Current and Future IGCC Technologies

DOE/NETL-2008/1337

A Pathway Study Focused on Non-Carbon Capture Advanced Power Systems R&D Using Bituminous Coal – Volume 1

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Disclaimer

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NETL Viewpoint

Background

Today's energy situation has created a dilemma for coal use in the United States. On one hand, the environmental challenges of using coal appear formidable, particularly with growing concern over the impact of carbon dioxide (CO_2) emissions on global climate change. This threatens coal's long-term future. On the other hand, the projected demand for electricity coupled with high fuel costs (particularly high oil prices and volatile natural gas prices) presents a near-term opportunity for the greater use of coal to ensure energy security for America. The solution to coal's "Catch-22" can be achieved through technological advancements that enable coal-based energy plants to produce much needed electricity and fuels for secure and stable economic growth while protecting the planet by preventing air pollution and greenhouse gas emissions. It is the development of this technological pathway that is the focus of this report.

Objective

The mission of the Department of Energy's (DOE) Clean Coal Program is to ensure the availability of ultraclean, abundant, low-cost domestic energy to fuel economic prosperity and strengthen energy security while enhancing environmental quality. The technologies presented in this document describe the multi-year strategy that will enable the Advanced Power Systems, (Gasification and Advanced Turbines Programs) Fuel Cells, and Sequestration Research and Development (R&D) Programs within the DOE's Clean Coal R&D Program to achieve this mission. A broad portfolio of technologies is being pursued along multiple technology paths to mitigate the risks inherent to R&D. The objective of this report is to use energy systems analysis and conceptual computer simulation models to quantify the impact of this portfolio of technologies on future power generation configurations. This report focuses on bituminous coal feedstock for Integrated Gasification Combined Cycle (IGCC) and Integrated Gasification Fuel Cell (IGFC) power plant configurations that do not capture CO_2. A second volume is underway to provide the same analysis for technologies that will improve the performance and reduce the cost for IGCC and IGFC power plants that employ carbon capture and sequestration.

Approach

The power plant configurations analyzed in this study were modeled using the ASPEN Plus™ modeling program. Emerging technologies were incorporated step-wise over time into the reference IGCC configuration to lay out a "pathway" of technology development and implementation. To the extent possible, a nominal 600 MW plant size was used for comparison between cases. Performance and process limits for advanced technologies were based upon information obtained from the technology developers or published technical reports. Cost estimates for novel technologies were provided by the vendors, or were scaled from existing design/build utility projects and best engineering judgment. Performance and capital and operating costs for conventional equipment were based on the "Cost and Performance Baseline for Fossil Energy Plants, Volume I", DOE/NETL-2007/1281. Capital costs reported are at the total plant cost level and do not include owner's costs, which can be substantial. Care must be taken to avoid comparing the capital costs of this report with those often reported for power plant projects under development, as the latter usually include significant owner's costs. Levelized cost of electricity was determined for all plants assuming investor owned utility financing.

Results

The cumulative impact of the portfolio of advanced technologies in DOE's Clean Coal R&D Program results in power plant configurations that are significantly more efficient and affordable than today's limited set of fossil energy technologies. In the IGCC process alone, there is the potential for 11 percentage point improvement over conventional gasification technology. With fuel cell technology, process efficiency improvements upwards of 24 percentage points are potentially achievable. Capital cost reductions result not only from less expensive technology alternatives such as warm gas cleanup and ITM air separation, but also from increased power generation brought about by advanced technology such as syngas turbines – resulting in cumulative total plant cost reductions by as much as $700/kW after all advanced technologies are implemented. Improvements in process efficiency, reductions in capital and operating expense, and increase in capacity factor all contribute to decreased cost of electricity (COE), projecting an overall decrease by more than 3 cents/kW-hr – or a decrease of 35 percent.

Results of the analysis clearly indicate that the current portfolio is capable of achieving the specific cost and efficiency goals set out by the Clean Coal R&D Program. The results also highlight the importance of continued R&D, large-scale testing, and integrated deployment so that these technologies are proven to the point where they become commercially-accepted technology for future coal-based power plants.

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DE-AI26-04NT42291

Acknowledgement

The authors wish to thank Julianne Klara and Gary Stiegel of DOE's National Energy Technology Laboratory (NETL) for helpful discussions and suggestions during the execution of this work. Numerous technical contributions were also provided by NETL's Richard Dennis, John Wimer, and Wayne Surdoval. Dale Keairns and Richard Newby of SAIC were instrumental in providing the pressurized solid oxide fuel cell process design.

This work was funded by the U.S. DOE's National Energy Technology Laboratory and performed by Noblis under a contract with the U.S. Department of the Interior (NBCH-D-02-0039/0051) and Interagency Agreement DE-AI26-04NT42291.

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EXECUTIVE SUMMARY

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 conceptual computer simulation models to quantify the impact of successful federally-funded R&D on future power systems configurations.

A variety of process scenarios that produce electric power from bituminous coal are analyzed in this study. Starting with a reference integrated gasification combined cycle (IGCC) plant using conventional technology, a series of process modifications are made to represent commercialization of advanced technologies. Impacts on both process performance and cost are evaluated. Technology development is examined from two perspectives: the first examines the individual contribution of each new advanced technology, and the second examines the cumulative impact as each technology is added to the most advanced process configuration. In this manner, the contribution of DOE's R&D program to future power systems technology can be measured and prioritized.

A focus on non-carbon capture cases represents the first phase, or Volume 1, of this pathway study; the second phase, to be addressed by a follow-on report (Volume 2), will examine processes involving carbon capture.

Volume 1 is organized into two parts. The body of this report presents an executive-level analysis of performance and cost for each case, and expected trends over time. The Supplement to Volume 1 is intended as a reference for engineers involved in systems analysis of processes similar to those conducted in this study. It provides additional detail regarding process flow diagrams, process descriptions, computer modeling approaches, capital equipment costs, economic assumptions, and detailed results comparisons between cases.

Reference Case Design Basis

Case 0 defines the reference, or 2002 "vintage" IGCC configuration that uses conventional technology. That process 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. This IGCC configuration represented conventional technology when DOE established advanced power system R&D program goals in 2003, and is the appropriate baseline against which to evaluate performance and cost improvements resulting from advanced technology.

Process Improvements from Advanced Technologies

The pathway study incorporates new R&D technology into appropriate advanced process configurations in order to examine the cumulative impact of DOE-sponsored technology development over time.

Starting with the reference IGCC configuration, capacity factor increases to 80 % in Case 1 reflecting improvements gained by operating experience from DOE's demonstration program. Case 2 replaces the 7FA syngas turbine with and advanced "F" frame turbine. Case 3 replaces

the coal slurry feed to the gasifier with dry feed by incorporating a coal feed pump. Capacity factor increases from 80 % to 85 % in Case 4, reflecting increased process reliability and availability stemming from advanced materials and process control. In Case 5, the cold gas cleanup section is replaced by partial warm gas cleanup: a transport desulfurizer (TDS) and direct sulfur reduction process (DSRP) followed by cold gas ammonia and mercury removal. Case 6 is identical to Case 5, except that the cold gas ammonia and mercury removal process steps are replaced with novel, warm gas treatment processes that result in full warm gas cleanup.

Case 7 represents improvements to the advanced "F" frame turbine by the 2010 timeframe; this advanced syngas turbine is termed the 2010-AST turbine. Case 8 replaces the conventional cryogenic ASU with an ion transport membrane (ITM) to produce oxygen for the gasifier. Case 9 replaces the 2010-AST turbine with an even more advanced syngas turbine (2015-AST) for the 2015 timeframe. In Case 10, the capacity factor again increases – this time from 85 % to 90 % to reflect additional operating experience and improvements in control and materials gained through DOE/NETL's demonstration program.

Finally, Case 11 incorporates a solid oxide fuel cell (SOFC); this case features a catalytic gasifier and has no combustion gas turbine. The process configurations with cumulative process improvements are summarized in Table ES-1 below, with technology changes between cases indicated in bold lettering.

Aspen Plus process simulations were formulated for each plant configuration to compute mass and energy balances and net process efficiencies. Based on plant capacity, conceptual capital cost estimates were developed, and the 20-year levelized cost of electricity was calculated for each case. For consistent comparison, all cost analyses were based on January 2007 dollars, and assumed construction to begin in January, 2007 with a 36-month construction schedule. Costs were based on those developed in NETL's Baseline Study [1], and the same methodology as in the Baseline Study was used to compute levelized cost of electricity. The Aspen Plus simulation and cost estimate from Case 2 were validated against NETL's Baseline Study Case 1, which has an identical process configuration: nearly identical performance and cost results were obtained.

Process simulations and economic evaluations were conducted for all advanced technologies in a stand-alone mode in order to analyze individual contributions from each technology, and also as a form of model validation. In particular, performance predictions for the warm gas cleanup and the ITM cases were validated against the respective technology developers' performance goals. Results from the stand-alone analyses are described in the body of this report, and validation results are provided in the appendix.

Table ES-1. Power System Technology Development

Case	Description
0	Reference Plant / Slurry Feed Gasifier / Cryogenic ASU / Cold Gas Cleanup / 7FA Syngas Turbine / 75 % Capacity Factor (2002 Technology)
1	Slurry Feed Gasifier / Cryogenic ASU / Cold Gas Cleanup / 7FA Syngas Turbine / **80 % Capacity Factor**
2	Slurry Feed Gasifier / Cryogenic ASU / Cold Gas Cleanup / **Advanced "F" Frame Syngas Turbine** / 80 % Capacity Factor
3	**Coal Feed Pump** / Cryogenic ASU / Cold Gas Cleanup / Advanced "F" Frame Syngas Turbine / 80 % Capacity Factor
4	Coal Feed Pump / Cryogenic ASU / Cold Gas Cleanup / Advanced "F" Frame Syngas Turbine / **85 % Capacity Factor**
5	Coal Feed Pump / Cryogenic ASU / **Transport Desulfurizer (TDS) and Direct Sulfur Reduction Process (DSRP)** / Advanced "F" Frame Syngas Turbine / 85 % Capacity Factor
6	Coal Feed Pump / Cryogenic ASU / TDS and DSRP / **Warm Gas Treatment for Ammonia and Mercury** / Advanced "F" Frame Syngas Turbine / 85 % Capacity Factor
7	Coal Feed Pump / Cryogenic ASU / Warm Gas Cleanup / **2010-AST Syngas Turbine** / 85 % Capacity Factor
8	Coal Feed Pump / **Ion Transport Membrane (ITM)** / Warm Gas Cleanup / 2010-AST Syngas Turbine / 85 % Capacity Factor
9	Coal Feed Pump / ITM / Warm Gas Cleanup / **2015-AST Syngas Turbine** / 85 % Capacity Factor
10	Coal Feed Pump / ITM / Warm Gas Cleanup / 2015-AST Syngas Turbine / **90 % Capacity Factor**
11	Catalytic Gasifier / Cryogenic ASU / Warm Gas Cleanup / **Pressurized Solid Oxide Fuel Cell** / 90 % Capacity Factor

Cumulative Impact of Advanced Technologies on Process Efficiency

Figure ES-1 shows the cumulative improvement in process performance as each technology is introduced. Cases that feature improved capacity factor (80 % CF, 85 % CF, and 90 % CF) do not contribute to performance efficiency because the capacity factor merely increases the time of on-stream operation, and therefore has a benefit solely in terms of reduced COE.

The advanced "F" frame turbine and coal feed pump contribute 2.5 and 2.1 percentage point efficiency improvements, respectively. These are slightly greater than the sum of their individual efficiency improvements in the reference plant, so some synergy results from the combined technologies.

Partial warm gas cleanup (WGCU) likewise improves performance of the cumulative process (by 2.1 percentage points) more than it does the performance of the reference plant (2.0 percentage points). Full warm gas cleanup (WGCU+) adds little to performance in the cumulative process (only 0.3 percentage points) because elimination of the ammonia quench, which avoids condensing moisture from fuel gas in the slurry feed gasifier case, does not represent as much of an advantage in a dry feed gasifier whose syngas has virtually no moisture in it.

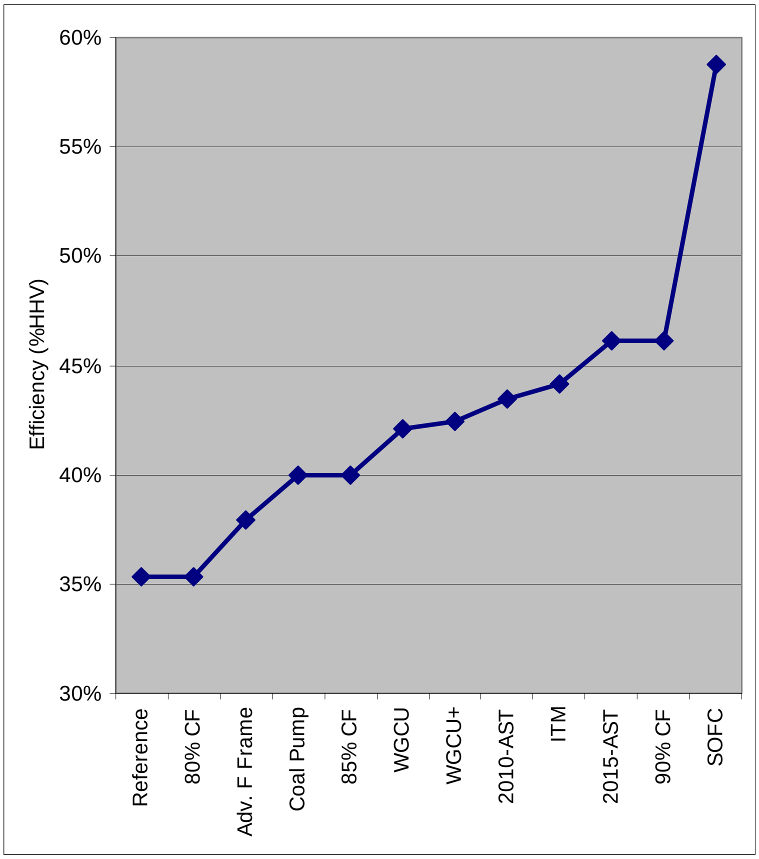

Figure ES-1. Cumulative R&D Impact on Efficiency

The 2010-AST turbine, ITM, and 2015-AST turbine cases each improve process efficiency (1.0, 0.9, and 2.0 percentage points, respectively) by a slightly greater amount than they improve the reference plant (0.9, 0.8, and 1.7 percentage points, respectively). This again demonstrates some synergy resulting from combined technologies.

The SOFC process yields 58.8 % plant efficiency. This process relies on a catalytic gasifier with very high (92.0 %) cold gas efficiency and full warm gas cleanup. Compared to the reference process, this represents a very substantial 23.4 percentage point improvement in process efficiency. The high plant efficiency is environmentally attractive because it reduces the production of CO_2 per MWe of power produced. In addition, the process produces a sequestration-ready CO_2 stream, resulting in a superior process from the perspective of cost of CO_2 avoided.

Cumulative Impact of Advanced Technologies on Total Plant Cost

As each advanced technology is introduced, total plant cost usually decreases, as shown in Figure ES-2. Improved capacity factor has no effect on TPC, just as it had no effect on process efficiency.

The advanced “F” frame turbine has the greatest effect of any technology on the cumulative TPC reduction ($304/kW); this is because of the large increase (150 MW) in net power output relative to replacing the 7FA syngas turbine. The incremental reduction from the 2010-AST turbine is $72/kW – not as dramatic a decrease because the power output with the 2010-AST is only 50 MW more than with the advanced “F” frame turbine. The incremental capital cost reduction from the 2015-AST turbine is only $15/kW; this is because of a large decrease (223 MW) in net power output from the plant because the number of trains is reduced from two to one in order to maintain nominal plant output of 600 MW.

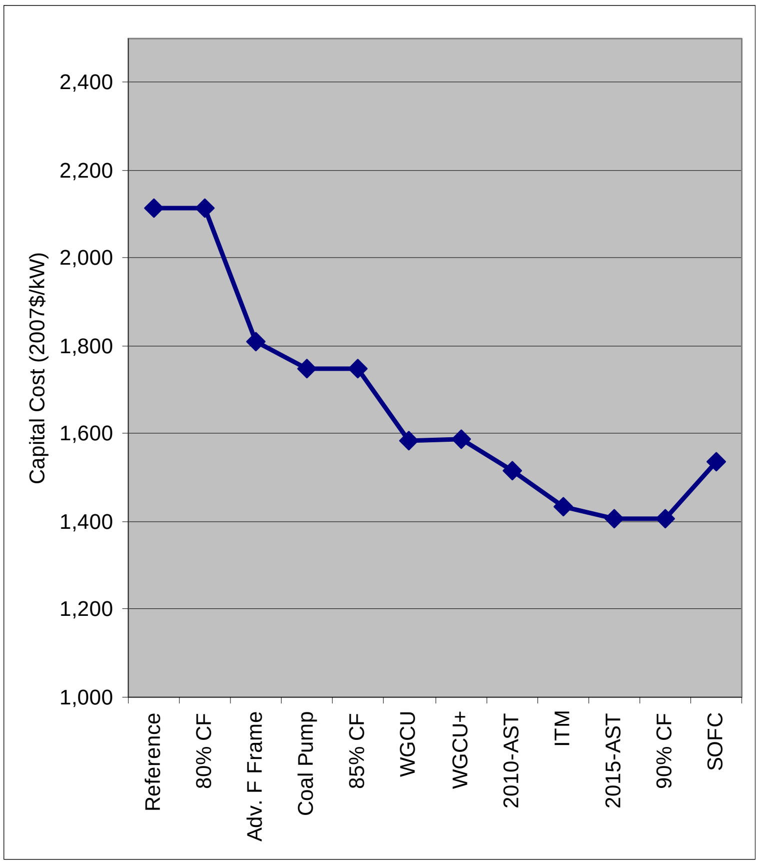

Figure ES-2. Cumulative R&D Impact on Total Plant Cost

As in the reference plant, warm gas cleanup and ITM have lower capital costs than the technologies that they replace, but TPC on a $/kW basis further decreases because net power produced by the plant increases by about 50 MW as a result of each of these technologies. These technologies contribute cumulative technology cost reductions of $164/kW and $118/kW, respectively. The cost difference between partial warm gas cleanup and full warm gas cleanup is negligible.

For the coal feed pump case, the dry feed gasifier section itself is only slightly less costly than the slurry feed gasifier section (by $24 MM), but the plant as a whole reduces in cost (by $80 MM) due to decreased coal flowrate which results in reduced oxygen requirement and smaller equipment sizes throughout the plant. Accounting for the reduced power output (by 23 MW) of the coal feed pump plant, TPC decreases by $60/kW.

As for the solid oxide fuel cell process, no systems analysis attempt was made to investigate an optimum process configuration; potential for further cost reduction could possibly result from ITM air separation or water gas shift of the fuel gas before it enters the fuel cell or other similar process modifications that may decrease total plant cost. The increase by $153/kW over the most advanced IGCC process with 90 % capacity factor (Case 10) is an artifact of the assumed capital costs of the fuel cell system and catalytic gasifier, and has considerable uncertainty at this time.

Cumulative Impact of Advanced Technologies on COE

As each new advanced technology is implemented step-wise in the cumulative advanced power system, the reduction in COE is represented in Figure ES-3. Due to greater on-stream operation, effects of improved capacity factor are as significant as the other advanced technologies. The increase to 80 % capacity factor results in a 4.0 mills/kW-hr decrease in COE, the increase to 85 % capacity factor results in a 2.9 mills/kW-hr decrease, and the increase to 90 % capacity factor results in a 2.7 mills/kW-hr decrease.

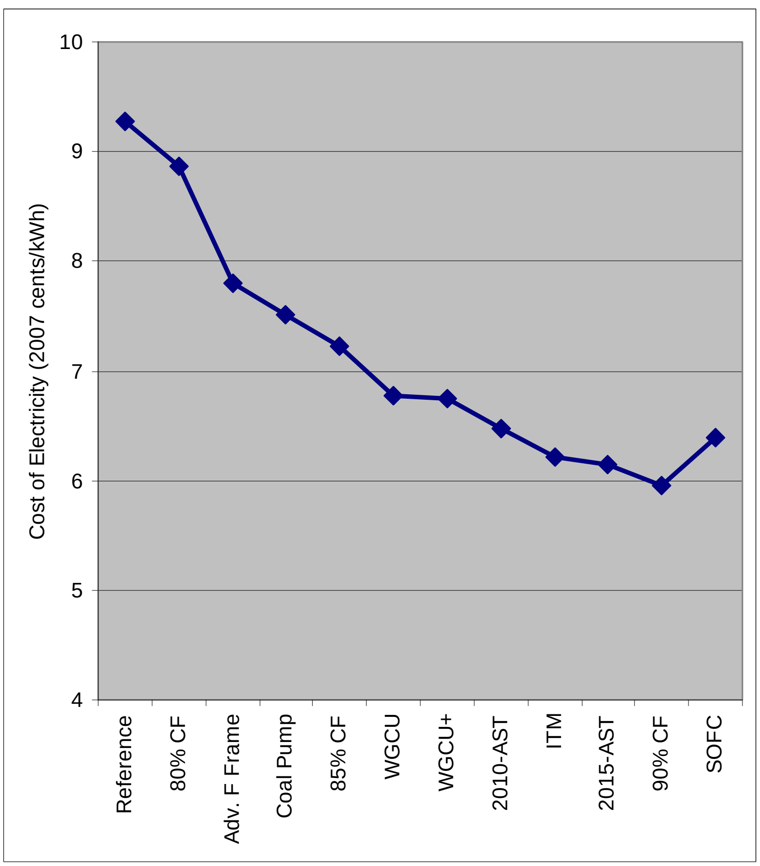

Figure ES-3. Cumulative R&D Impact on COE

The advanced “F” frame syngas turbine provides the single greatest decrease in COE (10.7 mills/kW-hr) due to the 150 MW increase in net power output and 2.5 percentage point plant efficiency increase made possible by air integration, improved turbine efficiency, and increased HRSG inlet temperature (allowing increased steam cycle superheat and reheat temperatures).

Partial warm gas cleanup results in a 4.5 mills/kW-hr decrease in COE. Because of very low moisture content in the fuel gas, the novel ammonia and mercury removal units in the full warm gas cleanup case result in a very small improvement in process efficiency. There is no significant difference in TPC between partial and full warm gas cleanup, so as a result the COE changes very little between these cases.

The 2010-AST syngas turbine increases plant power output by 50 MW over that of the advanced “F” frame turbine, and therefore results in a $72/kW reduction in TPC. There is also a 1.1 percentage point improvement in process efficiency over the advanced “F” frame turbine, resulting in reduced fuel cost. Overall, the 2010-AST turbine decreases COE by 2.7 mills/kW-hr in the cumulative technologies plant.

The ITM increases plant output by 49 MW with a corresponding decrease in TPC by $17 MM, resulting in a $118/kW decrease in total plant cost. Although the efficiency improvement is only 0.9 percentage points, the decreased TPC translates to a 3.6 mills/kW-hr decrease in COE.

The 2015-AST syngas turbine has a much higher power rating than the 2010-AST, but the reduction from two trains to a single train decreases the net plant power output by 223 MW resulting in only a $15/kW reduction in TPC and, therefore, a 0.5 mills/kW-hr reduction in COE.

The tremendous process efficiency (58.8 %) and low capital cost ($1,536/kW) of the SOFC process makes its COE competitive with the advanced IGCC processes, even before any systems analysis attempts are made at improved SOFC process configurations. Although the SOFC configuration examined in this study does not have the lowest COE, it represents great potential for carbon capture scenarios because the CO_2 product stream is sequestration-ready.

In summary, this pathway study evaluated anticipated process performance improvements and capital cost reductions resulting from advanced technology development sponsored by DOE. The technology pathway covers a time span of about eighteen (18) years, allowing for the process of technology development and implementation. These advanced technologies include innovations in gasification, syngas turbines, synthesis gas cleaning, air separation, and fuel cells.

The technology improvements examined in this study suggest significant reductions in the COE generated by these advanced power facilities and the value of combining advanced technology to capitalize on their synergistic impacts. Overall, this pathway study determined that DOE/NETL’s current R&D portfolio has the potential to reduce total plant cost (TPC) by 35 % and increase efficiency by 24 percentage points by 2020, resulting in a 37 % reduction in cost of electricity (COE).

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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 Integrated Gasification Combined Cycle (IGCC) and Integrated Gasification Fuel Cell (IGFC) technologies. In order to evaluate the benefits of ongoing R&D, Noblis utilized their energy systems analysis capabilities and conceptual computer simulation models to quantify the impact of successful federally-funded R&D on future power generation configurations.

Noblis developed Aspen Plus computer models for one IGFC and a series of IGCC configurations. These models provided material and energy balances to simulate the gasification of coal to clean synthesis gas and the subsequent utilization in syngas turbine, fuel cell, and steam turbine cycles. Economic models estimated capital and operating costs and calculate the 20-year levelized cost of electricity (COE) based upon standard discounted cash flow (DCF) analysis. An Aspen Plus simulation and cost estimate for one case were validated against a corresponding NETL Baseline Study [1] case, and were found to predict nearly identical performance and cost results.

Emerging advanced gasification, gas cleanup, air separation, syngas turbine, and solid oxide fuel cell technologies were incorporated step-wise over time into the reference IGCC configuration to lay out a "pathway" of technology development and implementation. Incorporation of these advanced technologies into the composite IGCC plant allows an estimate of the future benefits of these technologies to be quantified. These benefits are measured ultimately in terms of reduced cost of electric power.

In this report, a Reference Case IGCC configuration was established based on 2002 technology. Sequential improvements were then evaluated over the anticipated timeframe of advanced technology deployment. These improvements included advanced "F" frame syngas turbine, coal feed pump, greater on-stream time (or capacity factor), warm gas cleanup, improved advanced syngas turbine (2010-AST turbine), ceramic membrane technology for air separation, a further advanced syngas turbine (2015-AST turbine), and emergence of the pressurized solid oxide fuel cell. Increased capacity factor was attributed to advances in instrumentation and materials as well as operating experience gained from demonstrating these technologies over time through DOE programs including Clean Coal Technology, the Clean Coal Power Initiative, and FutureGen. To the extent possible, a nominal 600 MW plant size was used for comparison between cases.

2 Pathway Study Basis

A process flow diagram of the Reference Case is provided in Figure 2-1. This configuration was considered to be state-of-the-art when goals for the advanced power systems program were established in 2003, and is the standard against which all improvements are measured in this study. The process includes two 7FA gas turbines and a steam cycle operating at 1,800 psig with 1,000 ^oF steam superheat and 1,000 ^oF steam reheat. The as-received Illinois #6 bituminous coal feed contains 11.12% moisture, and has a higher heating value of 13,125 Btu/lb (dry basis).

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 gas turbine; the exact amount is determined by the gas turbine power rating, which is regulated to 192 MW per unit.

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

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 is cooled to 390 ^oF for COS hydrolysis. Following the exothermic COS hydrolysis reaction, the gas is cooled again; first to 310 ^oF to recover useful heat for fuel gas reheat and steam generation, next to 235 ^oF to recover useful heat for the steam cycle deaerator, then finally to 110 ^oF for NH_3 removal. The cooling temperatures of 310 ^oF and 235 ^oF 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 Selexol process that absorbs H_2S from the fuel gas. H_2S is stripped from the solvent in the solvent regenerator and the acid gas is sent to the Claus plant.

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 719 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 syngas mixture is burned in the topping combustor, reaching a temperature of 2,250 ^oF (fuel flow is regulated in order to obtain this temperature). The net gas turbine power output is 192 MWe per unit [2].

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 for acid gas removal (the Selexol solvent regenerator), the sour water stripper, and fuel gas reheating prior to the fuel gas expander.

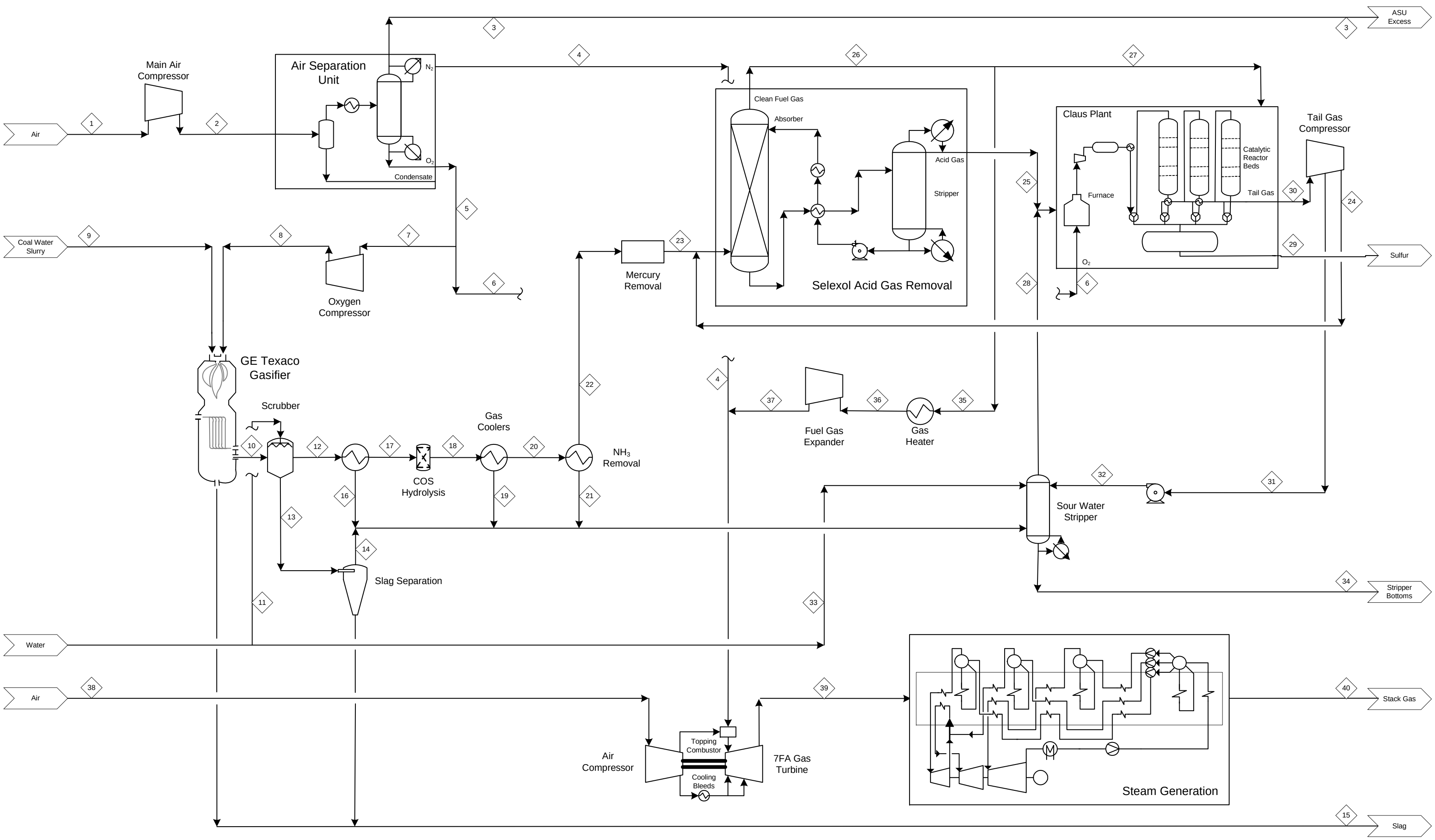

Figure 2-1. Process Flow Diagram of Reference Case 0

The design basis of NETL's Baseline Study was adopted so that results from this pathway study would be consistent with established results. Some of the more global process parameters are described below, while other case-specific design assumptions can be found in the Volume 1 Supplement along with more detailed documentation for each individual case.

2.1 Coal Analysis

Fuel quality has a significant effect on process performance. Table 2-1 details the coal feed analysis that is used for all cases in this study. The Illinois #6 bituminous coal comes from the Old Ben #26 mine, and is the same as used in NETL's Baseline Study. Note the fuel heating value of 13,126 Btu/lb (dry basis); this is equivalent to 11, 666 Btu/lb for as-received coal.

This coal has a relatively high chlorine content, which will be shown in the analysis to impact the sour water stripper operation in order to prevent corrosion; a water purge stream maintains chloride concentration below 1,000 ppm in the sour water stripper.

Table 2-1. Coal Analysis: Illinois #6 Old Ben #26 Mine

Proximate Analysis
As-Received (wt %)

Moisture	12.51
Ash	10.91
Volatile Matter	39.37
Fixed Carbon	49.72

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

2.2 Process Operating Assumptions

The cryogenic ASU operates at 10 atmospheres, producing 95 % pure oxygen for the gasifier (and Claus plant if cold gas cleanup is used). Nitrogen is used to dilute fuel to the gas turbine; in most cases, nitrogen is added to regulate fuel gas heating value to 125 Btu/scf (LHV) as a method for NOx control. If there is not sufficient nitrogen for dilution, steam is added to the fuel stream to meet the fuel specification. The ASU consumes a small quantity of low pressure steam to regenerate dehumidification sorbent, and a small quantity of medium pressure steam for an ammonia refrigeration system.

The slurry feed gasifier is assumed to operate at 2,400 ^oF with 98 % carbon conversion; the gasifier with dry feed provided by the coal feed pump is assumed to operate at 2,600 ^oF with 99.5 % carbon conversion. Gasifier pressure is 800 psia. In both cases, sufficient oxygen is provided to the gasifier to satisfy the energy balance. Exiting the gasifier, the radiant-only cooler reduces the raw syngas stream temperature to 1,250 ^oF. No convective cooler is present in cold gas cleanup cases, however a trim cooler is used to control temperature of the transport desulfurizer in the warm gas cleanup cases.

In cold gas cleanup processes, raw fuel gas exiting the gasifier 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 is cooled to 390 ^oF for COS hydrolysis. Following the exothermic COS hydrolysis reaction, the syngas is further cooled to condense water, ammonia, and cyanide and also to prepare for H_2S removal in the Selexol absorber. During this cooling, heat is assumed to be recoverable down to 235 ^oF for use in the bottoming cycle.

Condensate from the raw syngas is treated in the sour water stripper; a water purge is added to the sour water stripper in order to maintain chloride concentration below 1,000 ppm. Gas component separation in the Selexol process is based on proprietary information provided by UOP. Acid gas (stripped from the regenerated Selexol solvent) is treated in a Claus plant for sulfur recovery, and the tail gas is recycled to the Selexol absorber.

Four syngas turbines are examined in this pathway study; the 7FA, advanced “F” frame, 2010-AST, and 2015-AST. These turbines are all designed for operation using syngas fuel. They operate at increasing firing temperatures, pressure ratios, and power ratings as technology improves over time. All turbines except the 7FA are integrated with the ASU – providing part of the ASU’s air feed in order to reduce the work required of the main air compressor. The 7FA and advanced “F” gas turbines are now commercially available; the 2010-AST and 2015-AST (pseudonyms are used for the purpose of discussion) represent technology expected to be available in the 2010 and 2015 timeframes, respectively.

Turbine exhaust flows to the heat recovery steam generator (HRSG), which provides heat for a three pressure level steam cycle. High pressure steam superheat and reheat is 1,000 ^oF for the 7FA syngas turbine, but increases to 1,050 ^oF as turbine firing temperatures (and exit temperatures) increase in the other three turbine models. For all cases, the flue gas stack exit temperature is 270 ^oF; standardization of this value provides consistency to the quantity of recoverable heat from the HRSG.

2.3 Economic Analysis

The cost estimating methodology used in this study is consistent with that described in NETL’s Quality Guidelines for Energy Systems Studies (QGESS) [3]. Plant capital cost is estimated using the most accurate estimation methods available, taking into consideration plant size, number of process trains, sparing philosophy, and as much equipment-specific design information as possible. In general, scaling factors are used to calculate equipment costs based on capacity or throughput; the Supplement to Volume 1 describes specific methods used to estimate costs of the advanced technologies.

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.

Economic feasibility analysis can be performed using the Power Systems Financial Model (PSFM) [4], Version 5.0. Alternatively, 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 [5].

2.3.1 Capital Cost

The following Figure 2-2, taken from Chapter 6 of QGESS, 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.

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 EPCC at the process section level; however the Volume 1 Supplement contains additional process section detail for BEC, EPCC, and process and project contingencies for all cases.

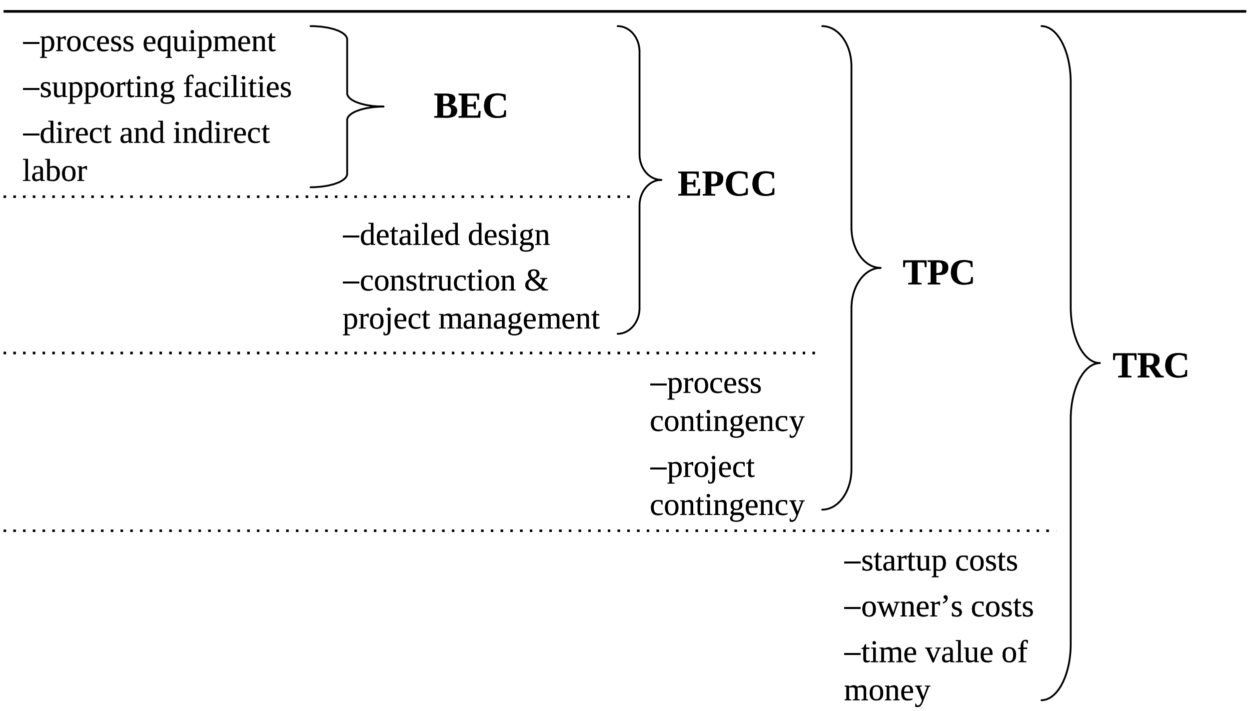

Figure 2-2. Elements of Capital Cost

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 have the same level of contingency as conventional technologies in order not to put the advanced technologies at a disadvantage due to uncertainties in their cost. Contingency estimates are added to the EPCC to calculate the Total Plant Cost (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.

Variable operating costs are estimated using 100 % capacity factor, and expressed as percent of EPCC if using the PSFM[1]. The PSFM applies the capacity factor to calculate actual annual variable operating cost. 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
Fuel Cell Stack Replacement
Spent Catalyst Waste Disposal
Ash Disposal

The PSFM computes fuel cost 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

[1] As an alternative to the PSFM, a separate Excel spreadsheet model was developed for economic analysis in this study; it was validated against the PSFM to verify that the calculations were implemented correctly. The spreadsheet model was developed to contain both capital cost algorithms and DCF calculations in a single file.

11,666 Btu/lb. For warm gas cleanup, costs of $14,000/ton for ZnO sorbent and $100/ton for trona are assumed[2]. The sorbent attrition rate is assumed to be 10-20 lb. per million lb. circulating sorbent.

2.3.3 Cost of Electricity

As an alternative to the PSFM, the levelized cost of electricity can be calculated directly using the formula:

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

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

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. Based on guidance from QGESS, the capital charge factor in this scenario is 17.5 %. Additional assumed financial parameters (used in NETL's Baseline Study) are itemized in Table 2-3 below.

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.

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

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

3 Analysis of Advanced Power Process Configurations

A variety of process scenarios that produce electric power from bituminous coal are analyzed in this study to determine the potential performance improvements and cost reductions resulting from advanced technology under development in DOE/NETL's Clean Coal R&D program. Starting with the reference IGCC plant, a series of process modifications is simulated to represent commercialization of advanced technologies. Impacts on both process performance and cost are evaluated. The impact of each individual technology is first evaluated within the framework of the reference plant. These process configurations are listed in Table 3-1, with each of the advanced technologies identified in bold letters. The suffix "a" on the case number indicates each technology evaluated singly in the reference plant.

Table 3-1. Stand-Alone Power System Technology Development

Case	Description
0	Reference Plant / Slurry Feed Gasifier / Cryogenic ASU / Cold Gas Cleanup / 7FA Syngas Turbine / 75 % Capacity Factor (2002 Technology)
2a	Slurry Feed Gasifier / Cryogenic ASU / Cold Gas Cleanup / **Advanced "F" Frame Syngas Turbine** / 75 % Capacity Factor
3a	**Coal Feed Pump** / Cryogenic ASU / Cold Gas Cleanup / 7FA Syngas Turbine / 75 % Capacity Factor
5a	Slurry Feed Gasifier / Cryogenic ASU / **Transport Desulfurizer (TDS) and Direct Sulfur Recovery Process (DSRP)** / 7FA Syngas Turbine / 75 % Capacity Factor
6a	Slurry Feed Gasifier / Cryogenic ASU / TDS and DSRP with **Warm Gas Treatment for Ammonia and Mercury** / 7FA Syngas Turbine / 75 % Capacity Factor
7a	Slurry Feed Gasifier / Cryogenic ASU / Cold Gas Cleanup / **2010-AST Syngas Turbine** / 75 % Capacity Factor
8a	Slurry Feed Gasifier / **Ion Transport Membrane (ITM)** / Cold Gas Cleanup / Advanced "F" Frame Syngas Turbine / 75 % Capacity Factor
9a	Slurry Feed Gasifier / Cryogenic ASU / Cold Gas Cleanup / **2015-AST Syngas Turbine** / 75 % Capacity Factor

The cumulative impact of all technologies available at any one time is also evaluated. That is, as each new technology becomes available, it is implemented in the composite process to evaluate potential improvements in either process performance or cost over time. Table 3-2 identifies the process configurations of these cases.

3.1 Case 0: Reference Plant

The reference plant is an IGCC process that includes slurry feed gasifier, cryogenic air separation, cold gas cleanup, 7FA syngas turbine, and 75 percent capacity factor. The process configuration is based on state-of-the-art technology available in 2002, and serves as an appropriate metric to evaluate technology progress because it was the basis used in 2003 to establish DOE's R&D program goals.

Table 3-2. Cumulative Power System Technology Development

Case	Description
0	Reference Plant / Slurry Feed Gasifier / Cryogenic ASU / Cold Gas Cleanup / 7FA Syngas Turbine / 75 % Capacity Factor (2002 Technology)
1	Slurry Feed Gasifier / Cryogenic ASU / Cold Gas Cleanup / 7FA Syngas Turbine / **80 % Capacity Factor**
2	Slurry Feed Gasifier / Cryogenic ASU / Cold Gas Cleanup / **Advanced "F" Frame Syngas Turbine** / 80 % Capacity Factor
3	**Coal Feed Pump** / Cryogenic ASU / Cold Gas Cleanup / Advanced "F" Frame Syngas Turbine / 80 % Capacity Factor
4	Coal Feed Pump / Cryogenic ASU / Cold Gas Cleanup / Advanced "F" Frame Syngas Turbine / **85 % Capacity Factor**
5	Coal Feed Pump / Cryogenic ASU / **Transport Desulfurizer (TDS) and Direct Sulfur Recovery Process (DSRP)** / Advanced "F" Frame Syngas Turbine / 85 % Capacity Factor
6	Coal Feed Pump / Cryogenic ASU / TDS and DSRP / **Warm Gas Treatment for Ammonia and Mercury** / Advanced "F" Frame Syngas Turbine / 85 % Capacity Factor
7	Coal Feed Pump / Cryogenic ASU / Warm Gas Cleanup / **2010-AST Syngas Turbine** / 85 % Capacity Factor
8	Coal Feed Pump / **Ion Transport Membrane (ITM)** / Warm Gas Cleanup / 2010-AST Syngas Turbine / 85 % Capacity Factor
9	Coal Feed Pump / ITM / Warm Gas Cleanup / **2015-AST Syngas Turbine** / 85 % Capacity Factor
10	Coal Feed Pump / ITM / Warm Gas Cleanup / 2015-AST Syngas Turbine / **90 % Capacity Factor**
11	Catalytic Gasifier / Cryogenic ASU / Warm Gas Cleanup / **Pressurized Solid Oxide Fuel Cell** / 90 % Capacity Factor

Figure 3-1 presents a block flow diagram of the process. The plant is configured with two trains of single-stage slurry feed gasifiers with radiant-only syngas coolers, two cryogenic air separation units, two trains of water scrub and carbonyl sulfide (COS) hydrolysis, a single train of Selexol acid gas removal, one train of sulfur recovery using conventional Claus technology, two trains of 7FA syngas turbines, one HRSG, and one steam turbine bottoming cycle with high, intermediate, and low pressure (condensing) turbine sections. Steam conditions are 1,800 psi and 1,000 ^{o}F for the HP turbine and 405 psi and 1,000 ^{o}F for the IP turbine.

This two-train IGCC plant processes 4,831 tons per day of as-received Illinois #6 coal to produce a net 487 MW of power. Carbon utilization is 98 percent, and overall efficiency is 35.4 percent (HHV basis). Total power generated includes 384 MW from the gas turbines, 6 MW from the fuel gas expanders, and 223 MW from the steam cycle. Auxiliary power use is estimated to be 127 MW. This performance, calculated by Noblis' Aspen Plus process model, is comparable to operation achieved at the Tampa Electric Plant, which uses the same technology.

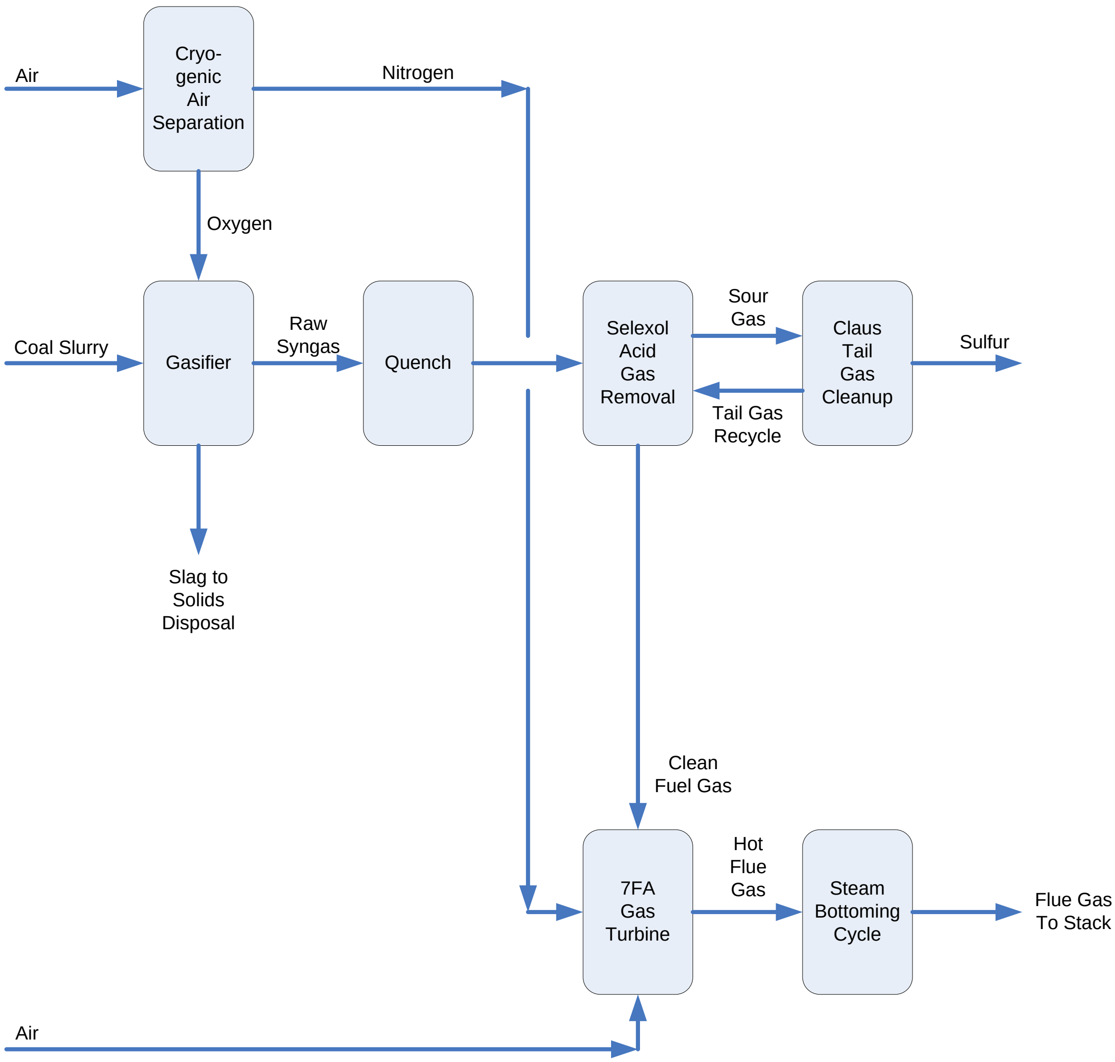

Figure 3-1. Case 0: Reference Plant Configuration

Cost Analysis

Table 3-3 below estimates the Engineering, Procurement, and Construction Cost (EPCC) for each major section of the process plant. Bare erected costs (BEC) are scaled from equipment costs in NETL's Baseline Study. Process and project contingencies (also from NETL's Baseline Study) are added to the EPCC to calculate the Total Plant Cost (TPC). The TPC does not include owner's costs, which might typically include a Technology Fee. The resulting TPC is $2,113/kW.

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 was used for consistency. Administrative labor is estimated as an overhead rate (25 %) to the sum of operating and maintenance labor.

Table 3-3. Case 0: Capital and O&M Cost Summary

Capital Cost ($1,000)					
Plant Sections	**EPCC**	**Process Cont'gncy**	**Project Cont'gncy**	**TPC**	**TPC $/kW**
1 Coal Handling	25,685	0	5,137	30,821	63
2 Coal Prep & Feed	39,472	1,312	8,195	48,980	101
3 Feedwater & Balance of Plant	28,606	0	6,471	35,077	72
4a Gasifier	184,371	18,725	33,116	236,212	485
4b Air Separation Unit	153,591	0	15,359	168,950	347
5a Gas Cleanup	93,441	75	18,873	112,389	231
5b CO_2 Removal & Compression	0	0	0	0	0
6 Gas Turbine	91,110	3,787	10,161	105,058	215
7 HRSG	44,560	0	4,951	49,511	102
8 Steam Cycle and Turbines	47,842	0	6,467	54,310	112
9 Cooling Water System	20,099	0	4,134	24.233	50
10 Waste Solids Handling System	34,981	0	3,771	38,752	80
11 Accessory Electric Plant	55,772	0	10,757	66,529	137
12 Instrumentation & Control	18,982	869	3,327	23,178	48
13 Site Preparation	13,956	0	4,187	18,143	37
14 Buildings and Structures	14,012	0	2,302	16,314	34
Total	866,482	24,769	137,207	1,028,457	2,113
O&M Cost ($1,000)					
Fixed Costs				**Total**	**% EPCC**
Labor				19,542	2.26
Variable Operating Costs*				**Total**	**% EPCC**
Maintenance Materials				18,368	2.12
Water				1,451	0.17
Chemicals				1,021	0.12
Waste Disposal				2,262	0.26
Total Variable Costs				23,102	2.67
Total O&M Cost*				42,644	4.92
Fuel Cost*				55,690	6.43
Discounted Cash Flow Results					
Total Plant Cost ($/kW)					2,113
Levelized Cost of Electricity ($/kW-hr)					0.0927

*Includes 75 % Capacity Factor

Variable operating costs are estimated using 75 % capacity factor – typical of the availability of IGCC plants in 2002/2003. Levelized cost of electricity is calculated using the equation of the previous section. Results from the discounted cash flow analysis, shown Table 3-3, indicate $0.0927/kW-hr 20-year levelized cost of electricity based on January 2007 dollars.

3.2 Increased Capacity Factor to 80 Percent

With IGCC operating experience gained from DOE's demonstration programs, plant availability is expected to improve to 80 % even without the need for improved technology. Capacity factor has no effect on the mass and energy balance computed in Case 0; only the variable operating costs and fuel cost are affected. Substituting the higher capacity factor into the equation for levelized cost of electricity, the levelized COE improves from $0.0927/kW-hr in Case 0 to $0.0887/kW-hr in Case 1 as the result of more hours of plant operation.

3.3 Advanced “F” Frame Syngas Turbine

The advanced “F” frame syngas turbine allows integration with the air separation unit (a portion of the air supply to the ASU is provided by the gas turbine). The advanced “F” frame syngas turbine produces more power, has a higher pressure ratio, and higher firing temperature than the 7FA syngas turbine. Because of the higher turbine firing temperature and subsequently higher turbine exhaust temperature, steam conditions are 1,800 psi and 1,050 ^{o}F for the HP turbine and 405 psi and 1,050 ^{o}F for the IP turbine.

3.3.1 Impact of Advanced “F” Frame Syngas Turbine in the Reference Plant (Case 2a)

Case 2a Configuration: Slurry Feed Gasifier, Cryogenic ASU, Cold Gas Cleanup, Advanced “F” Frame Syngas Turbine, 75 % Capacity Factor

Figure 3-2 presents the block flow diagram of the reference IGCC process with an advanced “F” frame syngas turbine. This two-train IGCC plant processes 5,900 tons per day of as-received coal to produce a net 637 MW of power. Overall efficiency is 37.9 percent (HHV basis). Carbon utilization is 98 percent and the capacity factor is 75 percent. Total power generated includes 8 MW from the fuel gas expander, 464 MW from the gas turbines and 293 MW from the steam turbine. Auxiliary power use is estimated to be 128 MW. Performance resulting from the advanced “F” frame gas turbine is compared against the Reference Case in the following table.

Table 3-4. Performance Impact of Advanced “F” Turbine in the Reference Plant

	Case 0	**Case 2a**
	Reference plant with 7FA	Reference plant with adv. “F”
Gas Turbine Power (MWe)	384	464
Fuel Gas Expander (MWe)	6	8
Steam Turbine Power (MWe)	223	293
Total Power Produced (MWe)	614	765
Auxiliary Power Use (MWe)	-127	-128
Net Power (MWe)	487	637
As-Received Coal Feed (lb/hr)	402,581	491,633
Net Heat Rate (Btu/kW-hr)	9,649	9,004
Net Plant Efficiency (HHV)	35.4 %	37.9 %

The 7FA syngas turbine in the Reference Case is rated at 192 MW, while the advanced “F” frame turbine in Case 2a is rated at 232 MW. Because of the lower turbine exit temperature in Case 0, steam superheat temperature is 1,000 ^{o}F rather than the 1,050 ^{o}F that’s possible in Case 2a due to the higher turbine exit temperature. The increased coal flowrate, made possible by greater turbine throughput, leads to increased heat recovery in the gasifier, syngas quench, and flue gas through the HRSG – thus further contributing to increased steam turbine power generation in Case 2a.

Although auxiliary power use appears to be nearly the same between cases, there are significant but off-setting differences in the ASU main air compressor and the nitrogen compressor. The ASU main air compressor power consumption decreases in Case 2a due to integration between the gas turbine air compressor and the ASU, which reduces the fresh air feed through the main air compressor and therefore reduces power consumption. This reduction in power consumption is counterbalanced by increased N_2 compressor power consumption, which is the result of greater flowrate through the gas turbine. As a fraction of total power produced, auxiliary power use decreases for the larger gas turbine with air integration.

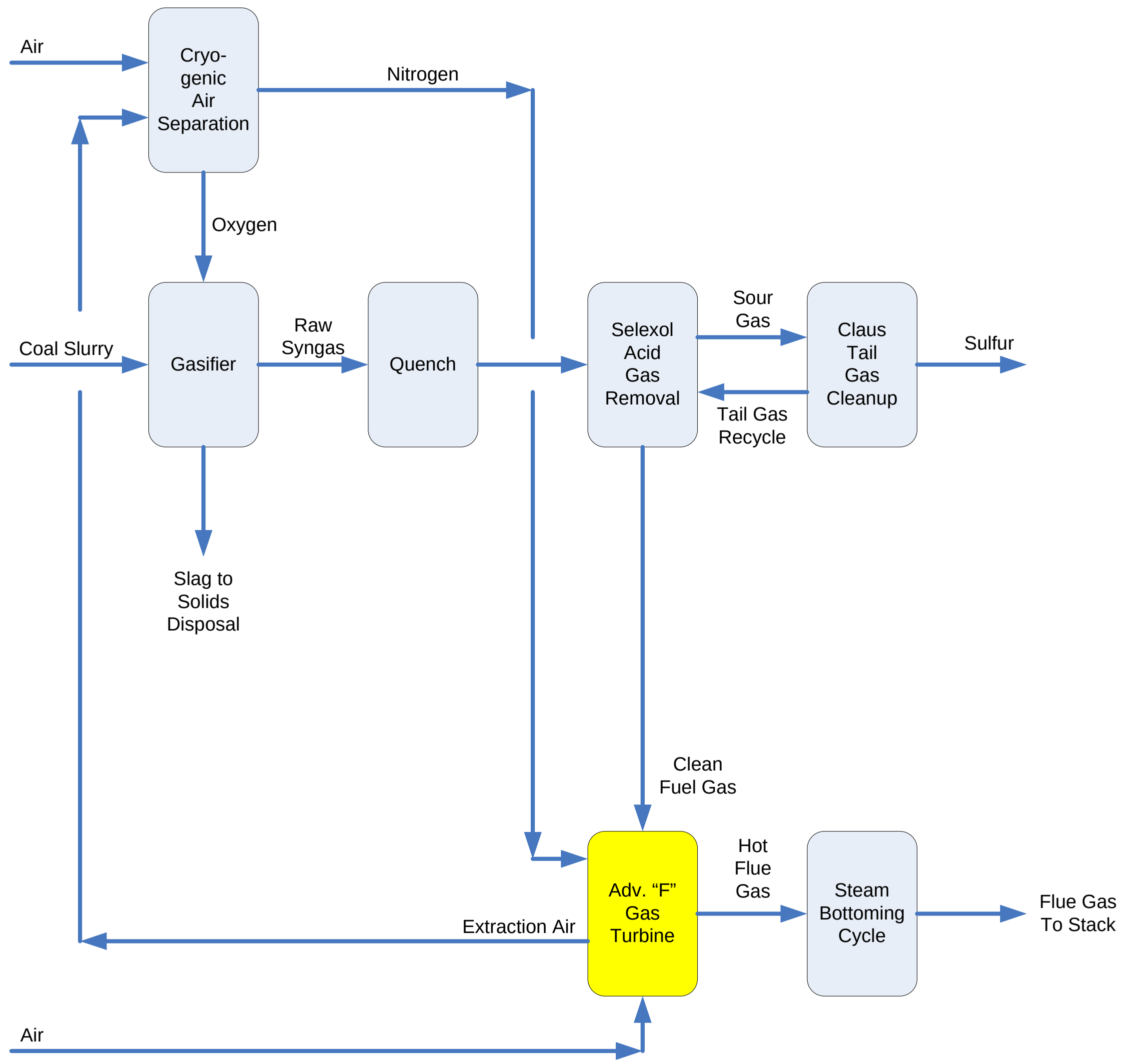

Figure 3-2. Case 2a: Advanced "F" Frame Syngas Turbine IGCC Configuration

Overall, the net plant efficiency increases by 2.5 percentage points going from the 7FA syngas turbine to the advanced "F" frame syngas turbine; the primary reasons for this are air integration from the gas turbine to the ASU, the higher efficiency of the advanced "F" frame syngas turbine, and the increased steam cycle superheat temperature.

Cost Analysis (Case 2a)

Table 3-5 below compares capital and O&M costs with the Reference Case. The choice of gas turbine is the reason for differences in capital costs between Case 0 (7FA turbine) and Case 2a (advanced "F" frame turbine). The advanced "F" turbine has a higher power rating, which increases coal flowrate to the process, and therefore equipment sizes throughout the plant; this is reflected in the higher EPCC and TPC costs in Case 2a. On a $/kW basis, the TPC of the advanced "F" turbine plant is less because of increased power output.

Comparing cost of electricity, the $0.0814/kW-hr of Case 2a is less than the $0.0927/kW-hr of Case 0 because of (1) larger gas turbine, which increases the plant output and therefore decreases the capital cost on a $/kW basis, and (2) increased plant efficiency due to the higher pressure ratio and firing temperature of the advanced "F" frame syngas turbine compared to the 7FA turbine.

Table 3-5. Case 2a: Capital and O&M Cost Comparison

	Case 0			Case 2a		
	Reference plant with 7FA			Reference plant with adv. "F"		
Capital Cost ($1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Sorbent Handling	25,685	30,821	63	29,076	34,890	55
2 Coal and Sorbent Prep & Feed	39,472	48,980	101	45,169	56,050	88
3 Feedwater & Balance of Plant	28,606	35,077	72	30,636	37,513	59
4a Gasifier	184,371	236,212	485	210,196	269,284	423
4b Air Separation Unit	153,591	168,950	347	167,073	183,781	289
5a Gas Cleanup	93,441	112,389	231	107,769	129,625	203
5b CO_2 Removal & Compression	0	0	0	0	0	0
6 Gas Turbine	91,110	105,058	215	103,491	119,302	187
7 HRSG	44,560	49,511	102	50,936	56,565	89
8 Steam Cycle and Turbines	47,842	54,310	112	57,934	65,820	103
9 Cooling Water System	20,099	24.233	50	22,515	27,140	43
10 Waste Solids Handling System	34,981	38,752	80	39,568	43,829	69
11 Accessory Electric Plant	55,772	66,529	137	58,402	69,559	109
12 Instrumentation & Control	18,982	23,178	48	19,010	23,212	36
13 Site Preparation	13,956	18,143	37	14,247	18,522	29
14 Buildings and Structures	14,012	16,314	34	14,974	17,421	27
Total	866,482	1,028,457	2,113	970,995	1,152,513	1,809

	Case 0		Case 2a	
O&M Cost ($1,000)				
Fixed Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Labor	19,542	2.26	22,548	2.32
Variable Operating Costs*	**Total**	**% EPCC**	**Total**	**% EPCC**
Maintenance Materials	18,368	2.12	21,339	2.20
Water	1,451	0.17	1,596	0.16
Chemicals	1,021	0.12	1,215	0.13
Waste Disposal	2,262	0.26	2,745	0.28
Total Variable Costs	23,102	2.67	26,896	2.77
Total O&M Cost	42,644	4.92	49,444	5.09
Fuel Cost*	55,690	6.43	68,008	7.00

	Case 0	Case 2a
Discounted Cash Flow Results		
Total Plant Cost ($/kW)	2,113	1,809
Levelized Cost of Electricity ($/kW-hr)	0.0927	0.0814

*Includes 75 % Capacity Factor

3.3.2

Cumulative Impact of R&D

Composite Process Configuration (Case 2): Slurry Feed Gasifier, Cryogenic ASU, Cold Gas Cleanup, Advanced "F" Frame Syngas Turbine, 80 % Capacity Factor

The improvement from Case 1 to Case 2 is replacement of the 7FA gas turbine with the more advanced "F" frame gas turbine. Replacement of the turbine is already represented by Case 2a above, so the cumulative impact can be evaluated simply by increasing the capacity factor of Case 2a to 80 %. As a result, the net plant efficiency of Case 2 is still 37.9 % (the same as Case 2a). The only change is to increase the net plant operating hours, which decreases the levelized cost of electricity from $0.0814/kW-hr to $0.0780/kW-hr.

This case is nearly identical to Case 1 of NETL's Baseline Study; a validation was performed to demonstrate that results are consistent. The validation is presented in Appendix A.1.

3.4 Coal Feed Pump

The benefit of this technology is to decrease the energy required to evaporate slurry water in the gasifier, thereby increasing cold gas efficiency of the gasifier. Dry feed is accomplished with a coal pump, which is assumed to be capable of delivering dry feed to the elevated gasifier pressure. A fluffing gas is required for coal transport, and has an assumed flowrate of 0.156 lb. fluff gas per lb. coal feed. The power requirement for the coal pump is 500 kW per gasifier.

The coal pump is assumed capable of delivering as-received coal to the gasifier without the need for coal drying. The coal feed, with 12.5 % moisture, is considered to contain sufficient moisture that additional steam is not needed for gasification.

3.4.1 Impact of Coal Feed Pump in the Reference Plant (Case 3a)

Case 3a Configuration: Coal Feed Pump, Cryogenic ASU, Cold Gas Cleanup, 7FA Syngas Turbine, 75 % Capacity Factor

The slurry feed gasifier is replaced with a coal feed pump that eliminates the need for slurry water, and the performance improvement is evaluated. The process configuration is identical to that in Figure 3-2, except that coal is delivered to the gasifier as dry feed rather than 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 and thereby increasing the cold gas efficiency of the gasifier.

The raw syngas composition in Case 3a has much less water because of the dry feed. Less coal is needed in this case, so the molar flowrate of raw syngas is also less. The concentration of CO in the Case 3a syngas is much greater – due to not having to oxidize carbon in the gasifier in order to evaporate slurry water.

With the 7FA reference plant gas turbine, neither case integrates air from the gas turbine to the ASU. Because of the decreased coal feedrate in Case 3a and corresponding decrease in gasifier oxygen required, all available N_2 from the ASU is used for fuel dilution and the fuel gas must also be humidified in order to generate sufficient flow through the gas turbine. Case 3a has, as a result, a higher mole fraction of H_2O in the fuel gas due to humidification.

Table 3-6 below summarizes the overall process performance for two process trains.

Table 3-6. Performance Impact of Coal Feed Pump in the Reference Plant

	Case 0	Case 3a
	Reference plant with slurry feed	Reference plant with coal feed pump
Gas Turbine Power (MWe)	384	384
Fuel Gas Expander (MWe)	6	7
Steam Turbine Power (MWe)	223	188
Total Power Produced (MWe)	614	579
Auxiliary Power Use (MWe)	-127	-113
Net Power (MWe)	487	466
As-Received Coal Feed (lb/hr)	402,581	365,931
Net Heat Rate (Btu/kW-hr)	9,649	9,157
Net Plant Efficiency (HHV)	35.4 %	37.3 %
Gasifier Cold Gas Efficiency	75.8 %	81.6 %

The reduced steam turbine power in Case 3a reflects decreased coal flowrate (as the result of not having to evaporate slurry water), leading to decreased heat recovery in the gasifier and syngas quench. Another factor adding to decreased steam turbine power in Case 3a is heat required to humidify the fuel stream.

The primary differences in auxiliary power consumption lay in the ASU main air compressor, the oxygen compressor, and Selexol auxiliaries. These all result from reduced coal feedrate to the gasifier in Case 3a, and also scale back all other auxiliary power accounts – reducing auxiliary power in Case 3a by 14 MW.

Overall, the net plant efficiency increases by 1.9 percentage points going from the Reference Case to the coal feed pump.

Cost Analysis (Case 3a)

Capital and O&M costs are compared with Case 0 results in Table 3-7. The coal feed pump Case 3a has a lower coal flowrate (due to not having to evaporate slurry water in the gasifier) and lower net power production; these are reflected in generally lower capital costs due to equipment scale factors. Some accounts, such as coal handling, coal prep, instrumentation, site preparation, and buildings, reduce slightly as a result. Other accounts, such as gasifier, ASU, and gas cleanup, have much more pronounced cost reductions as the result of less heat transfer in the radiant cooler, less oxygen demand in the gasifier, and less syngas to desulfurize. The net $74 million reduction in TPC translates to $65/kW (3 %) reduction in capital cost – due primarily to plant scale reductions made possible by the dry feed gasifier rather than the reduced cost of coal feed pump equipment vs. slurry feed equipment.

With little difference between total O&M cost between the Reference Case and the coal feed pump case, the primary operating cost reduction is in the fuel cost (which is made possible by the 1.9 percentage point improvement in process efficiency) of about $5 MM/yr. The combined reductions in capital cost and fuel cost contribute to a reduction in levelized cost of electricity from $0.0927/kW-hr to $0.0894/kW-hr, or about a 3.6 percent reduction in COE due to the coal feed pump.

Table 3-7. Case 3a: Capital and O&M Cost Comparison

	Case 0			Case 3a		
	Reference plant with slurry feed			Reference plant with coal pump		
Capital Cost ($1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Sorbent Handling	25,685	30,821	63	24,208	29,049	62
2 Coal and Sorbent Prep & Feed	39,472	48,980	101	38,364	47,373	102
3 Feedwater & Balance of Plant	28,606	35,077	72	25,291	30,961	66
4a Gasifier	184,371	236,212	485	167,010	214,134	459
4b Air Separation Unit	153,591	168,950	347	137,625	151,387	325
5a Gas Cleanup	93,441	112,389	231	85,697	103,057	221
5b CO_2 Removal & Compression	0	0	0	0	0	0
6 Gas Turbine	91,110	105,058	215	91,228	105,195	226
7 HRSG	44,560	49,511	102	44,482	49,425	106
8 Steam Cycle and Turbines	47,842	54,310	112	42,318	48,016	103
9 Cooling Water System	20,099	24,233	50	18,405	22,196	48
10 Waste Solids Handling System	34,981	38,752	80	31,179	34,543	74
11 Accessory Electric Plant	55,772	66,529	137	53,391	63,672	137
12 Instrumentation & Control	18,982	23,178	48	18,345	22,400	48
13 Site Preparation	13,956	18,143	37	13,701	17,812	38
14 Buildings and Structures	14,012	16,314	34	13,233	15,416	33
Total	866,482	1,028,457	2,113	804,477	954,636	2,048
O&M Cost ($1,000)						
Fixed Costs	**Total**		**% EPCC**	**Total**		**% EPCC**
Labor	19,542		2.26	18,039		2.24
Variable Operating Costs*	**Total**		**% EPCC**	**Total**		**% EPCC**
Maintenance Materials	18,368		2.12	17,681		2.20
Water	1,451		0.17	1,092		0.14
Chemicals	1,021		0.12	967		0.12
Waste Disposal	2,262		0.26	1,886		0.23
Total Variable Costs	23,102		2.67	21,626		2.69
Total O&M Cost	42,644		4.92	39,665		4.93
Fuel Cost*	55,690		6.43	50,620		6.29
Discounted Cash Flow Results						
Total Plant Cost ($/kW)			2,113			2,048
Levelized Cost of Electricity ($/kW-hr)			0.0927			0.0894

*Includes 75 % capacity factor

3.4.2

Cumulative Impact of R&D

Composite Process Configuration (Case 3): Coal Feed Pump, Cryogenic ASU, Cold Gas Cleanup, Advanced "F" Frame Syngas Turbine, 80 % Capacity Factor

In the cumulative case, the combined performance from increased capacity factor to 80 %, replacement of the 7FA turbine with advanced "F" frame turbine, and coal feed pump is examined. A block flow diagram of this process is shown in Figure 3-3. The table below compares the incremental improvement due to the coal feed pump.

Table 3-8. Incremental Performance Improvement from the Coal Feed Pump

	Case 2	Case 3
	80% CF, adv. "F"	80% CF, adv. "F", coal feed pump
Gas Turbine Power (MWe)	464	464
Fuel Gas Expander (MWe)	8	8
Steam Turbine Power (MWe)	293	256
Total Power Produced (MWe)	765	728
Auxiliary Power Use (MWe)	-128	-114
Net Power (MWe)	637	614
As-Received Coal Feed (lb/hr)	491,633	449,270
Net Heat Rate (Btu/kW-hr)	9,004	8,542
Net Plant Efficiency (HHV)	37.9 %	40.0 %
Gasifier Cold Gas Efficiency	76.0 %	81.9 %

The oxygen:coal weight ratio in Case 2 was 0.94 lb O_2 / lb dry coal. In Case 3, the ratio is 0.86 lb O_2 / lb dry coal. The reduced O_2 requirement is reasonable for Case 3. Less oxidation will be required per pound of coal in Case 3 since there is no slurry water to evaporate. As a result, gasifier cold gas efficiency increases from 76.0 % in Case 2 to 81.9 % in Case 3.

Three reasons account for reduced steam turbine power generation in Case 3. First, Case 3 partially humidifies the fuel gas because there is not enough N_2 from the ASU to dilute the fuel gas to the 125 Btu/scf heating value specification. Second, there is less coal flowrate through the gasifier in Case 3 since there is no need to evaporate slurry water, and therefore less heat is available in the radiant cooler for steam generation. Third, the flowrate of raw fuel gas in the quench system decreases in Case 3, reducing the amount of heat recovery. These factors account for 37 MW less steam turbine power generation in the case of the coal feed pump.

Auxiliary power consumption in Case 3 is 14 MW less than in Case 2 as the result of reduced oxygen demand and ASU air supply (reducing the power requirement of the main air compressor). Overall, the net power generated in Case 3 is 23 MW less than Case 2, but the coal feed rate required to achieve the 232 MWe gas turbine rating is significantly lower – resulting in an improved net plant efficiency from 37.9 % to 40.0 %.

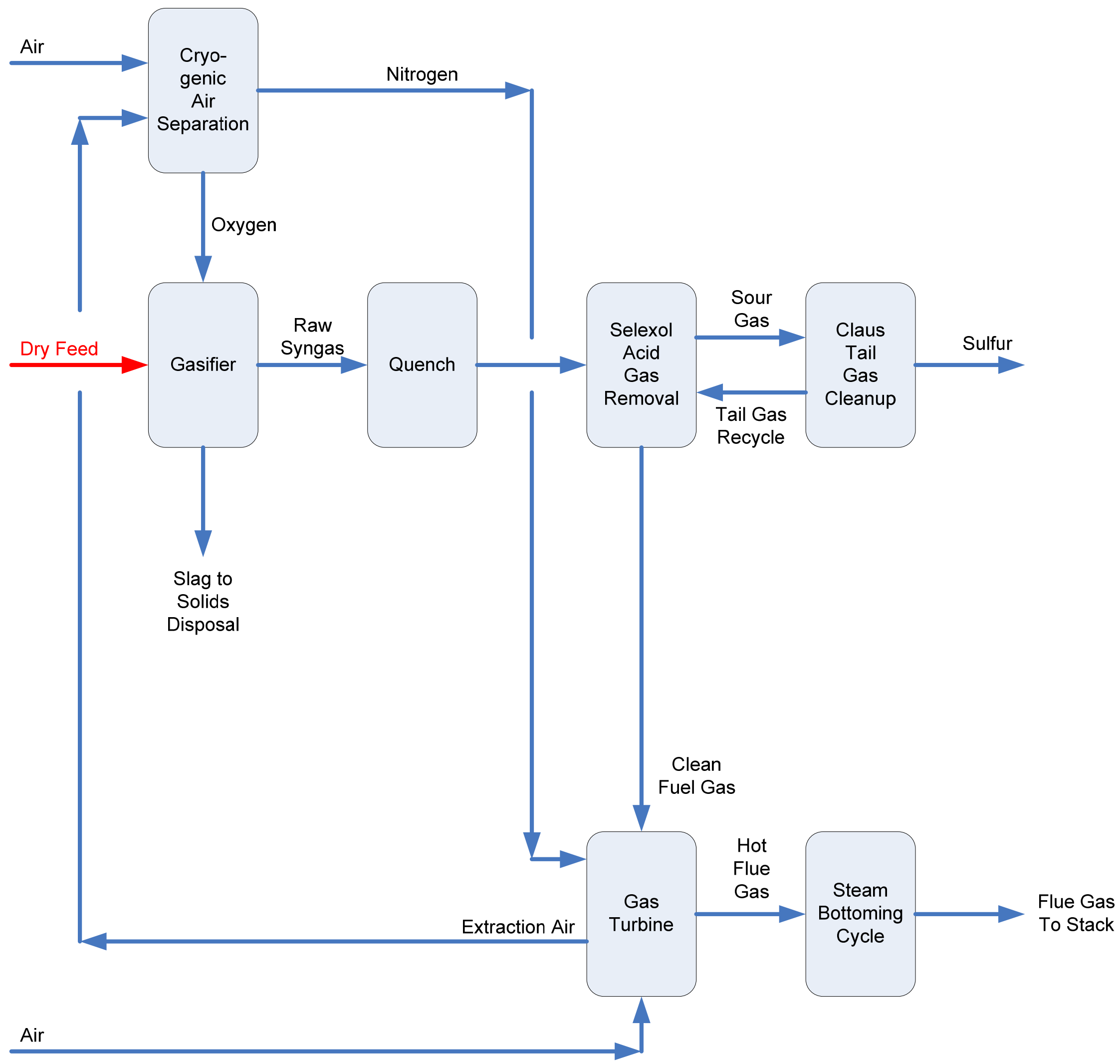

Figure 3-3. Case 3: Coal Feed Pump Has Nearly the Same Configuration as Case 2

Cost Analysis (Case 3)

As shown in Table 3-9, cost accounts in Case 3 generally decrease due to smaller equipment size as the result of reduced coal flowrate. Such accounts include coal handling, coal prep, balance of plant (BOP), gas cleanup, steam cycle, cooling water, and solid waste handling.

Greater cost reductions in gasifier (due to reduced radiant cooler heat duty) and air separation unit (due to reduced oxygen demand) reflect the primary cost advantages of switching from slurry feed gasifier to dry feed.

The bottom-line cost reduction in total plant cost is about $80 million, or in other words a reduction of about $60/kW. This translates to a COE reduction from $0.0780/kW-hr to $0.0751/kW-hr, a savings of about 3.7 % in cost of electricity.

Table 3-9. Case 3: Capital and O&M Cost Comparison

	Case 2			Case 3		
	80% CF, adv. "F"			80% CF, adv. "F", coal pump		
Capital Cost ($1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Sorbent Handling	29,076	34,890	55	27,494	32,993	54
2 Coal and Sorbent Prep & Feed	45,169	56,050	88	44,060	54,408	89
3 Feedwater & Balance of Plant	30,636	37,513	59	27,259	33,322	54
4a Gasifier	210,196	269,284	423	191,060	244,956	399
4b Air Separation Unit	167,073	183,781	289	148,372	163,209	266
5a Gas Cleanup	107,769	129,625	203	99,131	119,216	194
5b CO_2 Removal & Compression	0	0	0	0	0	0
6 Gas Turbine	103,491	119,302	187	103,552	119,373	195
7 HRSG	50,936	56,565	89	51,276	56,942	93
8 Steam Cycle and Turbines	57,934	65,820	103	52,627	59,769	97
9 Cooling Water System	22,515	27,140	43	20,994	25,313	41
10 Waste Solids Handling System	39,568	43,829	69	35,385	39,199	64
11 Accessory Electric Plant	58,402	69,559	109	56,192	66,908	109
12 Instrumentation & Control	19,010	23,212	36	18,430	22,503	37
13 Site Preparation	14,247	18,522	29	13,995	18,193	30
14 Buildings and Structures	14,974	17,421	27	14,244	16,579	27
Total	970,995	1,152,513	1,809	904,070	1,072,883	1,749

O&M Cost ($1,000)	Case 2		Case 3	
Fixed Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Labor	22,548	2.32	21,045	2.33
Variable Operating Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Maintenance Materials	22,762	2.34	21,993	2.43
Water	1,703	0.18	1,283	0.14
Chemicals	1,305	0.13	1,235	0.14
Waste Disposal	2,920	0.30	2,451	0.27
Total Variable Costs	28,694	2.96	26,961	2.98
Total O&M Cost	51,237	5.28	48,006	5.31
Fuel Cost	72,542	7.47	66,291	7.33

Discounted Cash Flow Results	Case 2	Case 3
Total Plant Cost ($/kW)	1,809	1,749
Levelized Cost of Electricity ($/kW-hr)	0.0780	0.0751

3.5 Increased Capacity Factor to 85 Percent

In Case 4, the process configuration and process performance remains the same as Case 3, but the capacity factor increases from 80 percent to 85 percent. 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 (with no additional capital or fixed O&M cost).

The differences between Case 3 and Case 4 lie in variable O&M costs, fuel cost, and plant revenues as the result of longer hours of operation. Variable O&M costs increase by about $1.7 MM/year, and fuel costs increase by about $4.1 MM/year. The increased plant revenue from additional power production results in decreased cost of electricity from $0.0751/kW-hr in Case 3 to $0.0722/kW-hr in Case 4 – a savings of about 3.9 % in cost of electricity resulting from increased capacity factor.

3.6 Transport Desulfurizer and Direct Sulfur Reduction Process

In Case 5, the primary process improvement is that the Selexol (cold gas cleanup) acid gas removal and Claus tail gas treatment processes are replaced with warm gas Transport Desulfurizer (TDS) and Direct Sulfur Reduction (DSRP) processes. Exiting the gasifier, raw syngas is cooled to approximately 950 ^{o}F in preparation for hydrogen chloride removal in a packed bed of Na_2CO_3 (trona). Hydrogen chloride is removed according to the reaction:

$$2\ HCl + Na_2CO_3\ (s) = 2\ NaCl\ (s) + CO_2 + H_2O$$

The syngas is cooled in preparation for contact with zinc oxide sorbent, which reacts with H_2S and COS to remove them from the syngas. The desulfurization reactions are:

$$H_2S + ZnO\ (s) = ZnS\ (s) + H_2O$$

$$COS + ZnO\ (s) = ZnS\ (s) + CO_2$$

Desulfurized syngas is cooled to about 150 ^{o}F in preparation for cold gas ammonia and mercury removal. Ammonia is removed by scrubbing with water. An activated carbon filter bed is used for mercury removal. Clean fuel gas is reheated before expansion through the fuel gas expander.

To regenerate the ZnO sorbent for the TDS, ZnS transfers to the TDS regenerator where it contacts with air and is oxidized at 1,100 ^{o}F according to the reaction:

$$ZnS\ (s) + 3/2\ O_2 = ZnO\ (s) + SO_2$$

The SO_2 (sour gas) that is generated flows to the DSRP for sulfur recovery, and the regenerated sorbent is returned to the transport desulfurizer. A small portion of clean fuel gas exiting the mercury removal section is used as reducing gas in the DSRP where sour gas is reduced, forming elemental sulfur product:

$$SO_2 + 2\ H_2 = 2\ H_2O + S$$

$$SO_2 + 2\ CO = 2\ CO_2 + S$$

DSRP tail gas, containing H_2O and CO_2, is compressed and recycled to the transport desulfurizer. The transport desulfurizer has the advantage of eliminating solvent regeneration (and therefore steam heat duty) in the Selexol reboiler. Instead, acid gas, deposited on a solid zinc oxide sorbent, is oxidized during sorbent regeneration.

While elimination of the Selexol reboiler reduces steam consumption, oxidation during zinc oxide sorbent regeneration actually produces heat – both effects contributing to increased steam power generation and therefore increased energy efficiency.

3.6.1 Impact of Partial Warm Gas Cleanup in the Reference Plant (Case 5a)

Case 5a Configuration: Slurry Feed Gasifier, Cryogenic ASU, Transport Desulfurizer and DSRP, 7FA Syngas Turbine, 75 % Capacity Factor

Table 3-10 below compares overall performance when the partial warm gas cleanup process is implemented in the reference plant.

The increased steam turbine power by 42 MW in Case 5a reflects elimination of the Selexol reboiler and the sour water stripper reboiler, and recovery of high quality heat from the clean syngas exiting the transport desulfurizer (as opposed to reheat of clean fuel gas prior to the fuel gas expander).

Table 3-10. Performance Impact of Partial Warm Gas Cleanup in the Reference Plant

	Case 0	**Case 5a**
	Reference plant with cold gas cleanup	Reference plant with partial warm gas cleanup
Gas Turbine Power (MWe)	384	384
Fuel Gas Expander (MWe)	6	7
Steam Turbine Power (MWe)	223	265
Total Power Produced (MWe)	614	656
Auxiliary Power Use (MWe)	-127	-129
Net Power (MWe)	487	527
As-Received Coal Feed (lb/hr)	402,581	412,206
Net Heat Rate (Btu/kW-hr)	9,649	9,123
Net Plant Efficiency (HHV)	35.4 %	37.4 %

The regeneration air compressor auxiliary power is a trade-off for elimination of the Selexol Unit Auxiliaries, which slightly increases auxiliary power use in warm gas cleanup by 2 MW. Auxiliary power accounts associated with the steam cycle and net plant power output are slightly greater in Case 5a due to the increased steam turbine power output in that case. Overall, auxiliary power increases in the transport desulfurizer case by about 2 MW.

Because of the large increase in steam turbine power generation, net plant efficiency increases by 2.0 percentage points by replacing the Reference Case cold gas cleanup with partial warm gas cleanup consisting of transport desulfurizer with chloride guard bed and DSRP.

Cost Analysis (Case 5a)

Capital and O&M costs are compared with Reference Case results in Table 3-11. The transport desulfurizer case has significantly greater net power production (527 MW vs. 487 MW) resulting from slightly greater coal feedrate and 2.0 percentage point increase in process efficiency; these translate to higher TPC in most capital cost accounts (but TPC decreases on a $/kW basis). Notable exceptions are the gas cleanup section (which replaces cold gas cleanup process equipment with less expensive warm gas cleanup equipment – resulting in a cost savings of $34 million) and the steam cycle (which has an increased power production of 42 MW, resulting in a cost increase of $7 million). Overall, there is a net decrease in TPC of $20 million; this translates to a decrease of $200/kW, or a 9.5 % decrease in capital cost on a $/kW basis.

Table 3-11. Case 5a: Capital and O&M Cost Comparison

	Case 0			Case 5a		
	Reference plant with cold gas cleanup			Reference plant with partial warm gas cleanup		
Capital Cost ($1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Sorbent Handling	25,685	30,821	63	26,064	31,277	59
2 Coal and Sorbent Prep & Feed	39,472	48,980	101	40,105	49,766	94
3 Feedwater & Balance of Plant	28,606	35,077	72	28,834	35,351	67
4a Gasifier	184,371	236,212	485	185,977	237,034	450
4b Air Separation Unit	153,591	168,950	347	153,726	169,098	321
5a Gas Cleanup	93,441	112,389	231	64,675	77,975	148
5b CO_2 Removal & Compression	0	0	0	0	0	0
6 Gas Turbine	91,110	105,058	215	91,438	105,437	200
7 HRSG	44,560	49,511	102	44,592	49,546	94
8 Steam Cycle and Turbines	47,842	54,310	112	54,049	61,385	116
9 Cooling Water System	20,099	24,233	50	21,801	26,280	50
10 Waste Solids Handling System	34,981	38,752	80	35,497	39,323	75
11 Accessory Electric Plant	55,772	66,529	137	56,820	67,754	129
12 Instrumentation & Control	18,982	23,178	48	19,089	23,309	44
13 Site Preparation	13,956	18,143	37	14,009	18,211	35
14 Buildings and Structures	14,012	16,314	34	14,617	17,010	32
Total	866,482	1,028,457	2,113	851,292	1,008,754	1,913

O&M Cost ($1,000)	Case 0		Case 5a	
Fixed Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Labor	19,542	2.26	19,542	2.30
Variable Operating Costs*	**Total**	**% EPCC**	**Total**	**% EPCC**
Maintenance Materials	18,368	2.12	19,215	2.26
Water	1,451	0.17	1,430	0.17
Chemicals	1,021	0.12	3,790	0.45
Waste Disposal	2,262	0.26	2,314	0.27
Total Variable Costs	23,102	2.67	26,749	3.14
Total O&M Cost	42,644	4.92	46,291	5.44
Fuel Cost*	55,690	6.43	57,021	6.70

Discounted Cash Flow Results	Case 0	Case 5a
Total Plant Cost ($/kW)	2,113	1,913
Levelized Cost of Electricity ($/kW-hr)	0.0927	0.0862

*Includes 75 % capacity factor

The cost of chemicals increases significantly from the Reference Case due to the cost of ZnO sorbent and trona. A slight attrition of sorbent (10-20 lb per million lb of sorbent recirculation) is assumed; fresh sorbent replacement cost is assumed to be $14,000/ton. The cost of trona is calculated as twice the stoichiometric quantity required to convert chloride, at a cost of $100/ton.

As a result of increased chemicals cost, total variable costs in Case 5a increase by about $3.6 MM/year. Fuel cost increases by about $1.3 MM/year due to the slightly increased coal feed rate. The decreased TPC and increased net power more than compensate for the increased operating costs, however, resulting in a levelized COE reduction from $0.0927/kW-hr in the

Reference Case to $0.0862/kW-hr in Case 5a – a reduction by 7.0 % in cost of electricity resulting from the transport desulfurizer with chloride guard bed and DSRP.

3.6.2 Cumulative Impact of R&D

Composite Process Configuration (Case 5): Coal Feed Pump, Cryogenic ASU, Transport Desulfurizer and DSRP, Advanced "F" Frame Syngas Turbine, 85 % Capacity Factor

The block flow diagram in Figure 3-4 shows the implementation of partial warm gas cleanup in the composite process with other advanced technology.

Overall process performance and the improvement in net plant efficiency due to warm gas desulfurization in the composite process are shown in Table 3-12.

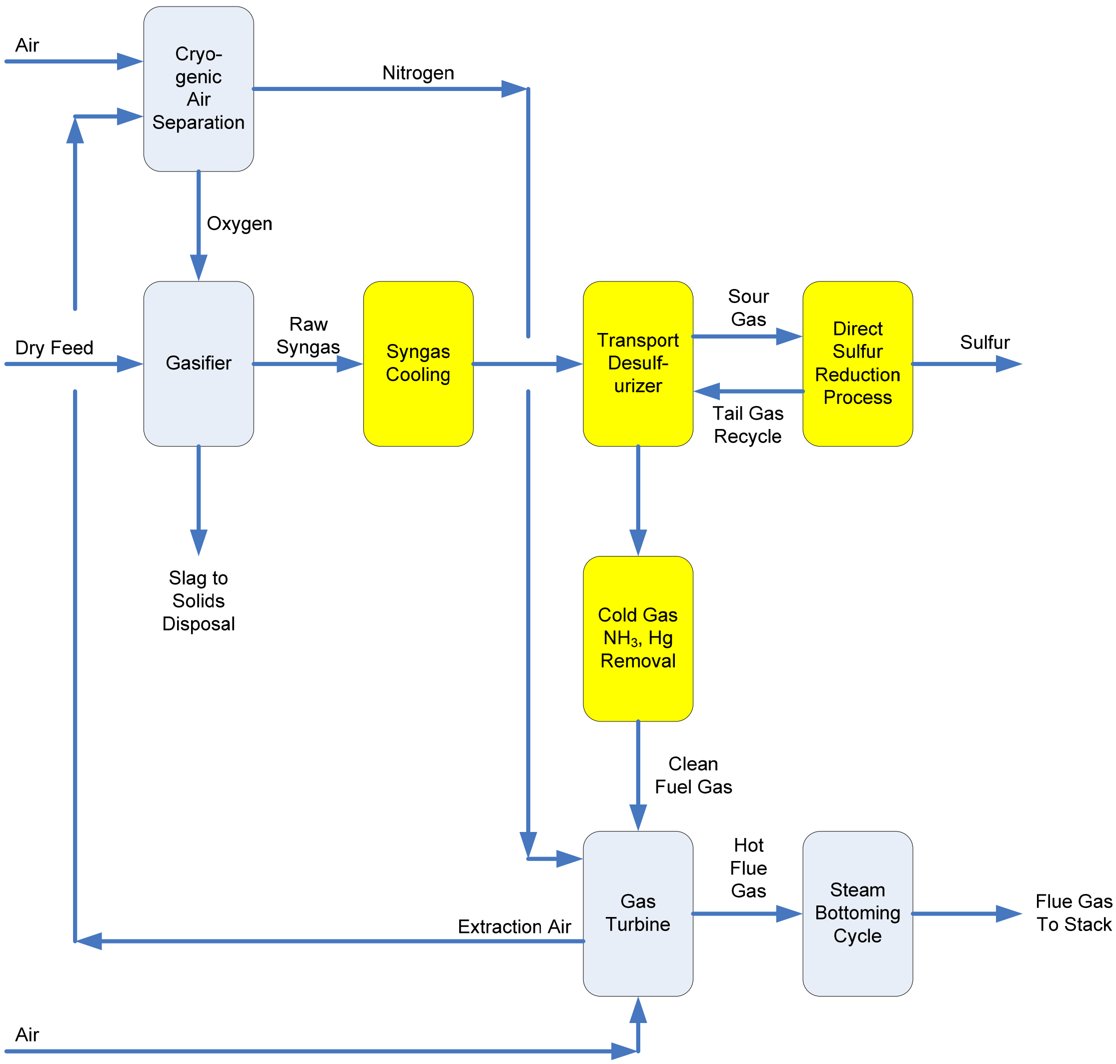

Figure 3-4. Case 5: IGCC With Transport Desulfurizer and DSRP

Table 3-12. Incremental Performance Improvement from Partial Warm Gas Cleanup

	Case 4	Case 5
	Adv. “F”, coal pump, 85 % CF	Adv. “F”, coal pump, 85 % CF, partial WGCU
Gas Turbine Power (MWe)	464	464
Fuel Gas Expander (MWe)	8	8
Steam Turbine Power (MWe)	256	305
Total Power Produced (MWe)	728	777
Auxiliary Power Use (MWe)	-114	-119
Net Power (MWe)	614	659
As-Received Coal Feed (lb/hr)	449,270	457,603
Net Heat Rate (Btu/kW-hr)	8,542	8,105
Net Plant Efficiency (HHV)	40.0 %	42.1 %

Case 5 generates significantly more steam turbine power (49 MW) as a result of eliminating the Selexol and sour water stripper reboilers, and less humidifying steam is needed in Case 5. Auxiliary power consumption increases slightly because the increase in regeneration air compressor power outweighs the savings in Selexol unit auxiliaries. The larger bottoming cycle in Case 5 also contributes to greater auxiliary power use.

Overall, the net power production is greater in Case 5 due to greater power recovered by the steam cycle. Although the coal feed rate required to achieve the 232 MWe gas turbine rating is somewhat greater, the additional steam power generation results in improved net plant efficiency from 40.0 % to 42.1 %.

Cost Analysis (Case 5)

Comparing TPC between Cases 4 and 5 in Table 3-13, the primary cost reduction occurs in the Gas Cleanup account. The reduction in that account is estimated at approximately $45 MM, or a reduction of $81/kW resulting from less expensive equipment.

The increased steam power production in Case 5 (by 49 MW) is responsible for increased steam cycle cost (by $8 MM). However, the increased net power production in Case 5 (by 45 MW) results in a consistent decrease in Total Plant Cost on a $/kW basis in all other accounts. The bottom-line cost reduction in total plant cost is almost $29 MM, resulting in a decrease of $164/kW.

The use of ZnO sorbent and trona increases the cost of chemicals significantly, but is a relatively small contribution to overall process economics. The transport desulfurizer with DSRP reduces COE from $0.0722/kW-hr to $0.0677/kW-hr – a savings of about 6.2 % in cost of electricity.

Table 3-13. Case 5: Capital and O&M Cost Comparison

	Case 4			Case 5		
	Adv. "F", coal pump, 85% CF			Adv. "F", coal pump, 85% CF, partial WGCU		
Capital Cost ($1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Sorbent Handling	27,494	32,993	54	27,810	33,372	51
2 Coal and Sorbent Prep & Feed	44,060	54,408	89	44,609	55,390	84
3 Feedwater & Balance of Plant	27,259	33,322	54	27,447	33,548	52
4a Gasifier	191,060	244,956	399	193,291	247,825	376
4b Air Separation Unit	148,372	163,209	266	146,987	161,685	245
5a Gas Cleanup	99,131	119,216	194	61,645	74,238	113
5b CO_2 Removal & Compression	0	0	0	0	0	0
6 Gas Turbine	103,552	119,373	195	103,621	119,452	181
7 HRSG	51,276	56,942	93	51,246	56,910	86
8 Steam Cycle and Turbines	52,627	59,769	97	59,672	67,803	103
9 Cooling Water System	20,994	25,313	41	22,844	27,537	42
10 Waste Solids Handling System	35,385	39,199	64	35,787	39,644	60
11 Accessory Electric Plant	56,192	66,908	109	57,541	68,497	104
12 Instrumentation & Control	18,430	22,503	37	18,626	22,743	35
13 Site Preparation	13,995	18,193	30	14,063	18,282	28
14 Buildings and Structures	14,244	16,579	27	14,923	17,361	26
Total	904,070	1,072,883	1,749	880,114	1,044,287	1,585

O&M Cost ($1,000)				
Fixed Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Labor	21,045	2.33	21,045	2.39
Variable Operating Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Maintenance Materials	23,368	2.59	24,471	2.78
Water	1,363	0.15	1,333	0.15
Chemicals	1,312	0.15	4,794	0.55
Waste Disposal	2,604	0.29	2,650	0.30
Total Variable Costs	28,646	3.17	33,249	3.78
Total O&M Cost	49,691	5.50	54,294	6.17
Fuel Cost	70,435	7.79	71,741	8.15
Discounted Cash Flow Results				
Total Plant Cost ($/kW)		1,749		1,585
Levelized Cost of Electricity ($/kW-hr)		0.0722		0.0677

3.7 Full Warm Gas Cleanup

For full warm gas cleanup, novel treatment systems for ammonia and mercury removal are added to the chloride guard bed, transport desulfurizer, and DSRP. Warm gas ammonia removal eliminates direct contact cooling with water to remove NH_3 downstream of the transport desulfurizer – effectively retaining moisture in the fuel gas because temperature remains above the dew point. For a fuel gas containing significant moisture, this has the benefit of maintaining flow through the fuel gas expander, and requires less dilution nitrogen in the topping combustor (which decreases auxiliary power consumption).

3.7.1 Impact of Full Warm Gas Cleanup in the Reference Plant (Case 6a)

Case 6a Configuration: Slurry Feed Gasifier, Cryogenic ASU, Warm Gas Cleanup, 7FA Syngas Turbine, 75 % Capacity Factor

Results are compared against the cold gas cleanup technology of Case 0 and cold gas ammonia and mercury removal process steps of Case 5a in order to evaluate the incremental contribution of the novel warm gas ammonia and mercury removal technologies.

Table 3-14. Performance Impact of Full Warm Gas Cleanup in the Reference Plant

	Case 0	**Case 5a**	**Case 6a**
	Reference plant with CGCU	Reference plant with partial WGCU	Reference plant with full WGCU
Gas Turbine Power (MWe)	384	384	384
Fuel Gas Expander (MWe)	6	7	9
Steam Turbine Power (MWe)	223	265	270
Total Power Produced (MWe)	614	657	663
Auxiliary Power Use (MWe)	-127	-129	-122
Net Power (MWe)	487	527	541
As-Received Coal Feed (lb/hr)	402,581	412,206	414,455
Net Heat Rate (Btu/kW-hr)	9,649	9,123	8,933
Net Plant Efficiency (HHV)	35.4 %	37.4 %	38.2 %

Because the clean fuel in Case 6a retains moisture, flowrate is greater and the power generated by the fuel gas expander increases by 2 MW over Case 5a. The increased 5 MW of steam turbine power in Case 6a reflects (1) improved thermal efficiency within the novel ammonia and mercury removal section as the result of not cooling to as low a temperature and reheating the syngas, and (2) the greater turbine exhaust temperature (and therefore HRSG inlet temperature) in Case 6a resulting from higher moisture content in that flue gas.

The primary difference in auxiliary power consumption is due to the nitrogen compressor. Case 6a retains all moisture in the syngas, and therefore a smaller amount of nitrogen from the ASU is injected to reach the design power rating of the gas turbine. This results in a net 7 MW decrease in auxiliary power consumption in Case 6a.

Overall, Case 6a produces 14 MW more power with only a slight increase in coal feed rate, increasing net plant efficiency from 37.4 % to 38.2 %. Compared to Case 0, the total net plant efficiency due to full warm gas cleanup improves from 35.4 % to 38.2 % -- an increase by 2.8 percentage points.

Cost Analysis (Case 6a)

Capital and O&M costs are compared with Case 5a results in Table 3-15. Because of (1) greater net power production (541 MW vs. 527 MW), and (2) 0.8 percentage point increase in process efficiency, most capital cost accounts increase slightly. The only notable exception is the gas cleanup section (which replaces the wet ammonia scrubber with higher temperature ammonia and mercury removal systems) – resulting in increased plant section cost by $7 million and total plant cost by $10 million. However, because of the increased net power production, total plant cost on a $/kW basis reduces from $1,913/kW to $1,882/kW – a decrease by $31/kW or 1.6 % going from partial warm gas cleanup to full warm gas cleanup.

Table 3-15. Case 6a: Capital and O&M Cost Comparison

	Case 5a			Case 6a		
	Reference plant with partial WGCU			Reference plant with full WGCU		
Capital Cost ($1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Sorbent Handling	26,064	31,277	59	26,150	31,380	58
2 Coal and Sorbent Prep & Feed	40,105	49,766	94	40,253	49,948	92
3 Feedwater & Balance of Plant	28,834	35,351	67	28,887	35,415	65
4a Gasifier	185,977	237,034	450	186,644	237,883	440
4b Air Separation Unit	153,726	169,098	321	154,255	169,681	314
5a Gas Cleanup	64,675	77,975	148	70,804	85,484	158
5b CO_2 Removal & Compression	0	0	0	0	0	0
6 Gas Turbine	91,438	105,437	200	91,852	105,917	195
7 HRSG	44,592	49,546	94	44,943	49,931	92
8 Steam Cycle and Turbines	54,049	61,385	116	54,744	62,178	115
9 Cooling Water System	21,801	26,280	50	21,985	26,501	49
10 Waste Solids Handling System	35,497	39,323	75	35,615	39,453	73
11 Accessory Electric Plant	56,820	67,754	129	56,066	66,828	123
12 Instrumentation & Control	19,089	23,309	44	18,774	22,924	42
13 Site Preparation	14,009	18,211	35	13,953	18,139	34
14 Buildings and Structures	14,617	17,010	32	14,638	17,033	31
Total	851,292	1,008,754	1,913	859,564	1,018,696	1,882

	Case 5a		Case 6a	
O&M Cost ($1,000)				
Fixed Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Labor	19,542	2.30	19,542	2.27
Variable Operating Costs*	**Total**	**% EPCC**	**Total**	**% EPCC**
Maintenance Materials	19,215	2.26	19,346	2.25
Water	1,430	0.17	1,441	0.17
Chemicals	3,790	0.45	3,812	0.44
Waste Disposal	2,314	0.27	2,327	0.27
Total Variable Costs	26,749	3.14	26,926	3.13
Total O&M Cost	46,291	5.44	46,468	5.40
Fuel Cost*	57,021	6.70	57,332	6.67
Discounted Cash Flow Results				
Total Plant Cost ($/kW)		1,913		1,882
Levelized Cost of Electricity ($/kW-hr)		0.0862		0.0846

*Includes 75 % capacity factor

O&M and fuel costs are relatively unaffected by the change in process configuration, so the difference in levelized COE is due almost entirely to the change in total plant cost. The change, from $0.0862/kW-hr to $0.0846/kW-hr, represents a $0.0016/kW-hr or 1.9 % reduction in COE due to the novel ammonia and mercury removal processes.

The overall reduction from the Reference Case 0 with cold gas cleanup ($2,113/kW capital and $0.0927/kW-hr COE) to full warm gas cleanup Case 6a ($1,882/kW capital and $0.0846/kW-hr

COE) represents a 10.9 % decrease in capital cost and 8.7 % decrease in cost of electricity based on 75 % capacity factor.

Nexant [6] reported a 3.6 percentage point process efficiency improvement from replacing cold gas cleanup with warm gas cleanup in an IGCC process with a slurry feed gasifier; this was somewhat greater than the 2.8 percentage point improvement between Noblis' Cases 0 and 6a. In a separate analysis [7], Noblis determined that the difference in process efficiency was due to a series of design features. The two most significant of these were:

- The quantity of reducing gas sent to the SCOT process for tail gas treatment and the ultimate disposition of the tail gas (whether discarded or recycled to Selexol).

- Utilization of low-quality heat from the low-temperature syngas cooling section – i.e. the assumed temperature cut-off at which heat was considered to be unrecoverable for purposes of steam generation.

When changes were made to the Noblis configuration, Nexant's results could be reproduced. This highlights the importance of defining the baseline when quoting technology improvements. A validation of costs also showed that the Noblis and Nexant estimates for cost reduction were of similar magnitude. Appendix A.2 describes the results validation.

3.7.2 Cumulative Impact of R&D

Composite Process Configuration (Case 6): Coal Feed Pump, Cryogenic ASU, Warm Gas Cleanup, Advanced "F" Frame Syngas Turbine, 85 % Capacity Factor

Figure 3-5 shows a block flow diagram of this process configuration. A key factor in the comparison between Cases 5 and 6 is the coal feed pump – as opposed to the slurry feed gasifier in the comparisons above between Cases 5a and 6a. Moisture from slurry water in Case 5a condenses during the quench for ammonia removal, but stays in the clean fuel gas in Case 6a thus increasing fuel flow and reducing the needed amount of nitrogen dilution.

Cases 5 and 6, on the other hand, have no appreciable moisture content because they have coal feed pumps, and therefore it doesn't make as much difference whether ammonia and mercury are removed at warm or cold temperature. Comparisons in Table 3-16 illustrate this.

Consistent with the comparison between Cases 5a and 6a, the slightly higher steam turbine power in Case 6 represents the effects of (1) not having to cool and reheat the syngas for NH_3 and mercury removal, and (2) having to humidify slightly less than in Case 5 to meet fuel specifications. However the auxiliary power consumption – and specifically the N_2 compressor work – is the same between Cases 5 and 6 when there was a difference of 7 MW between Cases 5a and 6a. This reduces the incremental process efficiency improvement to only 0.3 percentage points between Cases 5 and 6, as opposed to the 0.8 percentage point improvement between Cases 5a and 6a. The novel ammonia and mercury removal sections have a greater impact on the slurry feed gasifier process.

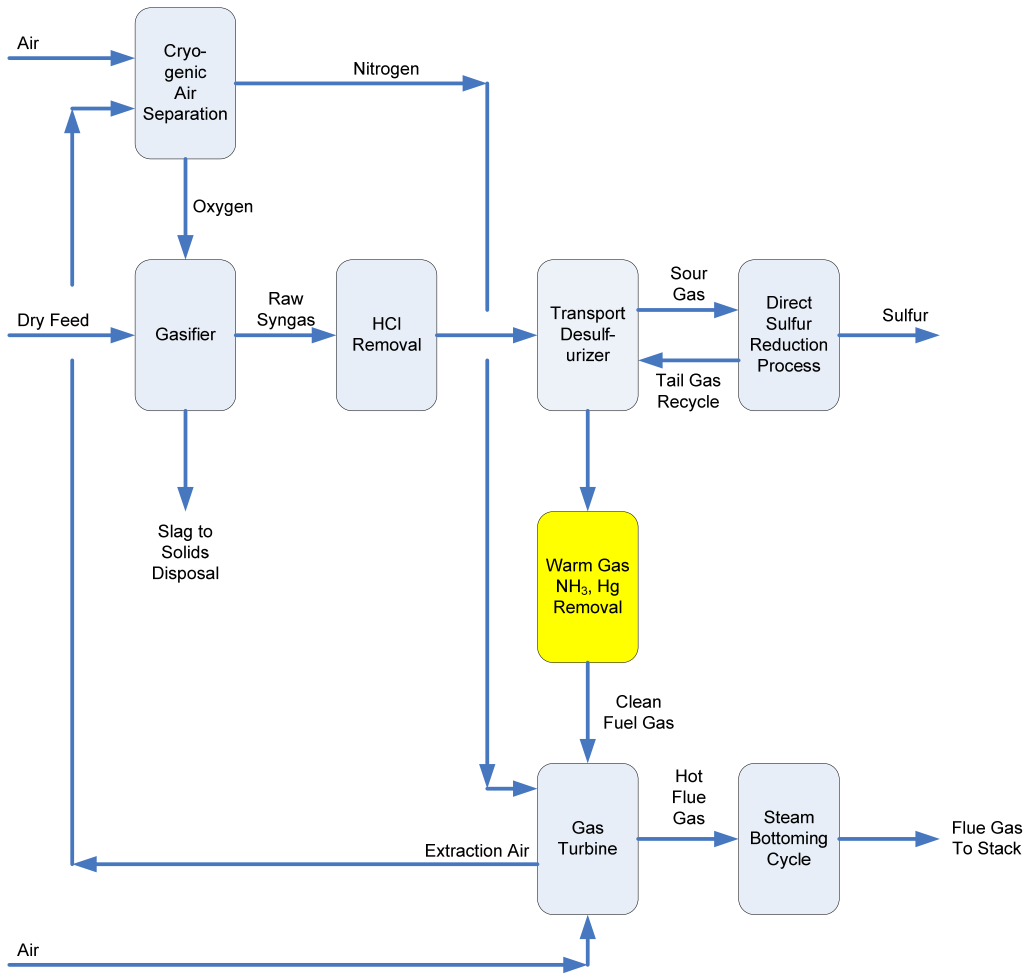

Figure 3-5. Case 6: IGCC With Novel Warm Gas Treatment for Ammonia and Mercury Removal

Table 3-16. Incremental Performance Improvement from Full Warm Gas Cleanup

	Case 5	**Case 6**
	Adv. "F", coal pump, 85% CF, partial WGCU	Adv. "F", coal pump, 85% CF, full WGCU
Gas Turbine Power (MWe)	464	464
Fuel Gas Expander (MWe)	8	9
Steam Turbine Power (MWe)	305	310
Total Power Produced (MWe)	777	783
Auxiliary Power Use (MWe)	-119	-119
Net Power (MWe)	659	664
As-Received Coal Feed (lb/hr)	457,603	457,710
Net Heat Rate (Btu/kW-hr)	8,103	8,042
Net Plant Efficiency (HHV)	42.1 %	42.4 %

Cost Analysis (Case 6)

Comparing total plant costs between Cases 5 and 6 in Table 3-17, the primary cost difference occurs in the gas cleanup account, which increases by about $9 MM. This is caused by (1) a slight increase in cost of mercury removal, and (2) a slight increase in cost of the novel ammonia removal system over the ammonia scrubber. The increase in the gas cleanup account is equivalent to about $12/kW; there is no significant difference in bottom-line total plant cost between the two cases. Likewise, there is no significant difference in operating costs; net power in Case 6 increases by less than 1 %, and the coal feed rates are very nearly equal. There is no significant COE improvement from the novel ammonia and mercury removal processes because neither the total plant cost nor the O&M cost changes.

Table 3-17. Case 6: Capital and O&M Cost Comparison

	Case 5			Case 6		
	Advanced "F", coal pump, 85% CF, partial WGCU			Advanced "F", coal pump, 85% CF, full WGCU		
Capital Cost ($1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Sorbent Handling	27,810	33,372	51	27,811	33,373	50
2 Coal and Sorbent Prep & Feed	44,609	55,390	84	44,617	55,096	83
3 Feedwater & Balance of Plant	27,447	33,548	52	27,451	33,552	51
4a Gasifier	193,291	247,825	376	193,316	247,855	373
4b Air Separation Unit	146,987	161,685	245	146,987	161,686	244
5a Gas Cleanup	61,645	74,238	113	68,801	82,937	125
5b CO_2 Removal & Compression	0	0	0	0	0	0
6 Gas Turbine	103,621	119,452	181	103,747	119,599	180
7 HRSG	51,246	56,910	86	51,262	56,927	86
8 Steam Cycle and Turbines	59,672	67,803	103	60,341	68,566	103
9 Cooling Water System	22,844	27,537	42	23,016	27,744	42
10 Waste Solids Handling System	35,787	39,644	60	35,793	39,651	60
11 Accessory Electric Plant	57,541	68,497	104	57,657	68,632	103
12 Instrumentation & Control	18,626	22,743	35	18,636	22,755	34
13 Site Preparation	14,063	18,282	28	14,063	18,282	28
14 Buildings and Structures	14,923	17,361	26	14,988	17,435	26
Total	880,114	1,044,287	1,585	888,486	1,054,090	1,588

O&M Cost ($1,000)				
Fixed Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Labor	21,045	2.38	21,045	2.37
Variable Operating Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Maintenance Materials	24,471	2.78	24,594	2.77
Water	1,333	0.15	1,343	0.15
Chemicals	4,794	0.55	4,808	0.54
Waste Disposal	2,650	0.30	2,651	0.30
Total Variable Costs	33,249	3.78	33,397	3.76
Total O&M Cost	54,294	6.16	54,442	6.13
Fuel Cost	71,741	8.15	71,758	8.08

Discounted Cash Flow Results		
Total Plant Cost ($/kW)	1,585	1,588
Levelized Cost of Electricity ($/kW-hr)	0.0677	0.0675

It is interesting to compare this result with the difference between Cases 5a and 6a. Recall that in those cases, TPC decreases by $31/kW and COE decreases by $0.0016/kW-hr. The size of the gas turbine, and therefore plant power production, is greater in Cases 5 and 6; this increases the TPC and, when divided by the larger net power values, brings the $/kW values much closer together. To elaborate further, the incremental gas cleanup cost due to ammonia and mercury removal in Cases 5a and 6a is $7.5 MM; in Cases 5 and 6, it is $7.4 MM (it is reasonable that the incremental cost in the coal feed pump cases is less because of smaller fuel gas volume in the warm gas cleanup scenario). The incremental cost of gas cleanup carries through to the bottom-line TPC – resulting in $9.9 MM incremental cost from Case 5a to 6a, and an incremental cost of $8.5 MM from Case 5 to 6. The capital cost impacts by the novel ammonia and mercury removal sections are similar, but when divided by net power output there is a more noticeable difference in the smaller capacity plant – resulting in a $30/kW reduction in the smaller plant as opposed to negligible increase in the larger plant.

In conclusion, most of the performance and cost improvements of warm gas cleanup result from the transport desulfurizer, DSRP, and chloride guard bed. The incremental benefits from novel ammonia and mercury removal in a dry feed gasifier scenario appear to be minor.

3.8 Advanced Syngas Turbine – 2010-AST

DOE sponsors R&D to develop, by 2010, advanced syngas turbine technology with improved performance efficiency. Performance improvements are expected from higher pressure ratio and turbine inlet temperature, which will improve efficiency of the turbine.

3.8.1 Impact of 2010-AST Syngas Turbine in the Reference Plant (Case 7a)

Case 7a Configuration: Slurry Feed Gasifier, Cryogenic ASU, Cold Gas Cleanup, 2010-AST Syngas Turbine, 75 % Capacity Factor

The process block flow diagram of the reference IGCC process with a 2010-AST syngas turbine is identical to Figure 3-2 from Case 2a. Like the advanced “F” frame syngas turbine, the 2010-AST produces more power, has a higher pressure ratio, and higher firing temperature than the 7FA syngas turbine. In order to protect business-sensitive information, 2010-AST turbine performance parameters are omitted from the following discussion. Because of the higher turbine firing temperature and subsequently higher turbine exhaust temperature, steam conditions are 1,800 psi and 1,050 ^{o}F for the HP turbine and 405 psi and 1,050 ^{o}F for the IP turbine.

This two-train IGCC plant processes 6,200 tons per day of as-received coal to produce a net 688 MW of power. Overall efficiency is 38.8 percent (HHV basis). Improved performance over the Reference Case is demonstrated in Table 3-18.

Because of the higher turbine exit temperature in Case 7a, steam superheat temperature is 1,050 ^{o}F rather than 1,000 ^{o}F in Case 0. The increased coal flowrate, made possible by greater turbine throughput, leads to increased heat recovery in the gasifier, syngas quench, and flue gas through the HRSG – thus further contributing to increased steam turbine power generation in Case 7a.

Table 3-18. Performance Impact of 2010-AST Syngas Turbine in the Reference Plant

	Case 0	Case 7a
	Reference plant with 7FA	Reference plant with 2010-AST
Gas Turbine Power (MWe)	384	500
Fuel Gas Expander (MWe)	6	8
Steam Turbine Power (MWe)	223	310
Total Power Produced (MWe)	614	818
Auxiliary Power Use (MWe)	-127	-130
Net Power (MWe)	487	688
As-Received Coal Feed (lb/hr)	402,581	519,515
Net Heat Rate (Btu/kW-hr)	9,649	8,806
Net Plant Efficiency (HHV)	35.4 %	38.8 %

The primary differences in auxiliary power consumption lay in the ASU main air compressor and the nitrogen compressor. The reduced ASU main air compressor power in Case 7a is due to integration between the gas turbine air compressor and the ASU, which reduces the fresh air feed through the main air compressor and therefore reduced power consumption. The increased N_2 compressor power consumption in Case 7a is due to greater flowrate through the gas turbine in Case 7a than in Case 0 because of the larger turbine.

Overall, net plant efficiency increases by 3.4 percentage points going from the 7FA syngas turbine to the 2010-AST syngas turbine. Compared to Case 2a, the 2010-AST turbine increases process efficiency by 0.9 percentage points over the advanced “F” frame turbine in the reference plant.

Cost Analysis (Case 7a)

Capital and O&M costs are compared with Case 0 results in Table 3-19. The 2010-AST turbine has a higher power rating, which increases coal flowrate to the process, and therefore equipment sizes throughout the plant; this is reflected in the greater EPCC and TPC costs in Case 7a.

On a $/kW basis, the TPC of the 2010-AST plant decreases by 18 % because of increased power production. Not only is the turbine power output of Case 7a greater, but the process efficiency is 3.4 percentage points greater than the 7FA case. The primary reasons for this are air integration from the gas turbine to the ASU, the greater efficiency of the 2010-AST syngas turbine, and the increased steam cycle superheat temperature.

Comparing cost of electricity, the $0.0782/kW-hr of Case 7a is 17 % less than the $0.0927/kW-hr of Case 0 because of (1) larger gas turbine, which increases the plant output and therefore decreases the capital cost on a $/kW basis, and (2) increased plant efficiency due to the higher pressure ratio and firing temperature of the 2010-AST syngas turbine compared to the 7FA turbine.

The reference plant with advanced “F” frame syngas turbine (Case 2a), by comparison, has $1,809/kW TPC and COE of $0.0814/kW-hr. The reference plant with 2010-AST turbine represents a 4 % reduction over the reference plant with advanced "F" frame turbine both in TPC (on a $/kW basis) and in COE.

Table 3-19. Case 7a: Capital and O&M Cost Comparison

	Case 0			Case 7a		
	Reference plant with 7FA			Reference plant with 2010-AST		
Capital Cost ($1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Sorbent Handling	25,685	30,821	63	30,087	36,104	52
2 Coal and Sorbent Prep & Feed	39,472	48,980	101	46,880	58,174	85
3 Feedwater & Balance of Plant	28,606	35,077	72	31,242	38,240	56
4a Gasifier	184,371	236,212	485	217,947	279,210	405
4b Air Separation Unit	153,591	168,950	347	171,740	188,914	275
5a Gas Cleanup	93,441	112,389	231	112,102	134,837	196
5b CO_2 Removal & Compression	0	0	0	0	0	0
6 Gas Turbine	91,110	105,058	215	108,790	125,399	182
7 HRSG	44,560	49,511	102	52,175	57,924	84
8 Steam Cycle and Turbines	47,842	54,310	112	60,308	68,528	100
9 Cooling Water System	20,099	24.233	50	23,125	27,874	41
10 Waste Solids Handling System	34,981	38,752	80	40,939	45,347	66
11 Accessory Electric Plant	55,772	66,529	137	59,509	70,849	103
12 Instrumentation & Control	18,982	23,178	48	19,099	23,321	34
13 Site Preparation	13,956	18,143	37	14,350	18,655	27
14 Buildings and Structures	14,012	16,314	34	15,208	17,690	26
Total	866,482	1,028,457	2,113	1,003,501	1,191,067	1,731

O&M Cost ($1,000)				
Fixed Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Labor	19,542	2.26	22,548	2.25
Variable Operating Costs*	**Total**	**% EPCC**	**Total**	**% EPCC**
Maintenance Materials	18,368	2.12	22,390	2.23
Water	1,451	0.17	1,641	0.16
Chemicals	1,021	0.12	1,283	0.13
Waste Disposal	2,262	0.26	2,896	0.29
Total Variable Costs	23,102	2.67	28,210	2.81
Total O&M Cost	42,644	4.92	50,758	5.06
Fuel Cost*	55,690	6.43	71,865	7.16
Discounted Cash Flow Results				
Total Plant Cost ($/kW)		2,113		1,731
Levelized Cost of Electricity ($/kW-hr)		0.0927		0.0782

*Includes 75 % capacity factor

3.8.2 Cumulative Impact of R&D

Composite Process Configuration (Case 7): Coal Feed Pump, Cryogenic ASU, Warm Gas Cleanup, 2010-AST Syngas Turbine, 85 % Capacity Factor

Table 3-20 below demonstrates improved overall process performance when the advanced "F" frame syngas turbine in Case 6 is replaced with a somewhat larger and more advanced 2010-AST turbine in Case 7.

Table 3-20. Incremental Performance Improvement from the 2010-AST Turbine

	Case 6	Case 7
	Coal pump, full WGCU, 85% CF, advanced “F”	Coal pump, full WGCU, 85%CF, 2010-AST
Gas Turbine Power (MWe)	464	500
Fuel Gas Expander (MWe)	9	9
Steam Turbine Power (MWe)	310	323
Total Power Produced (MWe)	783	832
Auxiliary Power Use (MWe)	-119	-118
Net Power (MWe)	664	714
As-Received Coal Feed (lb/hr)	457,710	480,583
Net Heat Rate (Btu/kW-hr)	8,042	7,849
Net Plant Efficiency (HHV)	42.4 %	43.5 %

Steam turbine power generation increases with the 2010-AST syngas turbine. Two reasons for this are increased coal feedrate and higher HRSG inlet temperature. The higher coal feedrate generates more heat in the gasifier and syngas cooling sections, which increases heat recovery for steam generation. The higher HRSG inlet temperature provides more sensible heat to the HRSG for steam generation.

Total auxiliary power consumption is very nearly identical between the two cases. The main air compressor in Case 7 consumes less power because of greater air extraction from the gas turbine, but the nitrogen compressor power consumption increases because more fuel, and therefore dilution nitrogen, is fed to the turbine.

The total power production and the net power production increase with the 2010-AST syngas turbine because of greater turbine power output and also more steam generation due to greater coal feedrate.

Overall, there is a 1.1 percentage point improvement – increasing net plant efficiency from 42.4 % to 43.5 %. This is a slightly greater improvement than in the reference plant comparison, in which performance improved by only 0.9 percentage point. The reason is the slurry feed gasifier in the reference plant; coal feedrate increases for the 2010-AST turbine, which increases the amount of slurry water to be evaporated in the reference plant – which is then condensed during cold gas cleanup and thus part of the energy contributed by increased coal flowrate in the slurry feed case is lost, resulting in reduced performance improvement than the coal feed pump case. This is one example of synergy resulting from advanced technologies.

Cost Analysis (Case 7)

The increased TPC of Case 7, shown in Table 3-21, reflects increased coal feedrate made possible by the larger gas turbine; increased coal feedrate increases size and throughput of all other process equipment. The corresponding increase in net power production however, when divided into the TPC, results in nearly a uniform 5 % reduction in TPC on a $/kW basis in all cost accounts. The TPC on a $/kW basis reduces from $1,588/kW to $1,516/kW. Because COE is dominated by capital cost, the COE reduces by 4 % from $0.0675/kW-hr to $0.0648/kW-hr.

These are approximately the same cost reductions over the advanced "F" frame syngas turbine as observed in the reference plant Case 7a.

Table 3-21. Case 7: Capital and O&M Cost Comparison

	Case 6			Case 7		
	Coal pump, full WGCU, 85% CF, advanced "F"			Coal pump, full WGCU, 85% CF, 2010-AST		
Capital Cost ($1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Sorbent Handling	27,811	33,373	50	28,667	34,400	48
2 Coal and Sorbent Prep & Feed	44,617	55,096	83	46,109	56,939	80
3 Feedwater & Balance of Plant	27,451	33,552	51	27,961	34,165	48
4a Gasifier	193,316	247,855	373	199,598	255,906	358
4b Air Separation Unit	146,987	161,686	244	149,311	164,243	230
5a Gas Cleanup	68,801	82,937	125	71,294	85,943	120
5b CO_2 Removal & Compression	0	0	0	0	0	0
6 Gas Turbine	103,747	119,599	180	109,034	125,681	176
7 HRSG	51,262	56,927	86	51,973	57,703	81
8 Steam Cycle and Turbines	60,341	68,566	103	62,144	70,623	99
9 Cooling Water System	23,016	27,744	42	23,475	28,295	40
10 Waste Solids Handling System	35,793	39,651	60	36,888	40,863	57
11 Accessory Electric Plant	57,657	68,632	103	58,336	69,406	97
12 Instrumentation & Control	18,636	22,755	34	18,600	22,711	32
13 Site Preparation	14,063	18,282	28	14,127	18,366	26
14 Buildings and Structures	14,988	17,435	26	15,149	17,620	25
Total	888,486	1,054,090	1,588	912,666	1,082,864	1,516

	Case 6		Case 7	
O&M Cost ($1,000)				
Fixed Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Labor	21,045	2.37	21,045	2.31
Variable Operating Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Maintenance Materials	24,594	2.77	25,698	2.82
Water	1,343	0.15	1,374	0.15
Chemicals	4,808	0.54	5,048	0.55
Waste Disposal	2,651	0.30	2,779	0.30
Total Variable Costs	33,397	3.76	34,899	3.82
Total O&M Cost	54,442	6.13	55,944	6.13
Fuel Cost	71,758	8.08	75,344	8.26
Discounted Cash Flow Results				
Total Plant Cost ($/kW)		1,588		1,516
Levelized Cost of Electricity ($/kW-hr)		0.0675		0.0648

3.9 Ion Transport Membrane

An alternative to cryogenic air separation, the ion transport membrane (ITM) produces a pure oxygen permeate stream at low pressure, leaving the nitrogen-rich non-permeate at high pressure for fuel stream dilution and expansion through the gas turbine. Although the oxygen must be compressed to gasifier pressure, the ITM has the advantage of reducing auxiliary power required to compress dilution nitrogen, and thus improves process efficiency.

The ITM is a ceramic perovskite-type material that, at high temperature (800-900 ^oC), allows the passage of oxygen ions across the ceramic membrane. These ions re-combine to form oxygen molecules on the permeate side of the membrane. In this manner, oxygen is separated from air to produce 100 percent pure oxygen. A small amount of clean fuel is oxidized directly with the ITM air feed stream to heat the air stream to ITM temperature.

A recent Gas Turbine World article [8] describes alternative configurations for full air integration, partial integration, and zero integration. The full air integration scenario includes a recuperator to transfer heat from the hot non-permeate stream to the feed air stream in order to reduce the amount of syngas used to heat the ITM. The recuperator increases capital equipment cost and also introduces a pressure drop across the ITM system that introduces the need for a boost compressor in order to provide sufficient pressure for the non-permeate stream to return to the turbine. The partial integration scenario, illustrated below in Figure 3-6, has no recuperator or boost compressor. Air extracted from the syngas turbine compressor is supplemented by a stand-alone air compressor to provide full air feed to the ITM. A small amount of syngas is oxidized to heat the feed air to the membrane. Oxygen is transported across the membrane; it must be cooled and compressed to gasifier pressure. With only a nominal pressure drop across the membrane, part of the nitrogen-rich non-permeate is used as syngas diluent in the turbine, and the remainder is expanded and cooled for heat recovery in the HRSG.

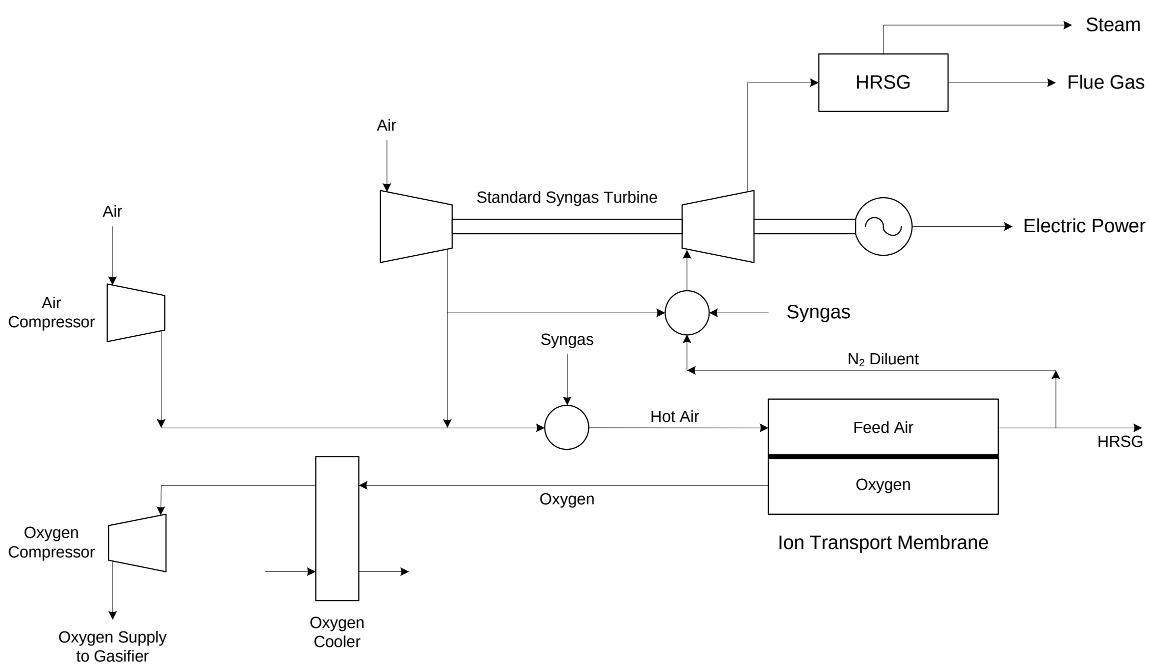

Figure 3-6. Partial ITM Air Integration Configuration

3.9.1

Impact of ITM in the Reference Plant (Case 8a)

Case 8a Configuration: Slurry Feed Gasifier, ITM, Cold Gas Cleanup, Advanced "F" Frame Syngas Turbine, 75 % Capacity Factor

A block flow diagram of the process with partial ITM air integration is shown in Figure 3-7; process details have been omitted to protect business-sensitive information. Note that this process is based on the advanced "F" frame syngas turbine for air extraction from the gas turbine; results from this case are compared against Case 2a, which is the reference process with advanced "F" frame syngas turbine. Although the Siemens SGT6-6000G turbine is the basis for the Gas Turbine World article, the advanced "F" frame turbine was chosen in this analysis for consistent comparison with other pathway study cases.

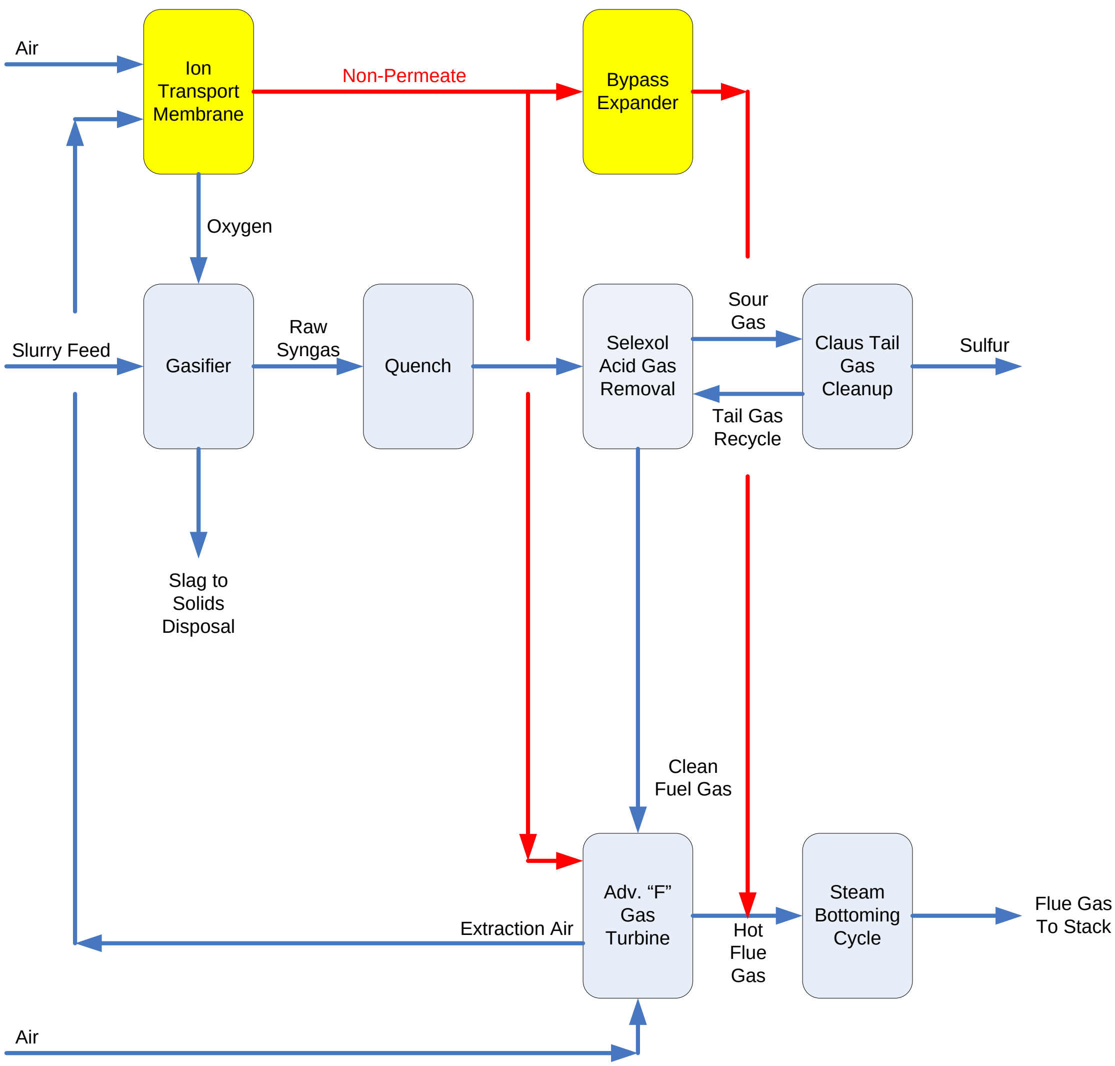

Figure 3-7. Case 8a: Reference IGCC Process With ITM Air Separation

Table 3-22 below compares overall process performance improvement due to air separation using the ITM.

Table 3-22. Performance Impact of ITM in the Reference Plant

	Case 2a	**Case 8a**
	Reference plant with adv. “F” and cryogenic ASU	Reference plant with advanced “F” and ITM
Gas Turbine Power (MWe)	464	464
Fuel Gas Expander (MWe)	8	8
Bypass Expander (MWe)	NA	47
Steam Turbine Power (MWe)	293	316
Total Power Produced (MWe)	765	834
Auxiliary Power Use (MWe)	-128	-156
Net Power (MWe)	637	678
As-Received Coal Feed (lb/hr)	491,633	518,870
Net Heat Rate (Btu/kW-hr)	9,004	8,924
Net Plant Efficiency (HHV)	37.9 %	38.2 %

In the ITM case, part of the N_2-rich raffinate bypasses the gas turbine to produce 47 MW. Steam turbine power production increases by 23 MW due to eliminating the steam duty of the cryogenic ASU and also increased process heat recovery resulting from increased coal feed rate. Auxiliary power consumption increases by 28 MW as the result of increased air flowrate to the ASU and higher oxygen compression ratio; the total increase is partly offset by eliminating the nitrogen compressor. The incremental power production results in net plant efficiency increasing from 37.9 % to 38.2 % – an increase by 0.3 percentage points.

This increase in process efficiency is slightly lower than Air Products’ expectations, although the values of net plant efficiency are different [9]; their baseline with cryogenic air separation had an efficiency of 38.4 % (HHV), increasing to 38.9 % with ITM air separation – an increase by 0.5 percentage points.

Cost Analysis (Case 8a)

Comparing capital costs between Cases 2a and 8a in Table 3-23, the TPC in most accounts such as coal handling, coal feed, BOP, gasifier, gas cleanup, HRSG, steam cycle, and waste solids handling system increase by between 2-8 percent because of higher plant throughput due to increased coal feed necessary to heat the ITM. The most significant difference occurs in the air separation unit (ITM) sub-account.

The bare erected cost of the ITM is assumed to be 67 % of the cost of an equivalent cryogenic ASU. Because of the different plant sizes, it is about 77 % of the cost of the cryogenic ASU in Case 2a. This reduces the cost of the ASU by about $42 MM, which equates to about $79/kW decrease in the cost of the ASU.

Table 3-23. Case 8a: Capital and O&M Cost Comparison

	Case 2a			Case 8a		
	Reference plant with advanced "F" and cryogenic ASU			Reference plant with advanced "F" and ITM		
Capital Cost ($1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Sorbent Handling	29,076	34,890	55	30,063	36,076	53
2 Coal and Sorbent Prep & Feed	45,169	56,050	88	46,839	58,124	86
3 Feedwater & Balance of Plant	30,636	37,513	59	31,227	38,223	56
4a Gasifier	210,196	269,284	423	217,002	278,016	410
4b Air Separation Unit	167,073	183,781	289	118,445	142,134	210
5a Gas Cleanup	107,769	129,625	203	110,816	133,289	197
5b CO_2 Removal & Compression	0	0	0	0	0	0
6 Gas Turbine	103,491	119,302	187	103,564	119,387	176
7 HRSG	50,936	56,565	89	52,626	58,460	86
8 Steam Cycle and Turbines	57,934	65,820	103	61,125	69,461	102
9 Cooling Water System	22,515	27,140	43	23,338	28,130	41
10 Waste Solids Handling System	39,568	43,829	69	40,909	45,314	67
11 Accessory Electric Plant	58,402	69,559	109	62,683	74,697	110
12 Instrumentation & Control	19,010	23,212	36	20,133	24,584	36
13 Site Preparation	14,247	18,522	29	14,554	18,920	28
14 Buildings and Structures	14,974	17,421	27	15,412	17,928	26
Total	970,995	1,152,513	1,809	948,736	1,142,740	1,685
O&M Cost ($1,000)						
Fixed Costs	**Total**	**% EPCC**		**Total**	**% EPCC**	
Labor	22,548	2.32		22,548	2.38	
Variable Operating Costs*	**Total**	**% EPCC**		**Total**	**% EPCC**	
Maintenance Materials	21,339	2.20		22,715	2.39	
Water	1,596	0.16		1,565	0.17	
Chemicals	1,215	0.13		1,298	0.14	
Waste Disposal	2,745	0.28		2,893	0.31	
Total Variable Costs	26,896	2.77		28,471	3.00	
Total O&M Cost	49,444	5.09		51,020	5.38	
Fuel Cost*	68,008	7.00		71,776	7.57	
Discounted Cash Flow Results						
Total Plant Cost ($/kW)		1,809		1,685		
Levelized Cost of Electricity ($/kW-hr)		0.0814		0.0775		

*Includes 75% capacity factor

Overall, the total plant cost decreases by $10 MM going from Case 2a to Case 8a. Because of increased net power production (678 MW vs. 637 MW) however, the TPC cost on a $/kW basis decreases from $1,809/kW to $1,685/kW. Annual fuel cost increases slightly due to additional coal needed to heat the ITM.

Despite the increased O&M and fuel costs, the decreased capital cost on a $/kW basis drives the COE down from $0.0814/kW-hr to $0.0775/kW-hr – a decrease of about 4.8 % in cost of electricity.

These cost and performance results are somewhat less than Air Products' expectations [10]. Air Products projects IGCC net power output to increase by 15 %; the increase from 637 MW to

678 MW is a 6 % increase. While the plant efficiency is expected to increase by 0.5 percentage point, the increase in Noblis' simulation is 0.3 percentage point. Air Products estimates the oxygen plant cost to decrease by 25 % on a $/sTPD O_2 basis; Noblis' estimate is a 23 % decrease on a $/kW basis (equal to a 27 % decrease on a $/sTPD basis). Finally, Air Products predicts the TPC on a $/kW basis to decrease by 9 %; Noblis' reduction from $1,809/kW to $1,685/kW represents a 6.9 % decrease. There are some proprietary aspects of Air Products' process that are not included in this analysis; this may explain the differences between Noblis and Air Products results.

3.9.2 Cumulative Impact of R&D

Composite Process Configuration (Case 8): Coal Feed Pump, ITM, Warm Gas Cleanup, 2010-AST Syngas Turbine, 85 % Capacity Factor

A block flow diagram of the ITM air separation unit implemented in the advanced technology process configuration is shown in Figure 3-8. Because the dry feed gasifier requires less oxygen than the slurry feed gasifier, the ITM will be smaller in this case; this represents a reduction in auxiliary power consumption compared to the reference process, and also eliminates the bypass expander. Table 3-24 below compares the overall process performance for the advanced technology case when the ITM replaces cryogenic ASU.

Table 3-24. Incremental Performance Improvement from ITM

	Case 7	**Case 8**
	Coal pump, full WGCU, 85% CF, 2010-AST, cryogenic ASU	Coal pump, full WGCU, 85% CF, 2010-AST, ITM
Gas Turbine Power (MWe)	500	500
Fuel Gas Expander (MWe)	9	9
Steam Turbine Power (MWe)	323	340
Total Power Produced (MWe)	832	849
Auxiliary Power Use (MWe)	-118	-123
Net Power (MWe)	714	725
As-Received Coal Feed (lb/hr)	480,583	480,947
Net Heat Rate (Btu/kW-hr)	7,849	7,734
Net Plant Efficiency (HHV)	43.5 %	44.1 %

The steam turbine power production in Case 8 increases by 17 MW because (1) the ITM air separation unit eliminates two significant steam requirements used in a cryogenic ASU; (2) steam added to humidify the fuel gas in the cryogenic process is replaced by water spray that is evaporated by cooling the N_2-rich raffinate, and (3) heat recovery from the oxygen and fluff nitrogen coolers in the ITM process.

Auxiliary power use decreases by 5 MW in Case 8 – the result of tradeoffs between main air compressor, ITM boost compressor, and oxygen compressors vs. eliminating the nitrogen compressor.

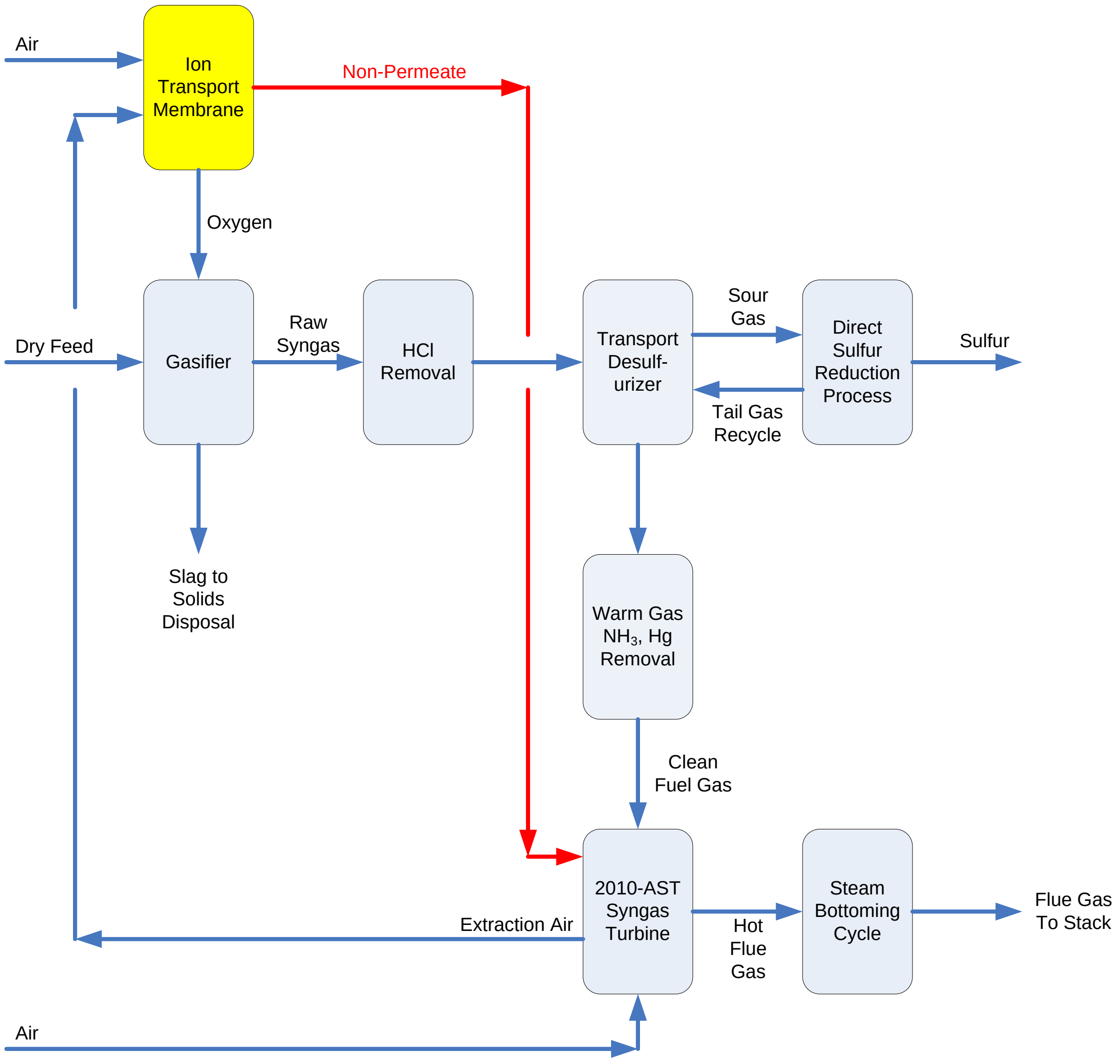

Figure 3-8. Case 8: Advanced Technology Process With ITM Air Separation

With the same coal feed rate, net power production increases by 11 MW – improving net plant efficiency from 43.5 % to 44.1 %.

While the ITM increases process efficiency by 0.3 percentage points in the reference process with slurry feed gasifier, cold gas cleanup, and advanced "F" frame turbine (Cases 2a and 8a), it has a slightly better performance improvement with coal feed pump, warm gas cleanup, and 2010-AST turbine – improving process efficiency by 0.6 percentage points. The dry feed gasifier in Case 8 requires less oxygen than slurry feed, and reduces the N_2-rich raffinate flowrate enough that all can be used as diluent in the gas turbine, eliminating the bypass expander. This increases the temperature at the inlet to the HRSG, thus increasing heat recovery in the steam cycle. The ample supply of diluent also eliminates the need for humidifying steam (as needed in Case 7).

Cost Analysis (Case 8)

Comparing capital costs between Cases 7 and 8 in Table 3-25, the TPC in most accounts such as coal handling, coal feed, BOP, gasifier, gas cleanup, HRSG, steam cycle, and waste solids handling system are very similar between cases; this is due to nearly the same coal feed rates. The only significant difference occurs in the air separation unit (ITM) sub-account.

Table 3-25. Case 8: Capital and O&M Cost Comparison

	Case 7			Case 8		
	Coal pump, full WGCU, 85% CF, 2010-AST, cryogenic ASU			Coal pump, full WGCU, 85% CF, 2010-AST, ITM		
Capital Cost ($1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Sorbent Handling	28,667	34,400	48	28,682	34,418	47
2 Coal and Sorbent Prep & Feed	46,109	56,939	80	46,132	56,967	79
3 Feedwater & Balance of Plant	27,961	34,165	48	27,968	34,174	47
4a Gasifier	199,598	255,906	358	198,789	254,893	351
4b Air Separation Unit	149,311	164,243	230	100,238	120,285	166
5a Gas Cleanup	71,294	85,943	120	69,056	83,223	115
5b CO_2 Removal & Compression	0	0	0	0	0	0
6 Gas Turbine	109,034	125,681	176	108,969	125,605	173
7 HRSG	51,973	57,703	81	51,988	57,719	80
8 Steam Cycle and Turbines	62,144	70,623	99	64,435	73,238	101
9 Cooling Water System	23,475	28,295	40	24,056	28,994	40
10 Waste Solids Handling System	36,888	40,863	57	36,901	40,877	56
11 Accessory Electric Plant	58,336	69,406	97	59,237	70,486	97
12 Instrumentation & Control	18,600	22,711	32	18,833	22,996	32
13 Site Preparation	14,127	18,366	26	14,177	18,430	25
14 Buildings and Structures	15,149	17,620	25	15,388	17,896	25
Total	912,666	1,082,864	1,516	864,848	1,040,201	1,434

O&M Cost ($1,000)				
Fixed Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Labor	21,045	2.31	19,542	2.26
Variable Operating Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Maintenance Materials	25,698	2.82	26,066	3.01
Water	1,374	0.15	1,314	0.15
Chemicals	5,048	0.55	5,060	0.59
Waste Disposal	2,779	0.30	2,781	0.32
Total Variable Costs	34,899	3.82	35,220	4.07
Total O&M Cost	55,944	6.13	54,762	6.33
Fuel Cost	75,344	8.26	75,401	8.72

Discounted Cash Flow Results		
Total Plant Cost ($/kW)	1,516	1,434
Levelized Cost of Electricity ($/kW-hr)	0.0648	0.0622

The bare erected cost of the ITM is assumed to be 67 % of the cost of an equivalent cryogenic ASU; with the slight difference in gasifier throughput, it is about 73 % of the cost of the cryogenic ASU of Case 7. This reduces the cost of the ASU by about $44 MM, which equates to about $64/kW decrease in the cost of the ASU.

Overall, the total plant cost decreases by $43 MM going from Case 7 to Case 8. Because of slightly increased net power production (725 MW vs. 714 MW), the TPC cost on a $/kW basis decreases from $1,516/kW to $1,434/kW.

With nearly equal O&M and fuel costs, the decreased capital cost drives the COE down from $0.0648/kW-hr to $0.0622/kW-hr – a decrease of about 4.0 % in cost of electricity.

3.10 Advanced Syngas Turbine – 2015-AST

By 2015, DOE has more aggressive performance efficiency improvement targets for advanced syngas turbine technology. Superior to the 2010-AST turbine, the 2015-AST performance improvements are expected from increased pressure ratio and turbine inlet temperature, further improving efficiency of the gas turbine.

3.10.1 Impact of 2015-AST Syngas Turbine in the Reference Plant (Case 9a)

Case 9a Configuration: Slurry Feed Gasifier, Cryogenic ASU, Cold Gas Cleanup, 2015-AST Syngas Turbine, 75 % Capacity Factor

The process block flow diagram of the reference IGCC process with a 2015-AST syngas turbine is identical to Figure 3-2 from Case 2a. Like the advanced "F" frame and 2010-AST syngas turbines, the 2015-AST produces more power, has a higher pressure ratio, and higher firing temperature than the 7FA syngas turbine. Turbine performance parameters for the 2015-AST are omitted from the following discussion in order to protect business-sensitive information. The increased turbine exhaust temperature (over that of the 7FA) enables steam superheat and reheat temperatures to 1,050 ^{o}F.

A single process train IGCC plant processes 4,300 tons per day of as-received coal to produce a net 500 MW of power. Overall efficiency is 40.5 percent (HHV basis). Carbon utilization is 98 percent and the capacity factor is 75 percent. Total power generated includes 6 MW from the fuel gas expander and 213 MW from the steam turbine. Auxiliary power use is estimated to be 89 MW. Performance improvement resulting from the 2015-AST is compared to the Reference Case in Table 3-26.

Table 3-26. Performance Impact of 2015-AST Syngas Turbine in the Reference Plant

	Case 0	**Case 9a**
	Reference plant with 7FA	Reference plant with 2015-AST
Gas Turbine Power (MWe)	384	370
Fuel Gas Expander (MWe)	6	6
Steam Turbine Power (MWe)	223	213
Total Power Produced (MWe)	614	589
Auxiliary Power Use (MWe)	-127	-89
Net Power (MWe)	487	500
As-Received Coal Feed (lb/hr)	402,581	361,531
Net Heat Rate (Btu/kW-hr)	9,649	8,435
Net Plant Efficiency (HHV)	35.4 %	40.5 %

Coal flowrate decreases in Case 9a due to combined reduced gas turbine power output and improved gas turbine efficiency. The reduced coal flowrate also reduces heat recovery from the gasifier and syngas cooling, leading to decreased steam turbine power generation.

The primary difference in auxiliary power consumption is the ASU main air compressor due to integration between the gas turbine air compressor and the ASU, which reduces the fresh air feed through the main air compressor and therefore reduced power consumption. All other auxiliary power accounts in Case 9a are generally less than Case 0 due to decreased coal flowrate and therefore decreased throughput by all plant sections.

Overall, the net plant efficiency increases by 5.1 percentage points going from the 7FA syngas turbine to the 2015-AST syngas turbine.

Cost Analysis (Case 9a)

Capital and O&M costs are compared with Case 0 results in Table 3-27. The choice of gas turbine is the reason for differences in capital costs between Case 0 (7FA turbine) and Case 9a (2015-AST turbine). The 2015-AST turbine has a higher power rating per unit and the number of turbine trains reduces from two to one in Case 9a. The reduction in number of trains – essentially providing one large train of gasification, ASU, gas cleanup, and gas turbine rather than two of each in Case 0 – represents an economy of scale, which explains the decreased cost of the gasifier, ASU, gas cleanup, and gas turbine sections in Case 9a.

On a $/kW basis, the TPC of the 2015-AST plant also decreases. Not only is the turbine power output of Case 9a greater, but the process efficiency is 5.1 percentage points greater than the 7FA case. As described above, the primary reasons for this are air integration from the gas turbine to the ASU, the greater efficiency of the 2015-AST syngas turbine, and the increased steam cycle superheat temperature.

Comparing cost of electricity, the $0.0768/kW-hr of Case 9a is less than the $0.0927/kW-hr of Case 0 because of (1) larger gas turbine machine, which decreases the capital cost on a $/kW basis, and (2) increased plant efficiency due to the higher pressure ratio and firing temperature of the 2015-AST syngas turbine compared to the 7FA turbine.

The reference process with advanced “F” frame syngas turbine (Case 2a), by comparison, has $1,809/kW TPC and COE of $0.0814/kW-hr. The reference process with 2010-AST syngas turbine (Case 7a) has $1,731/kW TPC and COE of $0.0782/kW-hr. The TPC of the 2015-AST syngas turbine process is the least due to capital cost savings resulting from the decrease of two trains to one, and the COE benefits from a reduction in number of plant operators, decreased O&M cost, and decreased fuel cost.

Table 3-27. Case 9a: Capital and O&M Cost Comparison

	Case 0			Case 9a		
	Reference plant with 7FA			Reference plant with 2015-AST		
Capital Cost ($1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Sorbent Handling	25,685	30,821	63	24,025	28,829	58
2 Coal and Sorbent Prep & Feed	39,472	48,980	101	36,711	45,553	91
3 Feedwater & Balance of Plant	28,606	35,077	72	27,614	33,887	68
4a Gasifier	184,371	236,212	485	136,501	174,821	350
4b Air Separation Unit	153,591	168,950	347	109,034	119,938	240
5a Gas Cleanup	93,441	112,389	231	69,903	84,086	168
5b CO_2 Removal & Compression	0	0	0	0	0	0
6 Gas Turbine	91,110	105,058	215	74,293	85,713	171
7 HRSG	44,560	49,511	102	38,761	43,020	86
8 Steam Cycle and Turbines	47,842	54,310	112	46,184	52,424	105
9 Cooling Water System	20,099	24.233	50	19,359	23,346	47
10 Waste Solids Handling System	34,981	38,752	80	32,738	36,269	73
11 Accessory Electric Plant	55,772	66,529	137	50,334	59,938	120
12 Instrumentation & Control	18,982	23,178	48	17,152	20,944	42
13 Site Preparation	13,956	18,143	37	13,430	17,459	35
14 Buildings and Structures	14,012	16,314	34	13,621	15,858	32
Total	866,482	1,028,457	2,113	709,661	842,084	1,684

O&M Cost ($1,000)				
Fixed Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Labor	19,542	2.26	16,535	2.33
Variable Operating Costs*	**Total**	**% EPCC**	**Total**	**% EPCC**
Maintenance Materials	18,368	2.12	17,880	2.52
Water	1,451	0.17	1,233	0.17
Chemicals	1,021	0.12	975	0.14
Waste Disposal	2,262	0.26	2,040	0.29
Total Variable Costs	23,102	2.67	22,128	3.12
Total O&M Cost	42,644	4.92	38,663	5.45
Fuel Cost*	55,690	6.43	50,011	7.05

Discounted Cash Flow Results		
Total Plant Cost ($/kW)	2,113	1,684
Levelized Cost of Electricity ($/kW-hr)	0.0927	0.0768

*Includes 75 % capacity factor

3.10.2

Cumulative Impact of R&D

Composite Process Configuration (Case 9): Coal Feed Pump, ITM, Warm Gas Cleanup, 2015-AST Syngas Turbine, 85 % Capacity Factor

Case 9 substitutes the 2015-AST syngas turbine for the 2010-AST syngas turbine that was present in Case 8. The table below compares the overall process performance for each plant.

Table 3-28. Incremental Performance Improvement from the 2015-AST Turbine

	Case 8	**Case 9**
	Coal pump, 85% CF, full WGCU, ITM, 2010-AST	Coal pump, 85% CF, full WGCU, ITM, 2015-AST
Gas Turbine Power (MWe)	500	370
Fuel Gas Expander (MWe)	9	6
Steam Turbine Power (MWe)	340	228
Total Power Produced (MWe)	849	604
Auxiliary Power Use (MWe)	-123	-76
Net Power (MWe)	725	528
As-Received Coal Feed (lb/hr)	480,947	335,026
Net Heat Rate (Btu/kW-hr)	7,734	7,400
Net Plant Efficiency (HHV)	44.1 %	46.1 %

Although the 2015-AST turbine produces more power per unit, there is only one train in Case 9 as opposed to two 2010-AST turbines in Case 8; turbine power consequently decreases, as does coal feedrate and all power accounts in general.

The 2015-AST syngas turbine increases process performance by 2.0 percentage points over Case 8. When the 2015-AST turbine replaces the 2010-AST turbine in the reference process, performance increases by 1.7 percentage points (Case 7a vs. Case 9a). In the cryogenic cases, the overpressure (the difference between turbine compressor delivery pressure and the ASU pressure) is lost – and more of it is lost in the 2015-AST case because of its higher pressure.

Operating at higher pressure than the gas turbine compressor, the ITM has a better “pressure match” with gas turbine compressor delivery pressure, which improves process efficiency and therefore the increased improvement of the 2015-AST over the 2010-AST in the ITM cases.

Cost Analysis (Case 9)

Comparing capital costs between Cases 8 and 9 in Table 3-29, the TPC in all accounts decreases because of reduced net power production, which corresponds to decreased coal flowrate and decreased plant equipment size, and therefore cost. The number of process trains (consisting of gasifier, ASU, gas cleanup, and gas turbine) decreases from two to one.

The reduction in TPC represents a reverse economy of scale, as TPC on a $/kW basis increases in every account except for the gasifier, ASU, gas cleanup, and gas turbine sections. Those accounts reduce in cost because of the reduction from two trains to one large train. In all other accounts, although the TPC decreases the cost on $/kW increases because of the reduced net power production.

Table 3-29. Case 9: Capital and O&M Cost Comparison

	Case 8			Case 9		
	Coal pump, 85% CF, full WGCU, ITM, 2010-AST			Coal pump, 85% CF, full WGCU, ITM, 2015-AST		
Capital Cost ($1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Sorbent Handling	28,682	34,418	47	22,918	27,502	52
2 Coal and Sorbent Prep & Feed	46,132	56,967	79	36,148	44,636	85
3 Feedwater & Balance of Plant	27,968	34,174	47	24,521	30,037	57
4a Gasifier	198,789	254,893	351	124,758	159,909	303
4b Air Separation Unit	100,238	120,285	166	63,491	76,189	144
5a Gas Cleanup	69,056	83,223	115	44,204	53,276	101
5b CO_2 Removal & Compression	0	0	0	0	0	0
6 Gas Turbine	108,969	125,605	173	74,457	85,902	163
7 HRSG	51,988	57,719	80	38,622	42,867	81
8 Steam Cycle and Turbines	64,435	73,238	101	48,479	55,039	104
9 Cooling Water System	24,056	28,994	40	19,870	23,960	45
10 Waste Solids Handling System	36,901	40,877	56	29,529	32,717	62
11 Accessory Electric Plant	59,237	70,486	97	48,666	57,891	110
12 Instrumentation & Control	18,833	22,996	32	16,427	20,058	38
13 Site Preparation	14,177	18,430	25	13,177	17,130	32
14 Buildings and Structures	15,388	17,896	25	13,580	15,809	30
Total	864,848	1,040,201	1,434	618,847	742,921	1,407

O&M Cost ($1,000)				
Fixed Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Labor	19,542	2.26	15,032	2.43
Variable Operating Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Maintenance Materials	26,066	3.01	20,611	3.33
Water	1,314	0.15	1,004	0.16
Chemicals	5,060	0.59	3,611	0.58
Waste Disposal	2,781	0.32	1,964	0.32
Total Variable Costs	35,220	4.07	27,191	4.39
Total O&M Cost	54,762	6.33	42,223	6.82
Fuel Cost	75,401	8.72	52,524	8.49

Discounted Cash Flow Results		
Total Plant Cost ($/kW)	1,434	1,407
Levelized Cost of Electricity ($/kW-hr)	0.0622	0.0615

Overall, the total plant cost decreases by $297 MM going from Case 8 to Case 9, but because of the decreased power production, the cost on a $/kW basis decreases by only $27/kW or 1.9 %.

The number of laborers, and therefore the fixed O&M cost, decreases as the result of reducing from two process trains to a single train. Variable O&M and fuel cost also decrease significantly as the result of reduced plant output. There is a slight net decrease in COE from $0.0622/kW-hr to $0.0615/kW-hr – a 1.1 % decrease as the result of the 2015-AST syngas turbine.

3.11 Increased Capacity Factor to 90 Percent

In Case 10, the process configuration remains the same as Case 9 (with process performance remaining the same as in Table 3-28 above for Case 9), but the capacity factor increases from 85 percent to 90 percent. This increased on-stream factor reflects anticipated improvements in process reliability, availability, and maintainability (RAM) due to DOE-sponsored R&D (with no additional capital or fixed O&M cost).

The differences between Case 9 and Case 10 lie in variable O&M costs, fuel cost, and plant revenues as the result of longer hours of operation. Variable O&M costs increase by about $1.6 MM/year, and fuel costs increase by about $3.1 MM/year. The increased plant revenue from additional power production results in decreased cost of electricity from $0.0615/kW-hr in Case 9 to $0.0595/kW-hr in Case 10 – a savings of about 3.3 % in cost of electricity resulting from increased capacity factor.

3.12 Pressurized Solid Oxide Fuel Cell

The solid oxide fuel cell offers potential for high efficiency conversion of chemical potential into electrical energy. Because the overall reaction of syngas and oxygen to form CO_2 and H_2O is exothermic, the fuel cell depends as much as possible on endothermic internal reforming of CH_4 to hydrogen and CO in order to limit temperature rise inside the fuel cell stack. Both the gasifier and fuel cell rely on a significant amount of steam, so warm gas cleanup is beneficial to avoid moisture condensation during desulfurization.

Process Configuration (Case 11): Catalytic Gasifier, Cryogenic ASU, Warm Gas Cleanup, Solid Oxide Fuel Cell, 90 % Capacity Factor

The fuel cell process configuration is based on a design proposed by SAIC [11]; the original process operating conditions were adopted in this study, and no further systems analysis attempt was made to optimize plant performance. This process feeds coal to a dry-feed, fluid bed, oxygen-blown catalytic gasifier. A block flow diagram is presented in Figure 3-9. Table 3-30 presents the calculated raw syngas composition, with high (16.6 mole percent) CH_4 content to promote reforming in the fuel cell.

Raw syngas passes through a high-efficiency cyclone to separate the bulk of entrained ash. The syngas then passes through a barrier filter (using ceramic or metal filter elements). Ash drained from the fluid bed gasifier and from the syngas cyclone is treated to separate and reprocess the gasification catalyst. The catalyst material is circulated back to the catalytic gasifier. A convective cooler generates steam, cooling the raw syngas from 1,300 ^{o}F to 950 ^{o}F.

The warm gas cleanup section is nearly identical to that used in the IGCC cases with GE gasifier, except that this case also includes a sulfur polishing step in order to attain very low sulfur concentration in the fuel cell feed stream. Raw syngas enters the chloride guard bed for HCl removal. The syngas is cooled in preparation for contact with zinc oxide sorbent, which reacts with H_2S to remove it from the syngas. To regenerate the sorbent, the ZnS transfers to the regenerator where it contacts with air and is oxidized. The SO_2 that is generated flows to the DSRP for sulfur recovery, and the regenerated sorbent is returned to the transport desulfurizer.

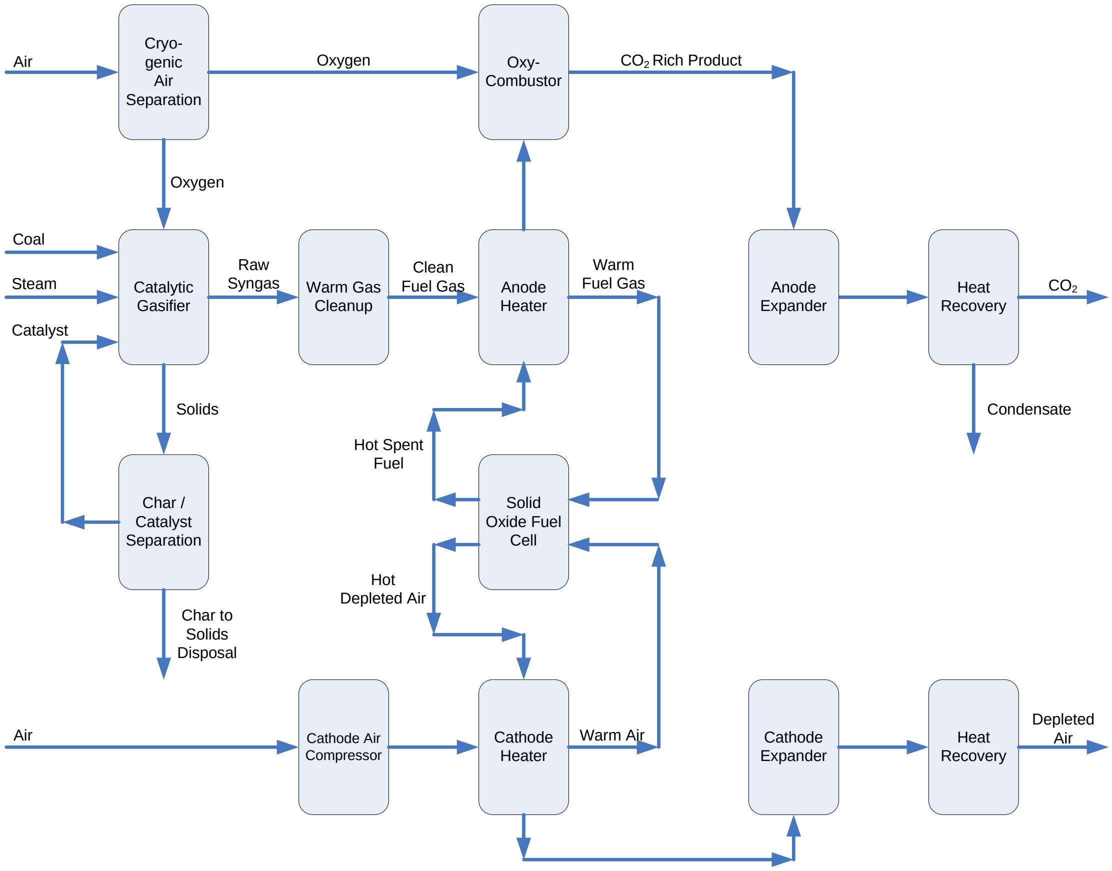

Figure 3-9. Case 11: Pressurized Solid Oxide Fuel Cell Process

Table 3-30. Raw Syngas Composition from the Catalytic Gasifier

	Syngas Composition
H_2 (mole %)	15.0
CH_4	16.6
CO	4.7
CO_2	20.7
H_2O	41.8
N_2	0.4
H_2S	0.6
NH_3	626 ppm
Ar	192 ppm
HCl	689 ppm
COS	98 ppm

Desulfurized syngas, coming from the transport desulfurizer at 900 ^{o}F, passes through a polishing bed to reduce H_2S concentration to a very low level. The desulfurized syngas is cooled to about 460 ^{o}F in preparation for mercury removal.

A small portion of the clean fuel gas exiting mercury removal is used as reducing gas in the DSRP. Here, regeneration gas from the Transport Desulfurization section is reduced, forming elemental sulfur:

$$SO_2 + 2\ H_2 = 2\ H_2O + S$$

$$3\ SO_2 + 2\ CH_4 = 2\ CO + 4\ H_2O + S$$

DSRP tail gas, containing H_2O and CO, is compressed and recycled to the transport desulfurizer. Elemental sulfur is condensed and removed as product.

Following chloride removal, desulfurization, and mercury removal, the clean fuel gas is ready for conversion in the fuel cell. High pressure steam can be added if necessary to adjust the hydrogen:carbon ratio in the fuel cell. The mixture is expanded to the fuel cell operating pressure of 275 psia. Heat exchange with the anode spent fuel stream heats the anode feed stream to 1,112 ^{o}F (600 ^{o}C).

On the cathode side, air is compressed to 290 psia. It is heated to 1,112 ^{o}F (600 ^{o}C) by the depleted air stream exiting the fuel cell cathode. Within the fuel cell anode, methane is completely reformed to CO and H_2. Oxygen diffuses from the cathode through the electrolyte to the anode, creating an electric potential, and reacts with H_2 that is formed from the equilibrium mixture of anode gases. Fuel conversion is assumed to be 85 %. The fuel cell inverter efficiency is assumed to be 96 %. A temperature rise of 150 ^{o}C from entrance to exit of the fuel cell is allowed; a large amount of cathode air must be circulated through the fuel cell to regulate temperature rise.

After heating the incoming cathode air stream, the spent cathode air enters an expander, and any remaining heat from the cathode expander exhaust is recovered for boiler feedwater heating. The spent anode fuel enters an oxy-combustor where remaining fuel is converted to flue gas. The hot flue gas is expanded and heat is recovered for steam generation. Following flue gas cooling, water is condensed and the remaining flue gas, consisting almost entirely of CO_2, can be compressed and transported for storage if sequestration is required.

All available process heat is collected to generate steam for the gasifier and the fuel cell anode; the process has no bottoming cycle. Table 3-31 below summarizes overall process performance.

Auxiliary power consumption is dominated by the large amount of cathode air that must be compressed and fed to the fuel cell in order to remove the large amount of heat generated from converting 85 % of the fuel gas in the fuel cell. The pressure is recovered in an expander, delivering 208 MW as part of the net power output.

Table 3-31. Performance Summary of the SOFC Process

	Case 11
	SOFC
Fuel Cell Power (MW)	517
Syngas Expander (MW)	22
Cathode Air Expander (MW)	208
Anode Exhaust Expander (MW)	132
Total Power Produced (MW)	879
Auxiliary Power (MW)	-276
Net Power (MW)	603
As-Received Coal Feed (lb/hr)	300,000
Net Heat Rate (Btu/kW-hr)	5,805
Net Plant Efficiency (HHV)	58.8 %
Gasifier Cold Gas Efficiency	92.0 %

Cost Analysis (Case 11)

Table 3-32 summarizes the total plant cost, O&M cost, and fuel cost of the process. A fuel cell system TPC of $550/kW was assumed.[3] 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. TPC includes equipment, labor, EPC services, and process and project contingencies. The same process and project contingencies used for the GE gasifier in the IGCC cases were assigned to the catalytic gasifier for this case. Ten percent process and ten percent project contingencies were assumed for the fuel cell system; this implies n^{th} plant design to evaluate the ultimate potential of fuel cell technology.

Total plant cost is based on a single process train. The total plant cost of $926 MM is less than the reference IGCC Case 0, but the fuel cell process generates nearly the same power as Case 3 with coal feed pump, cryogenic ASU, cold gas cleanup, and advanced "F" frame turbine. The large amount of power generated results in a TPC of $1,536/kW.

The very high process efficiency of 58.8 % results in a large cost savings in fuel. Particularly as fuel prices continue to put pressure on energy use, this high process efficiency will benefit fuel cell technology. The combination of low capital and fuel cost contributes to a COE of $0.0639/kW-hr (based on January 2007 dollars and 90 % capacity factor).

The fuel cell process configuration of Case 11 was developed by SAIC, and is described in NETL's report titled "The Benefits of SOFC for Coal-Based Power Generation" [11]. A comparison is provided in Appendix A.3 to support the results presented in Table 3-32.

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[3] A goal of the fuel cell program is to develop a power system with cost equal to or less than an equivalent natural gas combined cycle power system. That cost, in January 2007 dollars, was estimated to be $550/kW.

Table 3-32. Case 11: Capital and O&M Cost Summary

	Case 11		
	Solid Oxide Fuel Cell		
Capital Cost ($1,000)			
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Catalyst Handling	25,678	30,814	51
2 Coal and Catalyst Prep & Feed	33,550	41,428	69
3 Feedwater & Balance of Plant	17,805	21,649	36
4a Gasifier	123,853	155,335	258
4b Air Separation Unit	73,915	81,306	135
5a Gas Cleanup	55,056	66,351	110
5b CO_2 Removal & Compression	0	0	0
6 Gas Turbine	0	0	0
7 Fuel Cell	278,195	333,836	554
8 Steam Cycle and Turbines	0	0	0
9 Cooling Water System	11,507	13,935	23
10 Waste Solids Handling System	32,217	35,692	59
11 Accessory Electric Plant	73,623	87,996	146
12 Instrumentation & Control	23,674	28,907	48
13 Site Preparation	14,480	18,823	31
14 Buildings and Structures	8,594	10,097	17
Total	772,147	926,169	1,536

O&M Cost ($1,000)		
Fixed Costs	**Total**	**% EPCC**
Labor	18,039	2.34
Variable Operating Costs*	**Total**	**% EPCC**
Maintenance Materials	28,316	3.67
Water	158	0.02
Chemicals	3,836	0.50
Fuel Cell Stack Replacement	17,835	2.31
Waste Disposal	2,397	0.31
Total Variable Costs	52,542	6.81
Total O&M Cost	70,581	9.14
Fuel Cost*	49,799	6.45
Discounted Cash Flow Results		
Total Plant Cost ($/kW)	1,536	
Levelized Cost of Electricity ($/kW-hr)	0.0639	

*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 that were investigated.

4.1 Impact of Individual Technologies

Process Efficiency

Figure 4-1 illustrates the performance improvement as each of the advanced technologies is evaluated individually within the reference plant. Because it represents multiple advanced technologies, the SOFC process is not included in this comparison.

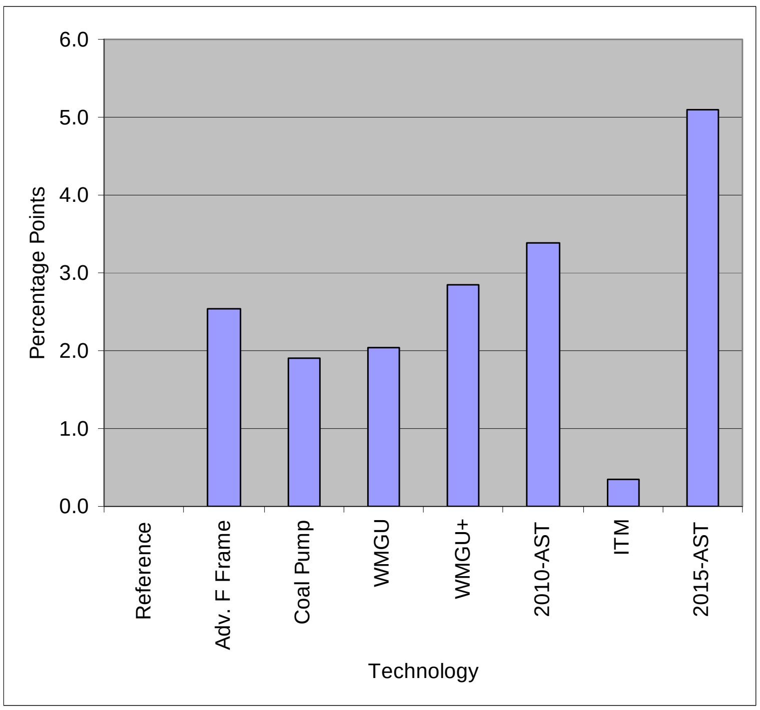

Figure 4-1. Impact of Each Technology on Process Efficiency in the Reference Plant

The advanced syngas turbines provide the greatest performance improvements as the result of air integration, increased turbine firing temperature and pressure ratio, and increased HRSG inlet temperature. Compared to the 7FA turbine, the advanced "F" frame turbine improves process efficiency by 2.5 percentage points, the 2010-AST improves by 3.4 percentage points, and the 2015-AST improves by 5.1 percentage points.

Partial warm gas cleanup (WGCU) improves process efficiency by 2.0 percentage points as the result of eliminating sour water stripper and Selexol reboilers; full warm gas cleanup (WGCU+) adds another 0.8 percentage points to process efficiency by eliminating fuel gas reheat and eliminating loss of latent heat due to condensation during syngas quench.

The coal feed pump improves process efficiency by 1.9 percentage points by eliminating evaporation of slurry water in the gasifier, thus increasing the cold gas efficiency of the gasifier (from 75.8 % to 81.6 %).

The ITM improves process efficiency by 0.3 percentage points (over the "reference" process with advanced "F" frame syngas turbine). This is not as dramatic a performance improvement as the other technologies described above, but as described below the ITM's greater contribution will be to reduce TPC and COE resulting from lower capital cost than cryogenic air separation.

Total Plant Cost

Reductions in total plant cost (on a $/kW basis) are illustrated in Figure 4-2 as each technology is individually substituted into the reference plant. All costs are based on January 2007 dollars. The advanced "F" frame, 2010-AST, and 2015-AST syngas turbines result in the most significant capital cost reductions of all technologies (by $304/kW, $382/kW, and $429/kW, respectively). These reductions are due more to the increased net power generated than from any change in turbine equipment cost. The turbine section itself contributes only $28/kW, $32/kW, and $44/kW reduction to the total plant cost, respectively.

The coal feed pump, likewise, reduces total plant cost by $65/kW not because of less expensive coal feed system to the gasifier, but because the coal flowrate decreases by 9 % resulting in reduced equipment sizes throughout the plant. The reduction in TPC on a $/kW basis (by only 3 %) is somewhat dampened, however, by decreased power output from the plant as a result of less coal feed.

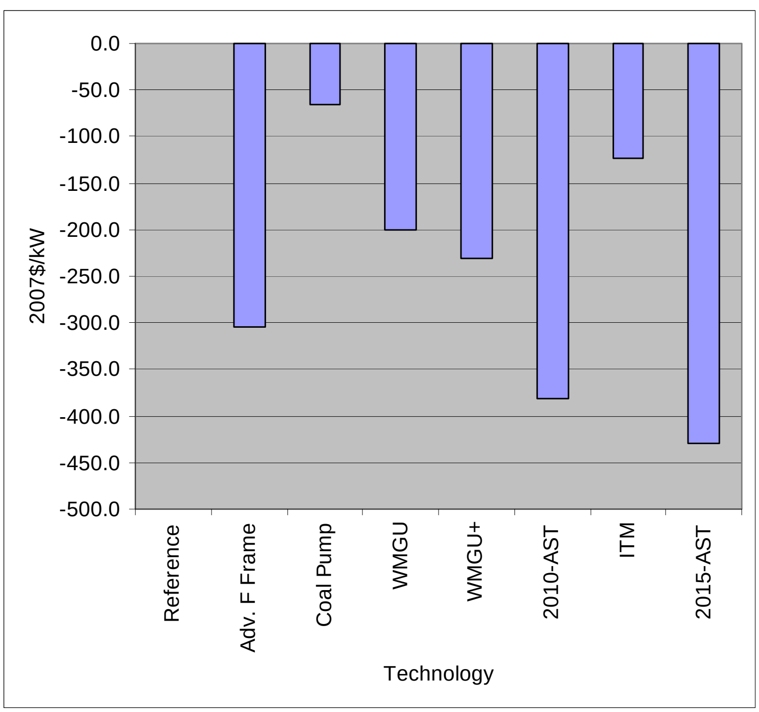

Figure 4-2. Impact of Each Technology on Total Plant Cost in the Reference Plant

Warm gas cleanup and ITM represent capital cost reductions from the cold gas cleanup and cryogenic ASU sections that they replace – reducing by $73/kW and $79/kW in section cost alone. However, that cost reduction is amplified throughout other plant sections by increased net power generated, reducing the entire plant cost by $231/kW and $124/kW, respectively.

Levelized Cost of Electricity

For each technology, process efficiency improvements (resulting in reduced fuel cost) and reduced total plant cost are reflected in the COE reductions illustrated in Figure 4-3. Capacity factor remains constant at 75 % in all reference plant cases.

Advanced syngas turbine technology has the most significant impact on COE reductions. Relative to the 7FA turbine, the advanced "F" frame, 2010-AST, and 2015-AST turbines reduce COE in the reference process by 11.3, 14.5, and 15.9 mills/kW-hr, respectively.

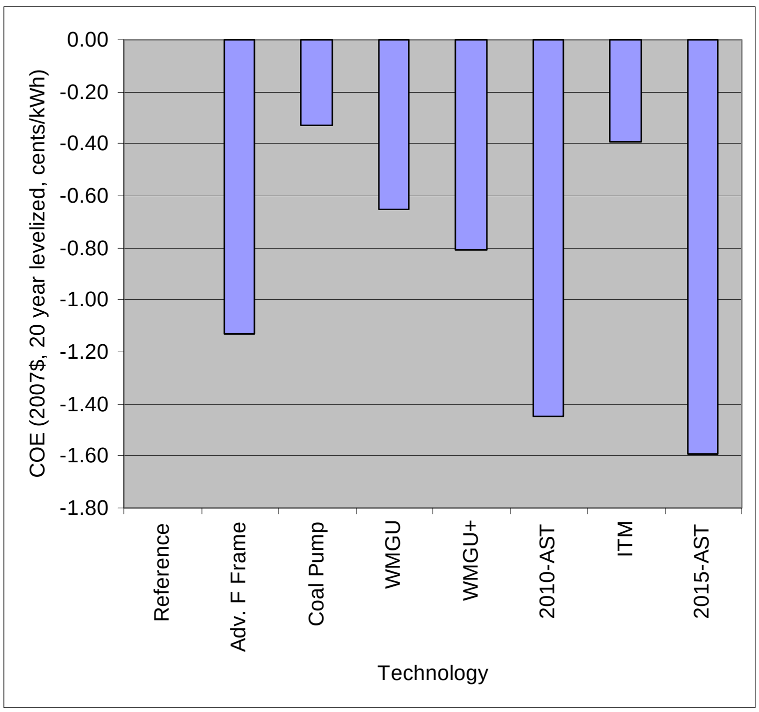

Figure 4-3. Impact of Each Technology on COE in the Reference Plant

Warm gas cleanup, because it has lower capital cost, greater plant power output, and higher process efficiency than cold gas cleanup, represents about a 6.5 mills/kW-hr reduction in COE for partial warm gas cleanup, and about 8.1 mills/kW-hr reduction for full warm gas cleanup.

The $124/kW reduction in total plant cost of the ITM plays a greater role in COE reduction than does the 0.3 percentage point improvement in process efficiency; these combine for a 3.9 mills/kW-hr COE reduction from ITM technology. Once again, this reduction is relative to the reference plant with advanced "F" frame gas turbine (Case 2a).

The coal feed pump contributes about a 3.3 mills/kW-hr reduction in COE resulting from $65/kW reduction in total plant cost (despite reduced net power output) and a 1.9 percentage point process efficiency improvement that helps to reduce fuel cost.

4.2 Cumulative Impact of Advanced Technologies

Process Efficiency

As each technology is introduced to the composite process, the following graph shows the cumulative improvement in process performance. Cases that feature improved capacity factor do not contribute to performance efficiency because the capacity factor merely increases the percentage of on-stream operation.

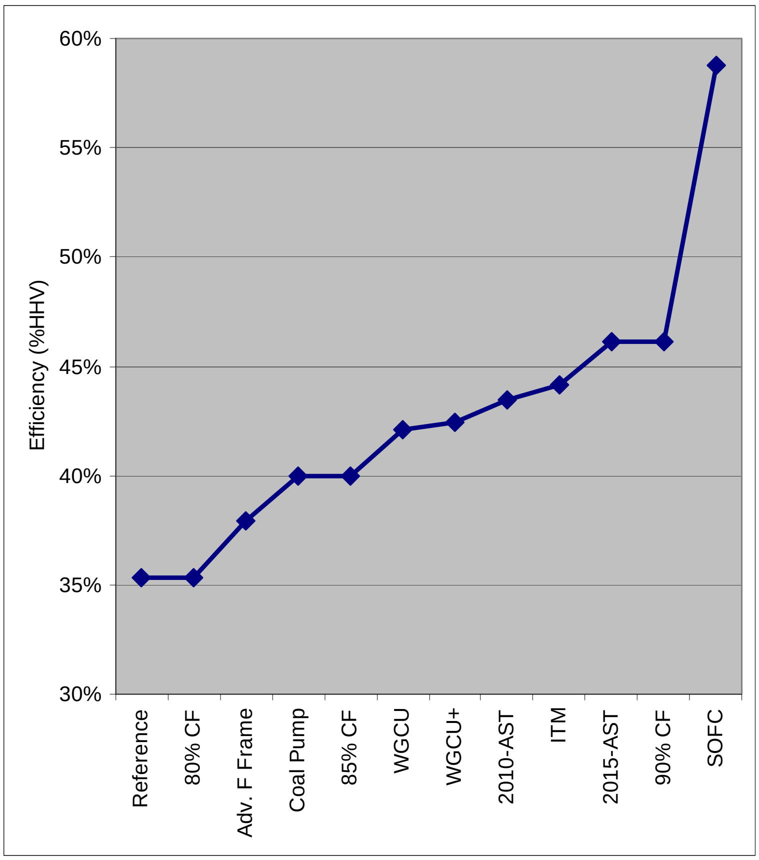

Figure 4-4. Cumulative Impact of R&D on Process Efficiency

The advanced "F" frame turbine and coal feed pump contribute 2.5 and 2.1 percentage point efficiency improvements, respectively. These are slightly greater than the sum of their individual efficiency improvements in the reference plant, so some synergy results from the combined technologies.

Partial warm gas cleanup also improves performance of the cumulative process (by 2.1 percentage points) more than it does the performance of the reference plant (2.0 percentage points). Full warm gas cleanup does not add very much more to performance in the cumulative process (only 0.3 percentage points) because elimination of the ammonia quench, which avoids condensing moisture from fuel gas in the slurry feed gasifier, does not represent as much of an advantage in a dry feed gasifier whose syngas has virtually no moisture in it.

The 2010-AST turbine, ITM, and 2015-AST each improve process efficiency (1.0, 0.7, and 2.0 percentage points, respectively) by slightly greater amount than they improved the reference plant (0.9, 0.3, and 1.7 percentage points, respectively). This again demonstrates some synergy resulting from combined technologies.

The integrated gasification solid oxide fuel cell process yields 58.8 % plant efficiency. This plant relies on a catalytic gasifier with very high (92.0 %) cold gas efficiency and full warm gas cleanup in order to avoid condensing moisture from syngas. Compared to the reference process, this represents a substantial 23.4 percentage point improvement in process efficiency. The high process efficiency is environmentally attractive because it reduces the production of CO_2 per megawatt of power produced. In addition, the sequestration-ready CO_2 stream that is produced holds promise for a superior process from the perspective of cost of CO_2 avoided for carbon capture scenarios.

Total Plant Cost

As each advanced technology is introduced to the composite process, total plant cost generally decreases as shown in Figure 4-5. Improved capacity factor has no effect on TPC, just as it had no effect on process efficiency.

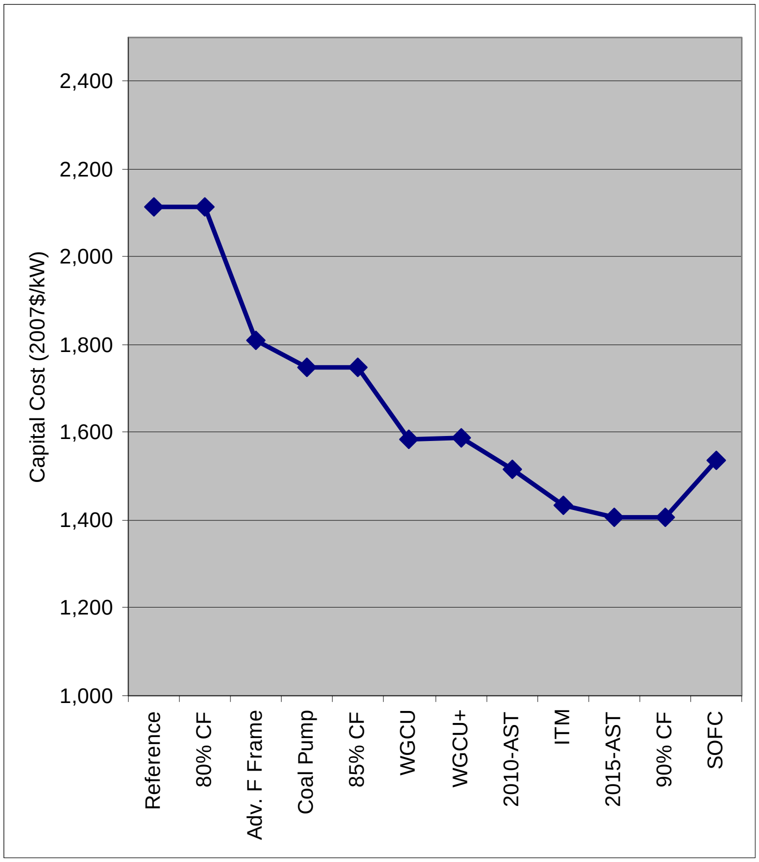

Figure 4-5. Cumulative Impact of R&D on Total Plant Cost

The advanced “F” frame turbine has greatest effect of any technology on the cumulative TPC reduction ($304/kW); this is because of the large increase (150 MW) in net power output relative to the 7FA syngas turbine that is replaced. The incremental reduction from the 2010-AST turbine is $72/kW – not as dramatic a decrease because the power output with the 2010-AST is only 50 MW more than with the advanced “F” frame turbine. The incremental capital cost reduction from the 2015-AST turbine is only $27/kW; this is because there is a large decrease (197 MW) in net power output from the plant because the number of trains has been cut from two to one in order to maintain nominal plant output of 600 MW.

As in the reference plant, the warm gas cleanup and ITM have a lower capital cost than the technologies that they replace, but TPC on a $/kW basis further decreases because net power produced by the plant increases by about 50 MW as a result of each of these technologies. These technologies have an incremental cost reduction of $164/kW and $82/kW, respectively. The cost difference between partial warm gas cleanup and full warm gas cleanup is negligible.

The gasifier resulting from the coal feed pump (with dry feed) is only slightly less costly than the slurry feed gasifier (by $24 MM), but the process as a whole reduces in cost (by $80 MM) due to decreased coal flowrate which results in smaller equipment sizes throughout the plant. Considering the reduced power output of the coal feed pump plant by 23 MW, TPC reduces by $60/kW.

No systems analysis attempt was made to investigate an optimum solid oxide fuel cell process configuration; there is potential for further cost reduction resulting from possibly using ITM air separation, water gas shift of the fuel gas before it enters the fuel cell, an alternate gasifier such as Great Point Energy’s bluegas™ that produces an all-methane syngas, or other similar process modifications that would likely decrease total plant cost. The increase by $129/kW over the Case 10 (90 % CF) advanced IGCC process is an artifact of the assumed capital costs of the fuel cell system and catalytic gasifier, and has considerable uncertainty at this time.

Cost of Electricity

As each new advanced technology is step-wise implemented in the advanced power system, the reduction in COE is represented in Figure 4-6. Effects of improved capacity factor are as significant as the other technology improvements that have yielded increased process efficiency and decreased capital cost. The increase to 80 % capacity factor results in a 4.0 mills/kW-hr decrease in COE, the increase to 85 % capacity factor results in a 2.9 mills/kW-hr decrease, and the increase to 90 % capacity factor results in a 2.0 mills/kW-hr decrease.

The advanced “F” frame syngas turbine provides the single greatest decrease in COE (10.7 mills/kW-hr) due to the 150 MW increase in net power output and 2.5 percentage point increase in plant efficiency due to air integration, improved turbine efficiency resulting from increased firing temperature and pressure ratio, and increased HRSG inlet temperature (allowing increased steam superheat and reheat temperatures).

Partial warm gas cleanup results in a 4.5 mills/kW-hr decrease in COE. Because of very low moisture content in the fuel gas, the novel ammonia and mercury removal units in the full warm gas cleanup case result in a very small improvement in process efficiency (leading to almost no change in fuel cost). There is no significant difference in TPC between partial and full warm gas cleanup, so as a result the COE changes very little between these cases.

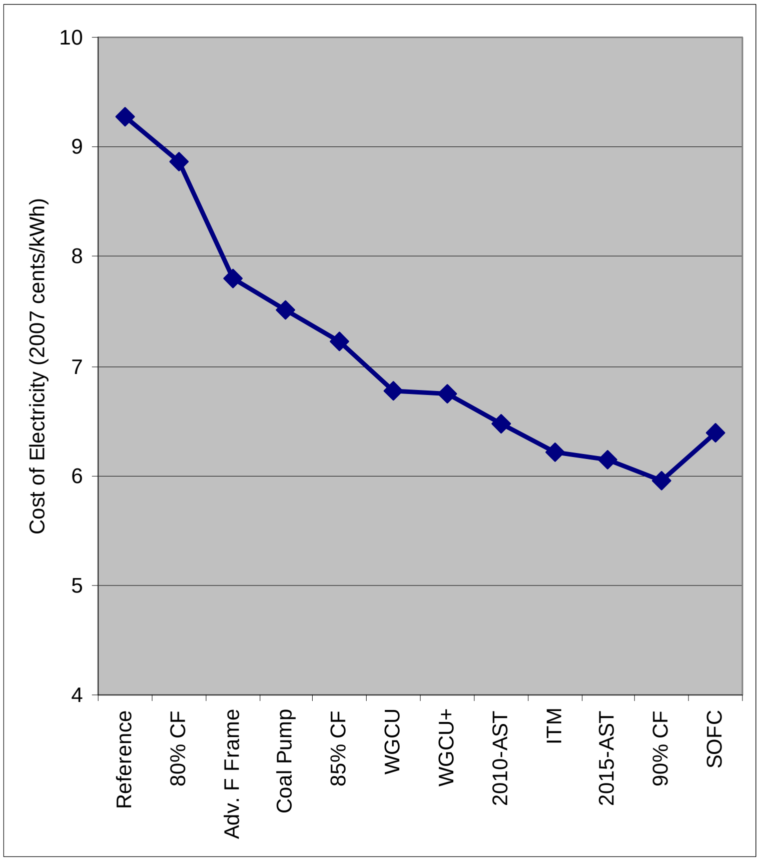

Figure 4-6. Cumulative Impact of R&D on Cost of Electricity

The 2010-AST syngas turbine increases plant power output by 50 MW over that of the advanced "F" turbine, and therefore results in a $72/kW reduction in TPC. There is also a 1.0 percentage point improvement in process efficiency over the advanced "F", resulting in reduced fuel cost. Overall, the 2010-AST turbine decreases COE by 2.7 mills/kW-hr in the cumulative technologies plant.

The ITM increases plant output by 11 MW with a corresponding decrease in TPC by $43 MM, resulting in a $82/kW decrease in total plant cost. Although the efficiency improvement is only 0.7 percentage points, the decreased TPC translates to a 2.6 mills/kW-hr decrease in COE.

The 2015-AST syngas turbine has a much higher power rating than the 2010-AST, but the reduction from two trains to a single train decreases the net plant power output by 197 MW resulting in only a $27/kW reduction in TPC and, therefore, a 0.7 mills/kW-hr reduction in COE.

The tremendous process efficiency (58.8 %) of the SOFC process makes its COE competitive with the most advanced Case 10 IGCC process, even before any systems analysis attempts at improved SOFC process configurations are made. The COE of 6.4 mills/kW-hr is based on an assumed fuel cell system TPC of $550/kW. With no further systems analysis attempt to improve process efficiency or power output, a TPC of $350/kW would be sufficient to reduce the SOFC cost of electricity to below that of the previous case with 2015-AST IGCC process and 90 % capacity factor. Although the particular SOFC configuration of Case 11 does not have the least COE, it has great potential for carbon capture scenarios because the CO_2 product stream is sequestration-ready.

5 SUMMARY

This pathway study evaluated anticipated process performance improvements and capital cost reductions resulting from advanced technology development sponsored by DOE. The study is presently confined to bituminous coal feedstock for process configurations that do not capture CO_2.

Advanced technology offers significant improvements in process efficiency. In the IGCC process alone, there is the potential for 11 percentage point improvement over the reference process. With SOFC technology, process improvements upwards of 24 percentage points are potentially achievable.

Capital cost reductions result not only from less expensive technology alternatives such as warm gas cleanup and ITM air separation, but also from increased power generation brought about by the advanced technology such as syngas turbines – resulting in cumulative total plant cost reductions by as much as $700/kW after all advanced technologies are implemented.

Improvements in process efficiency, reductions in capital and operating expense, and increase in capacity factor all contribute to decreased COE, projecting an overall decrease by more than 3 cents/kW-hr – or a decrease of 35 % in COE.

The advanced power systems technology pathway evaluated in this analysis 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 non-capture power generation, 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 at potentially lower cost than post-combustion alternatives. Volume 2 of this study will investigate applications of these DOE-sponsored advanced technologies in several different carbon capture configurations.

Appendix A Model Validations

A series of model validations, for both process performance and cost, is provided below to demonstrate that Noblis results presented in this report are consistent with those of other researchers and technology developers.

A.1 Case 2: Comparison with NETL Baseline Study

In order for the IGCC cases to be consistent with an established basis, Case 2 was given the same process configuration and design basis as NETL's Baseline Study Case 1. In the time since NETL's baseline case was developed, the radiant cooler temperature was determined to increase from 1,100 ^oF to 1,250 ^oF and the need for greater sour water stripper purge was identified in order to limit chloride concentration to 1,000 ppm. However, for the purpose of comparing Noblis' Aspen Plus process model with the baseline case, a simulation was developed using all the same process operating conditions as the Baseline Study case – identified as Case 2^* in the Volume 1 Supplement to this report. The following table compares process performance.

Table A-1. Case 2 Process Performance Closely Agrees With NETL Baseline Case

	Baseline Study	Case 2*
Gas Turbine Power (MWe)	464	464
Fuel Gas Expander (MWe)	7	8
Steam Turbine Power (MWe)	299	301
Total Power Produced (MWe)	770	772
Auxiliary Power Use (MWe)	-130	-128
Net Power (MWe)	640	644
As-Received Coal Feed (lb/hr)	489,634	491,336
Net Heat Rate (Btu/kW-hr)	8,922	8,900
Net Plant Efficiency (HHV)	38.2 %	38.3 %

Model results agree very closely with the Baseline Study. Note that the process efficiency of Case 2* is 38.3 % rather than 37.9 % in Case 2; this is due to the 1,100°F radiant cooler temperature (absorbing more heat from the raw syngas stream for steam generation) and lower sour water stripper heat duty (decreasing demand on the steam cycle).

Table A-2 compares capital and O&M costs with the Baseline Study Case 1. Although the TPC of the two cases agrees to within 0.2 %, the TPC on a $/kW basis is different by 0.8 %; this is due to slightly different net power production between the two cases (644 MW Noblis vs. 640 MW Baseline Study). This same difference in net power production is responsible for the slight difference in fuel cost and levelized cost of electricity. Notwithstanding, the results compare closely, and can be considered to agree.

Table A-2. Case 2*: Capital and O&M Cost Comparison

	Baseline Study			Case 2*		
Capital Cost ($1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Sorbent Handling	29,016	34,819	54	29,064	34,876	54
2 Coal and Sorbent Prep & Feed	45,072	55,887	87	45,148	56,024	87
3 Feedwater & Balance of Plant	30,687	37,580	59	30,630	37,506	58
4a Gasifier	213,000	273,078	426	213,027	273,112	424
4b Air Separation Unit	167,329	184,063	287	167,344	184,078	286
5a Gas Cleanup	108,066	129,980	203	107,726	129,573	201
5b CO_2 Removal & Compression	0	0	0	0	0	0
6 Gas Turbine	103,787	119,642	187	103,491	119,302	185
7 HRSG	51,530	57,247	89	50,936	56,565	88
8 Steam Cycle and Turbines	59,162	67,201	105	59,002	67,038	104
9 Cooling Water System	23,258	28,032	44	22,793	27,245	42
10 Waste Solids Handling System	39,686	43,960	69	39,555	43,815	68
11 Accessory Electric Plant	58,625	69,826	109	58,591	69,781	108
12 Instrumentation & Control	19,154	23,382	37	19,032	23,240	36
13 Site Preparation	14,369	18,681	29	14,250	18,524	29
14 Buildings and Structures	15,080	17,541	27	15,078	17,540	27
Total	977,821	1,160,919	1,813	975,666	1,158,449	1,799

	Baseline Study		Case 2*	
O&M Cost ($1,000)				
Fixed Costs	**Total**	**% EPCC**	**Total**	**% EPCC**
Labor	22,589	2.31	22,548	2.31
Variable Operating Costs*	**Total**	**% EPCC**	**Total**	**% EPCC**
Maintenance Materials	23,111	2.36	22,922	2.35
Water	1,767	0.18	1,710	0.18
Chemicals	1,339	0.14	1,304	0.13
Waste Disposal	2,919	0.30	2,918	0.30
Total Variable Costs	29,136	2.99	28,862	2.96
Total O&M Cost	51,725	5.29	51,410	5.27
Fuel Cost*	72,250	7.39	72,498	7.43
Discounted Cash Flow Results				
Total Plant Cost ($/kW)		1,813		1,799
Levelized Cost of Electricity ($/kW-hr)		0.0780		0.0774

*Includes 80% capacity factor

A.2 Case 6: Comparison with Nexant

Model Validation

Nexant [6] reported a 3.6 percentage point process efficiency improvement from replacing cold gas cleanup with warm gas cleanup in an IGCC process with a slurry feed gasifier; this was somewhat greater than the 2.8 percentage point improvement between Noblis' Cases 0 and 6a. In a separate analysis [7], Noblis determined that the difference in process efficiency was due to a series of design features. The two most significant of these were:

- The quantity of reducing gas sent to the SCOT process for tail gas treatment and the ultimate disposition of the tail gas (whether discarded or recycled to Selexol).

- Utilization of low-quality heat from the low-temperature syngas cooling section – i.e. the assumed temperature cut-off at which heat was considered to be unrecoverable for purposes of steam generation.

Other process differences and modeling assumptions included:

- Gasifier carbon conversion, pressure, and temperature
- Fuel gas heating value
- Gas turbine power and firing temperature
- Process heat losses
- Gas turbine air leakage and isentropic efficiencies
- CO_2 separation in the Selexol process (significant if the Claus tail gas is not recycled to Selexol)
- Auxiliary power requirements
- Fuel gas reheat temperature

Noblis' process parameters and modeling assumptions, to a great extent, are based on Case 1 from NETL's Baseline Study report. These design parameters are used throughout the pathway study for consistency – providing a common basis for comparison among advanced IGCC technologies. The remaining 0.8 percentage point in performance improvement between Noblis' and Nexant's results due to warm gas cleanup can be explained in terms of different process configurations and modeling assumptions; Noblis was able to reproduce Nexant's results when the same modeling assumptions were used.

Cost Validation

The improvement in capital cost and levelized COE due to warm gas cleanup is compared below with Nexant's study to measure the agreement between the two studies and possible reasons for differences. As already noted in the analysis of process efficiency improvement due to warm gas cleanup, multiple differences between Nexant's and Noblis' process parameters and modeling assumptions contribute to different process performance improvements attributed to warm gas cleanup.

The gas turbine (Nexant uses an advanced "F" turbine with no air integration whereas Noblis uses a 7FA turbine with no air integration) determines net power production. As observed from Noblis' results between the 7FA turbine in Case 0 and the advanced "F" frame turbine in Case 2a (both cases at 75 % capacity factor), total plant cost decreases by about $304/kW and cost of electricity decreases by $0.011/kW-hr when using the larger advanced "F" frame syngas turbine.

Notwithstanding the differences in process parameters and gas turbine selection, some comparisons can be made between the Nexant and Noblis results to assess the cost benefit due to warm gas cleanup.

Both Nexant and Noblis base their cost estimates on January 2007 dollars. As seen in Table A-3 below, the advanced "F" frame turbine produces more net power; when cold gas cleanup is replaced with warm gas cleanup, the power production increases by about 10 percent.

Table A-3. Comparisons of Improvements Due to Warm Gas Cleanup

	Nexant Case 3	Nexant Case 4	Noblis Case 0	Noblis Case 6a
	Adv. “F”, Cold Gas Cleanup	Adv. “F”, Warm Gas Cleanup	7FA, Cold Gas Cleanup	7FA, Warm Gas Cleanup
Net Power Production (MW)	585	641	487	541
Gas Cleanup Section ($/kW)	316	263	231	158
Total Plant Cost ($/kW)	1,904	1,635	2,113	1,882

Comparing gas cleanup section costs, the Noblis costs on a $/kW basis are less than Nexant. This result does not correlate with total plant cost, which increases on a $/kW basis for the smaller 7FA plant; the gas cleanup section represents a greater percentage of TPC in Nexant’s estimate than it does in Noblis’ estimate. Nexant’s warm gas cleanup cost decreases by $53/kW, or 17 % decrease over the cold gas cleanup cost. By comparison, Noblis’ warm gas cleanup cost decreases by $73/kW, or 32% decrease over the cold gas cleanup cost.

The gas cleanup section affects other areas of the plant (such as equipment size scaling, steam cycle capacity, and balance of plant), so the comparison of total plant cost is also impacted by the transition from cold gas cleanup to warm gas cleanup. Nexant’s TPC decreases by $269/kW, or a reduction by 14 % due to warm gas cleanup. Noblis predicts a $231/kW decrease in TPC, which corresponds to an 11 % reduction due to warm gas cleanup. These results, on a relative basis, agree better than the comparison on the basis of gas cleanup section alone.

Although there are discrepancies in TPC between the Nexant and Noblis cost estimates, both agree that a reduction of between 11-14 % in capital cost can be expected resulting from warm gas cleanup.

Nexant reported a reduction in COE from $0.0716/kW-hr to $0.0647/kW-hr resulting from the change from cold gas cleanup to warm gas cleanup; a reduction by 9.6 %. This was based on an 85 % capacity factor and fuel cost of $2.00/MMBtu.

Noblis’ COE (based on 75 % capacity factor and fuel cost of $1.80/MMBtu) reduced from $0.0927/kW-hr to $0.0846/kW-hr. By changing the capacity factor and fuel cost to the same basis as Nexant, Noblis’ results become $0.0885/kW-hr for cold gas cleanup reducing to $0.0801/kW-hr for warm gas cleanup – a savings of 9.1 % attributable to warm gas cleanup.

The fact that Noblis’ COE’s are respectively greater than Nexant’s – $0.0885/kW-hr vs. $0.0716/kW-hr for cold gas cleanup and $0.0801/kW-hr vs. $0.0647/kW-hr for warm gas cleanup – is expected because of the higher capital cost ($/kW) for the lower capacity 7FA plant compared to the advanced “F” turbine plant.

To summarize, given the differences in plant size, process performance improvement, uncertainties in cost estimation, and differences in economic assumptions, Nexant and Noblis independently estimate a reduction of between 11-14 % in capital cost, and a reduction of between 8-10 % in COE resulting from warm gas cleanup.

A.3

Case 11: Comparison with NETL

Model Validation

The fuel cell process configuration of Case 11 was developed by SAIC, and is described in NETL's report titled "The Benefits of SOFC for Coal-Based Power Generation" [11]. Because that process is fueled by Pittsburgh #8 coal, Noblis developed an Aspen Plus simulation based on Pittsburgh #8 coal and then switched the feedstock to the same Illinois #6 coal used in all the previous pathway study cases and increased the net power production to the nominal 600 MW plant size. Table A-4 compares overall process performance to a case provided by SAIC[4] that is similar to Case 4 published in the NETL report.

Table A-4. Comparisons of Fuel Cell Process Using Different Coals

	SAIC Pitt#8	Noblis Pitt#8	Noblis Ill#6
Fuel Cell Power (MW)	439	431	517
Syngas Expander (MW)	18	18	22
Cathode Air Expander (MW)	197	157	208
Anode Exhaust Expander (MW)	101	108	132
Total Power Produced (MW)	755	714	879
Auxiliary Power Use (MW)	-248	-213	-276
Net Power (MW)	507	501	603
As-Received Coal Feed (lb/hr)	228,420	228,420	300,000
Net Heat Rate (Btu/kW-hr)	5,661	5,732	5,805
Net Plant Efficiency (HHV)	60.3 %	59.5 %	58.8 %
Gasifier Cold Gas Efficiency	91.1 %	93.1 %	92.0 %

Compared to the SAIC case, fuel cell power in Noblis' Pittsburgh #8 simulation decreases because of reduced fuel utilization (85 % vs. 89 %). This also reduces the work recovered by the cathode air expander (and cathode air compressor) due to reduced air flow through the fuel cell. The net power generated is very nearly the same, as is the net plant efficiency.

All power accounts increase in the Noblis Illinois #6 case because of the nominal 600 MWe net power production. Comparing the two Noblis cases using different coals, net plant efficiency decreases because of the change in fuel quality; gasifier cold gas efficiency decreases when going to the Illinois #6 coal due to increased fuel moisture content and decreased coal heating value.

Cost Validation

Table A-5 compares capital and operating costs with Case 4 from NETL's "The Benefits of SOFC for Coal-Based Power Generation". The fuel cell process of NETL Case 4 is very similar to the SAIC fuel cell process against which process performance was compared, so it is reasonable to compare relative costs with Noblis' Case 11.

NETL's Case 4 produces a net 523 MW of power using Pittsburgh #8 coal. It has an overall process efficiency of 62.0 %, with a small power contribution from a steam cycle (that was not part of SAIC's process that was used as the basis for this case). The ASU in NETL's Case 4 produces 95 % pure oxygen.

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4 Personal correspondence with D. Keairns and R. Newby.

Noblis' capital cost estimates for coal and catalyst handling, preparation, and feed are greater than NETL's; this can be attributed to the uncertainty of the additional cost required for gasifier catalyst handling and feed systems. The same consideration also applies to the gasifier cost which includes the char/catalyst separation and coal/catalyst treatment systems; the Noblis gasifier cost estimate is 17 % less than NETL's estimate.

Noblis' ASU cost is 13 % higher than NETL's. The fact that Noblis' value is greater than NETL's is justifiable, considering that the oxygen purity is 99.5 % vs. 95 % in NETL's case.

Noblis' assumed TPC of $550/kW for the fuel cell system is 40 % greater than the $392/kW used in NETL's case. This more than accounts for the $93/kW difference in Total Plant Cost between the two estimates.

Noblis' fixed O&M cost is somewhat lower than NETL's; Noblis' estimate of 12 operators and technicians is based on a correlation used in the IGCC cases in which labor cost is a function of EPCC. NETL includes fuel cell stack replacement cost in fixed O&M. The larger net power production in Noblis' case is another reason for further decreasing fixed labor cost on a $/kW-hr basis; net power production in NETL's case is only 522 MW vs. 603 MW in Noblis' case.

For comparison purposes, the values listed in Table A-5 are based on 80 % capacity factor. Noblis' variable operating costs are significantly greater than NETL's. The two most significant cost accounts are maintenance materials and fuel cell stack replacement. Noblis assumed no change in the maintenance cost algorithm used in IGCC cases. Fuel cell stack replacement is assumed to cost $175/kW, with service life of 40,000 hours.[5] Noblis' chemical cost consists primarily of trona and ZnO sorbent costs, and does not include an estimate for gasifier catalyst cost. If Noblis' $0.0038/kW-hr (un-levelized) variable O&M cost for fuel cell stack replacement were moved to fixed O&M as in NETL's calculation, both Noblis' fixed O&M and variable O&M costs would be greater than NETL's. As shown under total O&M cost, Noblis' O&M cost is 23 % greater than NETL's. Noblis' resulting COE is 10 % greater than NETL's.

5 Replacement cost and service life were provided by personal communication from Wayne Surdoval, NETL.

Table A-5. Case 11: Capital and O&M Cost Validation

	NETL Case 4			Case 11		
Capital Cost ($1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC $/kW**	**EPCC**	**TPC**	**TPC $/kW**
1 Coal and Catalyst Handling			93[6]	25,678	30,814	51
2 Coal and Catalyst Prep & Feed				33,550	41,428	69
3 Feedwater & Balance of Plant				17,805	21,649	36
4a Gasifier			311	123,853	155,335	258
4b Air Separation Unit			120	73,915	81,306	135
5a Gas Cleanup			134	55,056	66,351	110
5b CO_2 Removal & Compression			0	0	0	0
6 Gas Turbine			0	0	0	0
7 Fuel Cell			392	278,195	333,836	554
8 Steam Cycle and Turbines			16	0	0	0
9 Cooling Water System				11,507	13,935	23
10 Waste Solids Handling System				32,217	35,692	59
11 Accessory Electric Plant				73,623	87,996	146
12 Instrumentation & Control				23,674	28,907	48
13 Site Preparation				14,480	18,823	31
14 Buildings and Structures			375[7]	8,594	10,097	17
Total			1,443	772,147	926,169	1,536

O&M Cost ($1,000)	NETL Case 4		Case 11	
Fixed Costs	**Total**	**$/kW-hr**	**Total**	**$/kW-hr**
Labor		0.0068	18,039	0.0043
Variable Operating Costs*	**Total**	**$/kW-hr**	**Total**	**$/kW-hr**
Maintenance Materials			25,170	
Water			141	
Chemicals			3,410	
Fuel Cell Stack Replacement			15,853	0.0038
Waste Disposal			2,130	
Total Variable Costs		0.0056	46,704	0.0111
Total O&M Cost		0.0124	64,743	0.0153
Fuel Cost*		0.0099	44,266	0.0105

Discounted Cash Flow Results	NETL Case 4	Case 11
Total Plant Cost ($/kW)	1,443	1,536
Levelized Cost of Electricity ($/kW-hr)	0.062	0.0687

*Includes 80% capacity factor

6 Coal handling is presumed to also include the preparation and feed systems that are evaluated separately in Noblis' cost estimate.

7 This number represents an account named "Other" in NETL's report. It is presumed to include feedwater and BOP, cooling water system, waste solids handling system, accessory electric plant, instrumentation & control, site preparation, and buildings and structures.

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List of Acronyms

AST	Advanced Syngas Turbine
ASU	Air Separation Unit
BEC	Bare Erected Cost
BOP	Balance of Plant
CCF	Capital Charge Factor
CF	Capacity Factor
COE	Cost of Electricity
COS	Carbonyl Sulfide
DB	Double-Declining Balance
DCF	Discounted Cash Flow
DOE	Department of Energy
DSRP	Direct Sulfur Reduction Process
EPCC	Engineering, Procurement, and Construction Cost
FYC	First Year Operating Costs
HHV	Higher Heating Value
HP	High Pressure
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
IGFC	Integrated Gasification Fuel Cell
IOU	Investor-Owned Utility
IP	Intermediate Pressure
ITM	Ion Transport Membrane
kW	kilowatt
kW-hr	kilowatt-hour
LF	Levelization Factor
LHV	Lower Heating Value
MM	million
MW	megawatt
MWe	megawatt - electric
MWh	megawatt hour
NETL	National Energy Technology Laboratory
NOx	Nitrogen Oxides
O&M	Operating and Maintenance
PSFM	Power Systems Financial Model
QGESS	Quality Guidelines for Energy System Studies
R&D	Research and Development
RAM	Reliability, Availability, and Maintainability
SOFC	Solid Oxide Fuel Cell
SOx	Sulfur Oxides
sTPD	Standard Tons per Day
TDS	Transport Desulfurizer
TPC	Total Plant Cost
TRC	Total Required Capital
WGCU	Warm Gas Cleanup