Impact of Cost Escalation on Power System R&D Goals

DOE/NETL-2008/1308

Re-baselining APS, CS & FC GRPA R&D Goals

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Table of Contents

Executive Summary

Research and development (R&D) technology cost and performance goals for the Clean Coal Program were developed in the early 2000s and were projected 10 to 15 years into the future. Since that time, the following factors make it necessary to adjust the goals:

- A recent imbalance in the supply and demand of materials and labor that has resulted in a significant increase in the cost of constructing utility plants beyond that attributable to general inflation.

- Access to commercial-scale Integrated Gasification Combined Cycle (IGCC) operating data that provides a more accurate baseline for measuring the degree of cost reduction and performance improvement that can be attributed to government-sponsored R&D.

This report recommends updates and/or clarifications to the goals for the following three technology areas in the Clean Coal R&D Program:

- Advanced Power Systems (APS), which consists of advanced gasification and advanced turbines,
- Carbon Sequestration (CS), specifically the carbon capture piece of the program, and
- Fuel Cells (FC), solid oxide fuel cells under development in the Solid Energy Conversion Alliance (SECA).

The Power Capital Costs Index (PCCI), released in May 2008 by the Cambridge Energy Research Associates (CERA), reveals a 60 percent increase in the capital cost of non-nuclear power plants between 2002 and 2007.

Recent rigorous cost analyses performed at the National Energy Technology Laboratory (NETL) predicted a similar increase. The cost to build a baseline IGCC plant (2002 vintage technology) was estimated from the plant's major equipment list, and was estimated to be $2,100/kW in 2007$. This is an increase of 62 percent compared to the cost of $1,300/kW (2002$) assumed when the goal was established. These goals are expressed as an overnight construction cost that includes costs for equipment, materials, labor, engineering and construction management, and process and project contingencies. Not included are allowance for funds used during construction (AFUDC), taxes, and other owner's costs (e.g. land costs, architectural and engineering costs, interconnection fees, owner's labor, site permits, public relations, etc.), which can be substantial. For example, with all of these items included, the total capital required to build the baseline IGCC would exceed $3,500/kW (2007$).

Use of the CERA PCCI to account for escalation was deemed a credible method for updating Clean Coal Program R&D technology goals. Adjusted for escalation, the Advanced Power Systems (APS) 2010 goal of $1,000/kW (2002$), would be equivalent to \$1,600/kW (3Q, 2007\$). The 2015 fuel cell module capital cost goal of \$400/kW (2000\$) would be equivalent to about \$700/kW (3Q, 2007\$).

The 2010 APS efficiency goal is set at 45 – 50 percent, higher heating value basis (HHV). Since that goal was established in 2002, several full-scale commercial IGCC plants have been built and are operating in the U.S. Operating data from these commercial IGCC deployments indicate that the highest efficiency achieved from 2002-vintage technology is 35 percent (HHV). This is five percentage points lower than the 40 percent assumed in 2002 for the baseline IGCC efficiency. Adjusting the baseline efficiency down to match actual operation, it is likely that the 10 point improvement expected from the current R&D portfolio will increase the efficiency only as high as 45 percent.

Currently, no commercial operating IGCC plants currently employ carbon capture and sequestration, so systems analyses must be relied on to estimate performance and cost. Rigorous NETL analyses estimate that equipping an IGCC with 90 percent carbon capture and sequestration increases the cost of electricity (COE) by 35 – 40 percent over the non-capture IGCC plant. This is consistent with the initial assumptions used to establish a Carbon Sequestration (CS) R&D goal of reducing that increase to only 10 percent over the non-capture IGCC plant by 2012. No changes are suggested for the CS R&D goal; however, details for the baseline configuration, level of capture, and cost components of COE should be added to the goal language for clarity.

1 Introduction

The Department of Energy has set aggressive goals for its fossil energy research and development programs. Measuring progress against these goals is critical in guiding technological development and in allocating resources. This paper provides details on the Government Performance and Results Act (GPRA) goals for the Advanced Power Systems (APS), Carbon Sequestration (CS), and Fuel Cell (FC) R&D programs. This paper describes proposed changes to these goals to adjust for an observed step-change increase in the capital cost of power plants and to reconcile differences between assumed baseline performance and actual operating data from first generation IGCC plants.

The current GPRA goals[1] are:

Advanced Power Systems (APS)

> By 2010, develop advanced coal-based power systems capable of achieving 45-50 percent thermal efficiency at a capital cost of $1,000 per kilowatt or less.

Carbon Sequestration (CS)

> By 2012, complete R&D to integrate this technology with CO_2 separation, capture, and sequestration into a "zero" emission configuration(s) that can provide electricity with less than a 10 percent increase in cost of electricity.

Fuel Cells (FC)

> By 2010, produce 3-10 kW solid oxide fuel cell (SOFC) modules having a capital cost of $400/kW and, by 2015, demonstrate MW-class fuel cell/turbine hybrids, using aggregated SOFC modules adaptable to coal and having a capital cost of $400/kW.

While this paper suggests adjustments to GPRA baseline and goals, a concerted effort is made to ensure that the goal maintains the degree of optimism or technology stretch proposed in the original GPRA goal, yet provide a fair framework for determining the level of progress made in the research program.

[1] Office of Clean Coal Strategic Plan, September 2006.

2 Advanced Power Systems GPRA Goals

2.1 GPRA Goal History

Circa 2000: Initial IGCC Goal was based on Cost of Electricity

Prior to 2002, the metric for Integrated Gasification Combined Cycle (IGCC) system research and development was quoted in terms of cost of electricity (COE). For an IGCC plant to be competitive, the goal was set at less than 4.5 cents/kWh (2002$) for busbar baseload power generation. This goal reflected the results of an extensive NETL-sponsored "Market-Based Study" that estimated the cost and performance of market-based IGCC plant configurations.[2] In this study, the baseline configuration (consisting of single-stage, slurry-fed gasification, cryogenic air separation, gas cooling and conditioning, acid gas removal, 7FA gas turbine, and reheat steam cycle) was estimated to have a 40 percent efficiency on a higher heating value (HHV) basis. The total plant cost[3] (TPC), consisting of overnight bare erected costs, engineering, and contingencies, was determined to be about $1,300/kW in 2002 dollars. The resulting COE for this plant was calculated to be 4.5 cents/kWh (2002$). At that time, this study served as a credible baseline for developing cost of electricity (COE) goals for IGCC.

2002: Capital Cost & Efficiency Goal Defined for IGCC

A study commissioned by NETL's Gasification Technology Team in 2002 developed a series of cost and efficiency curves for a variety of advanced IGCC configurations[4] to determine the lowest cost and highest efficiency technically achievable with the R&D portfolio. The baseline configuration in this study was identical to that of the 1999 "Market-based Study" with an overall efficiency of 40 percent (HHV), a capital cost of $1,294/kilowatt (kW), and a required selling price of electricity of 4.5 cents/kWh (2002$).

Starting with this baseline, R&D targets were set for overall cost reduction and efficiency improvements for the Advanced Power Systems R&D program. The efficiency and cost curves generated by the analysis determined that the R&D program could ultimately reduce the baseline IGCC TPC by 23 percent (from $1,300/kW to $1,000/kW, 2002$) and increase efficiency by 10 points (from a baseline efficiency of 40 percent). Intermediate milestones for the Program Assessment Rating Tool (PART) were also set using the results of this analysis. The GPRA (FY2003) goal shifted the previous COE goal to one that cites both efficiency and capital cost:

> **By 2010, develop advanced coal-based power systems capable of achieving 45-50 percent thermal efficiency at a capital cost of $1,000 per kilowatt or less.**

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[2] *Market-Based Advanced Coal Power Systems: Final Report*. DOE/FE 0400. May 1999.
[3] *The total plant cost as defined here does not include owner's costs and time value of money. It is critical to know what is and is not included in a capital cost estimate when comparing costs from different sources.*
[4] *Current and Future IGCC Technologies: Bituminous Coal to Power*. MTR-2004-05. August 2004.

This goal is used to measure progress of the Advanced Power Systems R&D program (which includes the Gasification and Advanced Turbine R&D programs). As written at that time, the goal did not specify whether the thermal efficiency was on a higher or lower heating value basis, did not define the capital cost components, and did not specify the dollar year basis for the $1,000/kW goal.

2.2 The Need to Update GPRA Baseline and Goals

Figure 1 illustrates the Gasification Technology Team's view of IGCC in the 2002 timeframe. The y-axis represents the total plant cost in 2002 constant dollars (inflation and escalation are not considered). The x-axis provides the year that the technology is expected to graduate from the R&D program and is ready for demonstration at a larger scale. The baseline configuration (2002 vintage) included a slurry gasifier, cryogenic air separation unit (ASU), Selexol acid gas removal (AGR), 7FA gas turbine, and a reheat steam cycle (1800 psig/1000F/1000F), and is represented by the red line. As mentioned previously, the plant was projected to have an efficiency of 40 percent HHV and a TPC of $1,300/kW (2002$). A constant baseline was assumed throughout the planning horizon.

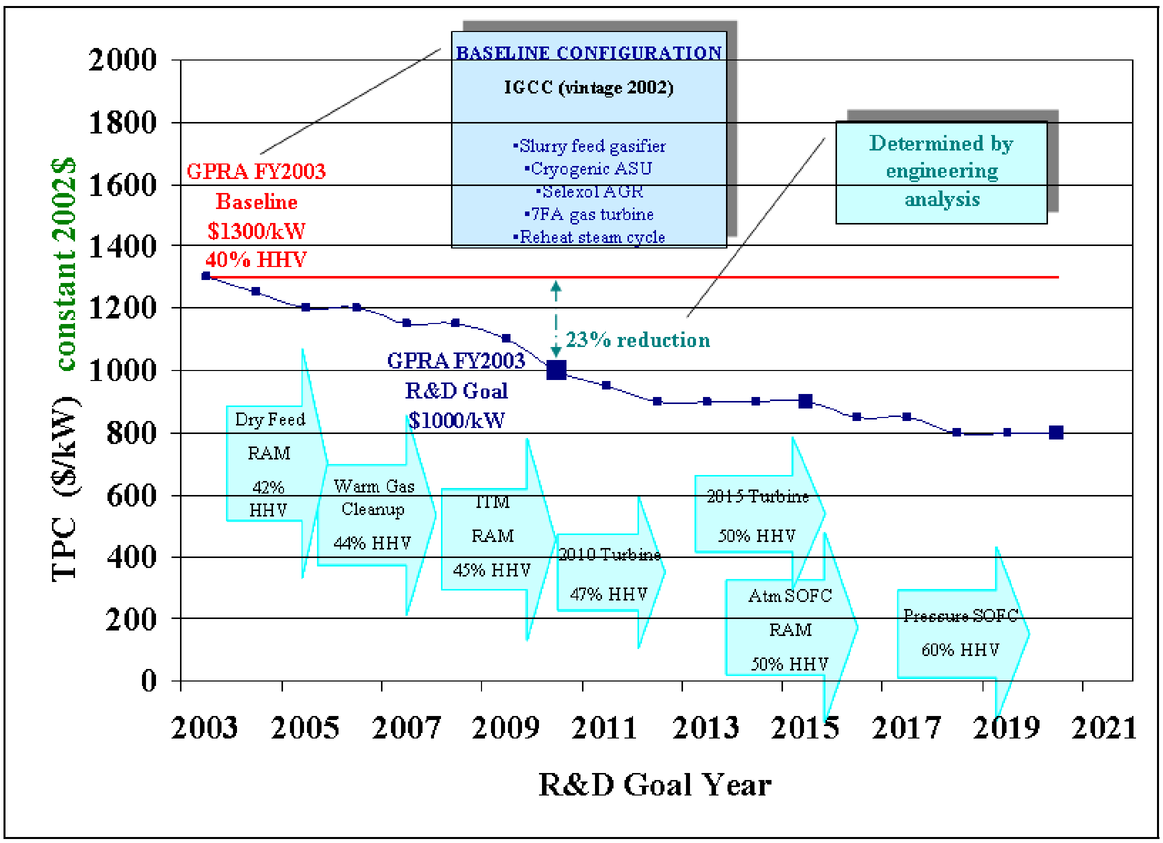

Figure 1. 2002 Snapshot for IGCC

In this same study,[4] technology advancements of the Advanced Power Systems R&D program were modeled and added to the baseline to determine the cumulative impact on cost and efficiency. The various technologies considered in the analysis are represented by the arrows on the lower half of this figure. As shown by the blue curve, the analysis determined that these technologies have the potential to reduce the baseline IGCC TPC by more than 20 percent (from $1,300/kW to $1,000/kW, in 2002$) and increase efficiency by 10 points.

However, the view in 2002 no longer holds true today due to the following factors, making it necessary to update GPRA goals and milestones:

1. **Significant cost increases have occurred in the power industry that are far beyond that due to inflation alone.** The costs of building all new power plants have more than doubled since 2000, according to the most recent IHS CERA Power Capital Costs Index (PCCI)[5]. The latest IHS CERA PCCI (Figure 2) shows that the cost of new power plant construction in North America has risen 130 percent in the last eight years. A majority of this cost increase has occurred since 2005, with the index rising 69 percent since then. In order to make meaningful determinations of R&D progress in reducing costs, the GPRA goal and milestone costs must be adjusted to account for the recent dramatic increase in the cost of materials and labor. Based on the index that excludes nuclear power plants, costs have increased by 60 percent between 2002, when the R&D goals were established, and the third quarter of 2007. Costs may need to be adjusted in future years if construction cost escalation and inflation trends shift significantly.

   Further documentation of recent power plant construction cost escalation is provided in Appendix A.

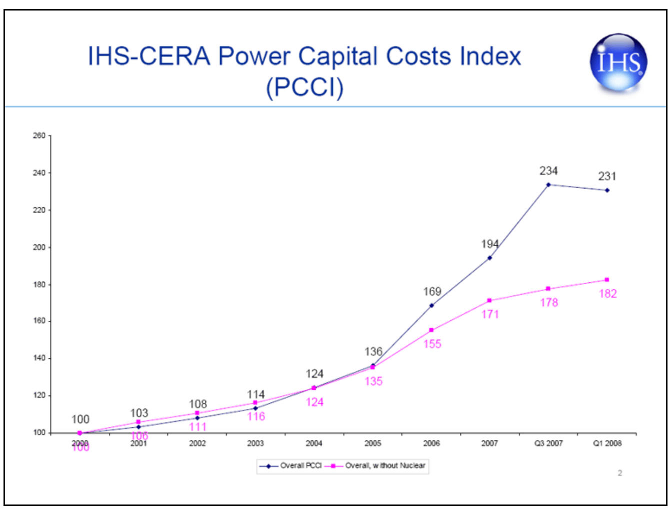

Figure 2. Power Plant Capital Cost Escalation Index

[5] http://www.ihsindexes.com/

2. **<u>The GPRA baseline plant efficiency of 40 percent, which was used to set R&D goals in 2002, was optimistic.</u>** The advanced power system baseline and goals were based on the estimated performance of an IGCC design that was considered state-of-the-art in the 2000 – 2002 timeframe. Actual plant data, more recent rigorous modeling, and 2007 vendor quotes for IGCC reference plants confirm that the 2002 vintage IGCC system, as envisioned for GPRA, would have had an efficiency of 35 percent rather than 40 percent (HHV basis). A summary of each of this evidence is listed below:

    - <u>Actual Plant Data</u>
      In August 2002, DOE issued the final report for the Tampa Electric Polk Power Station.[6] The Polk Power Station has the same design as the GPRA (FY2003) baseline configuration. Actual test results from this Clean Coal Demonstration Project report a net efficiency of 35.4 percent (HHV).

    - <u>Recent Analyses</u>
      An analysis of a 7FA IGCC baseline configuration was performed using up-to-date cost and performance information available in NETL's landmark report titled *Cost and Performance Baseline for Fossil Energy Plants*[7] (otherwise known as the Baseline Study). This analysis projected that the baseline configuration to have an efficiency of 35 percent (HHV). Details of this analysis are provided in Appendix B.

    - <u>Vendor Reference Plant Designs</u>
      GE Energy recently reported that their latest reference plant design is projected to have an efficiency of 38.5 percent, HHV, for a bituminous coal-fired IGCC plant operating with the more advanced 7FB gas turbine.[8,9] This reference plant is configured with a 7FB machine, which is more efficient than the turbine used in the GPRA (FY2003) baseline. Therefore, 40 percent efficiency would be considered optimistic even for a plant built with updated technology today.

   Therefore, the baseline IGCC plant efficiency used to set R&D goals was overestimated by 5 percentage points.

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[6] *Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project: Final Report.* DE-FC-21-91MC27363. August 2002.
[7] Cost and Performance Baseline for Fossil Energy Plants, DOE/NETL-2007/1281, Revision 1, August 2007.
[8] Thomas, Greg, "Delivering the IGCC Solution," GE Energy, 1/31/06.
[9] Rigdon, Robert and Miles, Kevin, "The Cleaner Coal Option," Power Engineering International, 7/06

3 Re-baselining Advanced Power Systems Cost & Efficiency Goals

3.1 *Defining the Baseline*

The previous chapter described that it is necessary to update the GPRA baseline to escalate the cost to current levels and reduce the efficiency to match actual performance data that is now available. Given both of these changes, an updated baseline for use in setting R&D goals is:

GPRA Goal Baseline
(updated June 2008)

IGCC plant vintage 2002 (slurry gasifier, 7FA turbine)
- Plant net efficiency (HHV) of 35 percent
- Total plant cost[a] of $2,100/kW (2007$)
- 20-year levelized COE of 9 cents/kWh (2007$)

[a] Expressed as overnight construction cost (bare erected costs, engineering costs, and contingencies). Not included are owners costs such as project development fees, land and site infrastructure improvements, pre-production costs, inventory capital, and allowance for funds used during construction. With these costs included, the total capital required would be equivalent to roughly $3,500/kW.

Using this updated baseline as the starting point, and maintaining the degree of optimism or technology stretch of the original GPRA goal, updated milestones can be established. For the APS program, the original goal expected up to a 10 point improvement in efficiency and a capital cost reduction of 23 percent (as determined previously in an engineering analysis and outlined in Figure 1).

3.1.1 Adjusting Cost Goal and Milestones for Escalation and Inflation

Based on the PCCI released in May 2008 by CERA (Figure 2), the capital required to build a non-nuclear power plant in 2007 is about 60 percent higher than the cost to construct one in 2002.

Index in 3Q 2007 = 178
Index in 2002 = 111
Percent Increase 2002 – 2007 = ((178-111)/111)*100 = 60 percent

This increase is consistent with recent rigorous cost analyses (see Appendix B) indicating that the cost to build a baseline IGCC plant in 2007 dollars would be $2,100/kW (overnight plant cost including engineering costs and contingencies). This is an increase of roughly 60 percent over the IGCC baseline cost of $1,300/kW (2002$) used in 2002 to establish the program goal.

Applying the PCCI to the APS 2010 goal of $1,000/kW (2002$) results in a 2007 equivalent cost of $1,600/kW. Table 2 provides the updated milestones and 2010 goal when a factor of 1.6 is applied to the original GPRA goals.

Table 2. Original and Proposed APS Cost Goals and Milestones

GPRA **FY2003** Cost Milestones ($/kW)		Updated Cost Milestones ($/kW) (as of 06/08)	
GPRA Target Year	**GPRA Goal 2002$**	**GPRA Target Year**	**GPRA Goal 2007$**
Baseline (2002)	1,300	Baseline (2007)	2,100
2005	1,200		
2006	Not Defined		
2007	1,150	2007	1,850
2008	1,150	2008	1,850
2009	1,100	2009	1,750
2010	1,000	2010	1,600

3.1.2 Placing the Efficiency Goal and Milestones in Perspective

The goal of the APS R&D program is to improve net efficiency by up to 10 percentage points between FY2003 and FY2010 in the increments shown in Table 2. The 10 point efficiency improvement was based on the results of engineering studies of various technology advancements, and is considered to be a stretch goal. Based on the initial IGCC baseline efficiency assumption of 40 percent, the efficiency goal was set as high as 50 percent (specifically, the goal was set as a range from 45 to 50 percent).

As outlined previously, actual plant data and recent engineering analyses confirmed that the baseline configuration efficiency should have been benchmarked at 35 percent rather than 40 percent. Maintaining the stretch goal of 10 points and based on a 35 percent baseline efficiency results in an upper limit of 45 percent for the efficiency goal. It should be noted that although no change has been made to the goal, efficiencies greater than 45 percent would be difficult to achieve with the current R&D portfolio.

3.1.3 Updated APS R&D GPRA Goal

After cost escalation, the GPRA goal for APS R&D is as follows:

APS GPRA Goal

(updated June 2008)

By 2010, develop advanced coal-based power systems capable of achieving 45-50 percent thermal efficiency[a] at a capital cost[b] of $1,600/kW or less (2007$).

[a] HHV basis

[b] Expressed as overnight construction cost (bare erected costs, engineering costs, and contingencies). Not included are owners costs such as project development fees, land and site infrastructure improvements, pre-production costs, inventory capital, and allowance for funds used during construction. With these costs included, the total capital required would be equivalent to roughly $2,500/kW.

4 Defining the Carbon Sequestration GPRA Goal

4.1 GPRA Goal History

COE Goal Developed to Replace $/ton Carbon Removed Goal

At its inception in 1997, the Carbon Sequestration (CS) R&D program adopted a goal of "reducing the cost of carbon sequestration to $10 net per ton of carbon emissions." [10] This initial goal had been criticized as overly aggressive and likely unattainable, unless speculative off-set costs such as oil production, gas production, or tax incentives were included. For example, the $10/tonne of carbon removed metric allowed only a 3 to 4 percent increase in COE (a greater than 90 percent reduction in capital cost!). Therefore, in the early 2000s, it was agreed that the goal be changed to a more realistic stretch goal based on COE. The 10 percent increase in COE is equal to $31/tonne of carbon or an approximate 75 percent reduction in capital cost. This is much more reasonable than the 90 percent reduction in capital cost required by the original goal.

An advantage of expressing the goal for capture and sequestration in terms of cost of electricity (or energy services for future plants) is that it accounts for the effects of both efficiency and cost and can be directly compared across a variety of power generation types. It is the measure used by decision makers to determine the impact of carbon capture and sequestration (CCS) on the cost of producing electricity. Comparing COE is valuable since the integration of carbon capture in a pre-combustion process, such as IGCC, will impact the overall efficiency and cost of the entire system. Unlike post-combustion capture, removal of CO_2 prior to combustion in an IGCC plant requires a significant amount of redesign to optimize temperature and pressure integration and minimize the cost. It is not a simple add-on to the back-end of the power cycle.

In late 2002, the CS R&D GPRA goal was defined as:

> **By 2012, complete R&D to integrate this technology with CO_2 separation, capture, and sequestration into a "zero" emission configuration(s) that can provide electricity with less than a 10 percent increase in cost of electricity.**

Clarifying Details for the COE Goal

As written above, the goal does not specify the baseline for which the change in COE should be estimated. It also doesn't clarify the degree of CO_2 capture required or the components of COE to be included in the 10 percent increase. However, these details were discussed in background documentation[11] developed when the GPRA COE goal was established. According to this documentation, the CS GPRA goal as originally

[10] Carbon Sequestration R&D Program Plan: FY 1999 – FY 2000
[11] Klara, Scott. "Cost Goals for Carbon Sequestration R&D," white paper, 2/13/03.

envisioned represented "a best case scenario for an advanced IGCC plant with the greatest available capture & sequestration technologies." Therefore, achievement of the cost goal is assumed to require integrated progress in both the APS and CS R&D programs. Other details included in this documentation include the following specifications:

- 90 percent CO_2 capture,
- The baseline for measuring the reduction in cost for an IGCC with carbon capture and sequestration (CCS) is a conventional IGCC power plant without capture, and
- The increase in COE includes capture, compression, transport, storage and monitoring costs.

Baseline

The background documentation for the CS goal references a conventional IGCC power plant configuration as the baseline; the same baseline assumed for the APS R&D goals. This configuration consists of a single-stage, slurry-fed gasifier, cryogenic air separation, gas cooling and conditioning, acid gas removal, 7FA gas turbine, and double reheat steam cycle. Figure 3 is a snapshot of the carbon sequestration baseline and goals as developed in late 2002. The cost of electricity for the baseline plant at that time was 4.5 cents/kWh (2002$), indicated by the red line.

R&D Impact

As shown by the blue line in Figure 3, the cost of integrating CCS into the baseline IGCC plant using conventional capture technology (two-stage Selexol system) increases COE by roughly 30 percent. The 2012 GPRA goal for CS R&D is indicated by the large square box and represents a 10 percent increase in COE over the baseline.

This COE was determined to be the lowest electric generating cost technically achievable by 2012 given the improvements in efficiency and the reduction in capital and operating costs expected from integrated technologies within the Clean Coal R&D program. Further, this goal is anticipated to make IGCC a competitive option in a carbon constrained environment. Recent analyses of power generation deployment under a range of carbon constrained scenarios projected that average electric generating cost will increase by at least that much.[12]

Removing 90 percent CO_2 from a power plant at increased efficiency and reduced costs requires tandem APS and CS R&D achievements toward the 2012 CS R&D goal. Some of the technology advancements expected from both programs are indicated by the blue and yellow arrows on Figure 3.

Combinations of advances in gasification, gas cleanup and separation, and power cycle technology provide synergistic benefits when combined with carbon capture and sequestration. Unlike post combustion capture, which is added to the back-end of a pulverized coal plant, pre-combustion CO_2 capture is a fully integrated system within the

[12] Energy Information Administration, Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007. April 2008. pp 27-28.

IGCC plant. Progress in CO2 capture technology cannot be assessed without considering the impacts and improvements of other parts of the IGCC system. Some of the advanced conversion technologies exhaust the fuel gas stream at conditions that are more amenable to capture, improving the overall process efficiency. Conversely, some advanced capture systems provide heat and pressure integration that fit well with the requirements of the power island and criteria pollution control systems providing an opportunity to increase power output and reduce auxiliary loads. Reductions in parasitic load in one section of the plant can have the impact of further reducing parasitic load in another portion of the process, generating additional savings.

Details about the technologies under development in the CS, FC and APS R&D programs are listed in Table 4. As the table shows, a significant number of unit operations and technologies are required to contribute to achieve a near-zero-emissions coal plant. Near-zero-emissions coal plants utilize advanced technologies to maximize efficiency and improve reliability, are capable of producing multiple products, have near-zero discharge of criteria pollutants and carbon dioxide, and have near-zero water usage.

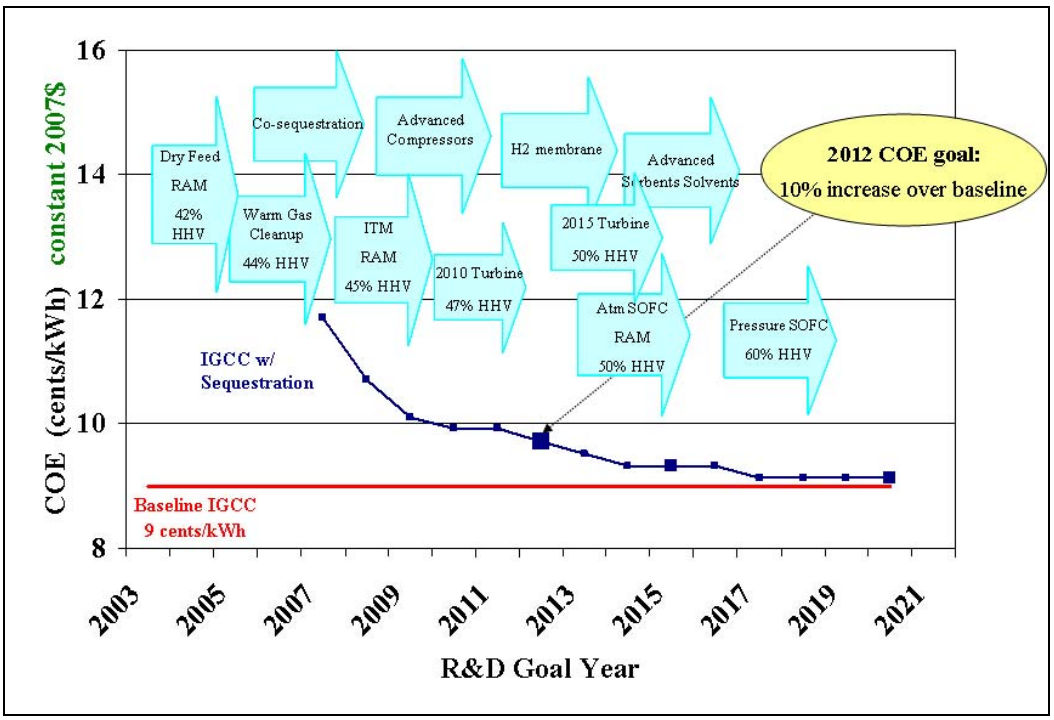

Figure 3. CS and APS R&D Needed to Reach 2012 Goal

Table 3. Integrated R&D Contributions for the 2012 COE Goal

R&D program	Technology Development	Potential Impact
Advanced Power	Dry-Feed System	Using pulverized coal under mechanical pressure to maintain a high pressure seal to the gasifier reduces heat penalty of slurry feed and high-moisture low-rank coals and reduces cost by eliminating expensive lockhopper systems. Dry-feed is expected to improve efficiency by about 2 percentage points, and can reduce capital costs if lockhoppers are eliminated.
	Multi-Contaminant Removal	A multi-component system capable of operating at 300 – 700 ºF provides better compatibility with downstream process components and enhances efficiency. Technology expected to remove nearly 100 percent of all contaminants, reduce IGCC capital costs by $60 – 80/kW by replacing multiple pollutant control units, and increase efficiency by 1–2 percent.
	ITM Membrane	Ion transport membranes produce pure oxygen with significant decrease in capital cost and auxiliary load compared to conventional cryogenic plants. ITM could provide capital cost savings of ~ $100/kW for a conventional IGCC plant along with 1–2 percentage points increase in overall thermal efficiency.
	Advanced Syngas/H_2 Turbine	Retaining advanced turbine performance for coal-derived synthesis gas and hydrogen-rich fuels can be accomplished by using diluents to reduce combustor temperature and by developing high-temperature materials, and new cooling techniques. This could gain as much as 2–3 percentage points in IGCC system efficiency and more than a $100/kW reduction in the capital cost through higher output.
	Oxy-fired Turbines	An oxygen-fired turbine produces exhaust that can be directly sequestered eliminating the need to separate out the criteria pollutants and CO_2. This configuration can capture CO_2 at a system efficiency of >40 percent efficiency.
	Advanced Compression	Compressing CO_2 to pipeline pressure requires significant energy. Advanced compressor systems reduce CO_2 compressor power consumption by 25-40 percent and do so at reduced capital cost.
	Advanced Instrumentation and Refractories	Process control is improved with monitoring systems that operate in harsh environments. New refractory materials that have increased durability and longer life provide higher availability and reduced maintenance costs. The result is improved availability by more than 5 percentage points, reduced annual operating and maintenance costs by $1–2 million, and improved thermal efficiency by 1 percentage point.
	Advanced Gasifiers	Advanced gasification concepts that increase throughput or reduce energy requirements have the potential to reduce capital cost by 7 – 15 percent and improve thermal efficiency by 2 – 4 percentage points. Some concepts are able to provide concentrated streams of H_2 and CO_2 directly from the gasifier (chemical looping) for low-cost carbon capture.
Carbon Sequestration	Advanced Sorbents and Solvents	Sorbents and solvents with higher CO_2 adsorption capacity reduce solvent requirements and costs. Those that can be regenerated at higher pressure result in reduced compressor power requirements and cost of operation. Increase in COE for CCS can be reduced by up to 4 percentage points.
	Water-Gas Shift Membrane	Promote higher conversion of CO and H_2O to CO_2 and H_2 than is achieved in a conventional water-gas-shift reactor. Offers the potential to reduce CO_2 capture costs to less than $10 per tonne of CO_2 while also reducing H_2 production costs. Efficiency gains of 1 - 3 percentage points are achievable. Increase in COE for CCS is reduced by > 15 percentage points.
	H_2 Membrane	Membranes capable of operating at higher temperature and pressure will eliminate cooling and reheating of gas streams and produce CO_2 at higher pressure than conventional technology. Increase in COE for CCS is reduced by 5 percentage points.
	Co-Sequestration of CO_2 and H_2S	Sulfur stored along with CO_2 so that sulfur and tail-gas treating can be eliminated reducing capital cost. The result is >20 percent reduction in sulfur removal cost and elimination of the parasitic load for elemental sulfur recovery. Increase in COE for CCS is reduced by about 1 percentage point.

4.2 Defining the Carbon Sequestration COE Baseline

Clearly defining the baseline for the GPRA COE goal is necessary to avoid confusion when determining progress of the R&D program. As was outlined in Chapter 3, and repeated here for clarity, the following is a definition of the baseline for use in determining the increase in COE when CCS is deployed.

GPRA Goal Baseline
(updated June 2008)

IGCC plant vintage 2002 (slurry gasifier, 7FA turbine)

- Plant net efficiency (HHV) of 35 percent
- Total plant cost[a] of $2,100/kW (2007$)
- 20-year levelized COE of 9 cents/kWh (2007$)

[a] Expressed as overnight construction cost (bare erected costs, engineering costs, and contingencies). Not included are owners costs such as project development fees, land and site infrastructure improvements, pre-production costs, inventory capital, and allowance for funds used during construction. With these costs included, the total capital required would be equivalent to roughly $3,500/kW.

4.3 Defining the Carbon Sequestration R&D Goal

The goal written in FY2003 did not include some needed details. The proposed re-wording of the GPRA goal listed below does not change the ultimate requirement, but lists the additional detail needed to ensure that the appropriate comparisons are made when determining the increase in COE.

Sequestration GPRA goal
(Updated June 2008)

By 2012, complete R&D to integrate this technology with CO_2 separation, capture, and sequestration into a "zero" emission configuration(s) that can provide electricity with less than a 10 percent[a] increase in cost of electricity[b].

[a] Compared to the COE for a conventional IGCC (circa 2002); estimated to be 9 cents/kWh in 2007$

[b] COE should include 90% capture, compression, transport, storage and monitoring of the CO_2.

5 Re-baselining Fuel Cell GPRA Cost Goal

5.1 GPRA Goal History

Capital Cost Goal for Fuel Cell Module Developed to be Competitive with Natural Gas Combined Cycles (NGCCs)

In 2000, the Solid State Energy Conversion Alliance (SECA) Fuel Cell R&D program adopted a capital cost goal of $400/kW for a solid oxide fuel cell module. The basis of this goal was a reasonable estimate of the average price of combined cycle gas turbines. It was expected that 2010 SECA fuel cells would compete successfully (on a capital cost basis) with commercial NGCCs. At that time, the cost of an NGCC was $400/kW (2000$). Ultimately, the SECA fuel cell is expected to be deployed in gasification-based systems where it will replace the conventional combined cycle turbine system in an IGCC configuration.

5.2 The Need to Update GPRA Baseline and Goals

Since 2000, when the original SECA fuel cell goals were established, significant cost increases have occurred in the power industry as the result of increased raw material costs, rising labor rates, and the shortage of engineering management and construction services. In order to make meaningful determinations of progress in reducing costs, the GPRA goal and milestone costs must be adjusted to account for the recent dramatic cost escalation. Using the same logic as for the original goal (that the SECA fuel cell should be competitive with a combined cycle gas turbine), an updated cost goal can be developed from recent estimates for NGCC plants. NETL obtained a 2007 ballpark estimate of $700/kW from a from a gas turbine vendor.

This cost is validated by the PCCI index developed by CERA, which shows that costs have escalated by 78 percent between 2000 and 2007.

Index in 3Q 2007 = 178
Index in 2000 = 100
Percent Increase 2000 – 2007 = ((178-100)/100)*100 = 78 percent

When a factor of 1.78 is applied to the original SECA goal of $400/kW, it increases the value to $712/kW in 2007$. Therefore, an updated goal for the SECA R&D program of $700/kW appears reasonable.

As future cost escalation and inflation trends shift, the cost goal may need to be further adjusted.

5.3 Updated Fuel Cell Capital Cost Goal

After cost escalation, the GPRA goal for SECA FC R&D is as follows:

Fuel Cell GPRA goal
(Updated June 2008)

By 2010, produce 3-10 kW solid oxide fuel cell (SOFC) modules having a capital cost of $700/kW (2007$) and, by 2015, demonstrate MW-class fuel cell/turbine hybrids, using aggregated SOFC modules adaptable to coal and having a capital cost of $700/kW (2007$).*

*Based on 2007$ capital cost of NGCC, installed.

6 Conclusion

For the following reasons, it is necessary to update cost-based R&D goals and the baseline used to measure technology progress:

- General inflation over the six to eight year period since the goals were established must be accounted for,
- An imbalance in the supply and demand of materials and labor has significantly increased the cost of constructing utility plants in recent times, beyond that attributable to inflation alone, and
- A more accurate baseline for establishing R&D goals and measuring progress can now be developed using commercial plant operating data.

Using a documented capital cost index developed by CERA, called PCCI, and operating data from the IGCC at Polk Power Station, the baseline for APS and CS goals and cost-based goals for APS and SECA have been updated.

The following list is a summary of the resulting changes:

- The baseline plant efficiency was reduced from 40 to 35 percent (HHV basis), the total plant cost was updated to $2,100/kW in 2007$ (an overnight construction cost), and the configuration was clearly defined.
- The APS R&D capital cost goal was updated for inflation and escalation resulting in an increase in the 2010 goal from $1,000/kW in 2002$ to $1,600/kW (an overnight construction cost) in 2007$.
- No changes were made to the APS R&D efficiency goal; however, it was noted that with a lower efficiency for the baseline, it will be difficult to exceed the lower range of the 45 – 50 percent efficiency goal.
- No changes were made to the CS R&D goal, except to clarify the baseline.
- The SECA FC R&D capital cost goal was updated for inflation and escalation resulting in an increase from $400/kW in 2000$ to $700/kW in 2007$ for the fuel cell system module installed cost.

Appendix A: Evidence of Cost Escalation

This appendix provides evidence of escalation in power plant costs since 2000. These significant economic changes will have an impact on GPRA cost goals that were set at the start of this decade.

The Cambridge Energy Research Association publishes up-to-date indices for the cost to build power plants, refinery and petrochemical plants, and upstream oil and gas projects. These indices can be found at www.ihsindexes.com. According to the power plant index chart in Figure A1, costs to build power plants has increased by more than 130 percent since 2000 if nuclear plants are included in the mix. Without nuclear plants, the escalation is still dramatic, with an increase of over 80 percent.

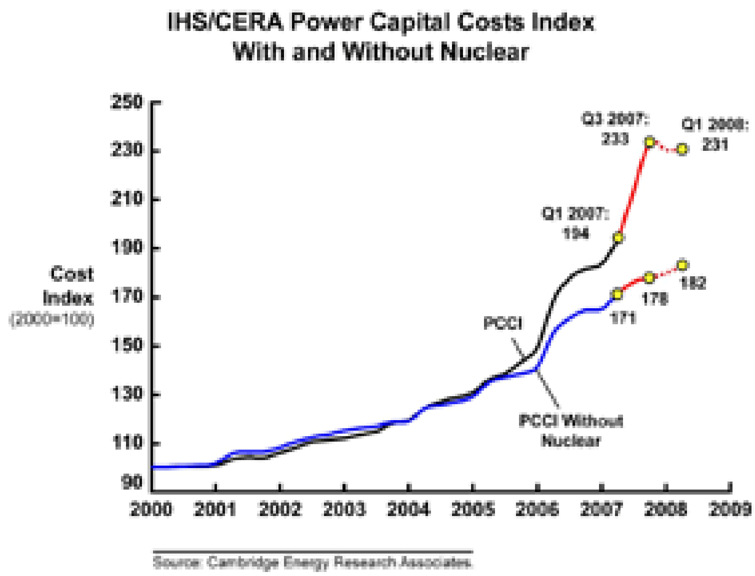

Figure A1. CERA PCCI Index

In April 2008, the Western Resources Advocates group issued a report titled "Investment Risk of Coal-Fired Power Plants."[13] In this report, the author reports that power plants have increased in recent years at a rate well in excess of the rate of inflation. His example cites that a power plant that cost $1,300/kW a few years ago would cost over $2,000 in late 2007. The following figure from that report shows that power structure costs have outpaced general inflation as measured by GDP.

[13] "Investment Risk of Coal-Fired Power Plants," Western Resource Advocates, April 2008.

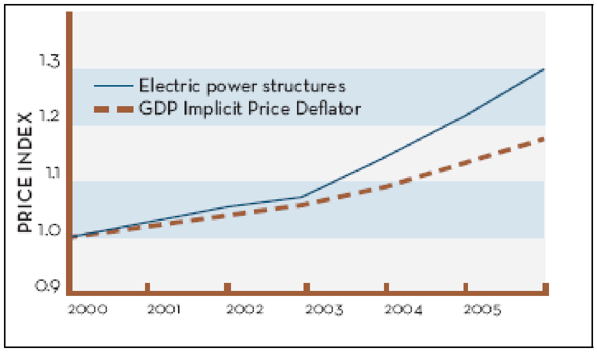

Figure A2. Price Indices for Private Fixed Investment in Electric Power Structures and for General Inflation

A report prepared by the Brattle Group for the Edison Foundation[14], documents recent increases in the construction cost of utility infrastructure and explains how these increased costs translate into higher consumer costs for electricity. The report cites dramatic increases in raw materials prices such as steel and cement as one factor. These costs have increased mainly due to increased global demand, and higher production and transportation costs in part owing to high fuel prices, and a weakening U.S. dollar.

The Edison Foundation report was featured in *Electric Perspectives*[15] in the September/October 2007 edition. The report included the following figure that illustrates recent price trends in power generation based on the Handy-Whitman Index data series, compared with the general level as measured by the gross domestic product (GDP) deflator over the same time period.

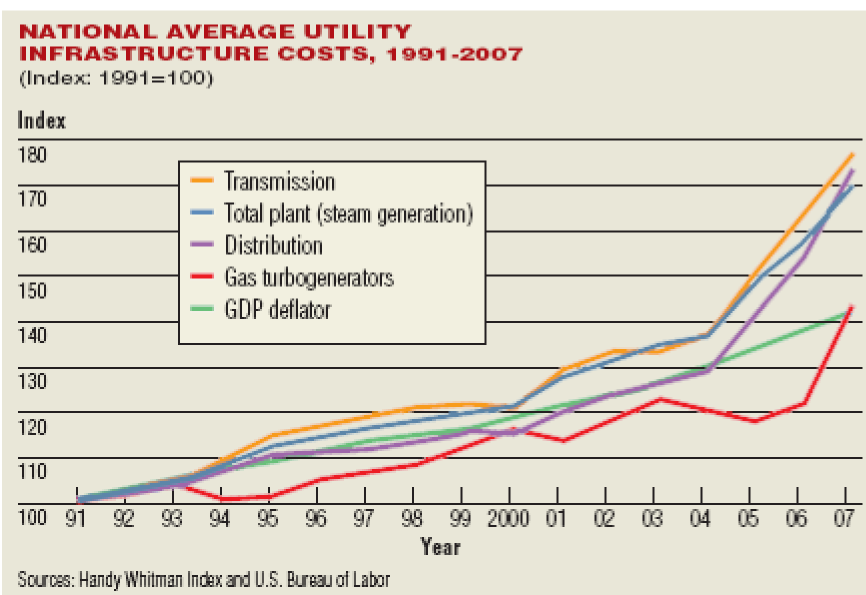

Figure A3. Generation, Transmission and Distribution Infrastructure Cost Trends

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14 "Rising Utility Construction Costs: Sources and Impacts" Edison Foundation. September 2007.

15 Chupka, Marc and G. Basheda. "An Upward Climb." *Electric Perspectives.* September/October 2007. Pages 20 -42

Figure A3 illustrates that steam pulverized coal-fired generation construction costs tracked the general inflation rate fairly well through the 1990s. In 2001, these costs began to rise modestly until 2004. A marked change occurred between January 2004 and January 2007, during which the cost of constructing steam generating units increased by 25 percent. This is more than triple the rate of inflation over the same time period. The cost of building gas turbo generators (natural gas-fired combustion turbines) actually fell between 2003 and 2005, but since 2006, has increased by nearly 18 percent.

According to the *Electric Perspectives* article there has been a dramatic escalation in equipment prices over the last 3 years, with some as high as 70 percent (Figure A4). Some experts believe that these costs may moderate some as the companies that make these materials and components gear up to meet demand. To what degree moderation will occur and just how soon it will happen remains to be seen.

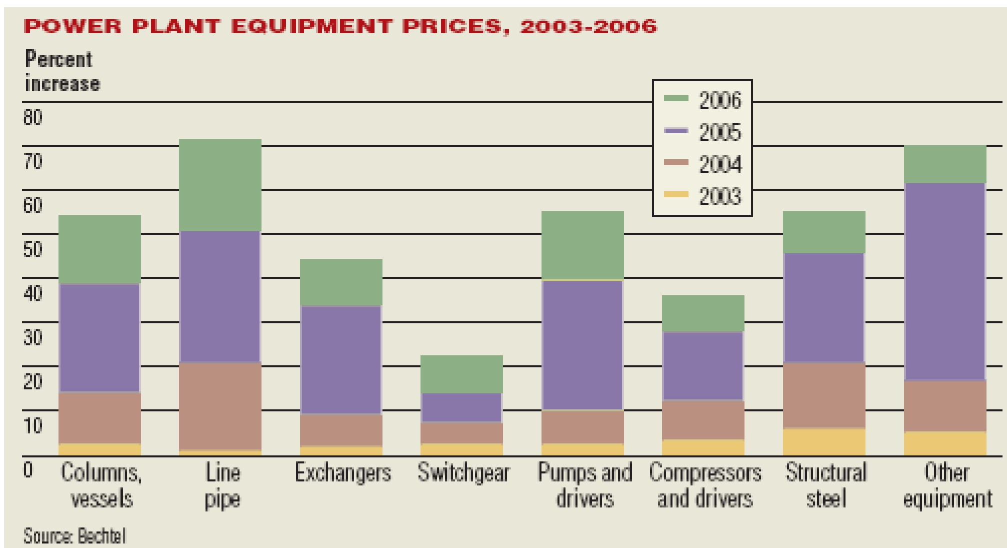

Figure A4. Escalation in Plant Equipment Costs

According to Standard & Poor's Ratings Service, in a 2007 *Energy Biz Insider*[16] article, global demand for infrastructure-related items and domestic investment in pollution control equipment, new generation, and transmission are not the only factors driving capital costs up. Labor costs have climbed to almost double 2001 rates. And Standard & Poor expects things to worsen as the availability of skilled labor gets tight and the need for new power generation and transmission at home and in Asia increases competition for resources.

An illustration of the increase in average national labor costs was provided in the *Electric Perspectives* journal article. As shown in Figure A5 labor costs over the past few years have experienced increases that exceed the rate of increase in GDP.

[16] "Capital Costs Challenge Industry." *Energy Biz Insider.* July 6, 2007.

There is no way to tell if costs will remain at this level over the longer term, but the magnitude of the change necessitates action with respect to the GPRA cost goals set for DOE's R&D program. Resetting cost goals should be re-evaluated each year using the best available escalation data to determine if a significant shift in costs calls for further adjustment.

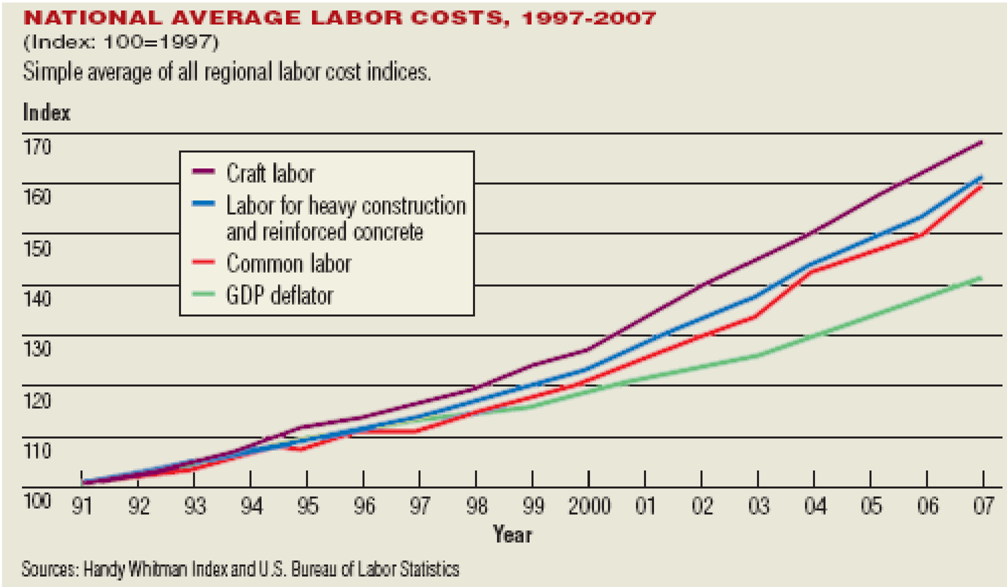

Figure A5. Labor Cost Trends

One need only look at recent applications filed by utilities to find evidence of the significant increase in the construction cost of coal-based power plants. Duke Energy planned in late 2004 to build a pair of coal-fired power plants to replace several plants built around the middle of the last century, at the Cliffside Steam Station, in North Carolina. In May 2005, a preliminary cost estimate placed the cost to build twin 800-megawatt units at $2 billion ($1250/kW). By November 2006 (only five months later), Duke increased the project cost estimate to $3 billion (or $1875/kW), and the North Carolina Utilities Commission decided to build only one unit, citing that Duke had not convinced them that it needed the extra capacity to serve projected native load demands. In May 2007, Duke provided its latest cost projection for the single coal-fired unit of $1.83 billion, an increase of more than 80 percent from the original 2004 estimate, or $2288/kW. When financing costs are included, the estimate rises to $2.4 billion (or about $3000/kW).[17]

As another example, Duke Energy and Otter Tail Power Company sought regulatory approval to build a 630-MW coal-based generating unit (Big Stone II) on the site of the existing Big Stone Plant near Milbank, South Dakota. In addition, the developers of Big Stone II proposed to build a new high-voltage transmission line to deliver power from Big Stone II and from other sources, including possibly wind and other renewable forms

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[17] "'Sticker Shock' for Power Projects As Materials Soar, Cost is Uncertain." *International Herald Tribune.* July 11, 2007.

of energy. Initial cost estimates for the power plant were about $1 billion, with an additional $200 million for the transmission line project. However, these cost estimates increased due to higher costs for construction materials and labor. The most recent estimate (excluding the transmission line) is roughly $1.3 billion or about $2100/kW.[18]
In December 2006, Westar Energy announced that it was postponing expansion plans for a new 600 MW coal-based generation facility due to significant increases in the estimated construction costs, which increased from $1.0 billion to about $1.4 billion (about $2300/kW) since the plant was first announced in May 2005.[4]

Table A1 summarizes utility cost estimates for recently proposed plants, illustrating that the capital costs are well over $2000/kW.

Table A1. Utility Estimates for Plant Cost

Plant	Size (MW)	Plant Cost (billion $)	Plant Cost ($/kW)
Duke Energy Cliffside Steam Station	800	1.83	2288
Duke Energy and Otter Tail Power Company Big Stone II	630	1.33	2100
Westar Energy	600	1.4	2300

In May 2007, DOE/NETL published a report on baseline costs and performance for fossil energy power plants that took great care in reflecting the economic impacts of rising construction costs.[19] This report will be hereafter referred to as the Baseline Study. The Baseline Study estimated the total plant cost (TPC) for a 2007 vintage IGCC plant based on a GE Energy gasifier and GE 7FB gas turbine to be $1813/kW.

To validate the Baseline Study cost estimates, recent quotes for proposed IGCC and pulverized coal (PC) builds were compared. A June 2006 article in *Argus Coal Daily* specified the engineering, procurement and construction cost as $1900/kW for IGCC plants.[20] Papers published in 2007 by MIT and EPRI also corroborate the plant capital costs projected by NETL.[21,22] Table A2 compares the DOE/NETL cost estimate with the MIT and EPRI costs and illustrates that the DOE/NETL costs fall in line with the others.

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[18] "Rising Utility Construction Costs: Sources and Impacts" Edison Foundation. September 2007.
[19] *Cost and Performance Baseline for Fossil Energy Plants: Volume 1.* DOE/NETL-2007/1281. May 2007.
[20] "AEP: IGCC to keep coal in the money." *Argus Coal Daily.* Volume 10. Number 124. June 29, 2006.
[21] *The Future of Coal: Options for a Carbon-Constrained World.* Massachusetts Institute of Technology. ISBN 978-0-615-14092-6. 2007.
[22] *Updated Cost and Performance Estimates for Clean Coal Technologies Including CO2 Capture.* Electric Power Research Institute. Technical Update 1013355. March 2007.

Table A2. Total Plant Cost Estimates				
Plant Type	**Study Source**	**Size (MW)**	**Efficiency (%HHV)**	**Plant Cost ($/kW)**
IGCC	MIT	500	38.4	1505§
	DOE/NETL	630	39.5	**1841***
	EPRI	615	38.2	2104*
SCPC	MIT	**500**	**38.5**	1400§
	DOE/NETL	**550**	**39.1**	**1575***
	EPRI	600	38.1	1797*

Note: Both MIT and EPRI reports use NETL data as one source of cost and performance data
*Total Plant Cost in 2007$ §Total Plant Investment in 2007$

Conclusion

The evidence provided in this appendix supports the fact that costs have increased significantly in the past few years, and by as much as 80 percent since the goals were established (2000 to 2002 time frame). GPRA goals must be adjusted in order to make fair comparisons against the baseline to determine R&D progress toward achieving those goals.

Appendix B: Re-Baselining Systems Analysis

B.1 Technical Documentation for GPRA Baseline

In May 2007, NETL issued the Baseline Study.[23] Case 1 of the Baseline Study is configured similarly to the GPRA (FY2003) Baseline with the following major exception: it uses an FB combustion turbine rather than an FA turbine. This appendix briefly describes Case 1 of the Baseline Study and explains how it was modified to more accurately represent the GPRA baseline. Specifically, the FB turbine was replaced with an FA turbine and adjustments were made to the heat integration scheme affection the steam cycle. AspenPlus simulation software was used to estimate the performance of this configuration. The result of this analysis shows that the GPRA baseline efficiency assumed in the 2002 timeframe was optimistic. Further, a revised cost estimate for the 7FA case indicates that the cost of the baseline plant design is 40 percent higher now compared to the costs estimated in 2002.

B.1.1 Process Description for Case 1 of the Baseline Study

The following describes Case 1 from the NETL Baseline Study. The process model is based on dual trains of single-stage slurry-fed gasifiers and includes two 7FB gas turbines and a steam cycle operating at 1,800 psig with 1,050 ^{o}F steam superheat and 1,050 ^{o}F 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, oxygen-blown gasifier. The gas turbine is integrated with the ASU, providing as much air as possible to the ASU without compromising the total gas flow through the gas turbine. This integration has the benefit of reducing the work required of the ASU Main Air Compressor, and also allows for the increased flow of medium-Btu fuel relative to natural gas.

The ASU is sized to provide sufficient oxygen to the gasifier. All of the N_2 by-product is compressed and injected into the topping combustor of the gas turbine. Oxygen is added to the gasifier to raise the temperature to 2,500 ^{o}F. Based on an elemental balance, and carbon conversion of 99.5 percent, chemical equilibrium is calculated at the adiabatic reactor temperature of 2,500 ^{o}F. The radiant gas cooler reduces exit gas temperature to 1,100 ^{o}F.

Exiting the gasifier, raw syngas is cooled and cleaned. Following particulate removal, desulfurization, ammonia, mercury, and other contaminant removal, the clean fuel gas is ready for combustion. It is reheated, expanded, and combusted in the gas turbine together with dilution nitrogen and humidifying steam. Enough steam is added to

[23] *Cost and Performance Baseline for Fossil Energy Plants: Volume 1*. DOE/NETL-2007/1281. May 2007.

regulate the fuel gas heating value to 124 Btu/scf. The gas mixture is burned in the topping combustor, reaching a turbine inlet temperature of 2,450 ^{o}F. The net gas turbine power output is 232 MWe per unit.

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.

Case 1 is estimated to have a net efficiency of 38 percent (HHV) and a capital cost of $1813/kW (2007$). The 20 year levelized cost of electricity for this configuration was estimated to be 8.3 cents/kWh.

B.1.2 Process Modifications to Generate GPRA (FY2003) Baseline

The Baseline Study Case 1 was used as the starting point to develop a simulation of the GPRA (FY2003) IGCC baseline configuration used to set goals and milestones. As mentioned earlier, Case 1 of the Baseline Study incorporated a more advanced gas turbine than the GPRA (FY2003) IGCC baseline. So the major change was to replace the 7FB gas turbine with a 7FA machine.

GPRA baseline includes two 7FA gas turbines and a steam cycle operating at 1,800 psig with 1,000 ^{o}F steam superheat and 1,000 ^{o}F steam reheat. The as-received Illinois #6 bituminous coal feed 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 ^{o}F during operation, the radiant gas cooler reduces exit raw gas temperature to 1,250 ^{o}F. 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 ^{o}F for COS hydrolysis. Following the exothermic COS hydrolysis reaction, the gas is cooled again; first to 310 ^{o}F to recover useful heat for fuel gas reheat and steam generation, next to 235 ^{o}F to recover useful heat for the steam cycle deaerator, then finally to 110 ^{o}F for NH_3 removal. The cooling temperatures of 310 ^{o}F and 235 ^{o}F were selected based on reasonable temperature approaches to the steam cycle streams.

The fuel gas enters packed carbon bed absorbers to remove mercury, followed by a 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 (the fuel flow is regulated in order to obtain this temperature). The net gas turbine power output is 192 MWe per unit.[24]

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.

B.1.3 GPRA (FY2003) Baseline Results Analysis

Simulation results are compared below against Case 1 results to analyze the performance difference between the 7FA and 7FB gas turbines.

Fuel Gas Comparison

Table B1 compares composition of raw syngas exiting the gasifier; the fuel gas stream entering the topping combustor (following dilution with N_2) is also compared.

Table B1. Syngas Composition

	GPRA (FY2003) Baseline	NETL Study Case 1
Mole fraction H_2O	0.163	0.162
CO_2	0.146	0.145
N_2	0.016	0.016
CH_4	0.001	0.001
CO	0.345	0.347
H_2	0.319	0.320
H_2S	0.007	0.007
Total moles/hr	42,562	51,972

[24] Gas turbine firing temperature and power output taken from "IGCC: What's GE Up To?", October 13, 2005, American Coal Council 2005 Coal Market Strategies, Norm Shilling, General Electric.

Following Dilution With N_2		
Moles N_2 added	34,493	39,767
Mole fraction H_2O	<0.001	<0.001
CO_2	0.089	0.091
N_2	0.501	0.487
CH_4	<0.001	<0.001
CO	0.211	0.217
H_2	0.194	0.201
Total moles/hr	69,745	82,873
LHV (Btu/scf)	121	125

The raw syngas compositions are very nearly the same; the difference between flowrate reflects the power produced by each gas turbine, with the 7FB turbine in Case 1 producing more power. The GPRA baseline does not have air integration, so the loss of one degree of freedom (the percent air extracted from the turbine compressor) makes the gas heating value in the GPRA baseline a dependent variable, while the heating value of the syngas in Case 1 is controlled to 125 Btu/scf. The resulting fuel gas heating value, 121 Btu/scf, is sufficiently low to limit NOx formation.

Gas Turbine

Turbine performance characteristics (per train) are compared in Table B2. The 7FA turbine in the GPRA baseline is rated for 192 MW, while the 7FB turbine in Case 1 is 232 MW.

Table B2. 7FA and 7FB Turbine Performance Comparison

	GPRA (FY2003) Baseline *7FA*	**NETL Study Case 1** *7FB*
Air Feed Rate (lb/sec)	800	951
Fraction Air Diverted to ASU	0	0.095
Fuel Heating Value (Btu/scf)	121	125
Fuel Flowrate (moles/hr)	34,873	41,437
Turbine Firing Temp (^oF)	2,250	2,450
Turbine Exhaust Temp (^oF)	1,072	1,160
Flue Gas Flowrate (moles/hr)	127,829	140,271
Turbine Power (MWe)	192	232

In both cases, the feed rate of coal and the fraction of N_2 added to the syngas stream are varied in order to meet the specified turbine firing temperature and turbine power output. In Case 1, the fraction of air extracted from the gas turbine to the ASU is also varied – fuel gas heating value is the additional degree of freedom, which is set to 125 Btu/scf.

Bottoming Cycle

Table B4 compares steam cycle performance for two process trains. Because of the lower turbine exit temperature in the GPRA baseline (1,072 ^oF), steam superheat temperature is 1,000 ^oF rather than 1,050 ^oF in Case 1.

Table B4. Steam Cycle Performance

	GPRA (FY2003) Baseline	NETL Study Case 1
HRSG Inlet Temperature (^oF)	1,072	1,160
Stack Gas Temperature (^oF)	270	270
Condenser Duty (MMBtu/hr)	1,191	1,524
Steam Turbine Power (MWe)	223	293

The difference in steam turbine power reflects the greater coal flowrate in Case 1, leading to increased heat recovery in the gasifier, syngas quench, and flue gas flow through the HRSG.

Auxiliary Power

Auxiliary power use by major process equipment is summarized in Table B5. All values are in units of kWe.

Table B5. Auxiliary Power Requirements

	GPRA (FY2003) Baseline	NETL Study Case 1
Coal Handling	518	633
Coal Milling	2,624	3,205
Coal Slurry Pumps	224	274
Slag Handling and Dewatering	1,347	1,645
Air Separation Unit Auxiliaries	1,168	1,420
Air Separation Unit Main Air Compressor	58,423	46,158
Oxygen Compressor	8,817	10,714
Nitrogen Compressor	31,625	36,460
Claus Plant Tail Gas Recycle Compressor	1,513	1,848
Boiler Feedwater Pumps	3,241	4,102
Condensate Pump	1	2
Flash Bottoms Pump	206	264
Circulating Water Pumps	3,824	4,896
Cooling Tower Fans	1,969	2,520
Scrubber Pumps	335	417
Selexol Unit Auxiliaries	3,236	3,260
Gas Turbine Auxiliaries	1,159	1,400
Steam Turbine Auxiliaries	105	137

Claus Plant/TGCU Auxiliaries	264	323
Miscellaneous Balance of Plant	3,345	4,168
Transformer Loss	2,955	3,682
Total Auxiliaries (kWe)	126,900	127,526

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 1 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 reduced N_2 compressor power consumption in the GPRA baseline is due to less flowrate through the gas turbine because of the smaller turbine.

Overall Process Performance

Table B6 summarizes the overall process performance for two process trains.

Table B6. Overall Performance

	GPRA (FY2003) Baseline	**NETL Study Case 1**
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	35.4 %	37.9 %

Total (gross) power production is reduced in the GPRA baseline as a result of the smaller, less efficient 7FA gas turbine. Further, less power is generated by the steam cycle – due primarily to less heat recovered by the gasifier radiant cooler and subsequent syngas cooling (as the result of lower coal feed rate). Auxiliary power consumption is comparable. Overall, the reduced net power generated in the GPRA baseline results in a substantial process efficiency penalty, dropping efficiency from 37.9 % to 35.4%.

B.2 Cost Estimate for GPRA (FY2003) Baseline

Capital Cost Estimate

Table B7 estimates the capital cost (in December 2006 dollars) of each major section of the process plant. Each section's Bare Erected Cost (BEC) represents the sum of major plant equipment within the section (including initial chemical and catalyst loadings), as well as materials and labor. A 9 % charge was applied to the BEC for engineering, procurement, and construction (EPC) services which, when added to the BEC, becomes the Engineering, Procurement, and Construction Cost (EPCC).

Process and project contingencies used in the NETL Baseline Study were the basis for all major equipment in each plant section. Contingency estimates are summarized in Table B7, and 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 Total Plant Cost is $2,113/kW in 2007$.

Table B7. Capital Equipment Costs by Plant Section

Plant Sections	BEC	EPCC	Process Cont'gncy	Project Cont'gncy	Total Plant Cost
1 Coal and Sorbent Handling	23,564	25,685	0	5,137	30,821
2 Coal and Sorbent Prep & Feed	36,213	39,472	1,312	8,195	48,980
3 Feedwater & Balance of Plant	26,244	28,606	0	6,471	35,077
4a Gasifier	169,148	184,371	18,725	33,116	236,212
4b Air Separation Unit	140,909	153,591	0	15,359	168,950
5a Gas Cleanup	85,726	93,441	75	18,873	112,389
5b CO_2 Removal & Compression	0	0	0	0	0
6Gas Turbine	83,587	91,110	3,787	10,161	105,058
7 HRSG	40,881	44,560	0	4,951	49,511
8 Steam Cycle and Turbines	43,892	47,842	0	6,467	54,310
9 Cooling Water System	18,439	20,099	0	4,134	24.233
10 Waste Solids Handling System	32,093	34,981	0	3,771	38,752
11 Accessory Electric Plant	51,167	55,772	0	10,757	66,529
12 Instrumentation & Control	17,415	18,982	869	3,327	23,178
13 Site Preparation	12,804	13,956	0	4,187	18,143
14 Buildings and Structures	12,855	14,012	0	2,302	16,314
Total	**794,937**	**866,482**	**24,769**	**137,207**	**1,028,457**

Operating & Maintenance Cost

Labor represents a fixed operating cost, and is based on the number of operating laborers in the plant. The NETL Baseline Study estimate for number of laborers, labor rates, burden, and administrative overhead were used for consistency. Administrative labor is estimated as an overhead rate (25 %) to the sum of operating and maintenance labor.

Variable operating costs are estimated using 100 % capacity factor, and expressed as percent of EPCC in the Power Systems Financial Model (PSFM). The PSFM applies the capacity factor to correct for actual annual variable operating cost. The PSFM computes fuel cost based on plant net power generation, heat rate, and fuel heating value. A coal cost of $42.11/ton is assumed, with a heating value of 11,666 Btu/lb.

Discounted Cash Flow Analysis

The PSFM computes the 20-year levelized cost of electricity. Following financing scenario guidelines for a high-risk Independently-Owned Utility (IOU), a 17.5 % capital charge factor is applied to the project. Additional economic parameters used in the PSFM are summarized in Table B8 below.

Results from the discounted cash flow analysis, shown in Table B9, indicate $0.0931/kW-hr levelized cost of electricity.

Table B8. PSFM Economic Parameters

Parameter	**Value**
Income Tax Rate	38 %
Repayment Term of Debt	15 years
Grace Period on Debt Payment	0 years
Debt Reserve Fund	None
Depreciation	20 years, 150 % declining balance
Working Capital	Zero
Plant Economic Life	30 years
Investment Tax Credit	0 %
Tax Holiday	0 years
Technology Fee	0 % of EPCC
Start-Up Costs	2 % of EPCC
All Other Additional Capital Costs	$0
EPC Escalation	0 %
Start of Construction	1/1/2007
Duration of Construction	36 months
Percentage Debt	45 %
Interest Rate	11.55 %
Financing Fee	0 %
Coal Levelization Factor	1.2022
O&M Levelization Factor	1.1568

Cost Analysis

Capital and O&M costs are compared with the NETL Baseline Study Case 1 results in Table B9. The choice of gas turbine is the reason for differences in capital costs between the GPRA baseline (7FA turbine) and Case 1 (7FB turbine). The 7FA turbine has a lower power rating, which decreases coal flowrate to the process, and therefore equipment sizes throughout the plant; this is reflected in the reduced EPCC and TPC costs for that case.

On a $/kW basis, the TPC of the 7FA plant increases because of reduced power output. Not only is the turbine power output of the GPRA baseline lower than the NETL Study Case 1, but the process efficiency is 2.5 percentage points less than the 7FB case. As described in Section B.1, the primary reasons for this are lack of air integration from the gas turbine to the ASU, the lower efficiency of the 7FA gas turbine, and the reduced steam cycle superheat temperature.

Comparing cost of electricity, the 0.0937 \$/kW-hr of the GPRA baseline represents a capacity factor of only 75%, whereas the 0.0780 \$/kW-hr of Case 1 represents a capacity factor of 80 %. The lower capacity factor is indicative of the availability of IGCC plants in the 2002 timeframe.

Table B9. Capital and O&M Cost Comparison

	Case 1			Case 0		
Capital Cost (\$1,000)						
Plant Sections	**EPCC**	**TPC**	**TPC \$/kW**	**EPCC**	**TPC**	**TPC \$/kW**
1 Coal and Sorbent Handling	29,076	34,890	55	25,685	30,821	63
2 Coal and Sorbent Prep & Feed	45,169	56,050	88	39,472	48,980	101
3 Feedwater & Balance of Plant	30,636	37,513	59	28,606	35,077	72
4a Gasifier	210,196	269,284	423	184,371	236,212	485
4b Air Separation Unit	167,073	183,781	289	153,591	168,950	347
5a Gas Cleanup	107,769	129,625	203	93,441	112,389	231
5b CO_2 Removal & Compression	0	0	0	0	0	0
6 Gas Turbine	103,491	119,302	187	91,110	105,058	215
7 HRSG	50,936	56,565	89	44,560	49,511	102
8 Steam Cycle and Turbines	57,934	65,820	103	47,842	54,310	112
9 Cooling Water System	22,515	27,140	43	20,099	24.233	50
10 Waste Solids Handling System	39,568	43,829	69	34,981	38,752	80
11 Accessory Electric Plant	58,402	69,559	109	55,772	66,529	137
12 Instrumentation & Control	19,010	23,212	36	18,982	23,178	48
13 Site Preparation	14,247	18,522	29	13,956	18,143	37
14 Buildings and Structures	14,974	17,421	27	14,012	16,314	34
Total	970,995	1,152,513	1,809	866,482	1,028,457	2,113
O&M Cost (\$1,000)						
Fixed Costs	**Total**		**% EPCC**	**Total**		**% EPCC**
Labor	22,548		2.32	22,548		2.60
Variable Operating Costs*	**Total**		**% EPCC**	**Total**		**% EPCC**
Maintenance Materials	22,762		2.34	18,368		2.12
Water	1,703		0.18	1,437		0.17
Chemicals	1,305		0.13	1,021		0.12
Waste Disposal	2,920		0.30	2,262		0.26
Total Variable Costs	28,694		2.96	23,088		2.67
Total O&M Cost	51,237		5.28	45,636		5.27
Fuel Cost*	72,542		7.47	55,690		6.43
Discounted Cash Flow Results						
Total Plant Cost (\$/kW)			1,809			2,113
Levelized Cost of Electricity (\$/kW-hr)			0.0780			0.0937

*Includes capacity factor