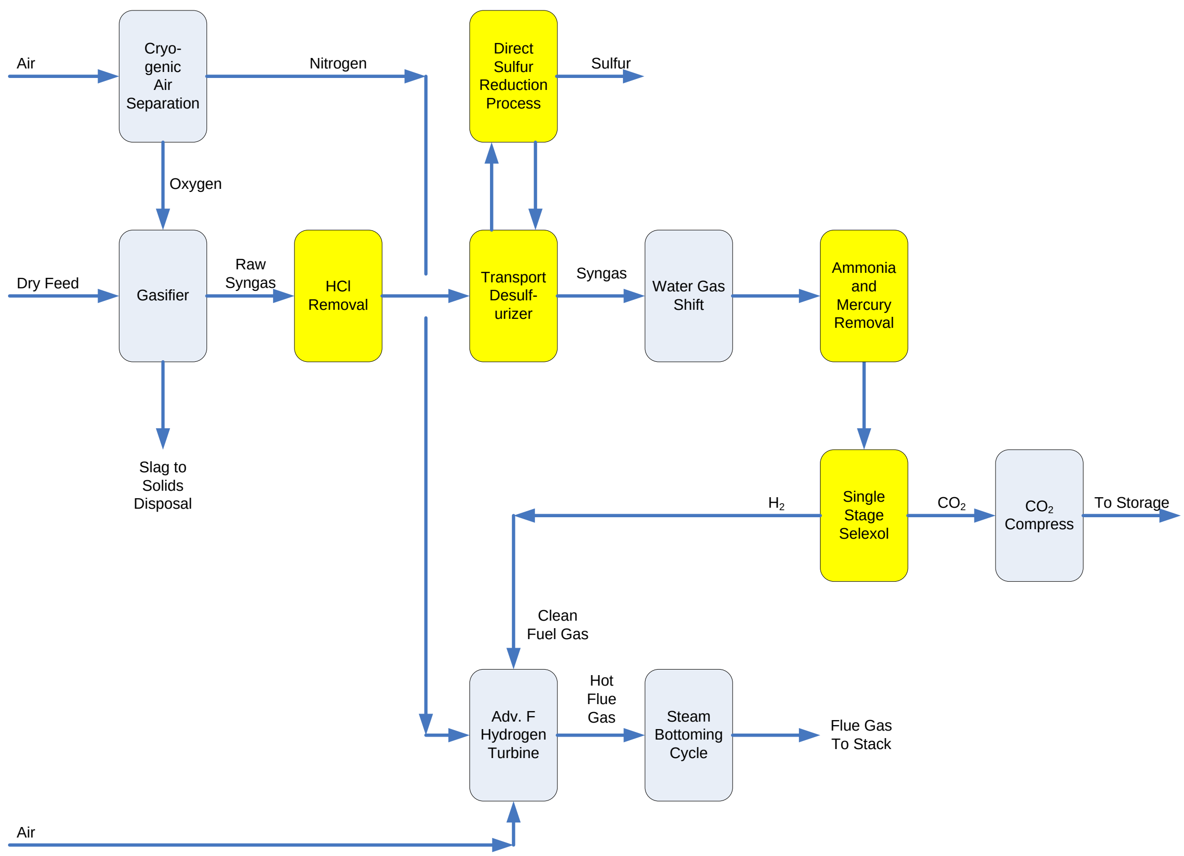

Figure 3-4. Warm Gas Cleanup With Selexol CO_2 Separation

Case Configuration: Coal Feed Pump, Cryogenic ASU, Warm Gas Cleanup, Single-Stage Selexol CO_2 Separation, Advanced "F" Hydrogen Turbine, 85 % Capacity Factor

The cold gas quench section is replaced with convective coolers and a chloride guard bed to remove HCl. This is followed by a transport desulfurizer with associated sorbent regenerator and DSRP.

Following desulfurization, two-stage shift, and warm gas ammonia and mercury removal, the H_2-rich syngas is quenched to remove water, and also to decrease temperature for entry to the Selexol absorber. The Selexol absorber produces low- and intermediate-pressure CO_2 streams that are directly compressed to sequestration pipeline pressure.

Table 3-9 compares process performance between cold gas cleanup and warm gas cleanup with Selexol CO_2 separation. Steam turbine power generation increases by 30 MW due to (1) elimination of the sour water stripper, (2) heat recovery during warm gas cleanup, and (3) greater heat recovery resulting from water gas shift.

Table 3-9. Incremental Performance Improvement from Warm Gas Cleanup

	85 % Capacity Factor	WGCU + Selexol
Gas Turbine Power (MWe)	464	464
Fuel Gas Expander (MWe)	7	8
Steam Turbine Power (MWe)	228	258
Total Power Produced (MWe)	699	730
Auxiliary Power Use (MWe)	-189	-195
Net Power (MWe)	510	535
As-Received Coal Feed (lb/hr)	459,257	469,765
Net Heat Rate (Btu/kW-hr)	10,497	10,243
Net Plant Efficiency (HHV)	32.5 %	33.3 %

The addition of (1) regeneration air compressor for warm gas cleanup, (2) increased N_2 compressor load for fuel diluent flow through the gas turbine, and (3) increased CO_2 compressor load due to increased flow of the CO_2 stream to sequestration are somewhat offset by reduced auxiliary load of the single-stage Selexol absorber, resulting in an auxiliary power increase by 6 MW.

With part of the desulfurized syngas used as reducing gas in the DSRP, slightly greater coal feed rate is needed for warm gas cleanup. The net impact of the higher auxiliary load and increased steam turbine power output is an increase of 25 MW, resulting in an increase in process efficiency from 32.5 % to 33.3 %.

Cost Analysis

See Appendix A for NETL's update to capital cost and COE.

Capital and O&M costs are compared in Table 3-10. The gasifier cost in the WGCU with single-stage Selexol case increases due to increased coal feed rate and addition of the convective heat exchanger; however, due to the 25 MW increase in net power generation, the cost on a $/kW basis decreases slightly. Despite increase in coal feed rate, the ASU cost remains the same because of lower oxygen requirement with the elimination of the Claus plant; ASU cost on a $/kW basis decreases by $16/kW.

Table 3-10. Warm Gas Cleanup With Selexol: Capital and O&M Cost Comparison

	85% Capacity Factor		**WGCU + Selexol**		**Δ**	
Capital Cost ($1,000)						
Plant Sections	**TPC**	**TPC $/kW**	**TPC**	**TPC $/kW**	**Δ TPC $/kW**	**% Δ**
1 Coal and Sorbent Handling	33,445	66	33,920	63	-3	-5
2 Coal and Sorbent Prep & Feed	55,442	109	56,073	105	-4	-4
3 Feedwater & Balance of Plant	34,231	67	34,503	64	-3	-4
4a Gasifier	247,284	485	257,684	482	-3	-1
4b Air Separation Unit	173,695	340	173,180	324	-16	-5
5a Gas Cleanup	226,119	443	240,416	449	6	1
5b CO_2 Removal & Compression	45,607	89	49,505	93	4	4
6 Gas Turbine	132,079	259	132,343	247	-12	-5
7 HRSG	53,439	105	53,848	101	-4	-4
8 Steam Cycle and Turbines	55,118	108	60,188	113	5	5
9 Cooling Water System	24,402	48	25,867	48	0	0
10 Waste Solids Handling System	39,732	78	40,291	76	-2	-3
11 Accessory Electric Plant	75,981	149	77,283	144	-5	-3
12 Instrumentation & Control	25,937	51	26,182	49	-2	-4
13 Site Preparation	18,958	37	19,050	36	-1	-3
14 Buildings and Structures	16,627	33	17,137	32	-1	-3
Total	1,258,097	2,465	1,297,471	2,425	-40	-2
O&M Cost ($1,000/yr)						
Fixed Costs	**Total**		**Total**		**Δ**	**% Δ**
Labor	24,051		24,051		0	0
Variable Operating Costs*	**Total**		**Total**			
Maintenance Materials	24,728		23,634		-1,094	-4
Water	1,524		1,567		43	3
Chemicals	2,092		6,076		3,984	190
Waste Disposal	2,659		2,720		61	2
Total Variable Costs	31,003		33,997		2,994	10
Total O&M Cost	55,054		58,049		2,995	5
Fuel Cost*	72,000		73,648		1,648	2
Discounted Cash Flow Results, levelized						
Capital Cost ($/kW-hr)	0.0579		0.0570			-2
Fixed O&M Cost ($/kW-hr)	0.0073		0.0070			-4
Variable O&M Cost ($/kW-hr)	0.0094		0.0099			5
Fuel Cost ($/kW-hr)	0.0228		0.0222			-3
TS&M Cost ($/kW-hr)	0.0039		0.0039			0
Levelized COE ($/kW-hr)	0.1014		0.1000			-1

*Includes 85 % Capacity Factor

Although the cost of warm gas cleanup is significantly less than two-stage Selexol, the cost of gas cleanup increases by $14 MM ($6/kW) because of the incremental cost of the second-stage Selexol absorber.

The slight $4/kW increase in cost of CO_2 compression in the warm gas cleanup case is due to slightly greater coal feed rate and therefore increased CO_2 product, and also a slightly more dilute stream (and therefore increased flowrate) from single-stage Selexol than from the two-stage Selexol section.

Overall, TPC increases by $39 MM but because of increased net power output, capital cost decreases by $40/kW.

Variable O&M costs increase by 10 % in the warm gas cleanup case primarily due to the cost of ZnO sorbent used in the transport desulfurizer. Fuel cost increases slightly, due to the 2 % increase in coal feed rate to the process.

With only small variations in both capital and operating expenses, all terms resulting from the discounted cash flow calculation are very similar, with a net reduction in COE from $0.1014/kW-hr to $0.1000/kW-hr – a 1 % decrease.

3.6 WARM GAS CLEANUP WITH HYDROGEN MEMBRANE

An innovative process technology, unique to the carbon capture configuration, is the hydrogen membrane which separates hydrogen from the warm syngas stream exiting the mercury and ammonia removal section. Hydrogen is removed at low partial pressure over two membrane stages; low partial pressure is achieved using N_2 sweep gas from the ASU. To purify for pipeline transport and sequestration, the CO_2-rich non-permeate is compressed to a liquid phase, and non-condensibles are separated and returned to the topping combustor. One benefit of the hydrogen membrane is that the CO_2 non-permeate is at high pressure, significantly reducing compressor load for sequestration.

Case Configuration: Coal Feed Pump, Cryogenic ASU, Warm Gas Cleanup, Hydrogen Membrane, Advanced "F" Hydrogen Turbine, 85 % Capacity Factor

Figure 3-5 shows a block flow diagram of this process configuration. Following transport desulfurization, the bulk of desulfurized syngas (already at 900 ^oF) is shifted in two stages. The high temperature shift operates at 650 ^oF, while the low temperature shift operates at 460 ^oF (a good temperature match for the novel ammonia and mercury removal section). Sufficient steam must be added to convert CO to CO_2 in order to achieve 90 % carbon capture. The low temperature shift favors H_2 formation, which is why water gas shift in the H_2 membrane, operating at higher temperature (700 ^oF), is not desired.

Clean syngas from mercury and ammonia removal is reheated to the membrane operating temperature (700 ^oF is mid-range of anticipated operating temperatures), and then it enters a two-stage hydrogen membrane separator. Each membrane stage separates 68 % of the available H_2 for a total of 90 % recovery. The permeate pressure of each stage is set to the turbine fuel valve pressure. The fuel flowrate is set to achieve a turbine exit temperature of 1,050 °F. The net gas turbine power output is 232 MWe per unit.

The CO_2-rich non-permeate from the membrane is cooled for heat recovery, and moisture is removed. The CO_2 is compressed to 2,200 psig for transport to sequestration. During compression, the CO_2–rich stream, at slightly greater than 80 mole % purity, is condensed in order to recover impurities (primarily N_2, CO, and H_2) which are returned to the topping combustor.

All available process heat is collected for steam generation in the bottoming cycle. Superheated steam is expanded through three turbines, with reheat after the high pressure turbine. The bottoming cycle also provides heat for shift steam generation.

Table 3-11 summarizes the overall performance for two process trains. Heat recovery increases in the hydrogen membrane case as the result of eliminating the Selexol reboiler duty, thereby increasing steam turbine power by 9 MW.

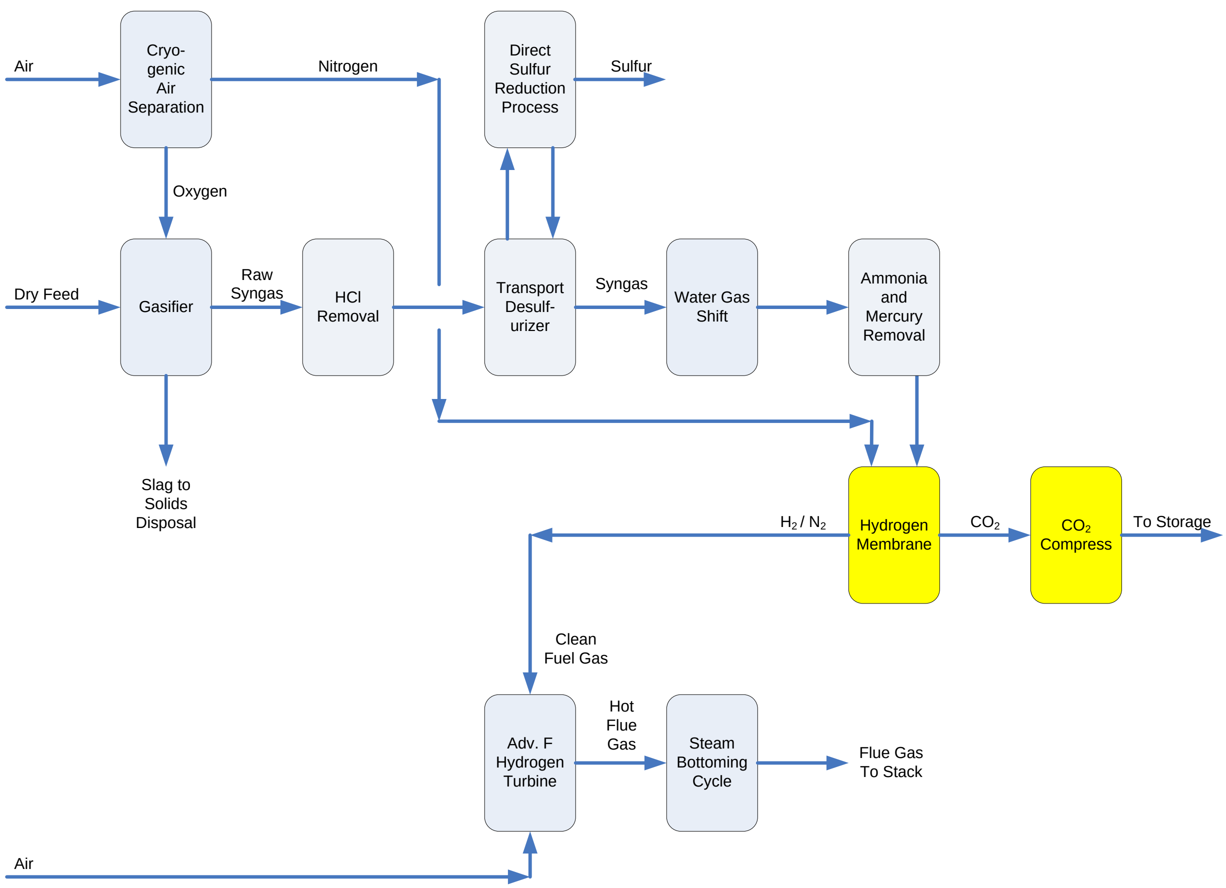

Figure 3-5. Warm Gas Cleanup With Hydrogen Membrane

Table 3-11. Incremental Performance Improvement from Hydrogen Membrane

	Warm Gas Cleanup + Selexol	Warm Gas Cleanup + H_2 Membrane
Gas Turbine Power (MWe)	464	464
Fuel Gas Expander (MWe)	8	NA
Steam Turbine Power (MWe)	258	267
Total Power Produced (MWe)	730	731
Auxiliary Power Use (MWe)	-195	-159
Net Power (MWe)	535	572
As-Received Coal Feed (lb/hr)	469,765	462,174
Net Heat Rate (Btu/kW-hr)	10,243	9,430
Net Plant Efficiency	33.3 %	36.2 %

Despite losing 8 MW from the fuel gas expander, the 9 MW increase in steam turbine power generation and the 36 MW decrease in auxiliary power results in a 37 MW increase in net power generation. The primary contributions to the decrease in auxiliary power are a 23 MW (60 %) reduction in CO_2 compression (because of high CO_2 delivery pressure from the hydrogen membrane) and elimination of Selexol auxiliaries for 13 MW.

With a slight decrease in coal feed rate, the net result is a plant efficiency increase by 2.9 percentage points from 33.3 % to 36.2 %.

Cost Analysis

See Appendix A for NETL's update to capital cost and COE.

Capital and O&M costs are compared in Table 3-12. Total plant cost for coal handling, coal feed, gasifier, ASU, and general plant (cooling water system, waste handling, site preparation, and buildings) accounts are very similar because the coal flowrates in both cases are nearly the same; TPC decreases by about 7 % on a $/kW basis for these accounts in the hydrogen membrane case because of greater net power production.

Gas cleanup cost decreases significantly due to replacing the gas quench, second-stage Selexol absorber, and fuel reheat equipment with the less-expensive H_2 membrane; the net reduction in gas cleanup cost is $92 MM, and the TPC reduction on a $/kW basis is $189/kW. The bare erected cost of the hydrogen membrane is based on a technology development target cost of $450 per square foot of membrane surface area, and with a service life of 5 years.

CO_2 compression cost decreases by $49/kW in the hydrogen membrane case because of decreased CO_2 compressor load. The high pressure of the non-permeate stream exiting the membrane allows expansion to provide auto-refrigeration to condense and separate CO_2, and the pressure of the expanded stream is still greater than recovery pressure from Selexol.

The cost of the gas turbine account decreases by $8 MM due to elimination of the syngas expander, resulting in a further reduction of $29/kW in TPC. Overall, the TPC of the hydrogen membrane case decreases by $378/kW. O&M costs decrease slightly as the O&M cost is roughly a function of TPC. Fuel cost decreases by 2 % resulting from improved process efficiency in the hydrogen membrane case.

Table 3-12. WGCU/H_2 Membrane: Capital and O&M Cost Comparison

	WGCU + Selexol		WGCU + H_2 Membrane		Δ	
Capital Cost ($1,000)						
Plant Sections	**TPC**	**TPC $/kW**	**TPC**	**TPC $/kW**	**Δ TPC $/kW**	**% Δ**
1 Coal and Sorbent Handling	33,920	63	33,576	59	-4	-6
2 Coal and Sorbent Prep & Feed	56,073	105	55,457	97	-8	-8
3 Feedwater & Balance of Plant	34,503	64	34,308	60	-4	-6
4a Gasifier	257,684	482	255,212	446	-36	-7
4b Air Separation Unit	173,180	324	178,584	312	-12	-4
5a Gas Cleanup	240,416	449	148,432	260	-189	-42
5b CO_2 Removal & Compression	49,505	93	25,392	44	-49	-53
6 Gas Turbine	132,343	247	124,363	218	-29	-12
7 HRSG	53,848	101	53,803	94	-7	-7
8 Steam Cycle and Turbines	60,188	113	61,669	108	-5	-4
9 Cooling Water System	25,867	48	26,288	46	-2	-4
10 Waste Solids Handling System	40,291	76	39,888	70	-6	-8
11 Accessory Electric Plant	77,283	144	73,141	128	-16	-11
12 Instrumentation & Control	26,182	49	24,716	43	-6	-12
13 Site Preparation	19,050	36	18,723	33	-3	-8
14 Buildings and Structures	17,137	32	17,111	30	-2	-6
Total	1,297,471	2,425	1,170,662	2,047	-378	-16
O&M Cost ($1,000/yr)						
Fixed Costs	**Total**		**Total**		**Δ**	**% Δ**
Labor	24,051		22,548		-1,503	-6
Variable Operating Costs*	**Total**		**Total**			
Maintenance Materials	23,634		23,656		22	0
Water	1,567		1,449		-118	-8
Chemicals	6,076		5,688		-388	-6
Membrane Replacement	NA		945		945	∞
Waste Disposal	2,720		2,675		-45	-2
Total Variable Costs	33,997		34,414		417	1
Total O&M Cost	58,049		56,963		-1,086	-2
Fuel Cost*	73,648		72,458		-1,190	-2
Discounted Cash Flow Results, levelized						
Capital Cost ($/kW-hr)	0.0570		0.0481			-16
Fixed O&M Cost ($/kW-hr)	0.0070		0.0061			-13
Variable O&M Cost ($/kW-hr)	0.0099		0.0094			-5
Fuel Cost ($/kW-hr)	0.0222		0.0205			-8
TS&M Cost ($/kW-hr)	0.0039		0.0039			0
Levelized COE ($/kW-hr)	0.1000		0.0880			-12

*Includes 85 % Capacity Factor

The $92 MM reduction in TPC of warm gas cleanup with the H_2 membrane compared to the cost of warm gas cleanup with second-stage Selexol cold gas cleanup process represents the primary cost advantage of this case. A secondary cost incentive is the increase in net power produced by the hydrogen membrane case, which further reduces the TPC on a $/kW basis. Compared to the Selexol process, CO_2 separation via the hydrogen membrane is projected to reduce the levelized COE from $0.1000/kW-hr to $0.0880/kW-hr – a decrease of 12 %.

3.7 ADVANCED HYDROGEN TURBINE, FIRST GENERATION (AHT-1)

DOE sponsors R&D to develop advanced turbine technology with improved performance efficiency. For the purposes of this analysis, this advanced hydrogen turbine is named AHT-1. Performance improvement is expected primarily from higher turbine inlet temperature, which will improve efficiency of the turbine over exiting state-of-the-art. A block flow diagram of an advanced turbine case is presented in Figure 3-6. In addition to modified turbine performance parameters, steam cycle superheat and reheat temperatures increase to 1,050 ^oF resulting from increased turbine exit temperature, and air integration becomes possible.

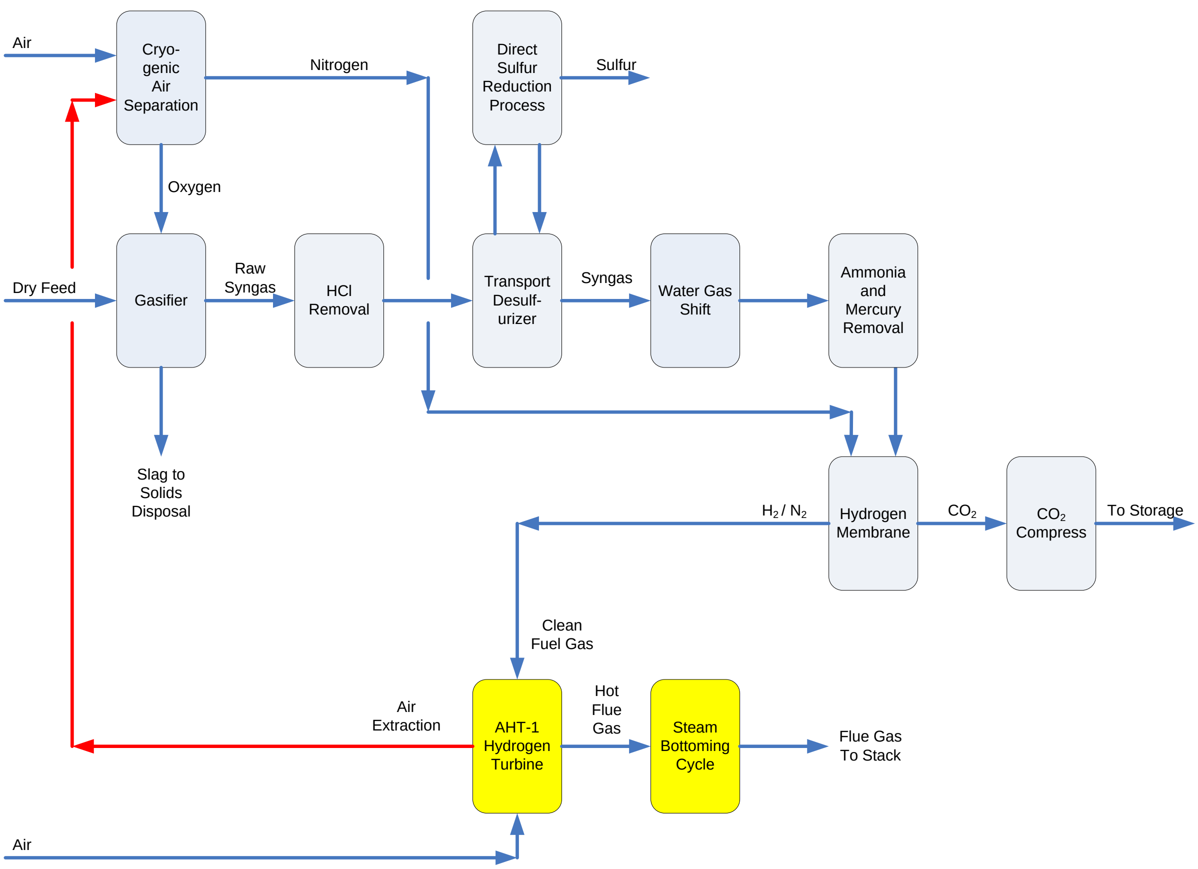

Figure 3-6. Advanced Hydrogen Turbine AHT-1

Case Configuration: Coal Feed Pump, Cryogenic ASU, Warm Gas Cleanup, Hydrogen Membrane, AHT-1 Turbine, 85 % Capacity Factor

Table 3-13 demonstrates improved overall process performance when the advanced "F" hydrogen turbine is replaced with a somewhat larger and more advanced AHT-1 turbine.

Gas turbine power increases by 36 MW due to the improved AHT-1 turbine. The higher pressure ratio and slightly greater throughput contribute to improved turbine performance. The turbine exit temperature limitation of 1,050 ^oF is lifted in the AHT-1 turbine due to expectations that R&D will provide improved materials to withstand high flue gas moisture content.

The 40 MW increase in steam turbine power results somewhat from increased coal feed rate (and associated process and HRSG heat recovery), but more importantly from increased steam superheat and reheat temperature to 1,050 ^oF which improves the heat rate (Carnot efficiency) of the bottoming cycle.

Auxiliary power use decreases by 11 MW due to air integration, which decreases the parasitic load on the ASU main air compressor.

Table 3-13. Incremental Performance Improvement from the AHT-1 Turbine

	WGCU+H_2 Membrane	AHT-1 Turbine
Gas Turbine Power (MWe)	464	500
Steam Turbine Power (MWe)	267	307
Total Power Produced (MWe)	731	807
Auxiliary Power Use (MWe)	-159	-148
Net Power (MWe)	572	659
As-Received Coal Feed (lb/hr)	462,174	506,903
Net Heat Rate (Btu/kW-hr)	9,430	8,976
Net Plant Efficiency (HHV)	36.2 %	38.0 %

Increased steam turbine power and reduced auxiliary power, together with a significant increase in gas turbine power, are responsible for the increased process efficiency from 36.2 % to 38.0 % – an increase of 1.8 percentage points. Because of the H_2-rich fuel in the carbon capture cases, operating constraints limit the performance of the advanced "F" turbine (introduced previously), specifically; (1) gas turbine and steam cycle performance are lower than in a non-capture scenario because of turbine exhaust temperature limit, and (2) due to the reduced volume of H_2-rich gas relative to syngas, no air integration is possible, which impacts ASU auxiliary load. These constraints are removed with advancement to the AHT-1 and, since those constraints never applied to the non-capture advanced turbine case, the impact of the AHT-1 advancement is greater in the carbon capture case (1.8 percentage point improvement) than in the non-capture case (1.0 percentage point improvement).

Cost Analysis

See Appendix A for NETL's update to capital cost and COE.

Capital and O&M costs are compared with results from the previous case in Table 3-14. Total plant cost for all sections increases due to the increased plant size. Because the AHT-1 produces more power, TPC decreases on a $/kW basis for all cost accounts.

Table 3-14. AHT-1 Turbine: Capital and O&M Cost Comparison

	WGCU + H_2 Membrane		**AHT-1 Turbine**		**Δ**	
Capital Cost ($1,000)						
Plant Sections	**TPC**	**TPC $/kW**	**TPC**	**TPC $/kW**	**Δ TPC $/kW**	**% Δ**
1 Coal and Sorbent Handling	33,576	59	35,559	54	-5	-8
2 Coal and Sorbent Prep & Feed	55,457	97	59,024	90	-7	-7
3 Feedwater & Balance of Plant	34,308	60	35,442	54	-6	-10
4a Gasifier	255,212	446	271,147	412	-34	-8
4b Air Separation Unit	178,584	312	180,416	274	-38	-12
5a Gas Cleanup	148,432	260	159,141	242	-18	-7
5b CO_2 Removal & Compression	25,392	44	27,860	42	-2	-5
6 Gas Turbine	124,363	218	125,785	191	-27	-12
7 HRSG	53,803	94	55,802	85	-9	-10
8 Steam Cycle and Turbines	61,669	108	68,004	103	-5	-5
9 Cooling Water System	26,288	46	27,662	42	-4	-9
10 Waste Solids Handling System	39,888	70	42,224	64	-6	-9
11 Accessory Electric Plant	73,141	128	73,134	111	-17	-13
12 Instrumentation & Control	24,716	43	24,207	37	-6	-14
13 Site Preparation	18,723	33	18,795	29	-4	-12
14 Buildings and Structures	17,111	30	17,654	27	-3	-10
Total	1,170,662	2,047	1,221,858	1,855	-192	-9
O&M Cost ($1,000/yr)						
Fixed Costs	**Total**		**Total**		**Δ**	**% Δ**
Labor	22,548		24,051		1,503	7
Variable Operating Costs*	**Total**		**Total**			
Maintenance Materials	23,656		25,370		1,714	7
Water	1,449		1,508		59	4
Chemicals	5,688		6,245		557	10
Membrane Replacement	945		1,041		96	10
Waste Disposal	2,675		2,935		260	10
Total Variable Costs	34,414		37,098		2,684	8
Total O&M Cost	56,963		61,150		4,187	7
Fuel Cost*	72,458		79,470		7,012	10
Discounted Cash Flow Results, levelized						
Capital Cost ($/kW-hr)	0.0481		0.0436			-9
Fixed O&M Cost ($/kW-hr)	0.0061		0.0057			-7
Variable O&M Cost ($/kW-hr)	0.0094		0.0087			-7
Fuel Cost ($/kW-hr)	0.0205		0.0195			-5
TS&M Cost ($/kW-hr)	0.0039		0.0039			0
Levelized COE ($/kW-hr)	0.0880		0.0814			-8

*Includes 85% Capacity Factor

The cost of the turbine is scaled to the turbine power rating; the increase in power rating of the 232 MW advanced “F” turbine to the 250 MW AHT-1 turbine increases turbine cost by $1,422 K. No cost premium is assumed for higher temperature operation. After accounting for the net power increase in the AHT-1 case, turbine cost decreases by $27/kW.

The TPC decreases by $192/kW as a result of the AHT-1 turbine. This is significantly greater than the $72/kW cost reduction in the non-capture scenario. Contributions of increased steam superheat/reheat temperature and air integration when transitioning from the advanced “F” turbine to the AHT-1 turbine result in an 87 MW increase in net plant power output which, when divided into the TPC, decreases TPC on a $/kW basis more than in the non-capture scenario. The cost reduction is not so much the result of the turbine cost, but the additional power generated by the plant as a consequence of the improved turbine.

The increased O&M and fuel costs reflect larger plant size and increased coal throughput. The net reduction in COE from $0.0880/kW-hr to $0.0814/kW-hr represents a 6.6 mills/kW-hr decrease in COE resulting from the AHT-1 turbine. The non-capture scenario, by comparison, results in a 2.7 mills/kW-hr decrease in COE.

3.8 ION TRANSPORT MEMBRANE

In this case, an ITM replaces the cryogenic ASU for oxygen production. Oxygen diffuses through a ceramic wall in the ITM based on partial pressure driving force, and leaves the nitrogen-rich non-permeate as secondary product. The non-permeate remains at high pressure, which is essentially the feed pressure to the ITM, while the oxygen permeate stream is produced at as low a pressure as possible in order to maximize partial pressure driving force for the separation and to reduce oxygen concentration in the non-permeate to as low as 2 mole %. The high pressure of the non-permeate stream is one of the advantages of the ITM; it eliminates the need for the N_2 compressor – reducing auxiliary power consumption, but that is partially offset by the increased power consumption of the ITM boost and oxygen compressors. The primary advantage of the ITM, however, is the reduced capital cost of air separation relative to a cryogenic ASU.

Case Configuration: Coal Feed Pump, Ion Transport Membrane, Warm Gas Cleanup, Hydrogen Membrane, AHT-1 Turbine, 85 % Capacity Factor

A block flow diagram of this process is shown in Figure 3-7.

The fraction of air integration is varied in order to meet the turbine power rating of 250 MW per unit. Coal feed rate (and therefore fuel flow) is adjusted to satisfy the turbine inlet temperature of 2,550 ^{o}F. Table 3-15 below compares overall process performance improvement due to air separation using the ITM.

Steam turbine power increases by 40 MW in the ITM case due to increased coal feed rate (and therefore heat recovery throughout the process) and also heat recovery from hot sweep gas from the ITM to the hydrogen membrane (as opposed to heating cold sweep gas from the cryogenic ASU in the previous case).

Although elimination of the nitrogen compressor in the ITM case decreases auxiliary load, it is counterbalanced by the ITM boost compressor and the oxygen compressor loads. The net auxiliary power increases by 8 MW.

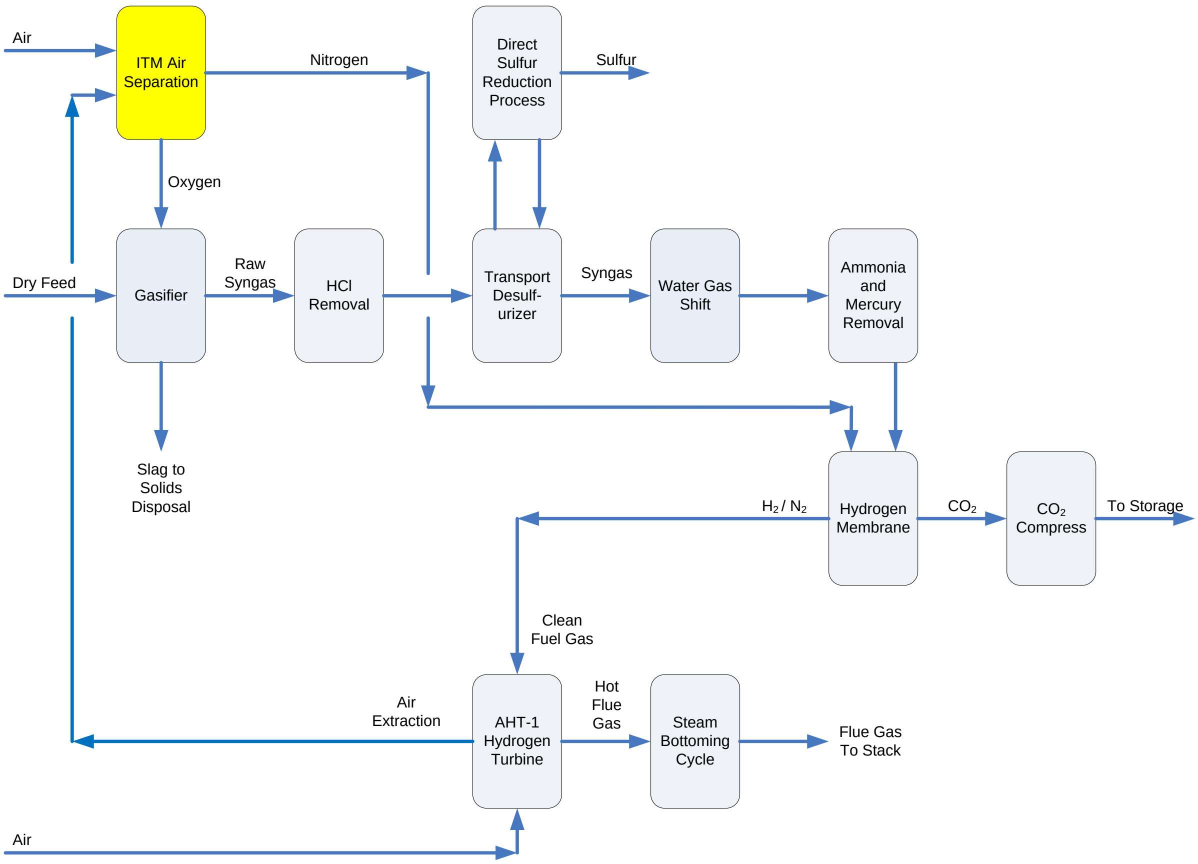

Figure 3-7. IGCC Process With ITM Air Separation

Table 3-15. Incremental Performance Improvement from the ITM

	AHT-1 Turbine	ITM
Gas Turbine Power (MWe)	500	500
Steam Turbine Power (MWe)	307	347
Total Power Produced (MWe)	807	847
Auxiliary Power Use (MWe)	-148	-156
Net Power (MWe)	659	691
As-Received Coal Feed (lb/hr)	506,903	527,717
Net Heat Rate (Btu/kW-hr)	8,976	8,908
Net Plant Efficiency (HHV)	38.0 %	38.3 %

The additional 32 MW net power generated in the ITM case is accompanied by increased coal feed required to (1) provide fuel to heat the ITM, and (2) to produce H_2 to consume residual oxygen in the sweep gas before it is introduced to the hydrogen membrane. The ITM process results in a 0.3 percentage point improvement in net plant efficiency for the carbon capture scenario.

In the non-capture scenario, process efficiency increases by 0.65 percentage points, and coal feed rate remains essentially unchanged. Of the fuel gas generated in the non-capture ITM case, 10 % of it is used to heat the ITM; in the carbon capture ITM case, only 1 % of the H_2 fuel stream is used to heat the ITM. A recuperator is responsible for reducing the amount of fuel needed to heat the ITM in the carbon capture case. Per discussion with the ITM technology developer, the recuperator would be appropriate for the carbon capture case but not for the non-capture case.

Cost Analysis

See Appendix A for NETL's update to capital cost and COE.

The ITM cost includes main air compressor, ITM boost compressor, recuperator, two membrane stages, air heater, oxygen coolers, oxygen compressors, fluff gas cooler, and fluff gas compressor. The capital cost of the ITM section is assumed to be the target development cost of 67 % that of a comparable cryogenic ASU plant.

Comparing capital costs in Table 3-16, total plant cost for coal handling, coal feed, gasifier, gas cleanup, CO_2 compression, and general plant systems (feedwater, cooling water system, waste handling, site preparation, and buildings) are similar because of similar coal feed rates. Because the ITM case produces 32 MW more power than the cryogenic case, TPC decreases slightly on a $/kW basis for these cost accounts.

The cost of the ASU decreases significantly because the ITM costs 1/3 less than a cryogenic ASU. Coupled with the increased power production, the cost reduction by $100/kW for the ASU is the single greatest contribution to the overall plant TPC reduction.

Gas turbine cost is unchanged. Considering the additional power generation in the ITM case, however, the gas turbine cost decreases by $9/kW. Steam turbine cost increases by $5/kW for the ITM case due to greater heat recovery and steam turbine power generation.

Overall, the $131/kW reduction in TPC is primarily due to capital cost savings in the ASU. The second most important factor in the cost reduction is the 32 MW increase in power generated by the ITM case.

O&M costs remain nearly the same, and fuel cost increases by 4 % due to increased coal feed rate. The reduction in COE from $0.0814/kW-hr to $0.0774/kW-hr, therefore, is due primarily to the decrease in capital cost of the ASU and increased net power production as the result of the ITM.

Table 3-16. ITM: Capital and O&M Cost Summary

	AHT-1 Turbine		ITM		Δ	
Capital Cost ($1,000)						
Plant Sections	**TPC**	**TPC $/kW**	**TPC**	**TPC $/kW**	**Δ TPC $/kW**	**% Δ**
1 Coal and Sorbent Handling	35,559	54	36,457	53	-1	-2
2 Coal and Sorbent Prep & Feed	59,024	90	60,651	88	-2	-2
3 Feedwater & Balance of Plant	35,442	54	35,957	52	-2	-4
4a Gasifier	271,147	412	277,047	401	-11	-3
4b Air Separation Unit	180,416	274	120,312	174	-100	-36
5a Gas Cleanup	159,141	242	167,120	242	0	0
5b CO_2 Removal & Compression	27,860	42	28,687	42	0	0
6 Gas Turbine	125,785	191	125,785	182	-9	-5
7 HRSG	55,802	85	55,904	81	-4	-5
8 Steam Cycle and Turbines	68,004	103	74,327	108	5	5
9 Cooling Water System	27,662	42	29,355	42	0	0
10 Waste Solids Handling System	42,224	64	43,285	63	-1	-2
11 Accessory Electric Plant	73,134	111	74,921	108	-3	-3
12 Instrumentation & Control	24,207	37	24,577	36	-1	-3
13 Site Preparation	18,795	29	18,954	27	-2	-7
14 Buildings and Structures	17,654	27	18,283	26	-1	-4
Total	1,221,858	1,855	1,191,624	1,724	-131	-7
O&M Cost ($1,000/yr)						
Fixed Costs	**Total**		**Total**		**Δ**	**% Δ**
Labor	24,051		22,548		-1,503	-6
Variable Operating Costs*	**Total**		**Total**			
Maintenance Materials	25,370		26,284		914	4
Water	1,508		1,470		-38	-3
Chemicals	6,245		6,535		290	5
Membrane Replacement	1,041		987		-54	-5
Waste Disposal	2,935		3,055		120	4
Total Variable Costs	37,098		38,331		1,233	3
Total O&M Cost	61,150		60,880		-270	0
Fuel Cost*	79,470		82,733		3,263	4
Discounted Cash Flow Results, levelized						
Capital Cost ($/kW-hr)	0.0436		0.0405			-7
Fixed O&M Cost ($/kW-hr)	0.0057		0.0051			-11
Variable O&M Cost ($/kW-hr)	0.0087		0.0086			-1
Fuel Cost ($/kW-hr)	0.0195		0.0193			-1
TS&M Cost ($/kW-hr)	0.0039		0.0039			0
Levelized COE ($/kW-hr)	0.0814		0.0774			-5

*Includes 85 % Capacity Factor

In the non-capture cases, TPC decreases by $82/kW as the result of the ITM. The cost reduction is somewhat greater in the carbon capture scenario, with a $131/kW decrease; the primary factor for larger decrease is the larger ASU required because of increased coal flow in carbon capture scenarios, and therefore greater potential for cost savings. The cost savings in ASU alone is $64/kW in the non-capture scenario versus $100/kW in the carbon capture scenario.

The capital cost reduction due to the ITM is reflected in greater reduction in COE in the carbon capture scenario (by 4.0 mills/kW-hr) than in the non-capture scenario (by 2.6 mills/kW-hr).

3.9 NEXT GENERATION ADVANCED HYDROGEN TURBINE (AHT-2)

DOE sponsors research to develop a turbine with even further improved performance over that of the AHT-1. This is projected to be accomplished with higher firing temperature, increased power rating, and improved stage efficiencies. The pseudonym AHT-2 is used to refer to this advanced hydrogen turbine.

Case Configuration: Dry Feed Gasifier, ITM, Warm Gas Cleanup, Hydrogen Membrane, AHT-2 Turbine, 85 % Capacity Factor

The process block flow diagram of this IGCC process with the AHT-2 hydrogen turbine is identical to Figure 3-7 above. A single train produces a net 502 MW of power. Overall efficiency is 40.0 % (HHV basis). Carbon utilization is 99.5 % and the capacity factor is 85 %. Performance resulting from the AHT-2 turbine is compared to the AHT-1 in Table 3-17.

Table 3-17. Incremental Performance Improvement from AHT-2 Turbine

	ITM	AHT-2 Turbine
Gas Turbine Power (MWe)	500	370
Steam Turbine Power (MWe)	347	232
Total Power Produced (MWe)	847	602
Auxiliary Power Use (MWe)	-156	-100
Net Power (MWe)	691	502
As-Received Coal Feed (lb/hr)	527,717	366,990
Net Heat Rate (Btu/kW-hr)	8,908	8,524
Net Plant Efficiency (HHV)	38.3 %	40.0 %

The overall decrease in net power generation is due to reducing the plant from two trains of AHT-1 turbines to a single train of AHT-2 turbine in order to maintain the nominal plant output of 600 MW. The decrease in coal feed rate results in less steam turbine power generation and less auxiliary power from a smaller plant. Net plant efficiency improves by 1.7 percentage points as the result of higher pressure ratio and improved engine efficiency of the AHT-2.

In the non-capture scenario, introduction of the next-generation advanced syngas turbine increases process efficiency by 2.0 percentage points above that of the first generation advanced turbine. The efficiency improvement is dampened in the carbon capture scenario because of (1) increased coal feed rate per MW of gas turbine power in carbon capture versus non-capture cases, and (2) increased auxiliary power for oxygen production (resulting from increased coal feed) and CO_2 compression.

Cost Analysis

See Appendix A for NETL's update to capital cost and COE.

Capital and O&M costs are compared in Table 3-18. The TPC in all accounts decreases because of reduced coal flowrate and decreased plant equipment size, and therefore cost. The number of process trains (consisting of gasifier, ASU, gas cleanup, CO_2 compression, and gas turbine) decreases from two to one. In each of these process sections, TPC on a $/kW basis decreases because of economy of scale for a single large train. All other process section accounts increase on a $/kW basis because of the decrease in net power production; this introduces a reverse economy of scale for those other process sections.

Table 3-18. AHT-2 Turbine (Single-Train): Capital and O&M Cost Summary

	ITM		AHT-2 Turbine (Single Train)		Δ	
Capital Cost ($1,000)						
Plant Sections	**TPC**	**TPC $/kW**	**TPC**	**TPC $/kW**	**Δ TPC $/kW**	**% Δ**
1 Coal and Sorbent Handling	36,457	53	29,100	58	5	9
2 Coal and Sorbent Prep & Feed	60,651	88	47,465	95	7	8
3 Feedwater & Balance of Plant	35,957	52	31,740	63	11	21
4a Gasifier	277,047	401	173,608	346	-55	-14
4b Air Separation Unit	120,312	174	77,413	154	-20	-11
5a Gas Cleanup	167,120	242	109,378	218	-24	-10
5b CO_2 Removal & Compression	28,687	42	19,957	40	-2	-5
6 Gas Turbine	125,785	182	83,208	166	-16	-9
7 HRSG	55,904	81	41,401	82	1	1
8 Steam Cycle and Turbines	74,327	108	55,760	111	3	3
9 Cooling Water System	29,355	42	24,243	48	6	14
10 Waste Solids Handling System	43,285	63	34,607	69	6	10
11 Accessory Electric Plant	74,921	108	62,181	124	16	15
12 Instrumentation & Control	24,577	36	21,672	43	7	19
13 Site Preparation	18,954	27	17,652	35	8	30
14 Buildings and Structures	18,283	26	16,184	32	6	23
Total	1,191,624	1,724	845,569	1,683	-41	-2
O&M Cost ($1,000/yr)						
Fixed Costs	**Total**		**Total**		**Δ**	**% Δ**
Labor	22,548		16,535		-6,013	-27
Variable Operating Costs*	**Total**		**Total**			
Maintenance Materials	26,284		20,751		-5,533	-21
Water	1,470		1,110		-360	-24
Chemicals	6,535		4,565		-1,970	-30
Membrane Replacement	987		692		-295	-30
Waste Disposal	3,055		2,125		-930	-30
Total Variable Costs	38,331		29,242		-9,089	-24
Total O&M Cost	60,880		45,777		-15,103	-25
Fuel Cost*	82,733		57,535		-25,198	-30
Discounted Cash Flow Results, levelized						
Capital Cost ($/kW-hr)	0.0405		0.0396			-2
Fixed O&M Cost ($/kW-hr)	0.0051		0.0051			0
Variable O&M Cost ($/kW-hr)	0.0086		0.0090			5
Fuel Cost ($/kW-hr)	0.0193		0.0185			-4
TS&M Cost ($/kW-hr)	0.0039		0.0039			0
Levelized COE ($/kW-hr)	0.0774		0.0761			-2

*Includes 85 % Capacity Factor

Overall, the total plant cost decreases by $346 MM going to a single train of the AHT-2 turbine. On a $/kW basis, the carbon capture plant with the AHT-2 turbine decreases by $41/kW or 2 %. In the non-capture cases, by comparison, TPC decreases by $319 MM and by $15/kW on a $/kW basis. The effect of the AHT-2 turbine on TPC is nearly the same in both capture and non-capture scenarios.

O&M cost reductions going from the two-train AHT-1 case to the single train AHT-2 case are also very similar between both non-capture and the capture scenarios.

The COE reduction from $0.0774/kW-hr to $0.0761/kW-hr in the carbon capture scenario (by 2 %) is similar to the 1 % decrease in COE in the non-capture scenario.

Two-Train Configuration

The discussion above features a single-train AHT-2 configuration that is constrained by the nominal plant size of 600 MW, which is the basis for this study. That process encounters a reverse economy of scale when the net plant power output is reduced to only 502 MW. If the process were allowed to maintain two power trains, with a net plant output of 1,004 MW, the process economics presented in Table 3-19 benefit from economy of scale compared to the previous case with the AHT-1 turbine.

The TPC in all accounts increases because of increased net power production, which corresponds to increased coal flowrate and increased plant equipment size, and therefore cost. On a $/kW basis, however, TPC decreases in all capital cost accounts. The bottom-line TPC decreases from $1,724/kW for the AHT-1 plant to $1,470/kW for the AHT-2 plant – a decrease of 15 %. COE then decreases by 11 % from $0.0774/kW-hr to $0.0692/kW-hr.

Table 3-19. AHT-2 Turbine (Two-Train): Capital and O&M Cost Summary

	ITM		AHT-2 Turbine (Two Trains)		Δ	
Capital Cost ($1,000)						
Plant Sections	**TPC**	**TPC $/kW**	**TPC**	**TPC $/kW**	**Δ TPC $/kW**	**% Δ**
1 Coal and Sorbent Handling	36,457	53	44,741	45	-8	-15
2 Coal and Sorbent Prep & Feed	60,651	88	75,780	75	-13	-15
3 Feedwater & Balance of Plant	35,957	52	40,708	41	-11	-21
4a Gasifier	277,047	401	344,033	342	-59	-15
4b Air Separation Unit	120,312	174	151,449	151	-23	-13
5a Gas Cleanup	167,120	242	213,905	213	-29	-12
5b CO_2 Removal & Compression	28,687	42	39,914	40	-2	-5
6 Gas Turbine	125,785	182	166,417	166	-16	-9
7 HRSG	55,904	81	68,483	68	-13	-16
8 Steam Cycle and Turbines	74,327	108	91,706	91	-17	-16
9 Cooling Water System	29,355	42	33,800	34	-8	-19
10 Waste Solids Handling System	43,285	63	53,045	53	-10	-16
11 Accessory Electric Plant	74,921	108	86,127	86	-22	-20
12 Instrumentation & Control	24,577	36	26,385	26	-10	-28
13 Site Preparation	18,954	27	20,075	20	-7	-26
14 Buildings and Structures	18,283	26	20,049	20	-6	-23
Total	1,191,624	1,724	1,476,615	1,470	-254	-15
O&M Cost ($1,000/yr)						
Fixed Costs	**Total**		**Total**		**Δ**	**% Δ**
Labor	22,548		28,561		6,013	27
Variable Operating Costs*	**Total**		**Total**			
Maintenance Materials	26,284		34,375		8,091	31
Water	1,470		1,768		298	20
Chemicals	6,535		9,124		2,589	40
Membrane Replacement	987		1,383		396	40
Waste Disposal	3,055		4,249		1,194	39
Total Variable Costs	38,331		50,900		12,569	33
Total O&M Cost	60,880		79,461		18,581	31
Fuel Cost*	82,733		115,070		32,337	39
Discounted Cash Flow Results, levelized						
Capital Cost ($/kW-hr)	0.0405		0.0345			-15
Fixed O&M Cost ($/kW-hr)	0.0051		0.0044			-14
Variable O&M Cost ($/kW-hr)	0.0086		0.0079			-8
Fuel Cost ($/kW-hr)	0.0193		0.0185			-4
TS&M Cost ($/kW-hr)	0.0039		0.0039			0
Levelized COE ($/kW-hr)	0.0774		0.0692			-11

*Includes 85 % Capacity Factor

3.10 INCREASED CAPACITY FACTOR TO 90 %

See Appendix A for NETL's update to capital cost and COE.

In this case, the single-train AHT-2 process configuration remains the same (with process performance remaining the same as in Table 3-17), but the capacity factor increases from 85 % to 90 %. This increased on-stream factor reflects anticipated improvements in process reliability, availability, and maintainability (RAM) resulting from additional operating experience and improvements in control and materials gained through DOE/NETL's demonstration and advanced research programs. As in Section 3.4, it is assumed that these advancements add little additional capital or fixed O&M cost. The increased power production translates into additional revenue, which has a direct positive impact on the COE. Capital and O&M costs for a single-train process are compared in Table 3-20.

Table 3-20. 90 % Capacity Factor: Capital and O&M Cost Summary

	AHT-2 Turbine (Single Train)		90% CF (Single Train)		Δ	
Capital Cost ($1,000)						
Plant Sections	**TPC**	**TPC $/kW**	**TPC**	**TPC $/kW**	**Δ TPC $/kW**	**% Δ**
1 Coal and Sorbent Handling	29,100	58	29,100	58	0	0
2 Coal and Sorbent Prep & Feed	47,465	95	47,465	95	0	0
3 Feedwater & Balance of Plant	31,740	63	31,740	63	0	0
4a Gasifier	173,608	346	173,608	346	0	0
4b Air Separation Unit	77,413	154	77,413	154	0	0
5a Gas Cleanup	109,378	218	109,378	218	0	0
5b CO_2 Removal & Compression	19,957	40	19,957	40	0	0
6 Gas Turbine	83,208	166	83,208	166	0	0
7 HRSG	41,401	82	41,401	82	0	0
8 Steam Cycle and Turbines	55,760	111	55,760	111	0	0
9 Cooling Water System	24,243	48	24,243	48	0	0
10 Waste Solids Handling System	34,607	69	34,607	69	0	0
11 Accessory Electric Plant	62,181	124	62,181	124	0	0
12 Instrumentation & Control	21,672	43	21,672	43	0	0
13 Site Preparation	17,652	35	17,652	35	0	0
14 Buildings and Structures	16,184	32	16,184	32	0	0
Total	845,569	1,683	845,569	1,683	0	0
O&M Cost ($1,000/yr)						
Fixed Costs	**Total**		**Total**		**Δ**	**% Δ**
Labor	16,535		16,535		0	0
Variable Operating Costs*	**Total**		**Total**			
Maintenance Materials	20,751		21,971		1,220	6
Water	1,110		1,176		66	6
Chemicals	4,565		4,833		268	6
Membrane Replacement	692		732		40	6
Waste Disposal	2,125		2,250		125	6
Total Variable Costs	29,242		30,962		1,720	6
Total O&M Cost	45,777		47,498		1,721	4
Fuel Cost*	57,535		60,920		3,385	6
Discounted Cash Flow Results, levelized						
Capital Cost ($/kW-hr)	0.0396		0.0374			-6
Fixed O&M Cost ($/kW-hr)	0.0051		0.0048			-6
Variable O&M Cost ($/kW-hr)	0.0090		0.0090			0
Fuel Cost ($/kW-hr)	0.0185		0.0185			0
TS&M Cost ($/kW-hr)	0.0039		0.0039			0
Levelized COE ($/kW-hr)	0.0761		0.0736			-3

*Includes 90% Capacity Factor

The differences between cases lie in variable O&M costs and fuel cost, which increase by about 6 % as the result of increased annual hours of operation. However, the discounted cash flow spreads fixed costs over a greater amount of power production, more than compensating for these additional costs and resulting in an overall decrease in cost of electricity from $0.0761/kW-hr to $0.0736/kW-hr – a savings of about 3 % in cost of electricity resulting from increased capacity factor.

Two-Train Configuration

If the capacity factor of the plant having two power trains of AHT-2 turbine is increased from 85 % to 90 %, the COE decreases from $0.0692/kW-hr to $0.0671/kW-hr – also a decrease of 3 %.

3.11 PRESSURIZED SOLID OXIDE FUEL CELL

The IGFC case represents an advanced process configuration that incorporates some, but not all of the advanced technologies in the IGCC pathway. In addition, some advanced conceptual technologies, such as the catalytic gasifier and pressurized oxycombustion unit are added because of their specific value in an IGFC plant.

The non-capture pressurized SOFC process from Volume 1 of this study was modified for carbon capture. This process[6] is ideal for carbon capture because the CO_2-rich fuel cell anode (spent fuel) stream is nearly sequestration-ready. The primary process change is to compress the CO_2 stream to 2,200 psig for transport to storage. A block flow diagram is provided in Figure 3-8. The nominal 600 MW plant size is maintained by adjusting coal feed rate.

Note that even though the CO_2 stream is to be compressed to 2,200 psig, the spent anode stream is still expanded for power recovery. The spent anode stream has 45 % moisture by weight, which is worthwhile to expand in order to recover work from the moisture and then re-compress the CO_2 after removing the moisture.

Another minor process change for this case is to add a bottoming cycle to evaluate the potential for waste heat recovery. The same three-pressure level steam cycle as used in the IGCC cases is used; however due to the larger amount of low quality heat in this case, the exhaust pressure from the low pressure turbine is increased to 1 psia in order to keep the steam quality at about 7 %.

[6] The pressurized SOFC process proposed by SAIC in the NETL report titled "The Benefits of SOFC for Coal-Based Power Generation" prepared by E. Grol, J. DiPietro, and J. Thijssen dated October 30, 2007 is the basis of this process design.[5]

Case Configuration: Catalytic Gasifier, Cryogenic ASU, Warm Gas Cleanup, Solid Oxide Fuel Cell, 90 % Capacity Factor

Table 3-21 compares process performance against the non-capture case. Coal feed rate in the carbon capture case increases by 15,000 lb/hr in order to maintain the 600 MW net power output. Increased coal feed rate increases power production from the fuel cell, syngas expander, cathode air expander, and anode exhaust expander. Gross (total) power production increases by 45 MW in the carbon capture scenario.

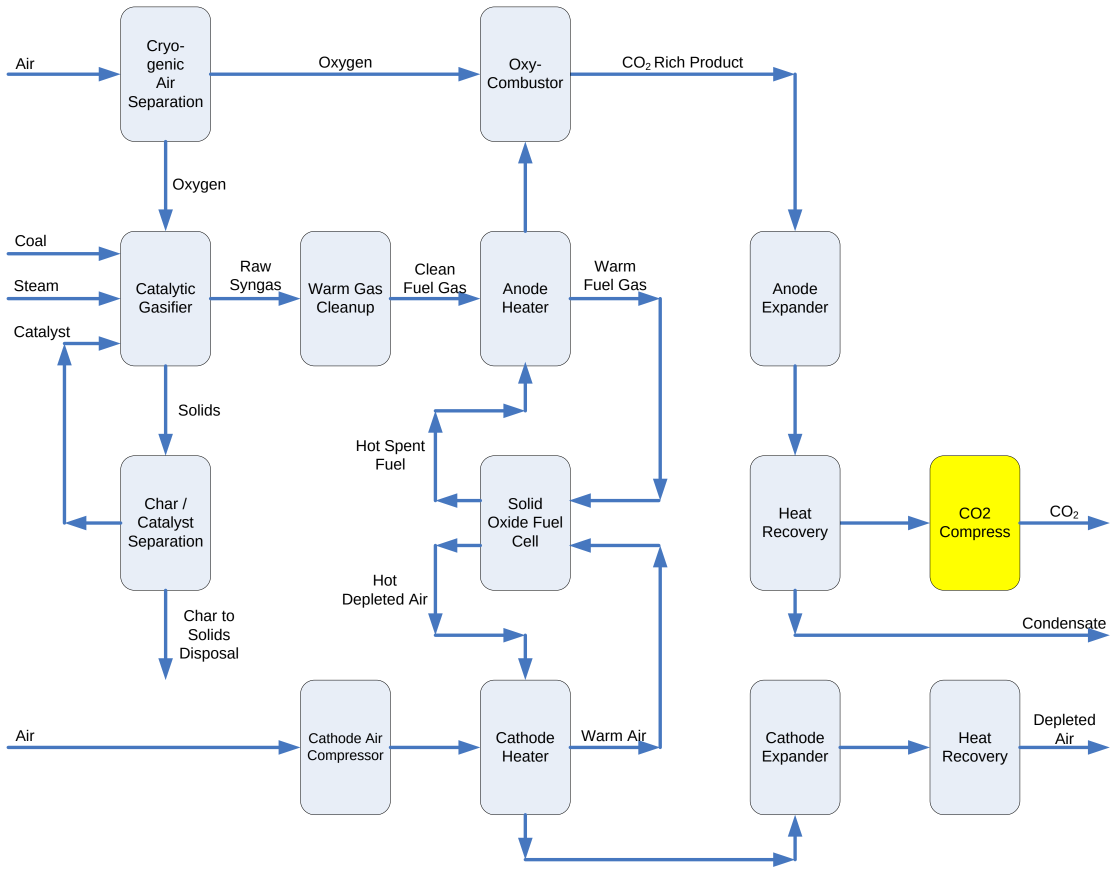

Figure 3-8. Pressurized Solid Oxide Fuel Cell

Auxiliary power use increases in the carbon capture scenario due to (1) additional flow through the cathode air compressor, and (2) need for the CO_2 compressor to pressurize the carbon stream to pipeline pressure.

Net plant efficiency decreases from 59.5 % to 56.3 %. This is a decrease by only 3.2 percentage points, which is less than the 5 percentage point decrease typical of the IGCC cases. Elimination of the need for CO_2 separation in the fuel cell case contributes to improved process efficiency in the carbon capture scenario. Notably, 100 % carbon capture is achieved; there are no carbon emissions other than the CO_2 product stream.

Table 3-21. Comparison of Non-Capture vs. Carbon Capture SOFC Scenario

	Non-Capture SOFC	SOFC With Carbon Capture
Fuel Cell Power (MW)	517	544
Syngas Expander (MW)	22	24
Cathode Air Expander (MW)	208	218
Anode Exhaust Expander (MW)	118	124
Steam Bottoming Cycle (MW)	21	22
Total Power Produced (MW)	886	931
Auxiliary Power Use (MW)	-276	-325
Net Power (MW)	610	606
As-Received Coal Feed (lb/hr)	300,000	315,000
Net Heat Rate (Btu/kW-hr)	5,737	6,063
Net Plant Efficiency	59.5 %	56.3 %
Gasifier Cold Gas Efficiency	92.0 %	92.1 %

Cost Analysis

See Appendix A for NETL's update to capital cost and COE.

Table 3-22 compares the total plant cost, O&M cost, and fuel cost of the non-capture and carbon capture scenarios. A TPC of $700/kW of fuel cell power is assumed for the fuel cell system.[7] The fuel cell system includes fuel cell stack, anode and cathode heaters, anode steam generator and reheat, syngas expander, cathode air compressor, anode and cathode expanders, inverter, catalytic oxidizer and oxygen boost compressor, condensate knockout, and foundations.

Cost accounts in the carbon capture case increase slightly due to the increased coal feed rate and therefore larger equipment sizes. On a $/kW basis, costs of most accounts are similar. The carbon capture case includes a $77/kW cost for CO_2 compression that is not incurred in the non-capture case. Although a larger fuel cell is needed in the carbon capture case, the TPC of the fuel cell decreases by $8/kW as the result of a new assumed cost of the fuel cell power island. The CO_2 compressor accounts for most of the $127/kW net increase in cost for the carbon capture process. This fuel cell case represents much less of an increase in TPC for the carbon capture scenario than any of the IGCC cases; the sequestration-ready CO_2 stream exiting the fuel cell accounts for the avoidance of increased cost for CO_2 separation in the gas cleanup account.

[7] The assumed cost of the fuel cell has changed since Volume 1.

Table 3-22. SOFC: Capital and O&M Cost Summary

	Non-Capture SOFC		SOFC With Carbon Capture		Δ	
Capital Cost ($1,000)						
Plant Sections	**TPC**	**TPC $/kW**	**TPC**	**TPC $/kW**	**Δ TPC $/kW**	**% Δ**
1 Coal and Catalyst Handling	30,814	51	31,764	52	1	2
2 Coal and Catalyst Prep & Feed	41,428	68	42,817	71	3	4
3 Feedwater & Balance of Plant	21,649	35	22,119	36	1	3
4a Gasifier	155,335	255	160,426	265	10	4
4b Air Separation Unit	81,306	133	84,494	139	6	5
5a Gas Cleanup	66,351	109	77,449	128	19	17
5b CO_2 Removal & Compression	0	0	46,376	77	77	∞
6 Gas Turbine	0	0	0	0	0	0
7 Fuel Cell	387,875	636	380,780	628	-8	-1
8 Steam Cycle and Turbines	15,542	25	16,073	27	2	8
9 Cooling Water System	13,711	22	14,079	23	1	5
10 Waste Solids Handling System	35,692	59	36,782	61	2	3
11 Accessory Electric Plant	88,137	144	92,989	153	9	6
12 Instrumentation & Control	28,911	47	30,282	50	3	6
13 Site Preparation	18,823	31	19,149	32	1	3
14 Buildings and Structures	10,097	17	10,241	17	0	0
Total	995,670	1,632	1,065,820	1,759	127	8
O&M Cost ($1,000/yr)						
Fixed Costs	**Total**		**Total**		**Δ**	**% Δ**
Labor	19,542		21,045		1,503	8
Variable Operating Costs*	**Total**		**Total**			
Maintenance Materials	28,487		29,552		1,065	4
Water	168		354		186	111
Chemicals	3,845		3,950		105	3
Fuel Cell Stack Replacement	17,835		18,759		924	5
Waste Disposal	2,397		2,481		84	4
Total Variable Costs	52,731		55,096		2,365	4
Total O&M Cost	72,273		76,141		3,868	5
Fuel Cost*	49,799		52,289		2,490	5
Discounted Cash Flow Results, levelized						
Capital Cost ($/kW-hr)	0.0362		0.0390			8
Fixed O&M Cost ($/kW-hr)	0.0047		0.0051			9
Variable O&M Cost ($/kW-hr)	0.0127		0.0133			5
Fuel Cost ($/kW-hr)	0.0124		0.0132			6
TS&M Cost ($/kW-hr)	NA		0.0039			∞
Levelized COE ($/kW-hr)	0.0661		0.0745			13

*Includes 90 % Capacity Factor

4. SUMMARY OF ADVANCED TECHNOLOGY IMPROVEMENTS

The information presented in the previous section is consolidated in the following discussion in order to summarize the relative benefits of the advanced technologies in both non-capture and carbon capture scenarios.

4.1 PROCESS EFFICIENCY

The following Figure 4-1 shows the cumulative improvement in process performance as each technology is introduced to the composite process. The uppermost curve represents non-capture scenarios, which consistently have higher process efficiency than the carbon capture scenarios. Cases that feature improved capacity factor do not affect performance efficiency because the capacity factor merely increases the percentage of on-stream operation.

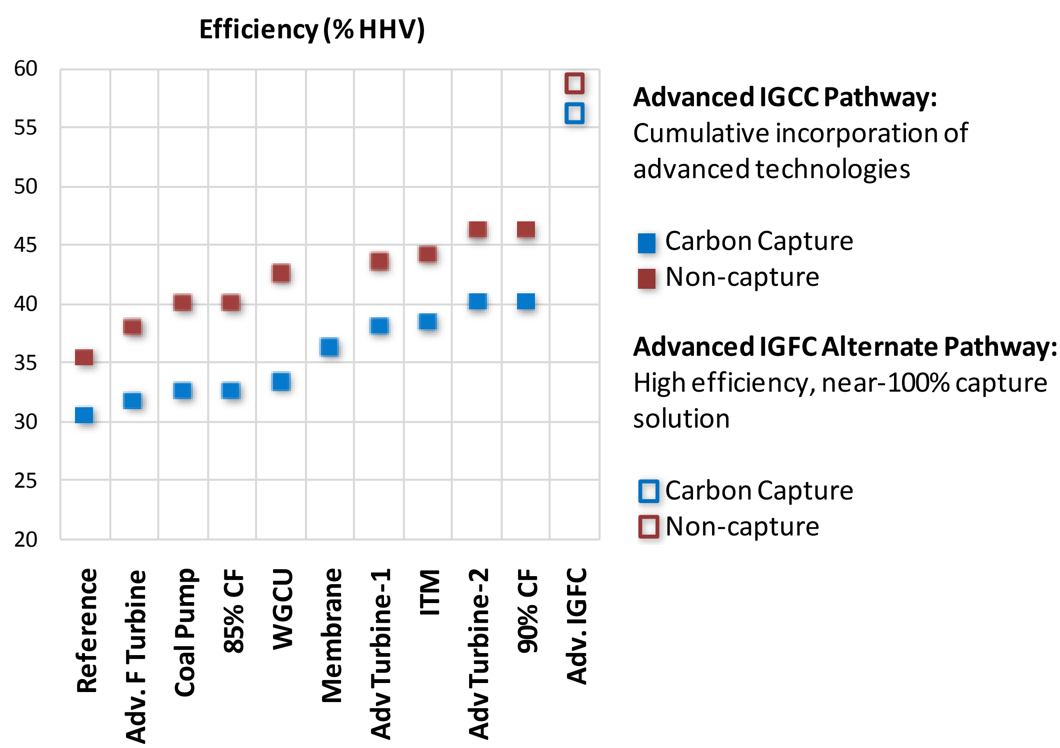

Figure 4-1. Cumulative Impact of R&D on Process Efficiency

Advanced turbines contribute strongly to increased process efficiency due to the combination of improved engine performance at increasingly higher pressure ratios and firing temperatures, and also increased turbine exit temperature, which improves heat recovery from the HRSG – especially if an increase in steam superheat temperature is involved. The 1.3 percentage point (%pt) improvement of the advanced "F" turbine is not as great in a carbon capture scenario as it is in the non-capture scenario (2.5 %pt); air integration is not possible in the carbon capture scenario, and the turbine exit temperature is not high enough that steam superheat temperature can be increased. When the first generation advanced turbines are introduced, however, the efficiency of the carbon capture scenario increases (1.8 %pt) more than in the non-capture scenario (1.0 %pt); this is due to the additional contributions of air integration and increased steam superheat temperature. The next-generation advanced turbines (Adv Turbine-2) contribute 2.0 and 1.7 %pt improvements to the non-capture and carbon capture scenarios, respectively. The total performance improvement due to the advanced turbines, therefore, is 5.5 %pt in the non-capture scenario and 4.8 %pt in the carbon capture scenario.

The coal feed pump makes a greater contribution to process efficiency improvement in the non-capture scenario (2.1 %pt) than in the carbon capture scenario (0.8 %pt). The coal feed pump increases process efficiency by eliminating the need to evaporate water in a slurry-fed gasifier. In the non-capture scenario with cold gas cleanup, that moisture is condensed and most of the latent heat is unrecoverable because of the low condensation temperature. In the carbon capture scenario with cold gas cleanup, on the other hand, moisture is needed for sour shift; so whether the moisture is provided by slurry water or addition of shift steam (following a dry feed gasifier) doesn’t have as much of an impact on process efficiency.

Warm gas cleanup (with Selexol CO_2 capture) improves process efficiency over cold gas cleanup by 0.8 %pt in the carbon capture scenario as the result of eliminating the sour water stripper reboiler duty; the improvement is not as great as the 2.5 %pt increase in the non-capture scenario because syngas is quenched prior to Selexol, knocking moisture out of flue gas that otherwise remains in the turbine fuel in the non-capture case – providing added flow through the turbine. However, warm gas cleanup (with hydrogen membrane) contributes an additional 2.9 %pt in process efficiency in the carbon capture scenario by eliminating the Selexol reboiler and auxiliary power, and also producing CO_2 at elevated pressure – reducing CO_2 compressor load.

The ITM does not contribute strongly to process performance in either the non-capture or carbon capture scenarios. The primary benefit of the ITM, as will be seen in the following discussion, is decreased capital cost of oxygen production.

Overall, advanced technologies increase IGCC process efficiency by as much as 10.7 %pt in non-capture scenarios and by 9.3 %pt in carbon capture scenarios. Non-capture scenarios benefit from (1) greater percentage of air integration for each turbine model due to the difference in syngas versus hydrogen fuel flow; (2) reduced coal flow rate per unit net power generation, thus reducing parasitic load of oxygen production; (3) no need for shift steam generation, thus increasing steam turbine power generation, and (4) no need for CO_2 compression, thus reducing parasitic losses.

The pressurized solid oxide fuel cell cases – both capture and non-capture – are capable of process efficiencies that approach 60 %. The catalytic gasifier, with high methane content in the syngas, operates with a cold gas efficiency in excess of 90 %. Conversion of chemical energy within the fuel cell, as opposed to thermal and mechanical energy in an IGCC process, enables the higher process efficiencies obtained in the SOFC cases. The difference in process efficiency between the non-capture and capture scenarios is simply due to the power needed to compress CO_2 to pipeline delivery pressure.

4.2 TOTAL PLANT COST

See Appendix A for NETL's update to capital costs. [8]

As each advanced technology is introduced to the composite process, total plant cost generally decreases as shown in Figure 4-2. The uppermost curve represents the carbon capture scenarios, which consistently have higher TPC due, at a minimum, to (1) additional equipment needed for CO_2 separation and compression; (2) additional equipment needed for shift steam generation, and (3) reduced net power generation. Improved capacity factor has no effect on TPC, as seen in Figure 4-2, just as it has no effect on process efficiency.

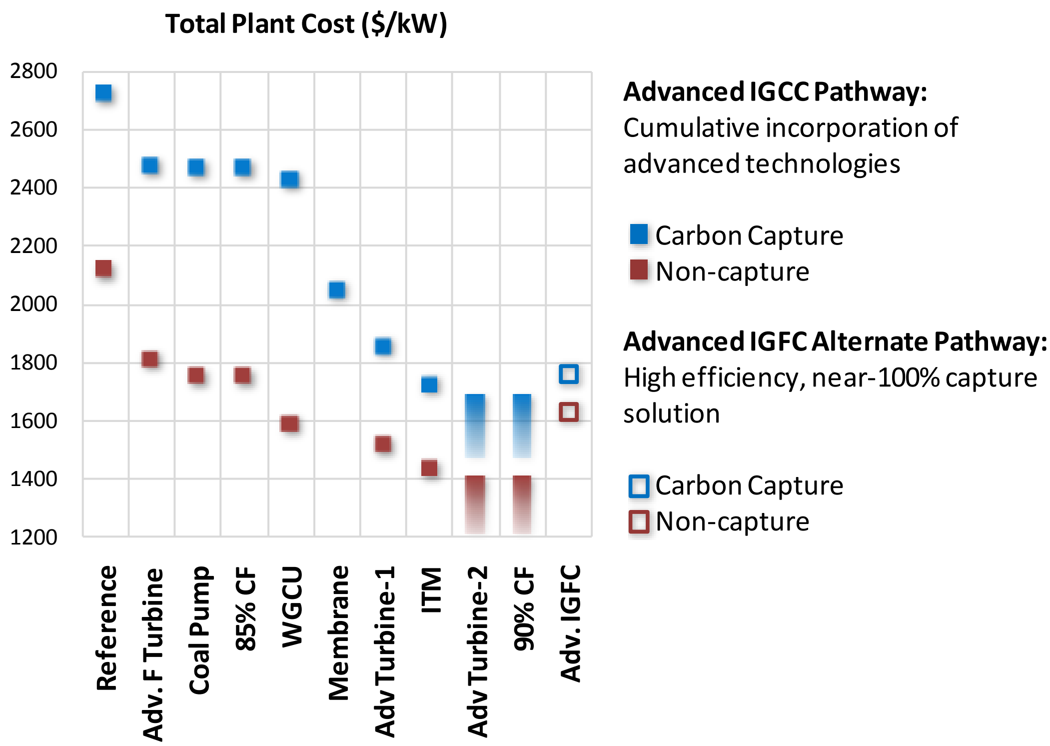

Figure 4-2. Cumulative Impact of R&D on Total Plant Cost

Advanced gas turbines significantly reduce total plant cost. Although the cost of the turbine itself increases due to increased size, TPC on a $/kW basis decreases because of increased net plant power. As in the discussion above on process efficiency, the advanced "F" turbine has more impact ($304/kW) in the non-capture scenario (versus $246/kW) because of air integration

[8] NETL is updating the performance, cost, and costing methodology as part of Revision 2 of "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity." The estimated capital cost and COE for the configurations presented in this report using this new methodology are reported in Appendix A.

and increased steam superheat temperature. The carbon capture case catches up somewhat when air integration and increased superheat temperature are introduced with the AHT-1 turbine; the non-capture cost reduction is $72/kW compared to $192/kW with carbon capture. As discussed in Section 3, the impact of the next-generation of advanced turbines is diminished by economy of scale when the number of trains is reduced from two to one in order to maintain the nominal 600 MW plant size; the TPC reductions are $27/kW and $41/kW for the non-capture and carbon capture scenarios, respectively. The bottom of the shaded bars in Figure 4-2 indicate that TPC continues to decrease if two trains turbine trains are installed – doubling the plant output and decreasing TPC by $219/kW in the non-capture scenario and by $254/kW in the carbon capture scenario.

The coal feed pump has negligible impact on TPC in a carbon capture scenario – only $7/kW compared to the $60/kW reduction in the non-capture scenario. This is because of the minor cost of equipment, coupled with greater reduction in net plant power (due to need for shift steam generation) in the carbon capture scenario than in the non-capture scenario.

While warm gas cleanup results in greater process efficiency improvement for the carbon capture scenario as shown above in Figure 4-1, its impact is especially pronounced in terms of TPC. The cost of warm gas desulfurization is less than single-stage Selexol to begin with (which partly accounts for the decrease in TPC of the WGCU+Selexol non-capture and carbon capture scenarios in Figure 4-2), but when the cost savings from eliminating the second stage Selexol absorber for CO_2 capture is added, the decrease in TPC of the gas cleanup section for the WGCU+Membrane carbon capture scenario becomes much greater. The cost of CO_2 compression, likewise, is much less in the WGCU+Membrane case than any of the previous carbon capture cases due to the higher pressure at which CO_2 is produced from the H_2 membrane. Finally, when the added net power generation (made possible by eliminating sour water stripper and Selexol reboiler duties and reduced CO_2 compression parasitic loss) is divided into the already-reduced TPC, the cost of the warm gas cleanup cases on a $/kW basis become $40/kW (for WGCU+Selexol) and $418/kW (for WGCU+Membrane) less than the cold gas cleanup carbon capture scenario.

The ITM is seen to reduce TPC by relatively more in the carbon capture scenario ($131/kW) than in the non-capture scenario ($82/kW). With increase in coal feed rate to generate hydrogen turbine fuel as opposed to syngas turbine fuel, the significance of the air separation unit increases. In other words, with increased oxygen demand in the carbon capture cases, the capital cost savings represented by the less-expensive ITM compared to cryogenic ASU has a greater impact on reducing cost.

Overall, a capital cost reduction of about $700/kW is anticipated from advanced technologies in non-capture IGCC applications. Even more significant, however, is an anticipated $1,000/kW reduction in cost for carbon capture IGCC applications.[9] The primary reasons for greater TPC reductions in the carbon capture scenarios are: (1) low cost of H_2 membrane for advanced CO_2 separation technology; (2) reduced parasitic load of CO_2 compression (and therefore increased

[9] TPC reduction is $1,000/kW for a nominal 600 MW-size plant (single AHT-2 turbine train); the reduction in TPC becomes $1,235/kW if two trains of AHT-2 turbine are built.

net plant power generated) due to high pressure at which CO_2 is separated by the H_2 membrane, and (3) reduced cost of CO_2 compressor equipment, again because of high pressure CO_2 separation.

The TPC of the most advanced IGCC process with carbon capture is nearly $280/kW greater than its non-capture counterpart. The SOFC capital cost, on the other hand, increases by only about $130/kW when carbon capture is added; the incremental cost to the SOFC scenario is essentially the CO_2 compressor, which is a relatively minor impact compared to the IGCC scenarios. The TPC of the carbon capture SOFC scenario is slightly greater than the most advanced IGCC configuration with carbon capture ($1,759/kW versus $1,683/kW).

4.3 COST OF ELECTRICITY

See Appendix A for NETL's update to COE.

As each new advanced technology is step-wise implemented in the advanced power system, the reduction in COE is represented in Figure 4-3. Effects of improved capacity factor become as significant as the other technology improvements that yield increased process efficiency and decreased capital cost. The increase to 85 % capacity factor results in a 4 % reduction in COE for both the non-capture and the carbon capture scenarios. The increase to 90 % capacity factor results in an additional 3 % reduction in COE for both the non-capture and carbon capture scenarios.

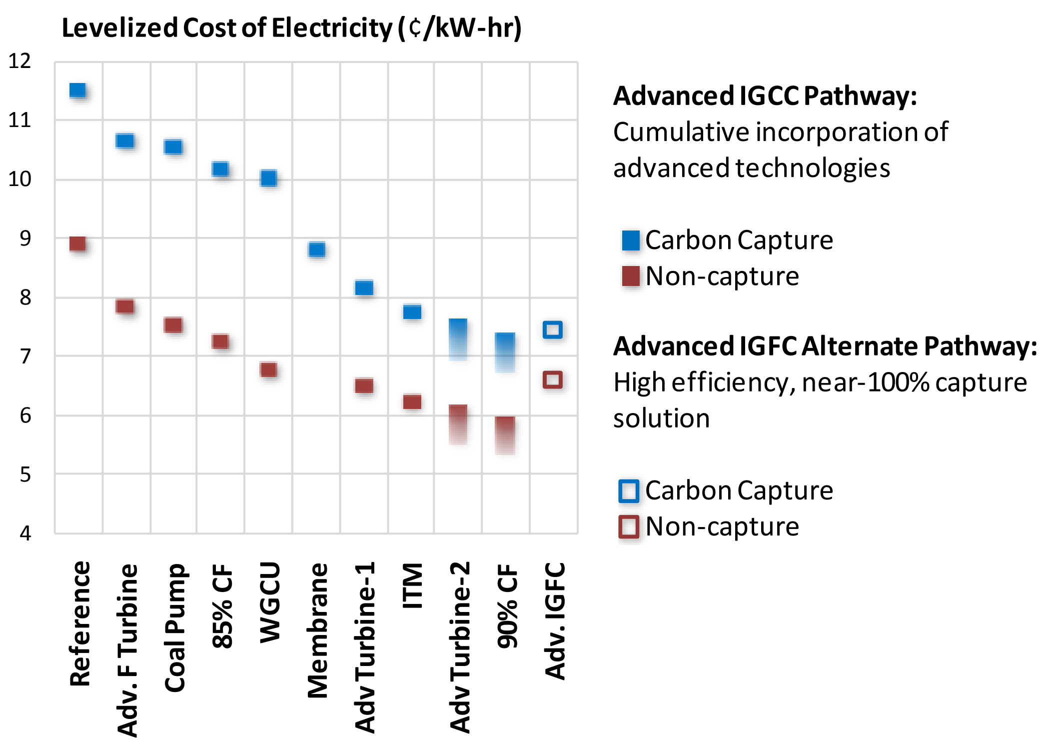

Figure 4-3. Cumulative Impact of R&D on Cost of Electricity

The advanced "F" turbine and the AHT-1 turbine contribute significant COE reductions in carbon capture scenarios – by 8.4 mills/kW-hr and 6.6 mills/kW-hr, respectively. The reduction in COE is slightly greater than in the non-capture scenarios (13.4 mills/kW-hr total). Due to economy of scale, the nominal 600 MW plant with a single AHT-2 turbine train results in a small (1.3 mills/kW-hr) decrease in COE. If two process trains are used as in the other IGCC plants, however, COE decreases by 12 % in the non-capture scenario and by 11 % in the carbon capture scenario.

Consistent with no appreciable change in either process efficiency or TPC, the coal feed pump has little impact on COE in an IGCC process with carbon capture.

Warm gas cleanup has a much greater impact on carbon capture IGCC scenarios than on the non-capture scenarios; this is chiefly due to the large decrease in TPC resulting from CO_2 separation and compression and increased net power generation. In the case in which warm gas cleanup is introduced together with the H_2 membrane, COE decreases by 13.4 mills/kW-hr or 13 % compared to cold gas cleanup.

ITM technology decreases the COE by 4.0 mills/kW-hr in the carbon capture scenario. It has a more pronounced effect on carbon capture scenarios than non-capture because, as explained above, coal feed rate increases for the carbon capture cases, providing more opportunity for cost reduction in the ASU. By comparison, the COE reduction in the non-capture scenario is 2.6 mills/kW-hr.

For a nominal 600 MW plant, cumulative reductions in COE resulting from advanced technology are 29 mills/kW-hr for non-capture IGCC scenarios, but 41 mills/kW-hr for carbon capture IGCC scenarios. Advanced technology, therefore, represents 23 % and 36 % reductions in COE for non-capture and carbon capture scenarios, respectively.

COE in the non-capture SOFC scenario increases by 11 % over that of the most advanced non-capture IGCC technology; this is due to a higher TPC that, even despite much higher process efficiency, results in a COE that is greater than IGCC by 6.6 mills/kW-hr. In the carbon capture scenario, the sequestration-ready CO_2 stream incurs minimal incremental capital cost for carbon capture. The resulting COE, aided by very high process efficiency, is 0.9 mills/kW-hr greater than the most advanced IGCC configuration with carbon capture.

4.4 DOE'S CARBON CAPTURE TARGETS

DOE's advanced power generation program goals are to achieve 90 % carbon capture while maintaining less than 10 % increase in COE over a 2003 reference IGCC plant having no carbon capture. That reference plant is represented in Case 0 in Volume 1 of this study. It consists of a slurry-fed gasifier, cryogenic ASU, single stage Selexol for sulfur removal, and 7FA syngas turbine. At 75 % capacity factor the COE of that plant is 9.3 ¢/kW-hr, so DOE's cost target for carbon capture is 10 % greater, or 10.2 ¢/kW-hr.

From Figure 4-3, DOE's carbon capture target will be met early in the pathway, specifically by the case with 85 % capacity factor. Other features of that case include advanced "F" hydrogen turbine, dry feed gasifier, cryogenic ASU, and cold gas cleanup.

All subsequent technology advancements will help to exceed DOE's carbon capture targets. By achieving the ultimate, most advanced IGCC and IGFC technologies projected in Figure 4-3, DOE could realize a 20 % *reduction* in COE over a 2003 IGCC plant having no carbon capture. The enabling technologies to achieve that improvement include:

- Advanced hydrogen turbines
- Warm gas cleanup
- Pressurized SOFC with catalytic gasifier
- Improved RAM
- ITM
- Coal feed pump

The technology pathway evaluated in this study covers a time span of about eighteen (18) years of technology development. Results of the analysis clearly indicate the importance of continued R&D, large scale testing, and integrated deployment so that future coal-based power plants will be capable of generating clean power with greater reliability and at significantly lower cost.

Aside from improved process efficiencies and reduced costs of electricity for both non-capture and carbon capture power generation alike, these advanced technologies enable (1) production of high-value products such as hydrogen, (2) integration with solid oxide fuel cells, and (3) pre-combustion carbon capture projected at lower cost than post-combustion alternatives.

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APPENDIX A: NETL UPDATE TO COST REPORTING

Revision 1 of the NETL Baseline Study [2] served as the primary basis for the performance and cost of conventional technology components in this report and provided the financial structure and cost of electricity calculation methodology. Revision 2 of the NETL Baseline Study (Nov 2010) [5] updates performance and significantly revises the reporting of capital costs and costing methodology. This Appendix provides the estimated capital cost and COE for each of the cases presented in this report consistent with the cost modifications in Revision 2 of the Baseline Study.

SUMMARY OF MODIFICATIONS

Revision 2 of the NETL Baseline Study included (1) performance/simulation updates, and (2) multiple changes to costs and cost reporting bases.

Performance Changes

Revision 2 performance modeling changes for Case 2 in the Baseline Study have the potential to improve the performance of the corresponding case in this report (Adv "F" Turbine).[10] However, it is not yet known if those improvements would translate into improvements for all subsequent advanced technology cases in this report. To address this discrepancy, this appendix modifies the efficiencies as follows: (1) the Adv "F" Case efficiency was set equal to that of Case 2 in Revision 2 of the NETL Baseline Study, (2) the efficiency of the most advanced IGCC case of 40.0% was maintained consistent with this study, and (3) the efficiencies of all intermediate cases were proportionally adjusted. This results in a slight reduction in the incremental efficiency improvements for each cumulative addition of advanced technology. No change was made to the efficiency of the advanced IGFC configuration.

Key Cost and Cost Reporting Modifications

Capital costs in Revision 2 of the NETL Baseline Study were reassessed at a component-by-component level. Updates to the capital costs in this report were revised and estimated at the plant level. A more detailed component-by-component level revision is planned for future revisions.

The remaining changes to Revision 2 of the Bituminous Baseline report that have been incorporated into the results presented in this appendix are as follows:

- All costs are reported in June 2007 dollars. June 2007 capital costs are approximately equal to January 2010 costs based on the *Chemical Engineering* Plant Cost Index.

[10] Revision 1 of the NETL Cost and Performance Baseline Volume 1 assumed "free" recovery of hydrogen and other components from the CO_2–rich streams exiting Selexol. Revision 2 modified the Selexol performance to correspond to a high hydrogen recovery, eliminating any need for further purification of the CO_2 streams exiting Selexol. This performance change was already incorporated in the initial publication of the corresponding cases in this report.

- Previously excluded capital costs, such as owner's costs, have been added and are reported as Total Overnight Cost (TOC). Costs are also presented as Total As-Spent Cost (TASC). Figure A-1 provides additional detail on what is included at each cost level. The COE now includes owner's costs, and interest and escalation during construction.
- The bituminous coal cost used in this study is $1.64/MMBtu. This cost was derived from data in the Energy Information Administration Annual Energy Outlook.
- Property taxes and insurance have been included as part of the fixed O&M cost.
- CO_2 TS&M costs have been updated.
- All O&M costs, including fuel, are assumed to escalate at a nominal rate of 3%, consistent with the assumed inflation rate.
- The operation period assumed for levelization is 30 years. The capital expenditure period is 5 years (one year of capital expenditure prior to construction and four years of construction).
- LCOE continues to be based on a current-dollar analysis, but the levelization factor calculation has been modified.

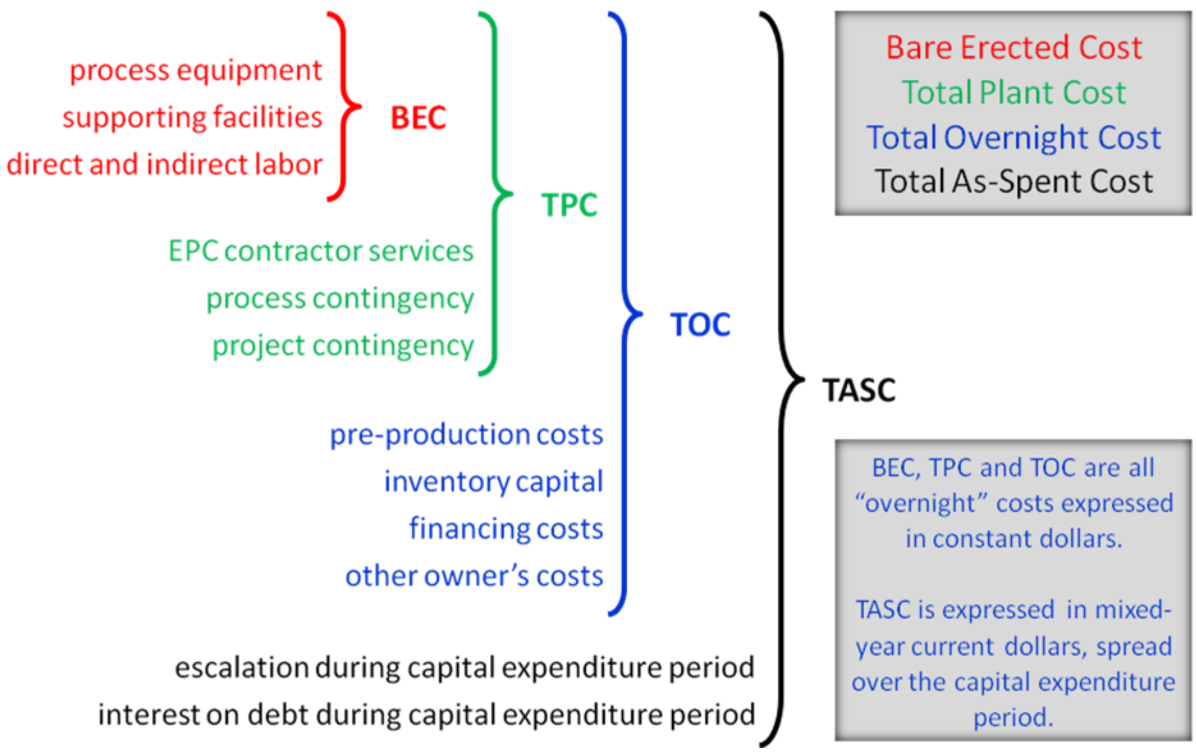

Figure A-1. Elements of Capital Costs

SUMMARY OF MODIFIED RESULTS

Figure A-2 depicts the cumulative improvements in process efficiency, TOC, and first-year COE as each technology is introduced for the carbon capture cases described in this study and the non-capture cases from Volume 1. TOC and first-year COE are updated consistent with the changes to Revision 2 of the NETL Baseline Study described above.

The bottom of the shaded bars on the TOC and COE pathways illustrate the impact of the AHT-2 turbine if two turbine trains were built. That installation would exceed the nominal 600 MW plant size for this study, but the point serves to illustrate the effect of economy of scale on process economics.

Table A-1 summarizes the updated results for each case with CCS.

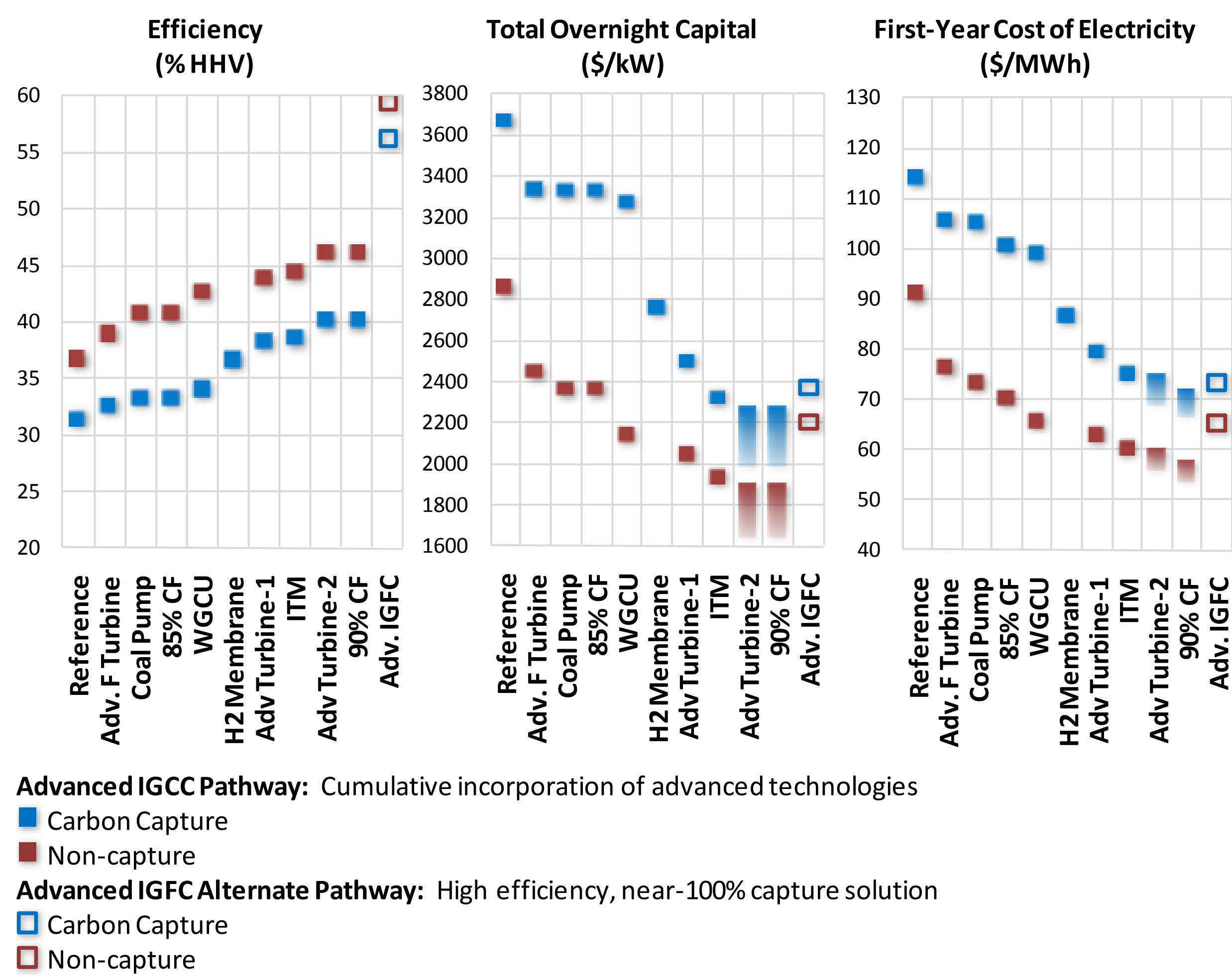

Figure A-2. Cumulative Impact of R&D on Gasification-Based Power Systems Performance and Cost

Table A-1. Summary of Updated Capital Costs and Cost of Electricity

All costs in June 2007 dollars (≈January 2010 dollars) unless otherwise indicated	Reference IGCC with CCS	Adv "F" Turbine	Coal Feed Pump	85% CF	WGCU/ Selexol	WGCU/H_2 Membrane	AHT-1 Turbine	ITM	AHT-2 Turbine	90% CF	Advanced IGFC with CCS
HHV Efficiency, %	31.5%	32.6%	33.3%	33.3%	34.0%	36.6%	38.2%	38.5%	40.0%	40.0%	56.3%
Net Plant Output, MW	444	543	510	510	535	572	659	691	502	502	606
Capacity Factor / Availability	80%	80%	80%	85%	85%	85%	85%	85%	85%	90%	90%
TPC, $/kW	2,980	2,710	2,700	2,700	2,660	2,240	2,030	1,890	1,850	1,850	1,930
TOC, $/kW	3,670	3,330	3,330	3,330	3,270	2,760	2,500	2,330	2,270	2,270	2,370
TASC, $/kW (mixed year dollars)	4,180	3,800	3,790	3,790	3,730	3,150	2,850	2,650	2,590	2,590	2,700
30-Year Levelized[1] COE, $/MWh	145	134	133	128	126	110	101	96	95	91	93
COE[2], $/MWh	114	106	105	101	99	87	80	76	75	72	73
Capital	65	59	59	56	55	46	42	39	38	36	37
Fixed O&M	15	15	15	14	13	12	11	10	10	9	10
Variable O&M	10	9	9	9	10	9	9	8	9	9	13
Fuel	18	17	17	17	16	15	15	15	14	14	10
CO_2 TS&M	6	5	5	5	5	5	4	4	4	4	4
Cost of Avoiding CO_2[2], $/tonne *Relative to Supercritical PC without CCS*	78	66	65	58	56	39	29	23	22	18	18

[1]Current-dollar levelization
[2]Assumes 3% nominal escalation per year of COE, fuel cost and O&M cost over the 30-year capital recovery period

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