LARGE FILING SEPERATOR SHEET

CASE NUMBER: 06-1358-EL-BGN

FILE DATE: 10/25/2007

SECTION: 1 of 4

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Exhibits

FILE

NRDC
THE EARTH'S BEST DEFENSE

NATURAL RESOURCES DEFENSE COUNCIL

October 25, 2007

Ohio Power Siting Board
180 East Broad Street
Columbus, Ohio 43215-3793

RE: Motion to Intervene in Case No. 06-1358-EL-BGN, In re: Application of American Municipal Power-Ohio for a Certificate of Environmental Compatibility and Public Need for an Electric Generation Station and Related Facilities in Meigs County, Ohio.

Dear Ohio Power Siting Board Members:

Please find enclosed for filing with the Board an original and ten copies of the Motion to Intervene and supporting documents of the Natural Resources Defense Council, Ohio Environmental Council, and Sierra Club in Case No. 06-1358-EL-BGN, American Municipal Power-Ohio's ("AMP") application for a certification for the proposed Meigs County electric generation station.

I would like to bring to the Board's attention that Exhibit 4 to our motion – the executive summary of an initial feasibility study for the proposed plant – has been stamped by AMP as confidential business information. We received the study through a public records request and therefore believe it to be part of the public record.

Please contact me at (312) 780-7431 if you have any questions. Thank you for your time and consideration.

Sincerely,

Shannon Fisk
Staff Attorney
Natural Resources Defense Council

www.nrdc.org

101 N. Wacker Drive, Suite 609
Chicago, IL 60606
TEL 312 663-9900
FAX 312 663-9970

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BEFORE THE
OHIO POWER SITING BOARD

Application of American Municipal Power, Ohio, Inc. (AMP-Ohio) for a Certificate of Environmental Compatibility and Public For the American Municipal Power Generating Station in Meigs County, Ohio	)))))	Case No. 06-1358-EL-BGN

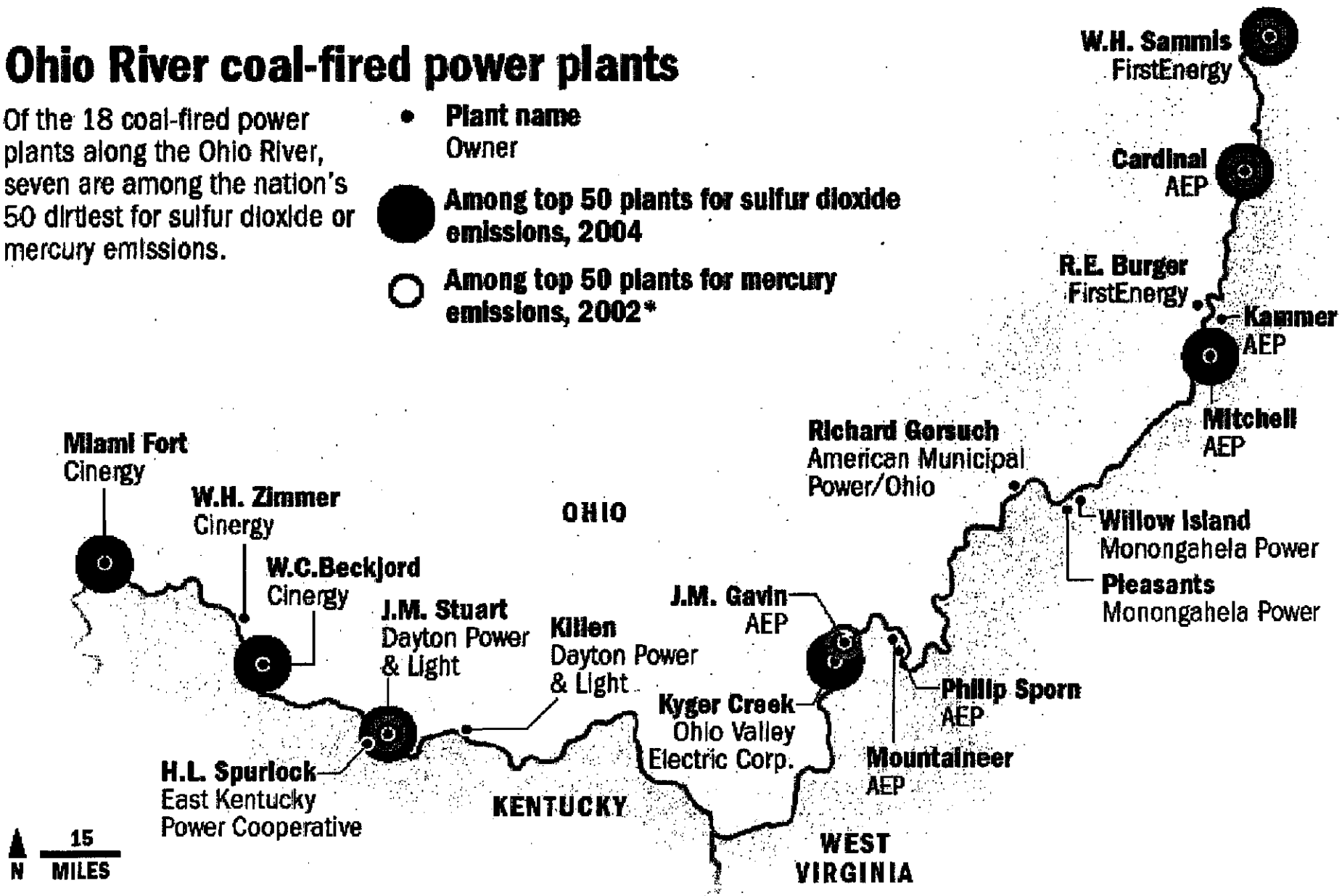
EXHIBITS FOR THE MEMORANDUM IN SUPPORT OF THE MOTION TO INTERVENE OF THE NATURAL RESOURCES DEFENSE COUNCIL, INC., OHIO ENVIRONMENTAL COUNCIL, AND SIERRA CLUB

October 25, 2007

Ohio River coal-fired power plants

Of the 18 coal-fired power plants along the Ohio River, seven are among the nation's 50 dirtiest for sulfur dioxide or mercury emissions.

- **Plant name**
  Owner
- **Among top 50 plants for sulfur dioxide emissions, 2004**
- **Among top 50 plants for mercury emissions, 2002***



* Most recent data available

Sources: Environmental Integrity Project, US Environmental Protection Agency Emissions Tracking System

TOM BAKER | DISPATCH

News from AMP-Ohio

AMERICAN MUNICIPAL POWER-OHIO IS DEDICATED TO PROVIDING SUPPORT SERVICES AND LOW-COST POWER SUPPLIES TO MEMBER MUNICIPAL ELECTRIC COMMUNITIES

For Immediate Release
October 28, 2005

Media contact:
Kent Carson
614/337-6222
614/578-5389
(cell)
kcarson@amp-ohio.org

AMP-OHIO ANNOUNCES SITE FOR NEW GENERATING FACILITY

(Pomeroy, Ohio) A southern Meigs County site has been identified for a new generating facility that could add approximately 150 new jobs and more than $20-million to the area's economy.

American Municipal Power-Ohio (AMP-Ohio) and partners, the Blue Ridge Power Agency (Blue Ridge) and the Michigan South Central Power Agency (MSCPA), today unveiled plans for a new electric power plant and identified southern Meigs County (Ohio) as the preferred site for the proposed American Municipal Power Generating Station.

The decision to locate the proposed facility in Meigs County is contingent upon permitting, geological studies and negotiations with state and local officials on appropriate incentives. Alternative sites and options are also being considered should the organization not be able to site the facility at this preferred location.

The announcement stems from a two-year process initiated following a strategic plan and including studies performed by the consulting engineering firms of Sargent & Lundy LLC and Black & Veatch, including an extensive request-for-proposal (RFP) process that considered long-term contractual arrangements and other options. The American Municipal Power Generating Station will contribute to meeting the long-term energy demands of 78 AMP-Ohio member communities participating in the study. Blue Ridge, a Danville, Virginia based joint action agency with 10 members and MSCPA, based in Litchfield, Michigan with five members, will also receive output from the facility once completed.

"A power supply needs analysis and the base load facility feasibility study indicated that construction of a new base load asset was the best approach to meeting the future needs of our member communities," said AMP-Ohio President/CEO Marc Gerken. "The participation of Blue Ridge (Power Agency) and MSCPA offers the opportunity for a cooperative partnership and more operational flexibility." "We are very excited about participation in this project," said Blue Ridge General Manger Duane Dahlquist. "It will afford our members the opportunity to secure a significant portion of their future power supply from a plant constructed, owned and operated by public power entitites. Compared to the current high cost and highly volatile wholesale power market from which our members must now buy, the power from this plant will be based on the cost to produce, thus ensuring reasonableness and much more certainty in future power rates for our members customers."

MSCPA General Manager Jack Bierl echoed the advantages the new plant would provide its customers. "We are very pleased to have the opportunity to participate in this project," he said. "Our members have long recognized the value of owning their own coal-fired generation. This project will not only secure a reliable source of economical energy for years to come, but also enable our members to benefit from the economies of scale provide by joint participation."

As proposed, the pulverized coal-fired plant will utilize the latest in proven clean coal technology to minimize the environmental impact and will allow the use of a fuel blend that includes Ohio coal. The facility would have a capacity of approximately 1,000 megawatts (MW). While a number of other sites both in and out of Ohio were identified, studied and could be utilized, the preferred location of the plant is near the Ohio River in Letart Township. The plant and associated facilities would occupy approximately 1,300 acres and would consist of a power plant with two stacks, coal unloading facilities, a fly ash disposal area, a substation and access roads.

"We're excited about today's announcement," Gerken said. "It is our firm belief, after considerable analysis, that Meigs County offers the best opportunity for our preferred site, and we look forward to being a part of this community for many years. The plant will have a positive impact on the local economy, and AMP-Ohio's demonstrated commitment

to environmental stewardship means local residents can rest assured that the impact of the plant will be minimized."

The approximately $1.2 billion project will bring 600-800 construction jobs to the region and once completed will employ approximately 150 people to operate the facility. It is projected that the American Municipal Power Generating Station will bring more than $20-million into the area economy annually. AMP-Ohio anticipates the facility being on-line by 2012.

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About AMP-Ohio - *American Municipal Power-Ohio is the Columbus, Ohio-based nonprofit wholesale power supplier and services provider for 81 member municipal electric systems in Ohio, 25 in Pennsylvania, two in West Virginia and two in Michigan. Formed in 1971, the organization is owned and governed by its member communities, dedicated to providing member assistance and low-cost power supply. In addition, AMP-Ohio serves as the project manager for groups of member municipal electric communities participating in joint ventures to share ownership of generation and transmission facilities - including Ohio's first commercial wind farm, located near Bowling Green.*

About Blue Ridge - *Blue Ridge Power Agency ("Blue Ridge") is a nonprofit, "joint action" agency that operates as directed by the Board of Directors. The ultimate goal of the organization is to pursue those activities that will ensure the most reliable, and lowest cost wholesale electric power supplies possible for its members today and in the future. There are currently 10 members of the agency, consisting of seven municipalities, one state institution and two electric cooperatives.*

About MSCPA - *Michigan South Central Power Agency is a municipal joint action agency formed in 1978 to serve its five member communities. The Agency owns and operates a 50 MW coal-fired generating station located in Litchfield, Michigan, and has developed two additional generation projects, as well as securing ownership in the METC transmission system for its members. As an "all requirements" provider, MSCPA is responsible for delivering 100 percent of the electric needs of each of its members.*

News from AMP-Ohio

AMERICAN MUNICIPAL POWER-OHIO IS DEDICATED TO PROVIDING SUPPORT SERVICES AND LOW-COST POWER SUPPLIES TO MEMBER MUNICIPAL ELECTRIC COMMUNITIES

For Immediate Release
May 22, 2006
Contact: Kent Carson
614/337-6222
614/578-5389 (cell)
kcarson@amp-ohio.org

AIR PERMIT APPLICATION FILED FOR AMERICAN MUNICIPAL POWER GENERATING STATION

(Columbus) American Municipal Power-Ohio (AMP-Ohio) has filed an application for a 1,000 megawatt power generating plant that, when completed, will be one of the cleanest facilities of its type in the nation. The American Municipal Power Generating Station (AMPGS) was announced last October and is under development near the Ohio River in southern Meigs County.

The air permit-to-install application, filed with the Ohio EPA, begins the process for obtaining an air permit for the facility, and is one of a number of permits that must be obtained during the permitting process.

The facility would utilize pulverized coal and incorporate the best of the latest generation of available and proven emission control technology to ensure that it meets or exceeds all environmental regulations and emissions limitation requirements. Once on-line, it will be one of the cleanest facilities of its type in the nation.

"The AMPGS is being designed from the ground up to minimize air emissions impacts and maximize efficiencies," said AMP-Ohio President/CEO Marc Gerken. "No reasonable comparisons to existing generating facilities in the region are possible because they are older facilities with different design and operating characteristics."

The proposed plant will have lower emissions compared to existing regional facilities when all pollutants are considered. The facility will be the largest generation project undertaken in Ohio in more than 20 years, and includes the first Class I modeling for an air emissions source in Ohio. The modeling involved studying the air

impact across a wide geographic area, stretching as far as 300 kilometers from the proposed plant site.

-more-

AMP-Ohio• 2600 Airport Drive, Columbus, Ohio 43219• Phone 614/337-6222• Fax 614/337-6240•

While development of the proposed AMPGS facility continues, AMP-Ohio also continues to be a leader in the deployment of renewable technologies in Ohio and the region by pursuing other generation projects. These projects include additional wind generation and low-impact hydro generation. AMP-Ohio is also seeking proposals for the redevelopment or repowering of the existing coal-fired Richard H. Gorsuch Generating Station, located near Marietta, Ohio, using emerging and innovative technology.

The approximately $1.5 billion AMPGS project will bring 600-800 construction jobs to the region and once completed will employ approximately 150 people to operate the facility. It is projected that the development will bring more than $20-million into the area economy annually. AMP-Ohio anticipates the facility being on-line by 2012.

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About AMP-Ohio - *American Municipal Power-Ohio is the Columbus, Ohio-based nonprofit wholesale power supplier and services provider for 81 member municipal electric systems in Ohio, 25 in Pennsylvania, four in Virginia, two in West Virginia and two in Michigan. Formed in 1971, the organization is owned and governed by its member communities, dedicated to providing member assistance and low-cost power supply. In addition, AMP-Ohio serves as the project manager for groups of member municipal electric communities participating in joint ventures to share ownership of generation and related facilities - including Ohio's first commercial wind farm, located near Bowling Green.*

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Initial Project Feasibility Study

American Municipal Power Generating Station Project

AMP OHIO

American Municipal Power - Ohio, Inc.

June 2007

R·W·BECK

EXECUTIVE SUMMARY

Introduction

American Municipal Power – Ohio, Inc. ("AMP-Ohio") is planning to construct a 960 net megawatt (MW)[1] coal-fired generating station consisting of two 480 MW units which will be located in Meigs County, Ohio, in the township of Letart Falls. The station is titled the American Municipal Power Generating Station ("AMPGS"), which together with other facilities and arrangements, comprises the AMPGS Project, also referred to herein as the Project.

AMP-Ohio has engaged R.W. Beck, Inc. ("R. W. Beck") to provide Owner Engineer ("OE") services for the AMPGS Project which include, among other things, the preparation of a Project Feasibility Study. The purpose of the Project Feasibility Study is to (1) address the technical, operational, and financial implications and risks of the Project, and (2) provide a comprehensive examination of the Project. Under the terms of the contract with AMP-Ohio with regard to the feasibility of the Project, R.W. Beck must provide the following: (i) an Initial Project Feasibility Study based on the most recent information available including updated costs of the Project, (ii) a Final Project Feasibility Study based on updated information available after the selection of an Engineer-Procure-Construct ("EPC") contractor; and (iii) summary reports for Project financing updated to reflect the most recent information available as of the date of the associated Official Statement. This report constitutes the Initial Project Feasibility Study (the "Report") and summarizes our work up to the date of this Report.

As used in this Report, the capitalization of any word not normally capitalized indicates that such word is defined in the particular agreement or other document discussed. References to and descriptions of such agreements or documents in this Report represent our understanding of certain general principles thereof, but do not purport to be complete and are qualified in their entirety by reference to such agreements or documents.

Description of AMP-Ohio Organization

AMP-Ohio was formed in 1971 under Ohio Revised Code Chapter 1702 as a nonprofit corporation. AMP-Ohio operates on a cooperative basis for the mutual benefit of its members, each of which owns and operates an electric utility distribution system and in some cases generating assets. As of May 7, 2007, AMP-Ohio had 120 members ("Members") – 81 in Ohio, 26 in Pennsylvania, seven in Michigan, four in Virginia and two in West Virginia. Since May 7, 2007, an additional borough located in

[1] The 960 MW rating reflects the projected summer capacity rating of the Project. The annual average rating is projected to be 987 MW.

Pennsylvania has become a member of AMP-Ohio. An additional city in Virginia, Front Royal, may become a member.

History and Development of Project

In 2002, AMP-Ohio completed a strategic plan which included a 20-year power supply needs analysis that identified the need for new base load generating capacity. The plan led AMP-Ohio to undertake a conceptual feasibility study and other studies, including evaluation of available base load power supply options, technology considerations, site alternatives, and fuel availability. In 2004, AMP-Ohio entered into a developmental agreement with Virginia-based Blue Ridge Power Agency ("BRPA" or "Blue Ridge") and Michigan South Central Power Agency ("MSCPA") to continue to investigate the development of a new base load resource on a joint basis. Certain members of BRPA and MSCPA are also Members of AMP-Ohio and potential participants in the new base load resource.

AMP-Ohio signed a contract with the engineering firm Sargent & Lundy ("S&L") in May of 2003 to provide various services associated with the early planning, evaluation and development of a base load generating facility. These services included: (i) technology analysis; (ii) site screening analysis; (iii) fuel availability and delivery cost analysis; (iv) site selection; (v) schematic design; (vi) summary project information for permitting; and (vii) Ohio Power Siting Board application. S&L provided a report for each task that summarized the methods and results of the investigations and evaluations. Based on the results of the site evaluation process and the final field surveys, the Letart Falls site in Meigs County, Ohio, was chosen as the preferred site. As follow-up to their initial services, S&L has provided information to support Project permit applications and other studies.

Overview of the Project Arrangement

As of the date of this Report, it is contemplated that approximately 97.5 percent of the AMPGS Project will be owned by AMP-Ohio and that AMP-Ohio will enter into take-or-pay power sales contracts with each of the participating AMP-Ohio Members (including those that are also members of BRPA or MSCPA). The remaining 2.5 percent of the AMPGS Project would be owned by the Central Virginia Electric Cooperative ("CVEC"). Contractual arrangements with respect to joint ownership and the operation of the AMPGS Project have not yet been developed. However, each of the two owners would be responsible for the financing of the respective ownership interest. In the event CVEC decides not to participate as a co-owner, AMP-Ohio expects to retain the CVEC share and own 100 percent of the AMPGS Project.

The AMP-Ohio Members that are participating in the AMPGS Project will execute power sales contracts with AMP-Ohio authorizing AMP-Ohio to finance, construct and operate the AMPGS Project and specifying the Member's obligations to take or pay for the power and transmission service from the AMPGS Project under the terms of the contract. Each participating Member will be entitled to receive a fixed entitlement share of the output of the AMPGS Project at a "postage stamp rate" that

will be designed to recover the fixed and variable costs of the AMPGS Project and certain related transmission services.

AMP-Ohio intends to finance the cost of acquisition and construction of the Project with revenue bonds authorized under a Master Trust Indenture and secured by the power sales contracts with the Members.

Project Timeline

The overall Project development timeline has a target of April 2013 for the commercial operation date of Unit 1 and October 2013 for Unit 2. As shown in the timeline below (Figure 1), the major milestones that are on the critical path of the Project schedule include:

- Ohio Members Ordinances passed by October 1, 2007
- Power Sales Contracts with Ohio Members signed by November 1, 2007
- Out-of-State (outside of Ohio) Power Sales Contracts signed by March 2008
- Exercise land options in July 2008
- Complete EPC Contract Negotiations by March 2009
- All construction permits approved by March 2009
- EPC Contract final Notice to Proceed ("NTP") for construction by April 2009

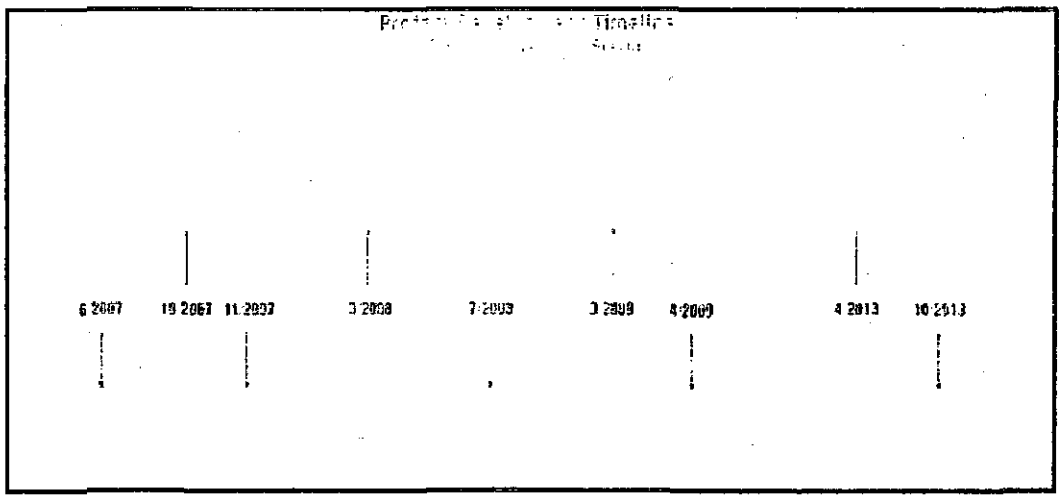

Figure 1 - Project Development Timeline

Project Description

The proposed AMPGS Project is a 960 MW[2] coal-fired generating station which is to be located in Meigs County, Ohio, in the township of Letart Falls. Figure 2 illustrates the AMPGS Project site location.

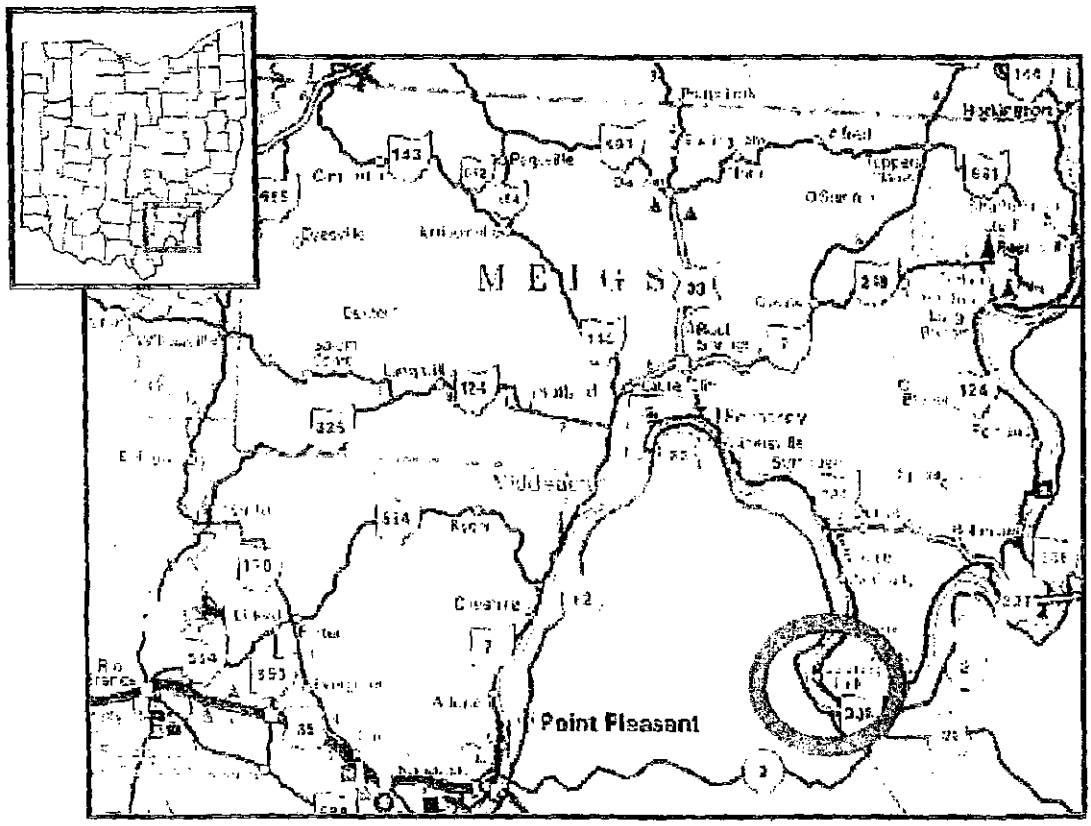

Figure 2 – AMPGS Site Location

The AMPGS Project site is a green field site with access to the Ohio River. Prior use of the site was primarily for agriculture. In total, the Project facilities, including the landfill, will have a footprint of approximately 1,000 acres, not including 600 acres of AMP-Ohio owned land to serve as a buffer.

The AMPGS Project will be operated as a base load plant comprised of two nominal 480 net MW generating units. Figure 3 provides a conceptual rendering of the Project site and equipment layout.

[2] The 960 MW rating reflects the projected summer capacity rating of the Project. The annual average rating is projected to be 987 MW.

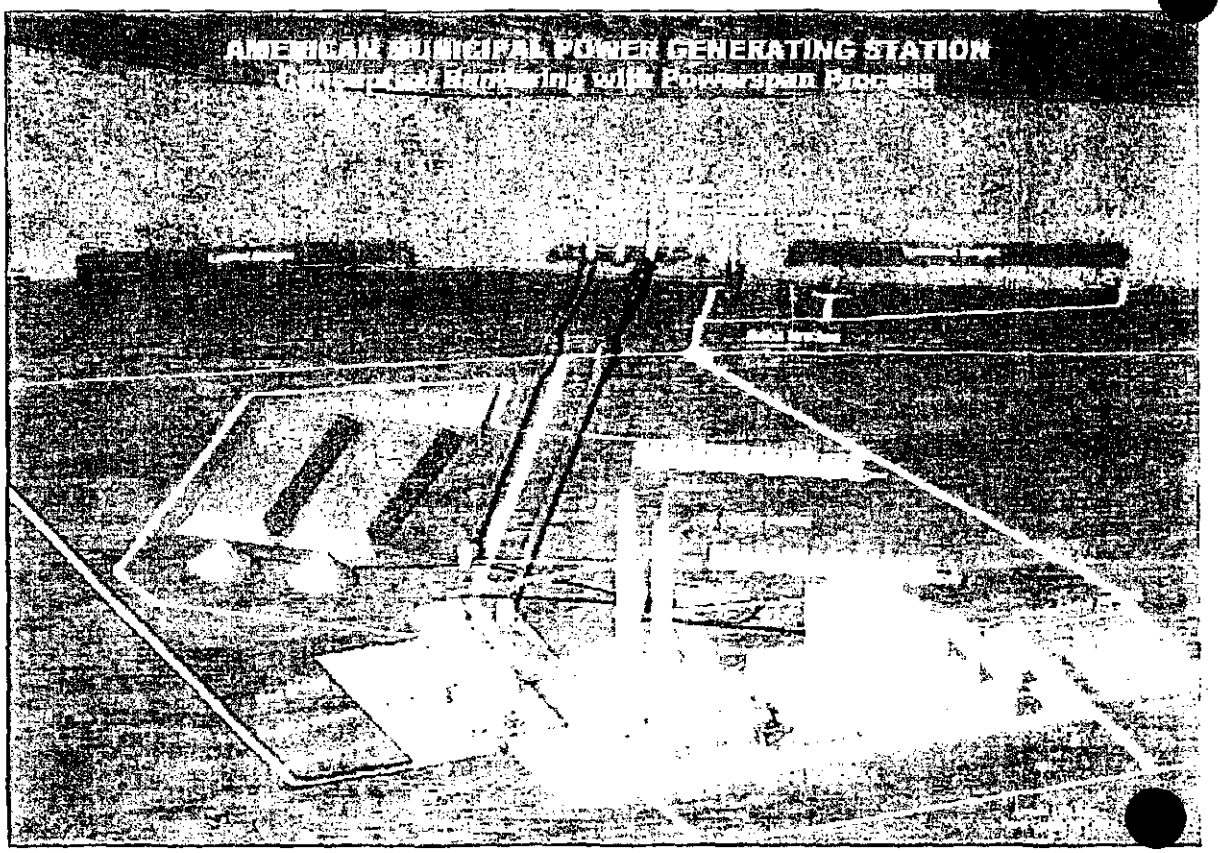

Figure 3 – Conceptual Rendering of AMPGS Project

The AMPGS will be required to comply with federal New Source Performance Standards ("NSPS") and will be permitted as a major new air emission source in a location designated as an "attainment" area for all criteria pollutants. AMP-Ohio submitted an application for a Permit to Install ("PTI") to the Ohio EPA in May 2006. The application for the PTI specifies that the Project will install Best Available Control Technology ("BACT") for control of emissions from AMPGS, including a filter baghouse to control particulates, low nitrogen oxide ("NOx") burners and selective catalytic reduction ("SCR") for control of NOx and Powerspan Corporation's ("Powerspan") multi-pollutant control technology ("ECO-SO_2 ") which will control emissions of sulfur dioxide ("SO_2"), fine particulate matter using a wet electrostatic precipitation ("Wet ESP"), mercury ("Hg"), and sulfuric acid ("H_2SO_4").

The Powerspan technology is discussed in further detail in Section 3 and Appendix D of this Report. This new technology is a wet flue gas desulfurization ("Wet FGD") system that uses urea, which will be processed to produce ammonia, which will then be used as a reagent in the wet FGD process to reduce SO_2 emissions from the plant's flue gas. The product from the reaction of SO_2 and ammonia is a liquid ammonium sulfate, which will be processed through a crystallizing process to produce solid ammonium sulfate, a fertilizer, which can be sold in the fertilizer market.

This technology has undergone a 50 MW demonstration test, but will need to be scaled up for application to the Project. In the event that the Powerspan technology

cannot be appropriately guaranteed by the EPC contractor for the AMPGS Project, a limestone wet scrubber could be developed to satisfy air permitting requirements for the Project.

The proposed two generating units are to be capable of burning a blend of Ohio, Central Appalachian and/or Southern Powder River Basin ("SPRB") coals. Coal will be delivered by barge to the generating station and will be moved to the site using a conveyor system. The steam generators for each unit are proposed to be subcritical pulverized coal ("PC") boilers that use natural gas as the startup fuel.

The AMPGS Project also includes: (i) the construction of an on-site switchyard and a double-circuit 345 kV transmission line from the AMPGS to an interconnection point at an existing transmission line; (ii) a tie point for the natural gas supply pipeline to the generating station; and (iii) an on-site solid waste landfill.

Estimated Capital Costs and Financing Requirements

The estimated capital costs for construction of the AMPGS Project are summarized in the following table. The total construction costs include EPC costs, transmission facilities (including an on-site 345 kV substation), land and infrastructure upgrades and owner's costs. The estimated value for the EPC contract is $2.148 billion for the two units and includes all costs associated with the engineering, design, equipment, material, construction and start-up of the Project facilities, and a provision for contractor escalation and contingency. A six percent contingency was included in this EPC contract estimate.

Other Project costs which will be contracted, constructed and paid separate from the EPC contract by AMP-Ohio include interconnecting 345 kV transmission line (double circuit), interconnection 345 kV switchyard, various electric system upgrades and land and infrastructure upgrades. Total estimated costs for these Other Project costs are $134.3 million.

Owner's costs are estimated to be $250.3 million (other than financing costs). Such costs include owner's engineer, environmental consultants, financial and legal consultants and AMP-Ohio staff expenses, initial inventories, spare parts, initial working capital and $100 million contingency. As of the date of this Report, the total cost of construction is estimated to be approximately $2.532 billion as summarized in Table 1 below.

Table 1
Estimated Costs of Construction[1]

Description	Dollars in Thousands
Capital Costs	
EPC Costs [2]	$2,148,180
Other Costs:	
Transmission Line and Interconnection Switchyard	24,000
Transmission System Upgrades [3]	65,000
Land and Infrastructure Upgrades [4]	45,300
Total Capital Costs	$2,282,480
Owner's Costs	
AMP-Ohio Staff, Legal, Engineers and Consulting Costs [5]	$49,300
Taxes and Insurance	28,000
Initial Inventories and Spare Parts [6]	35,000
Start-up and Commissioning Expenses	10,000
Working Capital [7]	5,000
Owner's Cost Escalation	23,000
Owner's Contingency	100,000
Total Owner's Costs (w/o Financing Costs)	250,300
Total Estimated Costs of Construction	$2,532,780

[1] The development of the estimated costs of construction of the AMPGS Project is set forth in Section 3.5 herein.
[2] Amount includes allowance for cost escalation, EPC profit and 6% contingency on EPC costs.
[3] Estimated costs associated with transmission system upgrades related to interconnecting the Plant to the PJM system. Does not include costs for potential transmission system upgrades relating to transmission services required to deliver capacity to the MISO Participants.
[4] Includes estimated costs of a gas line, land costs, rights of way, landfill development and infrastructure costs.
[5] Includes initial developmental costs to date, the estimated costs of AMP-Ohio staff costs related to management of permitting, licensing and the EPC open book process, legal, engineers and other consulting fees.
[6] Includes an allowance of $20 million for initial fuel and other commodity inventories and $15 million for initial spare parts inventory.
[7] Based on one month of fixed and variable operation and maintenance costs (excluding fuel and other commodities).

As shown in the table below, the total estimated amount of bonds to fund the cost of the Project including construction costs, interest during construction, deposit to a Reserve Account (as required by the Master Trust Indenture) and bond issuance expenses is estimated to be approximately $2.912 billion. AMP-Ohio's financing plan reflects issuance of variable-rate debt on an interim basis during the construction period to fund construction costs and interest during construction. Following the construction period, AMP-Ohio would then undertake permanent financing of the Project through issuance of fixed-rate long-term bonds that would refund the previously issued interim variable-rate debt. The estimated bond financing requirements are shown below in Table 2.

Table 2
Total Estimated Bond Amount

Description	Dollars in Thousands
Estimated Bond Amount	
Construction Costs [1]	$2,532,780
Net Interest During Construction [2]	270,722
Deposit to Reserve Account [3]	71,336
Issuance Expenses [4]	37,303
Total Estimated Bond Amount [5]	$2,912,141

[1] Per Table 6-1.
[2] Estimated amount to be deposited in the Interest Account to pay interest on bonds outstanding to July 1, 2013. Net of estimated interest earnings at an assumed rate of 3.75 percent on unexpended balances in the Construction Fund, Interest Account and Reserve Account during the construction period 2005 through 2013.
[3] Estimated amount required to be deposited into the Reserve Account based on one-half of the estimated maximum debt service on all Project permanent debt.
[4] Estimated expenses associated with bond underwriter's fees, legal fees, and other expenses incurred in connection with the bond financings. Such amounts were based on 0.5 percent of the principal amount of Bonds issued prior to permanent financing and 1 percent of the principal amount of Bonds issued in 2013 for permanent financing.
[5] This amount reflects 100 percent of the AMPGS Project. AMP-Ohio's ownership share at 97.5 percent would be $2,839,337,500.

Plans for Constructing and Operating the Plant

Schedule and Plan for Construction

Activities that are ongoing as of the date of this Report generally include permitting, Participant approvals, and the solicitation of EPC contractor proposals. It is expected that all the Participant contracts would be in place by March 2008. The initial EPC contract for preliminary design would begin in June 2008. The EPC contract is scheduled to be finalized by March 2009, followed by an EPC contract final NTP in April 2009. The final land purchase of the site is assumed to occur in July 2008. The last permit approval required is scheduled for February 2009. The estimated EPC schedule for engineering, procurement and construction of Unit 1 is a 48-month schedule beginning in April 2009 and ending with substantial completion in April 2013. The Unit 2 commissioning and substantial completion is assumed to occur approximately 6 months later than Unit 1, or October 2013.

AMP-Ohio plans to contract with a single firm to engineer (and design), procure the equipment, and construct ("EPC") the plant. This method reduces the number of contracts executed which makes contract administration by AMP-Ohio less labor intensive than having to negotiate several large contracts to accomplish the same tasks. It also minimizes many of the risks associated with interfacing and coordinating between different contractors.

In conjunction with using the EPC contracting method, establishing the contract as a fixed-price contract will mitigate some of AMP-Ohio's risk in meeting the Project's

schedule and budget. The key to successfully implementing a fixed price EPC contract is a well defined scope of the project. A method for helping to assure that the scope of the Project is defined to a sufficient level of detail and that both AMP-Ohio and the EPC contractor understand and agree on the scope is to develop the design of the plant to a sufficient level of detail before fixing the price and the schedule. To assure that AMP-Ohio is receiving a fair price and schedule for the Project, this up-front design work will be conducted under an "open book" policy which will provide details (i.e. scope of work, scope of supply, plant performance, price, and schedule guarantees) required to finalize the EPC contract between AMP-Ohio and the EPC Contractor.

The EPC contract will cover the majority of Project facilities to be constructed, except for the natural gas supply to the plant, the construction of the on-site switchyard and transmission line from the plant site to the tie-in point with the existing transmission grid, construction of transmission upgrades, the on-site landfill and communication ties to AMP-Ohio's communication system. Design, procurement and construction for these other facilities would be performed under separate contracts.

Plant Operation and Maintenance

As of the date of this Report, AMP-Ohio intends to assume the responsibilities of operating and maintaining the Project. This includes fuel procurement, fuel and ash handling, general materials procurement, environmental reporting and the overall operation and maintenance of the plant. AMP-Ohio plans to contract with The Andersons (a national agriculture company) for an initial 5-year period to operate and maintain the fertilizer plant, including procurement and supply of urea and marketing of the ammonium sulfate fertilizer produced from the Powerspan emission control system.

A projection of the performance, commodity prices, and operating expenses of the AMPGS Project for the period 2013 – 2032 is set forth in Attachment ES-1. The estimated operation and maintenance expenses for the Project are summarized in Table 3 below. Details associated with these estimates are included in Section 4, Section 6 and Attachment ES-1.

Table 3
Estimated Production Related O&M Expenses [1]

Category	2013$
Total Fixed O&M, $/kW-year	38.60
Variable O&M, $/MWh	8.59
Fuel, $/MWh	19.94
Total Annual Operating Costs, $/MWh	33.72

[1] Includes total fixed O&M, variable O&M, and fuel, including allowance costs (NO_x, SO_2, Hg and CO_2).

Fuel and Transportation

A blend of local high sulfur content coals with lower sulfur content coals is planned for the fuel supply to AMPGS. Such blending is due to the typically high sulfur content of the Ohio and other local bituminous coals. Blending Ohio coal is desirable even though it is higher in sulfur because it has lower transportation costs, which make it attractive for use in blending. In addition, there is also a possibility that a tax credit or another type of credit could be granted for using Ohio coal. Preliminary coal blending plans include options to blend Ohio coal and SPRB coal ("Western Blend") or a blend of Ohio coal and Central Appalachia coal ("Eastern Blend"). Table 4 below summarizes these coal blends and the estimated delivered cost.

Table 4
Fuel Supply Characteristics and Costs for Eastern and Western Blends [1]

	Eastern Blend	Western Blend
Percent Ohio Fuel (%)	34.00	51.80
Percent Lower Sulfur Fuel (%)	66.00	48.20
	(WV medium sulfur)	(SPRB)
Annual Tons for Blend [2]	2,815,705	3,338,354
Heating Value for Fuel Blend (Btu/lb)	12,051	10,535
Sulfur Content for Fuel Blend (%)	2.11	1.84
Ash Content for Fuel Blend (%)	10.83	7.85
Delivered Fuel Price for Blend ($/MMBtu) [3]	2.14	2.18

[1] Based on information from Sargent & Lundy's Fuel Forecast Update, Report Number SL-008668, dated January 2006.
[2] Fuel consumption values are based on average annual plant output of 987 MW (net); design heat rates of 9,233 Btu/kWh (Eastern Blend) and 9,570 Btu/kWh (Western Blend); and an annual average capacity factor of 85 percent.
[3] Fuel prices are escalated values for delivery in 2013.

The analyses in this Report reflect the Eastern Blend, since it results in the most cost effective fuel blend as of the date of this Report. However, coal prices and transportation costs are subject to market pressure that can affect the price of the blends. To allow the flexibility to use a cost effective fuel blend during the operation of the plant, a design basis fuel will be defined for the EPC Contract specifications; however, efforts will be made to use equipment that can process both an Eastern Blend and a Western Blend. A fuel supply plan will be developed, followed by the selection of the final coal blends and final contract negotiations with coal suppliers and with rail and barge transportation companies. It is anticipated that prior to issuing the EPC contract, the contracts (or letters of intent) for the coal supply and its transportation will be executed.

Environmental Considerations and Requirements

The Project is being planned to include air emission control systems to comply with the expected regulatory requirements, based on information in the air permit application for the Project. The following emission limitations are expected:

Table 5
Proposed Air Emission Limits and Controls

Pollutant	Control Systems	Emission Limit (lbs/MMBtu)
SO_2	Powerspan Wet Scrubber	0.15
NO_x	Low NO_x Burners and SCR	0.07
PM/PM10	Baghouse/Wet ESP	0.025
Hg [1]	Baghouse/Powerspan Wet Scrubber	4.3×10^{-6}

[1] Hg limit allows flexibility for the use of varying fuel blends (i.e. Eastern and Western blends).

The Project will be subject to certain environmental requirements that include, but are not limited to: (i) NO_X and SO_2 allowance obligations, including those required under the Clean Air Interstate Rule ("CAIR"); (iii) mercury emissions allowances obligations under the Clean Air Mercury Rule ("CAMR") which includes the establishment of a cap and trade program in which states, including Ohio, may choose to participate; and (iv) potential CO_2 emission allowances obligations in the form of either a carbon tax imposed on emissions of CO_2 or some form of a cap and trade system comparable to what presently exists for SO_2 and NO_X emissions.

The impact of complying with the these rules has been estimated in the projected operating results discussed in Section 6 by assuming that the Project will purchase allowances from the market. A carbon tax ranging between $5/ton to $15/ton (in 2006 dollars) is assumed to be in place beginning between 2012 and 2018. While there are different points of view and opinions on the CO_2 tax levels that may be imposed, the $5/ton to $15/ton range, in R. W. Beck's view, represents a reasonable assumption for the initial years of carbon regulation as supported by opinions expressed by other investigations and trading of CO_2 credits in European markets. Higher CO_2 tax levels may impact the AMPGS Project as well as the entire electric utility market in ways not identified in this Report. Projections of allowance costs for SO_2 and NO_X are based on EPA estimates and R. W. Beck's proprietary model that projects the marginal cost of pollutant reductions to comply with the Acid Rain and CAIR regulations. Projections of allowance costs for Hg are based on EPA estimates and R. W. Beck's data base of mercury control costs for compliance with CAMR. The actual price of allowances in the future will be market dependent and could be lower or higher than the cost estimates herein.

Status of Permits and Licenses Required

The Project must be constructed and operated in accordance with applicable environmental laws, regulations, policies, guidelines, codes and standards. Based on our review, AMP-Ohio has identified the major permits and approvals necessary for the construction and operation of the Project. AMP-Ohio is presently in the process of applying for/obtaining the key permits and approvals required to construct and operate the Project.

Required Transmission Services

To deliver the output of the AMPGS Project, AMP-Ohio must: (i) interconnect with PJM[3] through PJM's generator interconnection process as a Capacity Resource; and (ii) obtain firm point-to-point transmission service under the PJM Open Access Transmission Tariff ("PJM OATT") to deliver the Project output (or a portion thereof) to the MISO[4] border for those Participants that are located within MISO. As of the date of this Report, AMP-Ohio is in the process of taking the necessary steps to obtain these services.

Studies conducted as of the date of this Report by PJM indicate that the direct interconnection facilities for the Project totaling approximately $24 million include the construction of a double-circuit 345 kV transmission line from the Project to an interconnection point at an existing transmission line located approximately five (5) miles from the Project site. In addition, interconnection service requires the construction of approximately $58 million in transmission upgrades to the existing transmission system. These costs have been included in the capital costs of the Project. However, studies remain to be performed for point-to-point transmission service to MISO and for transmission service within MISO. There is also a schedule risk related to the time it will take to go through the interconnection process and construct the necessary transmission upgrades. Most of the required upgrades are estimated to take 12 months; however, some projects could take longer due to equipment lead times.

The System Impact Study conducted by PJM also identified certain conditions under which the plant output could be curtailed to 0 MW. One of these conditions is the outage of a transformer, and a failure of the transformer could mean a long outage (multiple months) for both the transformer and AMPGS. For purposes of this

[3] PJM Interconnection (PJM) is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity over thirteen states in the northeastern United States. PJM provides open access to transmission markets, long-term transmission planning and reliability, and operates a wholesale energy market. PJM's energy markets operations include Day-Ahead, Real-Time and Financial Transmission Rights markets. PJM also operates capacity markets.

[4] The Midwest Independent Transmission System Operator, Inc. (MISO) is a non-profit, member-based organization that provides open access to transmission markets, long-term transmission planning, and transparent prices and manages the security-constrained economic dispatch of generation over its fifteen state territory. MISO's energy markets operations include Day-Ahead, Real-Time and Financial Transmission Rights markets.

Feasibility Study, we have assumed a $7 million cost to purchase a backup transformer to mitigate this risk and have included this cost in the capital cost of the Project.

Lacking studies from PJM and MISO concerning additional transmission service or modifications to existing transmission service, we cannot know what potential transmission upgrades might be required. AMP-Ohio has initiated load flow studies to estimate the potential transmission upgrade costs to provide point-to-point transmission service from the Project to the participants in MISO.

Another risk that all power supply alternatives face is pricing differentials between the point of delivery and the point of receipt. In a Locational Marginal Pricing ("LMP") market such as PJM and MISO, this "basis differential" risk consists of three parts: (i) energy market basis differentials caused by congestion and marginal losses; (ii) capacity market basis differentials due to implementation of a location based capacity market which PJM implemented June 1, 2007; and (iii) potential pancaked charges (the Project will bear charges in the form of RTO administration fees and ancillary services charges for the point-to-point service to the PJM/MISO border based on the existing PJM and MISO rate design). Additionally the Project could bear wheeling charges based on any FERC approved transmission cost allocation methodology for new transmission facilities. While these risks are not expected to be as significant as the risks of new transmission upgrades, conditions can change over time.

Projected Operating Results of the AMPGS Project

R. W. Beck has prepared projections of the net power costs that will be the basis of the charges to the Participants for the AMPGS Project ("Projected Operating Results") for the period 2013 through 2032. These Projected Operating Results reflect 100 percent of the costs of the AMPGS Project[5] and are consistent with our understanding of the terms and conditions of the drafts of the Power Sales Contract and Master Trust Indenture, both dated as of April 2, 2007. The Projected Operating Results set forth the costs that comprise the Postage Stamp Rate ("PSR") as defined in the Power Sales Contract. The PSR is a uniform rate that will apply to all of the Participants. The Projected Operating Results also include a projection of the activities in the funds that are defined in the Master Trust Indenture and Power Sales Contracts.

Control of greenhouse gases such as CO_2 is receiving a great deal of attention within the United States Congress and many state legislatures. The predominant sentiment is that regulation is inevitable and only the timing and method of regulation is not presently known. In preparing the Projected Operating Results and other economic analysis included in this report, we have assumed that there will be a carbon tax imposed on emissions of CO_2 or some form of a cap and trade system with CO_2 emission allowances comparable to what presently exists for SO_2 and NO_X emissions.

[5] Because CVEC will own approximately 2.5 percent of the AMPGS Project, the AMP-Ohio ownership share will be approximately 97.5 percent which is less than 100 percent. However, we for purposes of the projections set forth here we have reflected 100 percent of the costs and output of the AMPGS Project.

The Projected Operating Results are set forth as Attachment ES-2 at the end of this Executive Summary and are based on the principal considerations and assumptions set forth in Section 9 of the Report. A summary of the projections are shown below in Table 6 for selected years.

We have also estimated the Participant sales of energy from their share of the AMPGS Project which are projected to be in excess of their load requirements and are assumed to be sold into the market. The total estimated surplus energy amounts for each year are shown on line 65 of Attachment ES-2. Such amount represents approximately 2.5 percent of the AMPGS Project energy. The estimated revenues from the sale of the surplus energy into the wholesale market for each year are shown on line 64. The projected net costs to the Participants after the credits for surplus energy sales shown in dollars and on average ($/MWh) are set forth on lines 67 and 69 of Attachment ES-2.

Table 6
Summary of AMPGS Projected Operating Results

	Description		2015	2020	2025	2030	2032
	Revenues:						
1	Participant Revenues [1]	$000	$458,230	$537,820	$590,968	$654,258	$684,523
2	Other Revenues [2]	$000	41,360	48,195	51,150	53,025	53,178
3	*Total Revenues*	$000	$499,590	$586,014	$642,118	$707,283	$737,700
	Operating Expenses:						
4	Fixed Operating Costs [3]	$000	$43,723	$48,522	$53,925	$60,009	$62,651
	Variable Operating Costs:						
5	Fuel Costs	$000	152,332	168,821	193,838	224,709	238,191
6	Non-Fuel Variable Operating Costs [4]	$000	94,361	154,048	176,872	203,756	215,851
7	*Variable Operating Costs*	$000	246,693	322,869	370,710	428,465	454,042
8	Replacement Power [5]	$000	21,731	26,822	29,449	29,314	30,510
9	*Total Operating Expenses*	$000	312,148	398,213	454,084	517,788	547,204
10	**Net Revenues [6]**	$000	$187,442	$187,801	$188,034	$189,494	$190,497
11	**Deposit to Working Capital Reserve Account [7]**	$000	1,301	1,659	1,892	2,157	2,280
12	**Debt Service [8]**	$000	169,220	169,220	169,220	169,220	169,220
13	**Deposit to Reserve & Contingency Fund [9]**	$000	16,922	16,922	16,922	18,117	18,997
14	**Total Revenue Requirements**	$000	$499,590	$586,014	$642,118	$707,283	$737,700
	Unit Operation:						
15	Net Capacity	MW	960.0	960.0	960.0	960.0	960.0
16	Gross Energy	GWh	7,349.2	7,349.2	7,349.2	7,349.2	7,349.2
17	Plus: Replacement Energy Purchases	GWh	303.0	303.0	303.0	303.0	303.0
18	Less: Surplus Energy Sales [10]	GWh	(504.0)	(504.0)	(504.0)	(504.0)	(504.0)
19	Net Energy	GWh	7,148.2	7,148.2	7,148.2	7,148.2	7,148.2
20	Capacity Factor	%	85.0%	85.0%	85.0%	85.0%	85.0%
	Average Project Costs (with CO2):						
21	*Net Fixed Costs*	*$/KW-mo*	18.36	18.66	19.12	19.60	20.01
22	*Net Non-Fuel Variable Costs*	*$/MWh*	13.20	21.55	24.74	28.50	30.20
23	*Net Fuel Costs*	*$/MWh*	20.73	22.97	26.38	30.58	32.41
24	*Average Costs to Participants*	*$/MWh*	64.10	75.24	82.67	91.53	95.76
	Average Project Costs (w/o CO2):						
25	*Average Costs to Participants [11]*	*$/MWh*	56.81	60.87	66.50	73.32	76.67

[1] Participant Revenues are equal to Total Revenue Requirements (line 14) less other revenues (line 2).
[2] Includes interest earnings, short-term market sales, transfers from R&C Fund and other Project revenues (if any).
[3] Includes fixed O&M, transmission costs, insurance, property taxes, AMP-Ohio A&G costs and bank and trustee fees.
[4] Includes environmental costs (including estimated CO_2 and mercury emissions costs), variable O&M, Powerspan costs and credits for fertilizer sales.
[5] Estimated cost of replacement power purchased from the short-term energy market to replace AMPGS during scheduled and forced outages.
[6] Equal to Total Revenues (line 3) less Total Operating Expenses (line 29).
[7] Deposit to Working Capital Reserve Account equal to 5% of the total monthly Operating Expenses.
[8] Estimated debt service on Bonds projected to be issued to finance the total cost of construction of the AMPGS Project.
[9] Deposit to Renewal & Replacement Account equal to the greater of 10% of Debt Service or the estimated renewals & replacements for such year.
[10] The quantity of short-term market energy sales that are expected to be in excess of the energy required under the Power Sales Contracts with the Participants.
[11] Net Project costs without CO_2 emissions costs

The development of the average AMPGS Project costs in $/MWh is shown on lines 45 through 59 of Attachment ES-2. The major components of the average annual Project costs are shown below in Figure 4. Net debt service, which represents approximately 29 percent of the total costs, equals the total debt service payments less interest earnings. Fuel cost represents approximately 34 percent of the total costs and includes the cost of coal purchases and coal transportation costs. CO_2 costs make up approximately 18 percent of the total costs and assume that a CO_2 tax would be put in place sometime during the period 2012-2018. Other environmental costs represent approximately 6 percent of the total costs and include emission costs and/or allowance costs related to SO_2, NO_x, and Hg. Other net operating costs include all other operating costs (net of other revenues) and represent approximately 13 percent of the total costs.

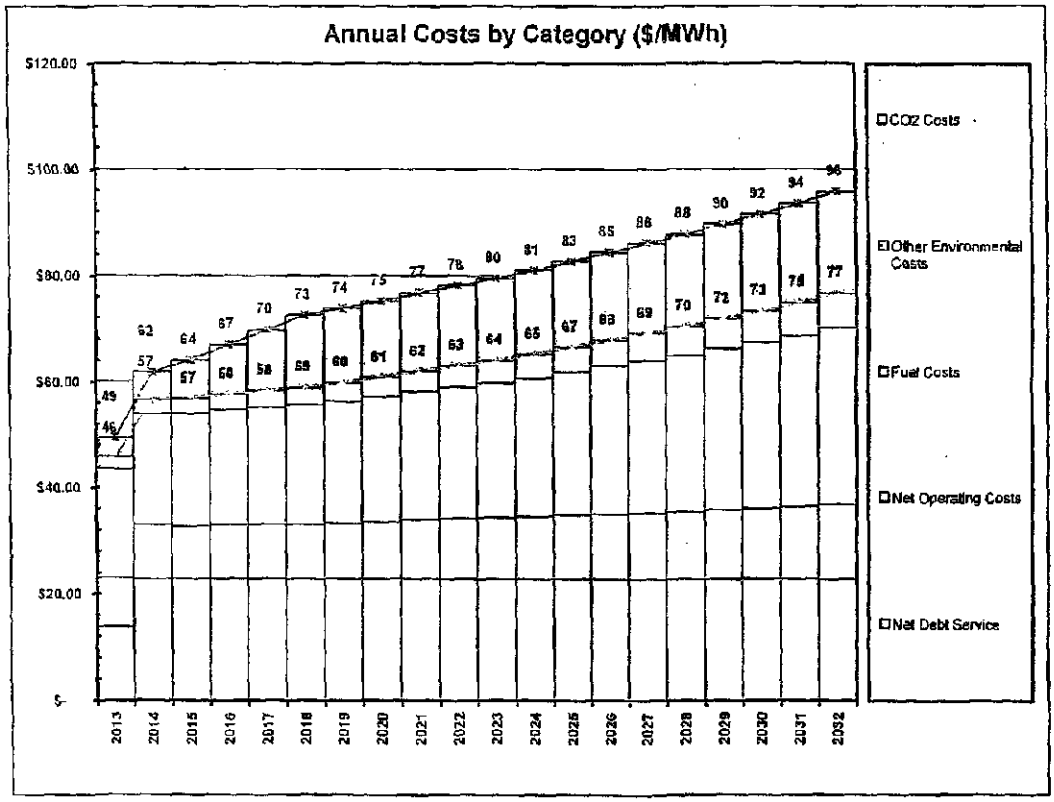

Figure 4 – Projected Annual Power Costs by Category ($/MWh)

AMPGS Project Participants

There are 87 Members[6] of AMP-Ohio that are participating in the development of the AMPGS Project (the "Participants"). The Participants consist of 29 cities and 46 villages in Ohio, 2 boroughs in Pennsylvania, 3 cities and 1 town in Virginia, 3 cities and 2 villages in Michigan and 1 city in West Virginia.

As set forth in Appendix A of the draft Power Sales Contract dated April 2, 2007, each of the AMPGS Participants has initially committed to a Project entitlement share of the AMPGS Project referred to as the Power Sales Contract Resource Share ("PSCR Share"). A list of the Participants and their respect PSCR Shares is shown on Attachment ES-3[7] included at the end of this Executive Summary.

The Participants' power supply arrangements may vary based on, among other things, the power pool or investor-owned utility service area in which their system is located. The majority of Members are associated with one of AMP-Ohio's power pools.

AMP-Ohio Members currently receive their power supply from a mix of resources that includes:

- wholesale power purchases through AMP-Ohio and on the open market from investor-owned utilities and marketers;
- energy produced at AMP-Ohio's 213 MW, coal-fired Richard H. Gorsuch Generating Station near Marietta, Ohio;
- individual community-owned generation facilities; and
- municipal generation joint ventures, including the 42 MW Belleville Hydroelectric Project at the Belleville Locks and Dam on the Ohio River; the 7.2 MW AMP-Ohio/Green Mountain Energy Wind Farm located near Bowling Green, Ohio and approximately 334 MW of distributed generation (either owned by AMP-Ohio or a municipal joint venture) strategically sited throughout the state, using natural gas and diesel technology.

The five Participants in Michigan are members of MSCPA which owns and operates a 50 MW (summer rating) power plant in Litchfield, Michigan on behalf of the MSCPA members. These five Participants also own 76 MW of peaking units and hydro resources. Also, MSPCA purchases partial requirements service from AMP-Ohio on behalf of the MSCPA members.

The four Participants in Virginia are members of BRPA. These four Members have purchased all requirements power from AMP-Ohio since July 2006.

Figure 5 below shows the total of the 87 Participants' projected peak demand, total capacity requirements (peak demand plus an allowance for 12 percent reserves),

[6] As of the date of this Report, there are 87 Participants. Front Royal, Virginia, is neither a Member of AMP-Ohio nor a Participant in the AMPGS Project. However, AMP-Ohio anticipates that Front Royal may become a Member and Participant in the AMPGS Project.

[7] Attachment ES-3 is a copy of Appendix A taken from a draft of the Power Sales contract dated April 2, 2007 discussed below.

existing power supply resources (coal, hydro, diesel, gas, wind and purchased power), the projected 960 MW of capacity from the AMPGS Project, and additional future power supply resource requirements over the period 2008-2027.

As can be seen from the figure, the capacity of the AMPGS Project is needed to fill the base-load requirements of the Participants on a total aggregate basis.

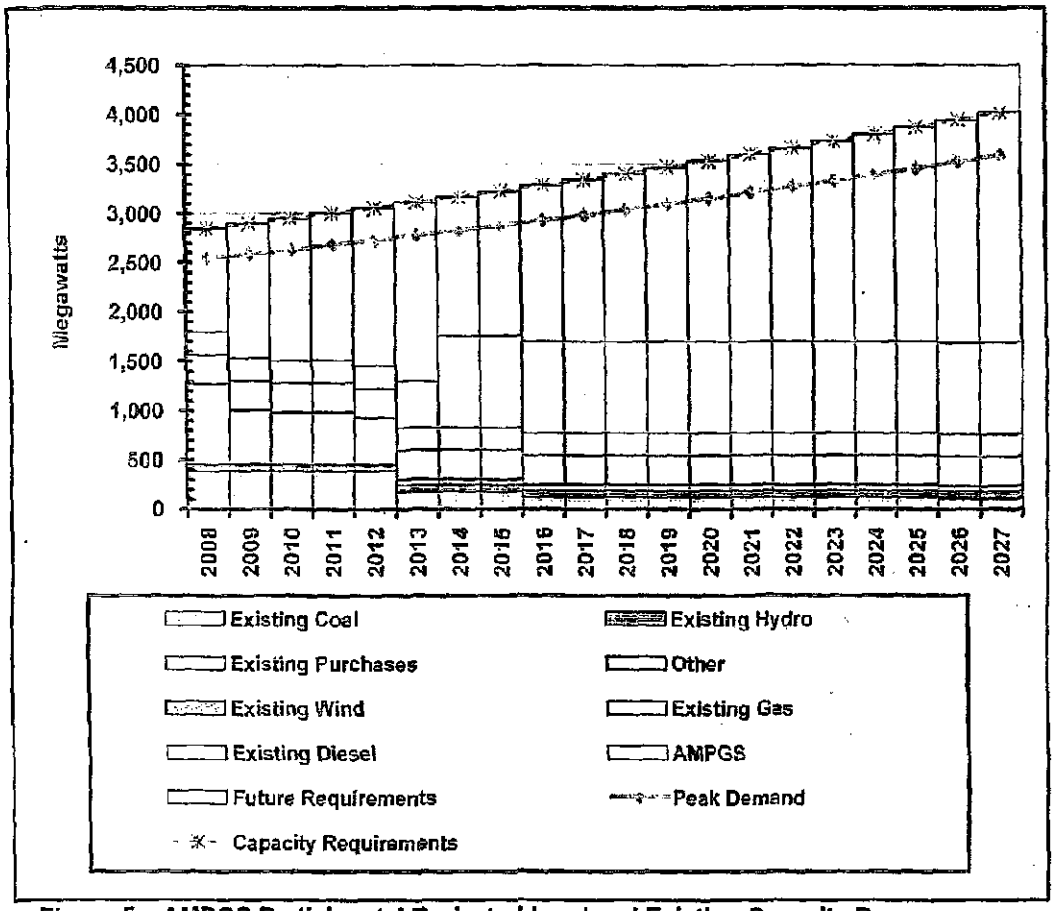

Figure 5 – AMPGS Participants' Projected Load and Existing Capacity Resources (Including AMPGS) [1]

[1] Excludes demand, existing capacity, resources, and capacity from AMPGS for Front Royal and CVEC. Assumed on-line dates of April 2013 for AMPGS Unit 1 and October 2013 for AMPGS Unit 2.

Power Sales Contracts Between AMP-Ohio and the Participants

The Power Sales Contract is the agreement that sets forth the rights and obligations of AMP-Ohio and each Participant with respect to the AMPGS Project. Given the corporate structure of AMP-Ohio, the governing bodies of the Members that enter into contractual arrangements with AMP-Ohio must authorize an ordinance that provides authority for the Member to enter into the Contract. Accordingly, with respect to the

Power Sales Contracts for the AMPGS Project, each Participant will be required to pass an ordinance by their local governing body. The ordinances for the AMPGS Project Power Sales Contract have been prepared for authorization by the governing body of each Participant to authorize execution of the Power Sales Contract by the Participant.

The Power Sales Contract referred to herein is the draft version of the document dated as of April 2, 2007. Under the Power Sales Contract, the Participant is entitled to receive its PSCR Share of the nominal power and associated energy from the Power Sales Contract Resources, which include the electric power and energy from AMP-Ohio's ownership share of AMPGS, all sources of replacement power, and certain transmission services. See Attachment ES-3 for the respective PSCR Share for each Participant. These are the amounts set forth in the Power Sales Contract as of April 2, 2007. The final BSPR Shares will be determined after all Participants have passed ordinances and executed the Power Sales Contract.

The Power Sales Contract is a "take or pay" contract between AMP-Ohio and each of the AMPGS Participants, whereby those Participants agree that, in order to obtain power and energy from the Power Sales Contract Resources, they are willing to pay for their respective rights to that power and energy at rates sufficient to enable AMP-Ohio to recover all of its costs incurred with respect to the AMPGS Project. The Participants are obligated to take or pay for their respective PSCR Share whether or not the Power Sales Contract Resources are complete, operable, or operating.

Under the Contract, all costs of the Project as set forth on monthly invoices from AMP-Ohio, including debt service, are to be recorded as an operation and maintenance expense of the Participant's electric system fund. Debt issued to finance the Project will be recorded on the books and records of AMP-Ohio. No AMPGS debt will be recorded on the books of the Participant.

The Board of Trustees, after consultation with the Participants Committee (discussed below), shall establish, maintain and adjust rates or charges, or any combination thereof, for the capacity and output of the Power Sales Contract Resources sold to Participants under this Contract. A Postage Stamp Rate and other rates and charges under the Contract will be set at levels that are sufficient to meet the Revenue Requirements of AMP-Ohio.

Project governance will be the responsibility of the AMP-Ohio Board of Trustees and the Participants Committee, which is a committee of the Board of Trustees formed by the Participants pursuant to provisions in the Power Sales Contract.

The by-laws of the Participants Committee are set forth in Appendix L of the Power Sales Contract. The Participants Committee will review construction progress, insurance, interim construction financing including capitalized interest, permanent financing and other plant operating matters. The Participants Committee will also make recommendations for rate setting to the Board of Trustees. The Participants Committee will consist of Participants that in total comprise at least 51% of the entitlement shares of AMPGS.

Some actions and authorizations require the approval of a Super Majority of the Participants. A Super Majority of the Participants is defined as 75% of the entitlements of all Participants.

Section 18 of the Power Sales Contract addresses the terms and conditions that are applicable in the event of a default by a Participant due to non-payment or other acts that would cause suspension of the rights of the defaulting Participant under the Contract. In certain default events, each non-defaulting Participant will be required to purchase a pro rata share of the defaulting Participant's entitlement to its PSCR Share, and this amount is referred to in the Contract as "Step Up Power". The amount of Step Up Power will not exceed an accumulated maximum kilowatts of 25% of the non-defaulting Participant's original PSBR Share in kilowatts without the consent of the non-defaulting Participant. Notwithstanding the provision for Step Up Power under the Power Sales Contract, a defaulting Participant is not relieved of its obligations under the Power Sales Contract.

Section 31 of the Power Sales Contract addresses various matters concerning the term of the Contract, including the effective date, the period over which the Contract will remain in effect, and termination by a Super Majority of Participants. Unless otherwise terminated, the Contract will remain in effect until February 28, 2057, and thereafter until all principal of, premium if any, and interest on all Bonds have been paid or deemed paid in accordance with the Trust Indenture. The Participant remains obligated to pay its respective share of the costs of terminating, discontinuing, disposing of, and decommissioning all Power Sales Contract Resources.

This section also includes a provision allowing Participants that execute the Contract prior to September 1, 2007, a one-time option to reduce the requested PSCR Share or repudiate the Contract upon certain notice provision to AMP-Ohio and prior to the defined "Effective Date" of the Contract. The Effective Date of the Contract is the date that is the later of March 1, 2008, and the date, not later than January 1, 2009, upon which Power Sales Contracts between AMP-Ohio and Participants have been executed such that the aggregate PSCR Shares of such Participants are not less than a nominal 750 MW.

Participant Need for AMPGS Project

In late 2006, AMP-Ohio contracted with R. W. Beck to develop long-term power supply plans for 119 of its Members. R. W. Beck prepared a report for each Member that included a 20-year load forecast, a 20-year optimal power supply plan and the key inputs and assumptions used to develop the plan. These reports were delivered to AMP-Ohio and its Members in February 2007 (the "February 2007 Member Power Supply Analysis").

In developing the plan for each Member, a generation expansion plan was developed assuming that the Member could participate in "slices" of future AMP-Ohio generating resources equal to 15 percent of the Member's projected 2027 peak demand (plus an allowance for 12 percent reserves). The generating resource options included in this study were future generic base load coal, natural gas-fired combined

cycle and peaking resources, the AMPGS Project, the Prairie State Energy Campus (a proposed mine-mouth coal plant in Illinois, referred to herein as "Prairie State"), proposed AMP-Ohio hydroelectric plants along the Ohio River, and future wind plants. The purchase power options included a 5-year peak load, 5x16 contract (five days a week for 16 hours per day) and a 10-year baseload, 7x24 (seven days a week for 24 hours per day) contract, as well as spot market purchases. The generation expansion plan was developed by considering shares (in terms of slices) of each of these options. The optimal power supply plan was developed by selecting the optimal power supply strategy (amount and timing of resource additions) that minimized the total net present value of power supply costs and risks over the 20-year period 2008-2027. The AMPGS Project was included as an option for those members that are participating in the development phase of the Project. The Prairie State project and hydro projects were included as an option for all Members.

The initial power supply plan developed for each member was intended to give that Member an indication of the optimal amount, timing, and type of power supply resources needed over the 20-year study period. Over the short-term, this plan provided each Member guidance on project participation levels among the future AMP-Ohio generation projects currently planned. Over the longer-term, the plan will be adjusted to take into consideration actual costs and other knowns that were projected in the initial plan and new market conditions and resource options.

In developing the plan for each Member, R. W. Beck utilized its Stochastic Econometric Regional Forecasting ("SERF") model and power supply planning approach. SERF generates stochastic[8] projections of fuel and power prices, utility loads and corresponding power costs for multiple portfolios of power supply resources. Using the SERF model, R.W. Beck developed stochastic projections of future power supply costs for each member using several alternative possible portfolios of resources, and identified the power supply portfolios that resulted in the lowest costs and risk to each Member over the 20-year period 2008-2027

A summary of power requirements and future resources for the aggregate of the optimal power supply plans for all the AMP-Ohio Members under the Base Power Supply Plan developed in February 2007 is summarized below. Figure 6 shows the aggregate of the 119 AMP-Ohio Members' projected peak demand, existing power supply resources and future power supply resources over the period 2008-2027. As can be seen from Figure 6, the need for future capacity and energy resources by 2013 is approximately 2,947 MW and increases to 3,360 MW by the end of the study period.

[8] Stochastic projections reflect the uncertainty and volatility in forecasting variables such as fuel costs and electric loads. A stochastic projection is usually captured by forecasting future values based on past economic behavior and numerous future outcomes. The resulting stochastic projection provides a range of potential values instead of one forecasted value.

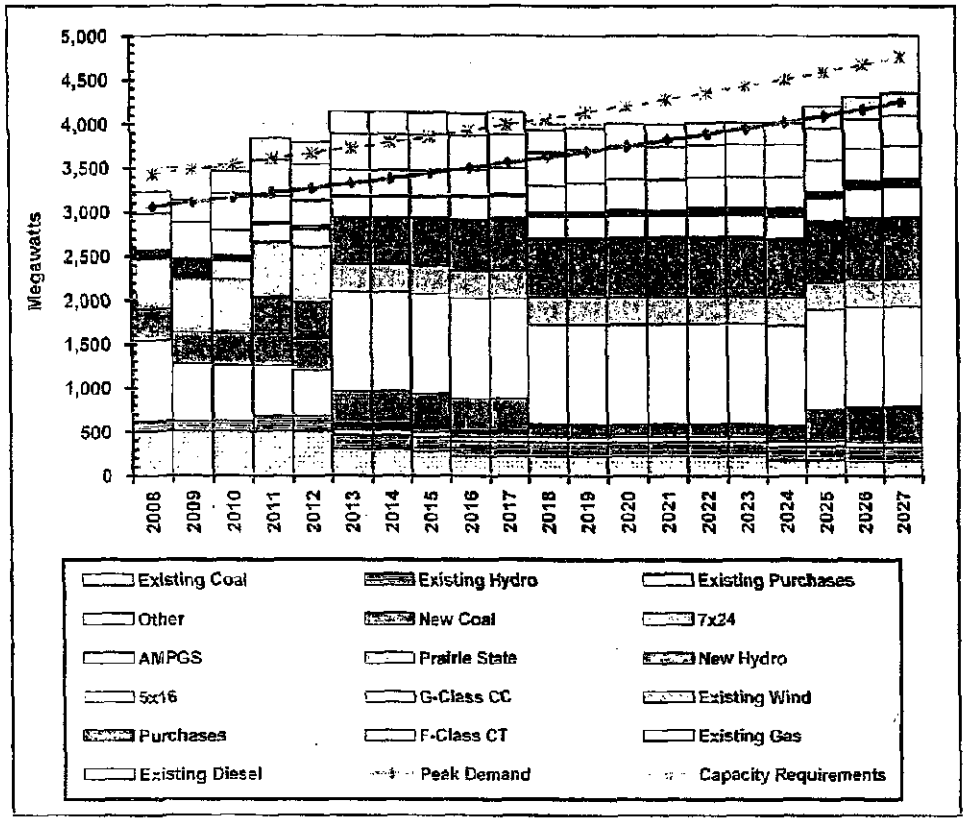

Figure 6 – AMP-Ohio Grand Total Power Supply Plan – Base Case

The timing, amount of capacity and type of capacity resources needed as indicated by the power supply plans is summarized in aggregate in Table 7 below. In addition to the capacity resource additions shown in the table, the power supply plans reflected annual forward purchases and short-term market purchases as needed to meet each Member's projected capacity and energy requirements.

Table 7
Summary of AMP-Ohio Total Power Supply Plan

	Cumulative Capacity Additions at Selected Years (MW)				
	2013	2015	2020	2025	2027
AMPGS [1]	1,140	1,140	1,140	1,140	1,140
Prairie State [2]	317	317	317	317	317
Hydro [3]	530	543	668	695	695
Coal	75	75	137	355	404
G-Class CC	228	228	251	251	345
F-Class CT	290	290	348	356	370
Contract Purchases [4]	367	367	62	71	89
Total	2,947	2,960	2,923	3,185	3,360

[1] The AMPGS Project was included as an option for those Members that are presently participating in the development phase of the Project. The total number of "slices" in the optimal power supply plans was not limited by the Members' actual participation level in the Project. However, each Member was limited to a maximum of two slices. The total capacity available from the AMPGS Project is estimated to be 960 MW, which is less (by 180 MW) than the total amount of AMPGS capacity needed as indicated from the power supply plans developed for all the Members in February 2007.

[2] The Prairie State project was included as an option for all Members. According to AMP-Ohio, as of the date of this Report, the total amount of capacity available to the AMP-Ohio Members from this project is 150 MW which is less (by 167 MW) than the amount needed indicated from the power supply plans.

[3] According to AMP-Ohio, the amount of capacity available from the proposed AMP-Ohio hydroelectric plants along the Ohio River is approximately 300 MW which is less (by 395 MW) than the amount of hydro capacity needed as indicated from the power supply plans developed for all the Members.

[4] Includes 5x16 and 7x24 forward contract purchases and other on-peak purchases estimated to be required in the future.

In summary, the February 2007 Member Power Supply Analysis indicates that in order to meet the Members projected power requirements, there is a requirement for additional base, intermediate and peaking type capacity and energy resources. The projected amount of additional capacity required is estimated to be 2,947 MW in 2013 growing to 3,360 MW by 2027. The amount of additional base load capacity projected (represented by AMPGS, Prairie State and new generic coal) totals 1,531 MW in 2013 growing to 1,861 MW by 2027.

In addition to identifying the amount and timing of future generating resources, the Power Supply Plans included a stochastic projection of the annual power supply costs reflecting the optimal Power Supply Plan for the period 2006 through 2027. The projected power supply costs for each Member were shown in terms of expected value, 5th percentile and 95th percentile[9].

[9] Expected value is the average of the 50 draws from the results of the stochastic model. There is a 5 percent probability that the results will be below the 5th percentile values and a 5 percent probability that the results will be above the 95th percentile values

Beneficial Use of the AMPGS Project

In accordance with Section 2 (B) (x) of the AMPGS Power Sales Contracts, we have prepared an analysis to determine if each Participant can beneficially utilize its PSCR Share (as defined in the Power Sales Contract) of the AMPGS Project. This analysis is based on each Participant's current PSCR Share. The PSCR Share may be modified and will be finalized after the execution of the Power Sales Contract which may differ from the PSCR Share assumed herein.

We have prepared three types of analysis to determine if the Participant can beneficially utilize its share of the AMPGS Project. The three analyses include:

- a comparison of AMPGS PSCR Share as a percent of peak demand for selected years,
- an analysis of potential surplus energy including identifying surplus energy sales from AMPGS and incremental surplus energy sales from existing Participant resources as a result of adding AMPGS, and
- an analysis of each Participant's projected power costs and risks, before and after its PSCR Share of AMPGS.

AMPGS Share Compared to Peak Demand

Power plants, such as AMPGS, that are designed to generate energy at its maximum capability when available are considered "base-load" plants because these plants are expected to be available to meet base (or minimum) load requirements. Therefore, in developing a power supply plan a utility will generally plan for enough capacity from base load plants or contracts at least equal to its projected minimum load. Most utilities plan for around 50-55 percent of their projected peak demand to be supplied from base-load type generation. If a utility has more base-load generation than its hourly load requirements, it must reduce the output of the base load plant or sell the surplus energy in a given hour. Because all the Participants are in regions where surplus energy can readily be sold, this planning criteria is not as important.

Attachment ES-4 at the end of this Executive Summary compares the AMPGS Participants' 2006, 2015 and 2025 peak demands with their respective shares in the AMPGS Project.

As shown in Attachment ES-4, the number of Participants with AMPGS Shares greater than 50 percent of their projected peak demand is:

- 22 based on the 2006 peak demand,
- 10 based on the 2015 projected peak demand, and
- 4 based on the 2025 projected peak demand (these four Participants represent approximately 45 MW of the Project capacity or approximately 5%).

On a total basis, the AMPGS capacity is approximately 30 percent of the aggregate peak demand in 2015. In aggregate, the AMPGS Participants can beneficially use the AMPGS capacity to meet their base load requirements.

This analysis does not take into consideration that some of the Participants have existing base-load type generation. However, the surplus energy analysis and the power cost and risk analyses described below do reflect existing base-load generation.

Surplus Energy Analysis

As discussed below, we have prepared stochastic projections of the total power supply cost for the period 2013 – 2027 for each of the AMPGS Participants for two cases. The first case includes the Participant's existing power supply resources (Existing Portfolio) and the second case includes the Participant's existing power supply resources and its current PSCR Share of the AMPGS Project (Portfolio with AMPGS). Based on the results of these projections, we computed the amount of the estimated surplus energy sales and associated revenues for each Participant from its share of AMPGS and the incremental surplus energy sales from the Participant's existing resources that result from adding its share of AMPGS. The results of this analysis are summarized below:

- Surplus energy from AMPGS
  - 28 Participants are projected to have surplus energy on an average annual basis ranging from 1 percent to 17 percent of the output from their AMPGS PSCR Shares
  - 13 Participants are projected to have surplus energy on an average annual basis greater than 5 percent of the output from their AMPGS PSCR Shares
- Additional surplus energy resulting from adding AMPGS to the Existing Portfolio
  - 50 Participants are projected to have surplus energy on an average annual basis ranging from 3 percent to 90 percent of the output from their AMPGS PSCR Shares
  - 28 Participants are projected to have surplus energy on an average annual basis greater than 15 percent of the output from their AMPGS PSCR Shares
  - 4 Participants are projected to have surplus energy on an average annual basis greater than 50 percent of the output from their AMPGS PSCR Shares (these four Participants represent approximately 36 MW of the Project capacity or approximately 4 percent)

Impact of AMPGS Project on Participant Costs and Risks

Using the power supply models developed for the February studies, R. W. Beck prepared stochastic projections of the total power supply costs for each of the AMPGS Participants reflecting the Participant's existing power supply resources (Existing Portfolio). The stochastic power cost projections produce a range of costs resulting from the estimated volatility in loads, fuel prices, market prices, and CO_2 costs. A sample of the projections for one Participant is shown in Figure 7 below.

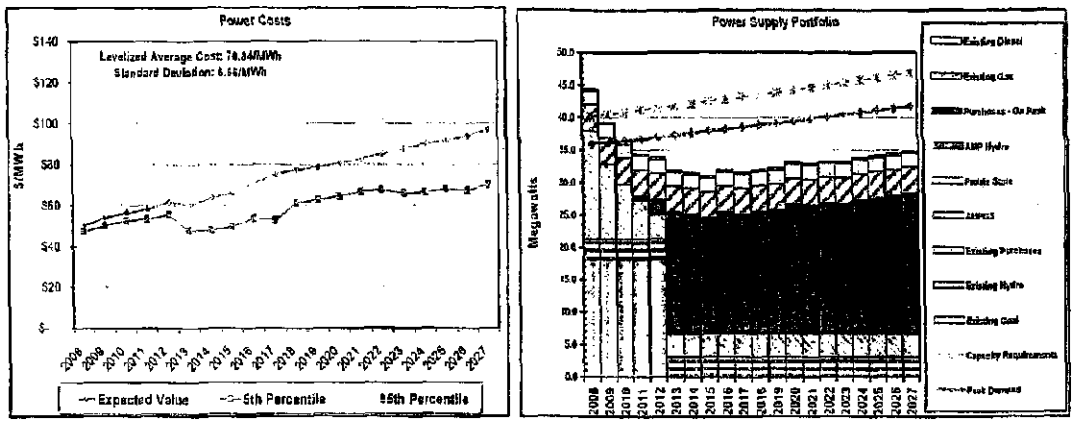

Figure 7 – Stochastic Projection of Participant Power Costs – Existing Portfolio

We also prepared stochastic projections of the total power supply costs for each AMPGS Participant reflecting the Participant's existing power supply resources and its current PSCR Share of the AMPGS Project (Portfolio with AMPGS). A sample of the projections for one Participant is shown in Figure 8 below.

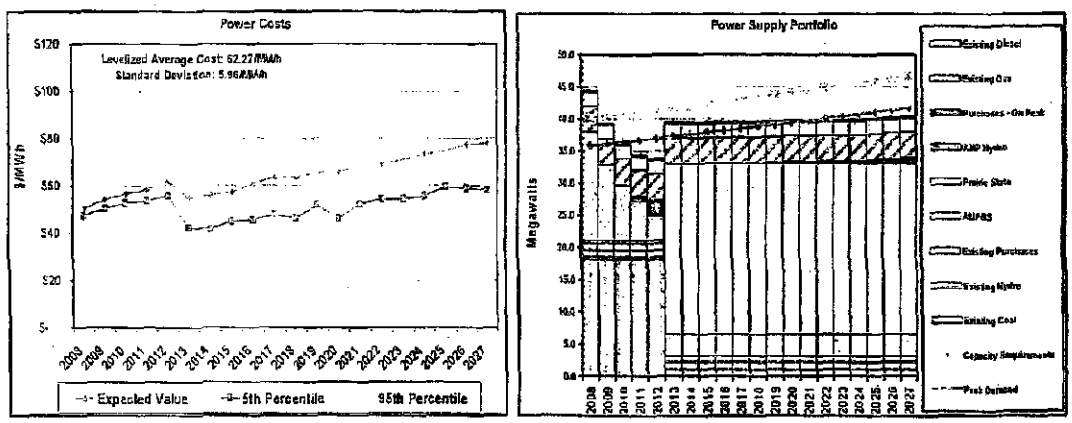

Figure 8 – Stochastic Projection of Participant Power Costs – Portfolio with AMPGS

Based on these power costs analyses, the projected power costs for every AMPGS Participant are lower under the portfolio with AMPGS than the existing portfolio.

In addition, we have prepared stochastic projections of the total power supply cost for the period 2013 – 2027 for each of the AMPGS Participants assuming that their respective AMPGS PSCR Share is increased by 25 percent. We have included this case to analyze the impact on the Participant's costs and risk of the 25 percent step-up provision under the Power Sales Contract.

The stochastic power cost projections produce a range of costs resulting from the estimated volatility in loads, fuel prices, market prices, and CO_2 costs. Based on this analysis we have developed an expected average annual cost (annual cost present valued to 2013 and averaged). From the results of the stochastic analysis we can estimate the uncertainty in future power costs (or risks) by computing the standard

deviation ("STD") in the projected average annual power costs under the 50 draws produced by the stochastic model.

The results of the stochastic analysis demonstrate that costs are lower under the Portfolio with AMPGS than the Existing Portfolio for all of the Participants. Also, costs are lower under the Portfolio with AMPGS including the 25 percent step-up than the Existing Portfolio for all of the Participants.

To illustrate the impact on costs versus risk for each Participant, we developed a chart that depicts expected costs (average annual costs) on the x-axis and risks (in terms of STD) on the y-axis for each of the three cases. A sample of the chart is shown in Figure 9 below.

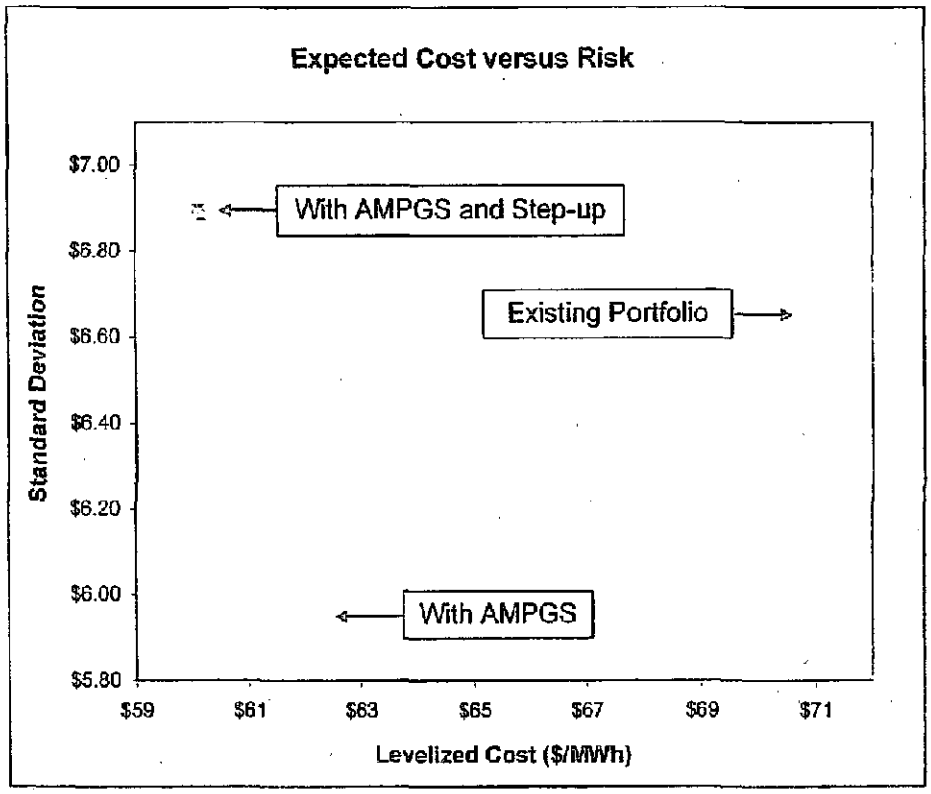

Figure 9 – Expected Cost versus Risk Chart for Sample Participant

Even though costs are lowered by the addition of the AMPGS PSCR Shares for all Participants, it is important to consider the impact on risks.

For all but four Participants, risks (as measured by the STD) are lower under the Portfolio with AMPGS than the Existing Portfolio. These four Participants represent approximately 36 MW or four percent of the AMPGS Project capacity. Also, for all but seven Participants, risks are lower under the Portfolio with AMPGS including the 25 percent step-up than the Existing Portfolio for all of the Participants. These seven Participants represent approximately 49 MW or 5 percent of the AMPGS Project capacity.

Analysis of Potential Project Risks

To address the potential risks of the AMPGS Project, we have prepared a qualitative risk assessment and a quantitative risk assessment. An overview of the major elements of the risk assessments are:

- Qualitative risk assessment
  - Develop risk inventory of all risks of the Project
  - Evaluate risk in terms of likelihood of occurrence and potential impact on Participant costs
  - Identify risk mitigation strategies
- Quantitative risk assessment
  - Develop stochastic projections of Participant power costs for beneficial use analysis (Discussed herein under Beneficial Use of AMPGS Project)
  - Develop stochastic projections of AMPGS annual power cost projections that quantifies major risks of the AMPGS Project

Qualitative Risk Assessment

R. W. Beck and AMP-Ohio worked together to develop the qualitative risk assessment of the AMPGS Project. The qualitative risk assessment involved developing a risk inventory of the risks that could occur for the AMPG Project, characterizing each relevant risk source as being "low," "moderate," or "high" and developing risk mitigation strategies for each risk source.

Developing the risk inventory was approached from the perspective of three risk environments. Internal risks are those risks that occur internal to the AMP-Ohio organization or the AMPGS Project and can be controlled by processes implemented by AMP-Ohio. Internal risks include: strategic risks, operational risks, financial risks and technology risks. AMP-Ohio will have moderate control over the risks that occur in the electric market environment. Risks included in the market environment include: price risks, transmission cost risks, and credit risks. There are market derivatives and hedging instruments available to manage market risks. External risks related to event risks, hazard risks, legal and contractual risks and risks related to the political, regulatory and environmental are the most difficult to control.

As demonstrated in Figure 10 below, in developing the overall risk level for each of the risk sources, both the likelihood of the event occurring and the impact on cost were considered. Risk were assessed both on a "Gross" and "Net" basis. The gross risk assessment reflects the characterization of the risks before risk mitigation strategies are considered. The net risk assessment reflects the characterization of the risks assuming risk mitigation strategies are in place and effective. As illustrated in the chart below, those risks that reside in the yellow, orange or red squares of the risk matrix are likely to have the greatest impact on the Project. All other risks would be considered low to moderate and would reside in the green and light green squares.

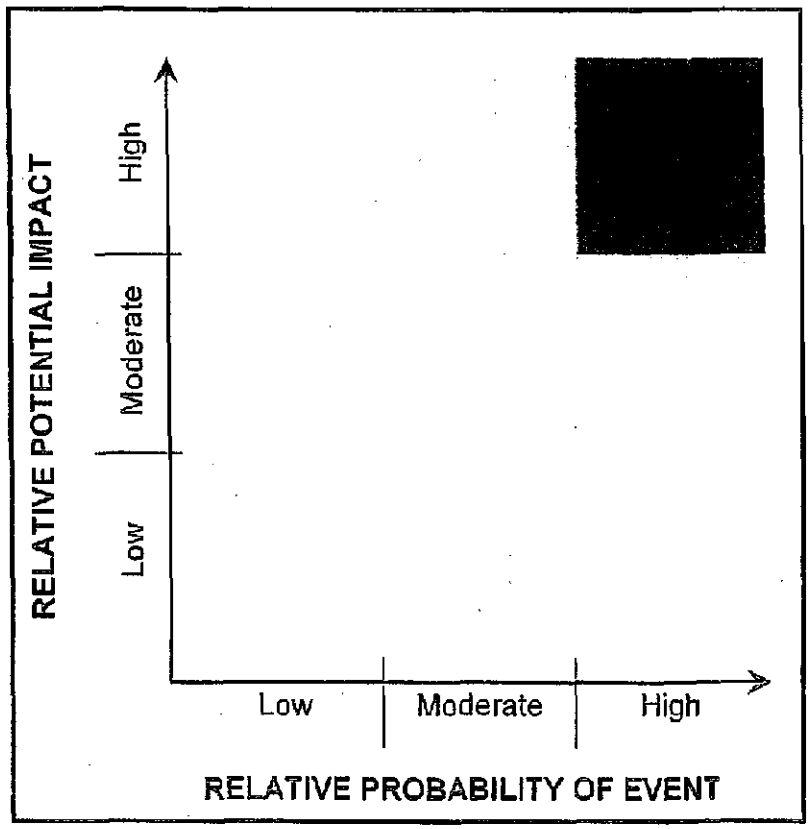

Figure 10 – Risk Matrix

In summary, for each of the three risk environments the risks that would be considered moderate to high risk are summarized below in Table 8. All other risks would be considered low to moderate.

Table 8
Summary of Qualitative Risk Assessment Results

Risk Category:	Major Source of Risk Characterized as Moderate to High
Internal Risk	• Developmental and Construction Cost Risks (potential delays, cost overruns and availability of human craft resources)
Market Risk	• Price Risks (related to volatility in coal prices, fertilizer prices and SO_2, NO_X allowance prices)
External Risk	• Regulatory Risks (related to more stringent environmental laws associated with CO_2 and mercury)

Risk Mitigation Strategies

The qualitative risk assessment process identified a number of potential, or existing, risk mitigation strategies which are summarized below:

Internal Risk Environment

Strategic risks related to potential changes in the Participants competitive position would be mitigated by keeping the costs (and cost increases) of the Project to the Participants as low (and stable) as possible though the use of longer-term debt, low cost tax-exempt financing and use of rate stabilization funds (if needed).

Operational risks would be mitigated by developing procedures to attract and maintain highly qualified staff, training programs, developing high standards for plant performance, sound maintenance programs, and state-of-the-art systems.

Financial risk would be mitigated by (i) the establishment of reserves for the Project, debt service coverage ratios, step-up provisions in the Power Sales Contracts; (ii) development of a financial plan and use of interest rate swaps to mitigate the risk of interest rate fluctuations; and (iii) AMP-Ohio's existing Member credit program.

Development and Construction risks deserve significant consideration. Mitigation strategies include close oversight as owner through an experienced Owner's Engineer, liquidated damages clauses, penalty clauses and incentive clauses in contracts and procurement documents, early procurements and sound planning.

Technology risks would be mitigated through the incorporation of design specifications and guarantees in the EPC contract.

Market Risk Environment

Price risks would be mitigated by (i) development of appropriate coal purchase agreements and designing the AMPGS plant with the flexibility to burn different types of coal; (ii) development of an agreement with The Andersons to provide urea for the Powerspan process and to market the sale of the fertilizer produced by the Powerspan process and (iii) installation of best available technology to control SO_2 and NO_X emissions.

Transmission risks would be mitigated by proper oversight of the processes required to interconnect the AMPGS Project to the PJM grid and the use of allocated FTRs and AARs to mitigate congestion costs.

Credit risks will be mitigated by screening of counterparties so that only large highly rated financial institutions are used and only proposals from a limited number of large nationally recognized firms are considered for the EPC contractor.

External Risk Environment

Event risks related to unplanned outages will be somewhat mitigated by the fact that the AMPGS plant is a two unit plant. Event risks related to unplanned transportation interruptions will be mitigated by the development of adequate storage for commodities inventories to carry operations through any delivery interruptions.

Hazard risks can be mitigated through training programs, good oversight as an owner, appropriate insurance instruments, establishment of reserves (if necessary) and implementing a reliable and sound design for the plant.

Legal and contractual risks surrounding counterparty performance creates the need to negotiate a comprehensive EPC contract prior to signing contracts. The contract will

need to contain strong provisions to protect AMP-Ohio from liability of actions of the counterparties. Legal and contractual risks related to potential Participant default are mitigated by the step-up provisions in the Power Sales Contract.

Regulatory risks related to more stringent environmental regulations associated with CO_2 and mercury emissions may be somewhat mitigated by continued monitoring of environmental regulations and planning for the potential impact on the Project. The Powerspan technology will somewhat mitigate the additional costs for carbon capture if required in the future.

Quantitative Risk Assessment

The quantitative risk analysis should take into consideration the risks that have been identified under qualitative risk analysis that could have a substantial impact on future power costs for each alternative. These risk variables include the following:

- price risks including: coal price volatility, market price volatility (effects surplus energy sales), load forecast (effects surplus energy sales) and fertilizer price volatility (revenues from Powerspan scrubber);
- construction cost risks including: potential increases in construction costs and potential delays in on-line date;
- interest rate risks including: short-term variable rate volatility and long-term fixed rates fluctuations; and
- environmental cost risks including: SO_2 and NOx allowance costs and potential CO_2 and Mercury emission costs.

Based on the volatility defined for each risk variable, we have used stochastic modeling and statistical analysis techniques to analyze how in aggregate these risks could impact AMP-Ohio's projected net Participant power costs. The results of the risk analysis include a projection of the potential range (with a certain confidence level) and expected value of the annual net cost to the Participants for the AMPGS Project.

Figure 11, below, provides a graphical representation of the results of the probabilistic analysis, in terms of the average net costs to the Participants associated with the AMPGS Project with CO_2 cost (in $/MWh), for an expected value and a 90% confidence interval (area between the 5% and 95% confidence estimate). From a risk perspective, the level of uncertainty or volatility in each case is proportional to the size of the range between the 5% and 95% estimates. The band between the 5% and 95% estimates represents the 90% confidence interval—in other words, you would expect the average annual net Participant costs to be within this band 90% of the time.

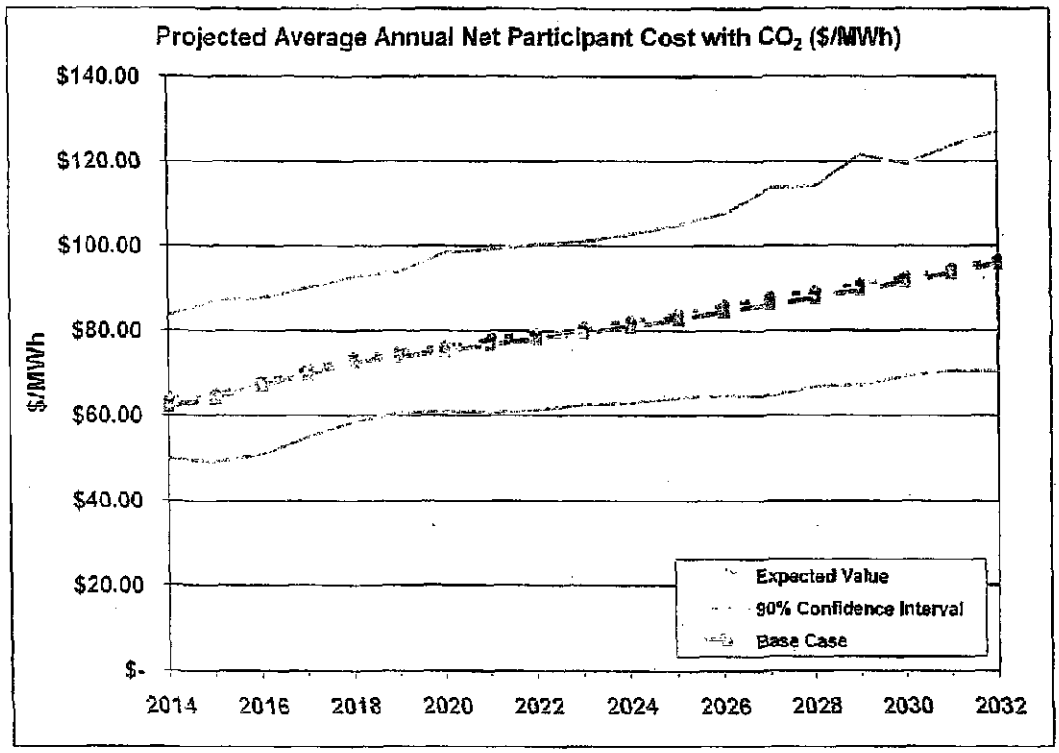

Figure 11 Net Participant Costs (with CO_2) at 90% Confidence Interval ($/MWh)

The projected net Participant power costs with CO_2 are projected to be approximately $77.55 / MWh on an average annual levelized[10] basis over the period 2013 through 2032. The projected uncertainty in future power costs as measured by the standard deviation in the projected average annual levelized power costs is estimated to be approximately $ 10.71 / MWh (or 14%).

In the case with CO_2, the major risk factors that cause the uncertainty in power costs and their contribution to the STD are shown in Table 9 below.

[10] The average annual levelized net Participant power costs where developed by computing the net present value of the net costs divided by the net present value of the net energy over the period 2013 through 2032.

Table 9
Risk Factors Contribution to STD with CO_2

Description	Contribution to STD	
	$/MWh	% of Total
Coal Prices	2.90	27%
Urea and Ammonium Sulfate Prices	2.58	24%
CO_2 Costs	2.34	22%
Construction Cost, Schedule, and Interest Rates	2.32	22%
Surplus & Replacement Energy Costs	0.36	3%
SO_2, NO_x, and Mercury Costs	0.21	2%
Total	10.71	100%

As shown above, in the case with CO_2, the uncertainty in the projected net power costs to the Participants is most influenced by CO_2 costs, coal prices, urea and ammonium sulfate prices, and construction and financing cost uncertainty.

Obligations and Risks of Ownership

The ownership of the AMPGS Project will carry with it the obligations and attendant risks in such ownership. An important goal of AMP-Ohio in developing the contractual arrangements related to the AMPGS Project has been and will be to mitigate, to the extent possible, the risks of developing, constructing and owning a 960 MW coal plant. However, inherent in any ownership are risks that require recognition by AMP-Ohio and the potential Participants, and these risks could be substantial. The potential impact of risks have been discussed and analyzed herein. These analyses and discussions may not be all-inclusive. However, it should be pointed out that the impact of many of the risks which are now the responsibilities of investor-owned utilities or other wholesale providers supplying wholesale power to the Participants are or would be reflected in the rates charged to the Participants for power and energy, but usually at a higher cost of money than AMP-Ohio. In considering approval of the AMPGS Project, the individual Participants should carefully weigh the benefits and responsibilities of ownership of the AMPGS Project.

Initial Findings and Conclusions

For purposes of this Report, we have conducted our initial engineering studies and reviews to consider the technical feasibility of the AMPGS Project and we have prepared an initial economic analysis for the Project over the forecast period 2013-2032.

In the preparation of the studies and analyses set forth in this Report, we have made certain assumptions with respect to conditions that may occur in the future. While we believe these assumptions are reasonable for the purpose of this Report, they are dependent upon future events and actual conditions may differ from those assumed. In addition, we have used and relied upon certain information and assumptions

provided to us by AMP-Ohio and others. While we believe the sources to be reliable, we have not independently verified the information and offer no assurances with respect thereto. To the extent that actual future conditions differ from those assumed herein, the actual results will vary from those forecast. Section 9.2 of the Report lists the principal considerations and assumptions made by R. W. Beck in preparing the studies and analyses set forth in this Report and rendering the initial findings and conclusions set forth in Section 9.3 of the Report and repeated below.

Based upon such considerations and assumptions and upon the analyses and studies as summarized in this Report, including all appendices, which Report and appendices should be read in their entirety in conjunction with the following, we are of the opinion that:

1. Provided that on-going site investigations do no reveal anything that would prohibit construction, the site is suitable for the construction and operation of the AMPGS Project.

2. The proposed pulverized coal-fired steam electric plant technology to be incorporated in the AMPGS Project is a sound and proven method of electricity production.

3. The scale up of the Powerspan ECO-SO_2 process from the commercial demonstration unit to the size of the AMPGS Project is within technical feasibility given the types of equipment involved and the vendors' demonstrated experience with the equipment. However, it is not unreasonable to expect that issues not presently contemplated could arise as the full scale installation is designed, constructed and tested. We expect that such issues can be accommodated by adjustments in the field and/or modifications to the equipment. Provided true and meaningful "wrap" guarantees are obtained from the EPC/Process Contractor(s), such modifications and the associated financial responsibilities would be the responsibility of the EPC/Process Contractor(s).

4. Provided that the facility is designed, constructed and maintained as proposed, and the required renewals and replacements are made on a timely basis, the AMPGS Project should have a useful life of at least 40 years.

5. Proposed plans for design, construction and operation of the AMPGS Project are being developed in accordance with good engineering practices and generally-accepted industry practices.

6. Based on our review of the expected fuel quality and conceptual design information developed by S&L, an availability factor of 88 percent, an annual average capacity of 987 MW and a net heat rate of 9,325 Btu/kWh, assuming utilization of an eastern coal fuel blend, are achievable.

7. The planned construction schedule with a duration of 48 months, preceded by an 8 to 9 month open book preliminary design phase, is reasonable for the AMPGS Project.

8. AMP-Ohio has identified the key permits and approvals required for construction and operation of the AMPGS Project, and has submitted permit applications to the appropriate regulatory agencies for such key permits and approvals.

9. The preliminary estimated total construction cost for the AMPGS Project of $2.532 billion was prepared in accordance with generally-accepted practices and methods and reflects equipment, material and labor market conditions in the region of the AMPGS Project as of the date of this Report. The cost is comparable to similar projects with which we are familiar.

10. The methodology for preparing the initial O&M cost estimate for the AMPGS Project and the estimated O&M costs that are reflected in the projected power costs of the AMPGS Project are reasonable for the proposed plant configuration and are comparable with similar projects with which we are familiar, after adjustment for incorporation of the Powerspan technology

11. It is presently estimated that an aggregate principal amount of bonds totaling approximately $2.912 billion will be required to be issued over the period 2008 through 2013 to pay for the cost of construction of the AMPGS Project, based on AMP-Ohio's proposed financing plan and the assumed bond interest rates and financing requirements. The approximate bond amount for an AMP-Ohio ownership share of 97.5 percent would be $2.839 billion.

12. The Participants' PSCR Shares in the AMPGS Project can be beneficially utilized by the various AMPGS Participants as follows::

    a) The projected power costs over the period 2013 through 2027 for each AMPGS Participant are lower under the power supply arrangement including 100 percent their PSCR Share of the AMPGS Project compared to the existing power supply arrangement.

    b) The projected power cost risks (as measured by the estimated standard deviation in power costs for the risk variables evaluated, as discussed in Section 2.5.4 of this Report) over the period 2013 through 2027 for all but four of the AMPGS Participants are lower under the power supply arrangement including 100 percent their PSCR Share of the AMPGS Project compared to the existing power supply arrangement.

    c) The aggregate amounts of capacity and energy from the AMPGS Project, after giving effect to the sale of a portion of the AMPGS Project output in the short-term energy market, can be beneficially utilized by the Participants in serving the aggregate long-range base-load power and energy requirements of the Participants.

13. The Participants' PSCR Shares adjusted to reflect a 25 percent step-up requirement, (pursuant to Section 18 of the Power Sales Contract) can be beneficially utilized by the various AMPGS Participants as follows:

    a) The projected power costs over the period 2013 through 2027 for each AMPGS Participant are lower under the power supply arrangement including 125 percent of their PSCR Share of the AMPGS Project compared to the existing arrangement.

    b) The projected power cost risks (as measured by the estimated standard deviation in power costs for the risk variables evaluated, as discussed in Section 2.5.4 of this Report) over the period 2013 through 2027 are lower for all but seven of the AMPGS Participants under the power supply arrangement including 125 percent of their PSCR Share of the AMPGS Project compared to the existing power supply arrangement.

14. The AMPGS Project can be interconnected to the PJM system at the interconnection location selected by AMP-Ohio, and the proposed contracted capacity can be delivered to the PJM Participants. In order for AMPGS Project capacity to be delivered to the MISO Participants, further transmission system upgrades may be required for firm transmission service, which could cause the AMPGS Project postage stamp rates to increase. AMP-Ohio has initiated power flow studies to estimate the potential transmission upgrades and associated costs to provide firm transmission service from the Project to the MISO Participants.

15. The AMPGS Project represents a reasonable cost long-term base-load power supply option for the AMPGS Project Participants.

16. AMP-Ohio recognizes that there are internal, market, and external risk events that could occur in the future and adversely impact the AMPGS Project. AMP-Ohio should be able to manage certain of those risks through prudent utility practices and implementation of the risk mitigation strategies that have been identified.

American Municipal Power Generating Station
Projected Operating Costs of AMPGS Plant
Base Case

Line No.	Description	2013 (1)	2014	2015	2016	2017	2018	2019	2020	2021	2022
	PERFORMANCE										
1	Capacity (MW) [2]	987	987	987	987	987	987	987	987	987	987
2	Capacity Factor (%)	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%
3	Availability (%) [3]	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%
4	Energy Generation (GWh) [4]	7,349	7,349	7,349	7,349	7,349	7,349	7,349	7,349	7,349	7,349
6	Net Plant Heat Rate (Btu/kWh) [5]	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325
7	Total Coal Consumption (BBtu) [6]	68,531	68,531	68,531	68,531	68,531	68,531	68,531	68,531	68,531	68,531
8	Heating Value of Coal (Btu/lb)	12,051	12,051	12,051	12,051	12,051	12,051	12,051	12,051	12,051	12,051
9	Coal Consumption (Tons x 10^3) [6]	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843
10	Total NO_X Allowances Purchased (Tons) [7]	3,398	3,398	3,398	3,398	3,398	3,398	3,398	3,398	3,398	3,398
11	Mercury Allowances Purchased (Tons) [8]	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473
12	SO_2 Allowances Purchased (Tons) [9]	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140
13	CO_2 Allowances Purchased (Tons x 10^3) [10]	7,367	7,367	7,367	7,367	7,367	7,367	7,367	7,367	7,367	7,367
14	Urea - SCR Consumption Rate (Tons) [11]	5,587	5,587	5,587	5,587	5,587	5,587	5,587	5,587	5,587	5,587
15	Urea Consumption (Tons x 10^3) [12]	114	114	114	114	114	114	114	114	114	114
16	Ash Production (Tons x 10^3) [13]	356	356	356	356	356	356	356	356	356	356
	COMMODITY PRICES										
17	General Inflation (%) [14]	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40
18	Coal Commodity Price ($/Ton) [15]	$43.85	44.84	45.59	46.47	47.43	48.28	49.36	50.52	51.85	53.21
19	Coal Transportation Price (Blended) ($/Ton) [16]	$7.69	7.85	7.98	8.14	8.31	8.46	8.65	8.85	9.08	9.32
20	All-In Average Coal Price Delivered ($/MMBtu)	$2.14	2.19	2.22	2.27	2.31	2.35	2.41	2.46	2.53	2.59
21	Urea Price ($/Ton) [17]	$310	318	325	333	341	349	358	366	375	384
22	SO_2 Allowances ($/Ton) [18]	$1,291	1,389	1,486	1,522	1,558	1,596	1,634	1,673	1,713	1,754
23	Mercury Allowances ($/Oz) [19]	$1,211	1,302	1,398	1,517	1,642	1,771	1,906	2,047	2,138	2,233
24	NO_X Allowances - Annual ($/Ton) [20]	$1,322	1,411	1,505	1,608	1,714	1,829	1,951	2,082	2,221	2,370
25	NO_X Allowances - Ozone ($/Ton) [21]	$2,163	2,320	2,487	2,666	2,859	3,065	3,286	3,523	3,777	4,049
26	CO_2 Allowances ($/Ton) [22]	$3.38	5.19	7.08	9.06	11.14	13.29	13.61	13.94	14.27	14.62
27	Activated Carbon Costs ($/Ton) [23]	$0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	OPERATING EXPENSES ($000) [24]										
28	Coal Commodity	$124,692	127,498	129,627	132,143	134,853	137,272	140,368	143,658	147,432	151,302
29	Coal Transportation	$21,841	$22,332	22,705	23,147	23,621	24,044	24,587	25,163	25,824	26,503
30	Auxiliary Fuel	$0	0	0	0	0	0	0	0	0	0
31	Start-Up Fuel	$0	0	0	0	0	0	0	0	0	0
	Fixed O&M										
32	Labor	$15,334	15,702	16,079	16,465	16,860	17,264	17,679	18,103	18,537	18,982
33	Operator G&A	$576	590	604	619	634	649	665	681	697	714
34	Other Fixed [25]	$16,141	16,528	16,925	17,331	17,747	18,173	18,609	19,058	19,513	19,981
35	Fixed O&M	$32,051	32,820	33,608	34,415	35,241	36,086	36,953	37,840	38,747	39,677
	Variable O&M										
36	Major Maintenance/Capital Expenses [26]	$12,106	12,396	12,694	12,998	13,310	13,630	13,957	14,292	14,635	14,985
37	Other Variable [27]	$8,647	8,854	9,067	9,285	9,507	9,736	9,969	10,208	10,453	10,704
38	Variable O&M	$20,753	21,250	21,761	22,283	22,817	23,366	23,926	24,500	25,088	25,690
	Emissions Allowances										
39	SO_2 Emissions Allowances	$6,636	7,139	7,638	7,823	8,008	8,203	8,399	8,599	8,805	9,015
40	Mercury Emissions Allowances	$5,709	6,141	6,589	7,153	7,740	8,352	8,988	9,650	10,079	10,527
41	NO_X Emissions Allowances - Annual	$3,171	3,384	3,611	3,853	4,111	4,386	4,680	4,994	5,328	5,685
42	NO_X Emissions Allowances - Ozone	$2,162	2,318	2,485	2,665	2,857	3,063	3,284	3,521	3,775	4,047
43	CO_2 Emissions Allowances	$24,877	38,210	52,170	66,777	82,056	97,932	100,282	102,689	105,153	107,677
44	Emissions Allowances	$42,555	57,192	72,493	88,271	104,772	121,936	125,633	129,453	133,140	136,951
45	Activated Carbon	$0	0	0	0	0	0	0	0	0	0
46	Urea - SCR	$1,733	1,774	1,817	1,860	1,905	1,951	1,998	2,046	2,095	2,145
	Powerspan										
47	Urea Cost ($/Yr)	$35,454	36,305	37,176	38,068	38,982	39,917	40,875	41,856	42,861	43,890
48	Waste Disposal Cost ($/Yr)	$4,106	4,204	4,305	4,408	4,514	4,623	4,734	4,847	4,964	5,083
49	Auxiliary Power ($/Yr)	($1,017)	(1,041)	(1,066)	(1,092)	(1,118)	(1,145)	(1,172)	(1,200)	(1,229)	(1,259)
50	Renewals, Replacements & Maintenance	($71)	(72)	(74)	(76)	(78)	(79)	(81)	(83)	(85)	(87)
51	Other Operating Costs	$12,764	13,070	13,384	13,705	14,034	14,371	14,716	15,069	15,430	15,801
52	Labor	$657	673	689	706	723	740	758	776	794	814
53	Transportation	$4,120	4,219	4,321	4,424	4,530	4,639	4,750	4,864	4,981	5,101
54	Solid Fertilizer Credit	($44,385)	(45,451)	(46,541)	(47,658)	(48,802)	(49,973)	(51,173)	(52,401)	(53,659)	(54,946)
55	Liquid Fertilizer Credit	($1,088)	(1,114)	(1,141)	(1,168)	(1,196)	(1,225)	(1,254)	(1,284)	(1,315)	(1,347)
56	Powerspan [28]	$10,540	10,793	11,052	11,318	11,589	11,867	12,152	12,444	12,742	13,048
57	Maintenance Parts and Services	$0	0	0	0	0	0	0	0	0	0
58	Water Treatment Chemicals	$0	0	0	0	0	0	0	0	0	0
59	Sales Tax on Commodities [29]	$0	0	0	0	0	0	0	0	0	0
60	Insurance and Property Tax [30]	$5,552	5,552	5,552	5,552	5,552	5,552	5,552	5,552	5,552	5,552
61	Corporate G&A [31]	$500	512	524	537	550	563	576	590	604	619
62	Total Operating Expenses	$260,217	279,723	299,140	319,526	340,901	362,637	371,745	381,245	391,224	401,487
	AVERAGE BUSBAR COST [32]										
63	Total Annual Costs	$260,217	279,723	299,140	319,526	340,901	362,637	371,745	381,245	391,224	401,487
64	Fixed Operating Cost ($000)	$38,103	38,884	39,684	40,504	41,343	42,201	43,081	43,982	44,903	45,848
65	Fixed Operating Cost ($/kW-yr) [33]	$38.60	39.40	40.21	41.04	41.89	42.76	43.65	44.56	45.49	46.45
66	Fixed Operating Cost ($/MWh)	$5.18	5.29	5.40	5.51	5.63	5.74	5.86	5.98	6.11	6.24
67	Total Variable Operating Cost ($000)	$222,114	240,839	259,456	279,022	299,558	320,436	328,664	337,263	346,321	355,639
68	Total Variable Operating Costs ($/MWh) [34]	$30.22	32.77	35.30	37.97	40.76	43.60	44.72	45.89	47.12	48.3[illegible]
69	Fuel Cost ($/MWh)	$19.94	20.39	20.73	21.13	21.56	21.95	22.45	22.97	23.57	24.19
70	Non-Fuel Variable Operating Costs ($/MWh)	$10.28	12.38	14.58	16.84	19.20	21.65	22.28	22.92	23.55	24.20
74	AVG. OPERATING COST (with CO2) ($/MWh)	$35.41	38.06	40.70	43.48	46.39	49.34	50.58	51.88	53.23	54.63
75	AVG. OPERATING COST (without CO2) ($/MWh)	$32.02	32.66	33.60	34.39	35.22	36.02	36.94	37.90	38.93	39.98

American Municipal Power Generating Station
Projected Operating Costs of AMPGS Plant
Base Case

Line No.	Description	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
	PERFORMANCE										
1	Capacity (MW) [2]	987	987	987	987	987	987	987	987	987	987
2	Capacity Factor (%)	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%
3	Availability (%) [3]	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	88.0%
4	Energy Generation (GWh) [4]	7,349	7,349	7,349	7,349	7,349	7,349	7,349	7,349	7,349	7,349
5	Net Plant Heat Rate (Btu/kWh) [5]	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325	9,325
7	Total Coal Consumption (BBtu) [6]	68,531	68,531	68,531	68,531	68,531	68,531	68,531	68,531	68,531	68,531
8	Heating Value of Coal (Btu/lb)	12,051	12,051	12,051	12,051	12,051	12,051	12,051	12,051	12,051	12,051
9	Coal Consumption (Tons x 10^3) [6]	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843	2,843
10	Total NO_X Allowances Purchased (Tons) [7]	3,398	3,398	3,398	3,398	3,398	3,398	3,398	3,398	3,398	3,398
11	Mercury Allowances Purchased (Tons) [8]	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473	0.1473
12	SO_2 Allowances Purchased (Tons) [9]	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140	5,140
13	CO_2 Allowances Purchased (Tons x 10^3) [10]	7,367	7,367	7,367	7,367	7,367	7,367	7,367	7,367	7,367	7,367
14	Urea - SCR Consumption Rate (Tons) [11]	5,587	5,587	5,587	5,587	5,587	5,587	5,587	5,587	5,587	5,587
15	Urea Consumption (Tons x 10^3) [12]	114	114	114	114	114	114	114	114	114	114
16	Ash Production (Tons x 10^3) [13]	356	356	356	356	356	356	356	356	356	356
	COMMODITY PRICES										
17	General Inflation (%) [14]	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40
18	Coal Commodity Price ($/Ton) [15]	$54.57	56.27	58.01	59.85	61.62	63.44	65.32	67.25	69.24	71.28
19	Coal Transportation Price (Blended) ($/Ton) [16]	$9.56	9.86	10.16	10.48	10.79	11.11	11.44	11.78	12.13	12.49
20	All-In Average Coal Price Delivered ($/MMBtu)	$2.66	2.74	2.83	2.92	3.00	3.09	3.18	3.28	3.38	3.48
21	Urea Price ($/Ton) [17]	$393	403	412	422	432	443	453	464	475	487
22	SO_2 Allowances ($/Ton) [18]	$1,796	1,840	1,864	1,929	1,975	2,022	2,071	2,121	2,172	2,224
23	Mercury Allowances ($/Oz) [19]	$2,332	2,436	2,544	2,657	2,775	2,899	3,028	3,163	3,303	3,450
24	NO_X Allowances - Annual ($/Ton) [20]	$2,529	2,699	2,879	3,072	3,278	3,498	3,732	3,982	4,249	4,534
25	NO_X Allowances - Ozone ($/Ton) [21]	$4,341	4,654	4,990	5,350	5,736	6,150	6,593	7,069	7,579	8,125
26	CO_2 Allowances ($/Ton) [22]	$14.97	15.33	15.69	16.07	16.46	16.85	17.26	17.67	18.09	18.53
27	Activated Carbon Costs ($/Ton) [23]	$0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	OPERATING EXPENSES ($000) [24]										
28	Coal Commodity	$155,173	160,011	164,946	170,171	175,207	180,389	185,724	191,216	196,869	202,688
29	Coal Transportation	$27,180	28,027	28,892	29,807	30,689	31,597	32,532	33,493	34,483	35,503
30	Auxiliary Fuel	$0	0	0	0	0	0	0	0	0	0
31	Start-Up Fuel	$0	0	0	0	0	0	0	0	0	0
	Fixed O&M										
32	Labor	$19,438	19,904	20,382	20,871	21,372	21,885	22,410	22,948	23,499	24,063
33	Operator G&A	$731	748	766	785	803	823	842	863	883	905
34	Other Fixed [25]	$20,461	20,952	21,455	21,970	22,497	23,037	23,590	24,156	24,736	25,330
35	Fixed O&M	$40,630	41,604	42,603	43,626	44,672	45,745	46,842	47,967	49,118	50,298
	Variable O&M										
36	Major Maintenance/Capital Expenses [26]	$15,346	15,714	16,091	16,477	16,873	17,278	17,692	18,117	18,552	18,997
37	Other Variable [27]	$10,961	11,224	11,494	11,770	12,052	12,341	12,637	12,941	13,251	13,569
38	Variable O&M	$26,307	26,938	27,585	28,247	28,925	29,619	30,329	31,058	31,803	32,566
	Emissions Allowances										
39	SO_2 Emissions Allowances	$9,231	9,457	9,683	9,915	10,151	10,395	10,644	10,900	11,161	11,429
40	Mercury Emissions Allowances	$10,995	11,484	11,995	12,529	13,086	13,668	14,276	14,911	15,574	16,267
41	NO_X Emissions Allowances - Annual	$6,068	6,473	6,907	7,369	7,863	8,390	8,952	9,552	10,192	10,875
42	NO_X Emissions Allowances - Ozone	$4,339	4,652	4,987	5,347	5,733	6,146	6,589	7,065	7,574	8,121
43	CO_2 Emissions Allowances	$110,261	112,908	115,617	118,392	121,234	124,143	127,123	130,174	133,298	136,497
44	Emissions Allowances	$140,892	144,974	149,189	153,552	158,067	162,742	167,584	172,602	177,799	183,189
45	Activated Carbon	$0	0	0	0	0	0	0	0	0	0
46	Urea - SCR	$2,196	2,249	2,303	2,358	2,415	2,473	2,532	2,593	2,655	2,719
	Powerspan										
47	Urea Cost ($/Yr)	$44,943	46,022	47,126	48,257	49,415	50,601	51,816	53,059	54,333	55,637
48	Waste Disposal Cost ($/Yr)	$5,205	5,330	5,457	5,588	5,723	5,860	6,001	6,145	6,292	6,443
49	Auxiliary Power ($/Yr)	($1,289)	(1,320)	(1,352)	(1,384)	(1,417)	(1,451)	(1,486)	(1,522)	(1,558)	(1,596)
50	Renewals, Replacements & Maintenance	($89)	(92)	(94)	(96)	(98)	(101)	(103)	(106)	(108)	(111)
51	Other Operating Costs	$16,180	16,568	16,966	17,373	17,790	18,217	18,654	19,102	19,560	20,030
52	Labor	$833	853	874	894	916	938	960	983	1,007	1,031
53	Transportation	$5,223	5,349	5,477	5,608	5,743	5,881	6,022	6,166	6,314	6,466
54	Solid Fertilizer Credit	($56,265)	(57,615)	(58,998)	(60,414)	(61,864)	(63,349)	(64,869)	(66,426)	(68,020)	(69,653)
55	Liquid Fertilizer Credit	($1,379)	(1,412)	(1,446)	(1,481)	(1,516)	(1,553)	(1,590)	(1,628)	(1,667)	(1,707)
56	Powerspan [28]	$13,361	13,682	14,010	14,347	14,691	15,044	15,405	15,774	16,153	16,541
57	Maintenance Parts and Services	$0	0	0	0	0	0	0	0	0	0
58	Water Treatment Chemicals	$0	0	0	0	0	0	0	0	0	0
59	Sales Tax on Commodities [29]	$0	0	0	0	0	0	0	0	0	0
60	Insurance and Property Tax [30]	$5,552	5,552	5,552	5,552	5,552	5,552	5,552	5,552	5,552	5,552
61	Corporate G&A [31]	$634	649	665	681	697	714	731	748	766	785
62	Total Operating Expenses	$411,926	423,687	435,746	448,341	460,915	473,875	487,231	501,004	515,199	529,841
	AVERAGE BUSBAR COST [32]										
63	Total Annual Costs	$411,926	423,687	435,746	448,341	460,915	473,875	487,231	501,004	515,199	529,841
64	Fixed Operating Cost ($000)	$46,816	47,805	48,820	49,859	50,921	52,011	53,125	54,267	55,436	56,635
65	Fixed Operating Cost ($/kW-yr) [33]	$47.43	48.43	49.46	50.52	51.59	52.70	53.82	54.98	56.17	57.38
66	Fixed Operating Cost ($/MWh)	$6.37	6.50	6.64	6.78	6.93	7.08	7.23	7.38	7.54	7.71
67	Total Variable Operating Cost ($000)	$365,110	375,882	386,926	398,482	409,994	421,864	434,106	446,737	459,763	473,206
68	Total Variable Operating Costs ($/MWh) [34]	$49.68	51.15	52.66	54.22	55.79	57.40	59.07	60.79	62.56	64.39
69	Fuel Cost ($/MWh)	$24.81	25.59	26.38	27.21	28.02	28.84	29.70	30.58	31.48	32.41
70	Non-Fuel Variable Operating Costs ($/MWh)	$24.87	25.56	26.27	27.01	27.77	28.56	29.37	30.21	31.08	31.98
74	AVG. OPERATING COST (with CO2) ($/MWh)	$56.05	57.65	59.29	61.01	62.72	64.48	66.30	68.17	70.10	72.10
75	AVG. OPERATING COST (without CO2) ($/MWh)	$41.05	42.29	43.56	44.90	46.22	47.59	49.00	50.46	51.96	53.52

American Municipal Power Generating Station
Projected Operating Costs of AMPGS Plant
Base Case

NOTES:

[1] Assumed commercial operation date of January 1, 2013.

[2] Assumed net dependable capacity under normal operating conditions, including allowance for long-term degradation.

[3] Based on estimates provided by R. W. Beck for expected average annual maximum availability level. Includes provision for both forced and scheduled outages.

[4] Assumes Project is base-loaded and operated at full load whenever the plant is available.

[5] Net plant heat rate assumed to average 9,325 Btu/kWh, as estimated by Sergeant Lundy ("S&L"), including an annual allowance for plant degradation.

[6] Annual fuel consumption at the projected annual capacity factors and heat rates, assuming a higher heating value of the coal of 12,051 Btu/lb.

[7] NO_x allowances that the Project is projected to purchase based on an assumed emissions rate of 0.07 lbs/MMBtu.

[8] Mercury allowances that the Project is projected to purchase based on an assumed emissions rate of 4.30×10^{-6} lbs/MMBtu.

[9] SO_2 allowances that the Project is projected to purchase based on an assumed emissions rate of 0.15 lbs/MMBtu.

[10] CO_2 allowances that the Project is projected to purchase based on an assumed emissions rate of 215 lbs/MMBtu.

[11] Annual quantity of urea required for operation of the SCR at the indicated capacity factors assuming an uncontrolled emission rate of 0.25 lbs/MMBtu and a controlled rate of 0.07 lbs/MMBtu and 2.11 percent sulfur fuel.

[12] Annual quantity of urea required for operation of the Powerspan Scrubber at the indicated capacity factors assuming 2.11 percent sulfur fuel.

[13] Annual quantity of bottom ash and fly ash produced, based on an ash content of the coal of 10.83 percent.

[14] Based on projections prepared by Blue Chip Economic Indicators.

[15] FOB price of coal as projected by the latest S&L report, in 2009 dollars and escalated at R.W. Beck's coal price escalation rates from its most recent market price forecast.

[16] Based on estimates provided by S&L for coal delivery in early 2009, in 2009 dollars and escalated at a rate of 3 percent.

[17] Based on an assumed urea price in 2007 of $270 per ton, escalated at the general rate of inflation thereafter.

[18] SO_2 allowance costs assumed to be $1,094 per ton in 2006. Projections of allowance costs are based on EPA estimates and R.W. Beck's proprietary model.

[19] Mercury allowance costs based on an assumed cost of $27.8 million per ton in 1999 dollars.

[20] NO_x annual allowance cost assumed to be $1,120 per ton in 2006. Projections of allowance costs are based on EPA estimates and R.W. Beck's proprietary model.

[21] NO_x ozone season allowance cost assumed to be $1,833 per ton in 2007 dollars. Projections are based on EPA estimates and R.W. Beck's proprietary model.

[22] A carbon tax is assumed to begin during the period 2012 to 2018 with a 28.6 percent probability of occurrence in 2012, increasing to 100 percent by 2018. CO_2 annual allowance cost assumed to be $10.24 per ton in 2007, escalated at the general rate of inflation thereafter.

[23] No carbon injection assumed for Mercury control.

[24] O&M expenses estimated by R.W. Beck to reflect the normal range of costs for similar coal-fired plants, equipped with conventional limestone scrubber systems, with which R.W. Beck is familiar. These costs are assumed to escalate at the general rate of inflation except as noted.

American Municipal Power Generating Station
Projected Operating Costs of AMPGS Plant
Base Case

[25] Additional fixed operations and maintenance expenses estimated by R.W. Beck. Includes projected costs for routine preventative maintenance performed during outages, plant support equipment and temporary labor, vehicle maintenance, structure and grounds maintenance and demand-related backfeed electric charges.

[26] Maintenance expenditures as estimated by R.W. Beck. Includes projected costs and capitalized expenditures for scheduled major overhauls that require an extended outage.

[27] Additional variable operations and maintenance expenses, estimated by R.W. Beck. Includes projected costs for routine scheduled maintenance performed during outages, raw and process water, sewage expenses, waste disposal, chemicals and gases, consumable materials and supplies and energy-related backfeed electric charges.

[28] Powerspan variable costs include urea, ash disposal, adjustments for auxiliary power consumption and steam consumption, adjustments for makeup water, cooling water, equipment air, natural gas, maintenance, labor and other fertilizer plant operating costs. Also included are costs for mercury disposal, ammonium sulfate transportation and fertilizer revenues associated with the operation of Powerspan. These costs are assumed to escalate at the general rate of inflation except as noted.

[29] Based on a sales rate of 0.0 percent applied to all Project equipment and materials which are tax exempt, coal commodity, auxiliary fuel, urea, ammonia, carbon and water treatment chemical costs.

[30] Based on $0.10 per $100 of the estimated gross plant value to be insured. Property taxes are currently estimated to be the same as insurance costs per year. Property taxes are estimated based on 0.10 percent of gross plant investment.

[31] Based on estimate provided by AMP Ohio, escalated thereafter by the general rate of inflation.

[32] Excludes costs associated with debt service.

[33] Fixed Operating Costs include labor, other fixed expenses, insurance, property taxes and general and administrative costs.

[34] Variable Operating Costs include coal, coal transportation, auxiliary fuel, emissions allowances, activated carbon, ash disposal, Powerspan, ammonia, water treatment chemicals, and other variable expenses.

AMP-Ohio Generating Station
Projected Operating Results

	Description		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	REVENUES:											
1	Participant Revenues [1]	$000	$176,719	$442,576	$458,230	$479,191	$498,910	$518,937	$528,080	$537,920	$548,594	$558,630
2	Interest Earnings [2]	$000	5,161	6,541	6,263	6,212	6,198	6,184	6,178	6,214	6,249	6,286
3	Short-term (Market) Sales [3]	$000	5,548	29,746	30,571	31,929	35,451	37,977	37,952	39,016	39,330	40,366
4	Other Project Revenues	$000	0	0	0	0	0	0	0	0	0	0
5	Transfers from R&C Fund [4]	$000	0	0	4,526	4,228	3,924	3,612	3,292	2,965	2,630	2,287
6	Other Receipts	$000	0	0	0	0	0	0	0	0	0	0
7	*Total Revenues [5]*	$000	$187,448	$478,863	$499,590	$521,560	$544,481	$566,709	$575,503	$586,014	$596,803	$607,589
	OPERATING EXPENSES [6]:											
	Fixed Operating Costs:											
8	Fixed O&M	$000	$16,026	$32,820	$33,608	$34,414	$35,240	$36,086	$36,952	$37,839	$38,747	$39,677
9	Insurance & Property Taxes [7]	$000	2,804	5,607	5,607	5,607	5,607	5,607	5,607	5,607	5,607	5,607
10	Transmission Costs [8]	$000	1,837	3,763	3,853	3,946	4,040	4,137	4,237	4,338	4,442	4,549
11	AMP-Ohio A&G Costs [7]	$000	500	512	524	537	550	563	576	590	604	619
12	Bank and Trustee Fees [7]	$000	125	128	131	134	137	141	144	148	151	155
13	Other Direct Project Costs	$000	0	0	0	0	0	0	0	0	0	0
14	*Fixed Operating Costs*	$000	$21,291	$42,830	$43,723	$44,638	$45,575	$46,534	$47,516	$48,522	$49,562	$50,607
	Variable Operating Costs:											
15	Fuel Costs	$000	573,267	$149,830	$152,332	$155,290	$158,474	$161,316	$164,955	$168,821	$173,258	$177,805
16	SO_2 Emissions Costs	$000	3,318	7,139	7,638	7,523	8,008	8,203	8,399	8,599	8,805	9,015
17	NO_x Emissions Costs	$000	2,667	5,702	6,098	6,517	6,968	7,449	7,964	8,514	9,103	9,732
18	Hg Emissions Costs	$000	2,626	6,080	6,524	7,083	7,664	8,269	8,899	9,554	9,979	10,423
19	CO_2 Emissions Costs	$000	12,438	38,208	52,167	66,773	82,051	97,926	100,276	102,663	105,147	107,671
20	Variable O&M	$000	4,324	8,855	9,067	9,285	9,507	9,736	9,969	10,209	10,454	10,704
21	Gross Urea and Powerspan Costs	$000	28,673	59,132	60,551	62,004	63,492	65,016	66,577	68,175	69,811	71,488
22	Fertilizer Credits [9]	$000	(22,737)	(46,564)	(47,682)	(48,826)	(49,998)	(51,198)	(52,427)	(53,685)	(54,974)	(56,293)
23	*Variable Operating Costs*	$000	$104,975	$228,381	$246,693	$265,949	$286,168	$306,717	$314,612	$322,869	$331,581	$340,544
	Replacement Power [10]:											
24	Capacity Purchases	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Energy Purchases	$000	0	20,295	21,731	23,440	25,111	25,737	25,618	26,822	27,824	28,547
26	Transmission Costs	$000	0	0	0	0	0	0	0	0	0	0
27	*Total Replacement Power Purchases*	$000	$0	$20,295	$21,731	$23,440	$25,111	$25,737	$25,618	$26,822	$27,824	$28,54
28	*Total Operating Expenses*	$000	$126,266	$291,507	$312,148	$334,027	$356,852	$378,988	$387,746	$398,213	$408,857	$419,698
29	Net Revenues [11]	$000	$61,182	$187,356	$187,442	$187,534	$187,629	$187,721	$187,757	$187,801	$187,846	$187,891
30	Deposit to Working Capital Reserve Account [12]	$000	$526	$1,215	$1,301	$1,392	$1,487	$1,579	$1,616	$1,659	$1,704	$1,749
	DEBT SERVICE:											
31	Principal	$000	$0	$60,015	$62,265	$64,600	$67,023	$69,536	$72,144	$74,849	$77,656	$80,568
32	Interest	$000	54,603	109,205	106,955	104,620	102,197	99,684	97,076	94,371	91,564	88,652
33	*Total Debt Service [13]*	$000	$54,603	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220
34	Other Debt Payments	$000	0	0	0	0	0	0	0	0	0	0
35	*Total Debt Service Requirement*	$000	$54,603	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220	$169,220
	RESERVE AND CONTINGENCY FUND (Deposits to R&C Sub Accounts):											
36	Overhaul Account	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	Renewal and Replacement Account [14]	$000	6,053	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922	16,922
38	Capital Improvements Account	$000	0	0	0	0	0	0	0	0	0	0
39	Rate Stabilization Account	$000	0	0	0	0	0	0	0	0	0	0
40	Environmental Improvement Account	$000	0	0	0	0	0	0	0	0	0	0
41	Other	$000	0	0	0	0	0	0	0	0	0	0
42	*Total R&C Fund*	$000	$6,053	$16,922	$16,922	$16,922	$16,922	$16,922	$16,922	$16,922	$16,922	$16,922
	Available for Transfer to General Account											
43	Net Revenues Available for Transfer to General Account [15]	$000	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)
44	Amounts Available from R&C Fund to Transfer to General Account [16]	$000	$0	$4,526	$4,226	$3,924	$3,612	$3,292	$2,965	$2,630	$2,287	$1,935
45	**Total Revenue Requirements [17]**	$000	$187,448	$478,863	$499,590	$521,560	$544,481	$566,709	$575,503	$586,014	$596,803	$607,589

BEFORE THE
LOUISIANA PUBLIC SERVICE COMMISSION

APPLICATION OF ENTERGY LOUISIANA, LLC, FOR APPROVAL TO REPOWER THE LITTLE GYPSY UNIT 3 ELECTRIC GENERATING FACILITY AND FOR AUTHORITY TO COMMENCE CONSTRUCTION AND FOR CERTAIN COST PROTECTION AND COST RECOVERY	)	**DOCKET NO. U-30192**

DIRECT TESTIMONY OF DAVID A. SCHLISSEL ON BEHALF OF THE ALLIANCE FOR AFFORDABLE ENERGY, LOUISIANA ENVIRONMENTAL ACTION NETWORK, SIERRA CLUB, GULF RESTORATION NETWORK, SAL K. GIARDINI, JR., EARLENE ROTH, AND WARREN PIERRE

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SEPTEMBER 14, 2007

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List of Exhibits

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1. Introduction

Q. What is your name, position and business address?

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government and utilities. A complete description of Synapse is available at our website, www.synapse-energy.com.

Q. Please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 28 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My recent clients have included the New Mexico Public Regulation Commission, the General Staff of the Arkansas Public Service Commission, the Staff of the Arizona Corporation Commission, the U.S. Department of Justice, the Commonwealth of Massachusetts, the Attorneys General of the States of Massachusetts, Michigan,

New York, and Rhode Island, the General Electric Company, cities and towns in Connecticut, New York and Virginia, state consumer advocates, and national and local environmental organizations.

I have testified before state regulatory commissions in Arizona, New Jersey, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, Rhode Island, Wisconsin, Iowa, South Dakota, Georgia, Minnesota, Michigan, Florida and North Dakota and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is attached as Exhibit DAS-1.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Alliance for Affordable Energy ("AAE"), Louisiana Environmental Gulf Network, Sierra Club, Gulf Restoration Network, Sal K. Giardini, Jr., Earlene Roth, and Warren Pierre.

Q. Have you testified previously before this Commission?

A. No.

Q. What is the purpose of your testimony?

A. Synapse was retained by the Alliance for Affordable Energy to evaluate the proposal by Entergy Louisiana, LLC ("Entergy Louisiana" or "the Company") to repower the Little Gypsy Unit 3 electric facility as a circulating fluid bed ("CFB") generating unit that would burn a mixture of petroleum coke (petcoke) and coal. This testimony presents the results of our analyses.

Q. Please summarize your conclusions.

A. My conclusions are as follows:

1. The Fundamental and PROSYM analyses presented by Entergy Louisiana to justify the Repowering Project as the lowest cost option reflect an unreasonably range of potential carbon dioxide (CO_2) emissions allowance

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costs. In particular, the "Reference Case" scenarios examined by the Company which assume \$0/ton CO_2 prices (that is, no federal legislation regulating greenhouse gas emissions) are highly unrealistic and unlikely.

2. The Commission should rely on the Synapse forecasts of likely CO_2 emissions allowance prices when it considers the relative economics of the proposed Repowering Project.

3. The Fundamental and PROSYM analyses presented by Entergy Louisiana do not reflect a reasonable range of alternatives to the Repowering Project. For example, these studies do not reflect any demand side management or renewable resources as part of a portfolio of alternatives to the repowering of Little Gypsy Unit 3.

4. Given the experience of other power plant projects and the worldwide demand for power plant design and construction resources, commodities and labor, it is reasonable to expect that the cost of the Repowering Project will increase before the project is completed.

5. The results of the Company's Fundamental Analysis do not show that the Repowering Project would be the lower cost option under reasonable assumptions regarding future construction costs, CO_2 costs and natural gas prices. For example, the repowering of Little Gypsy Unit 3 as a CFB plant would be the higher cost option if the construction cost of the Repowering Project increases by another 10 or 20 percent even if the Company's unreasonably low forecasts of CO_2 prices are used.

6. The results of the PROSYM analysis suggest that the Fundamental Analysis significantly overstates the economic benefits of the Repowering Project.

7. Although Entergy Louisiana's PROSYM analysis shows a net present value benefit to the Repowering Project, that analysis unrealistically reflects \$0/ton CO_2 prices. Even if the Company's unreasonably low base or high CO2 prices were reflected in the analysis, the Repowering Project would be the higher cost option.

8. Even though Entergy Louisiana's PROSYM analysis shows a net present value benefit to the Repowering Project during the years 2012 through 2036, the CCGT alternative would be the lower cost option, on a cumulative net present value basis, through the year 2031.

For these reasons, the Commission should reject Entergy Louisiana's request for approval to repowering Little Gypsy Unit 3 and for authority to commence construction and for certain cost protection and cost recovery.

Q. In general, are you in favor of the repowering of older, less efficient power plants?

A. Yes. I believe that the repowering of older generating facilities often can provide economic and environmental benefits. Unfortunately, that does not appear to be the case with Entergy Louisiana's proposed repowering of the Little Gypsy Unit 3 as a CFB coal-fired unit.

2. The Appropriate Carbon Dioxide Emission Allowance Prices To Use In Evaluating Proposed Electric Generating Projects

Q. How does Entergy Louisiana view the prospects for carbon regulation?

A. Entergy Louisiana witness Schott has testified that "The Company believes that future climate change legislation is possible, and based upon recent activity, increasingly probable."[1]

Q. Do you agree with this assessment?

A. I believe that it is not a question of "if" with regards to federal regulation of greenhouse gas emissions but rather a question of "when." In addition, we agree with Entergy Louisiana witness Schott that there are uncertainties as to the design and details of the CO_2 regulations that ultimately will be adopted and implemented.[2]

Q. What mandatory greenhouse gas emissions reductions programs have begun to be examined in the U.S. federal government?

A. To date, the U.S. government has not required greenhouse gas emission reductions. However, a number of legislative initiatives for mandatory emissions reduction proposals have been introduced in Congress. These proposals establish carbon dioxide emission trajectories below the projected business-as-usual emission trajectories, and they generally rely on market-based mechanisms (such

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[1] Direct Testimony of Matthew J. Schott, Jr., at page 26, lines 13-14.
[2] Direct Testimony of Matthew J. Schott, Jr., at page 24, line 9, to page 25, line 4.

as cap and trade programs) for achieving the targets. The proposals also include various provisions to spur technology innovation, as well as details pertaining to offsets, allowance allocation, restrictions on allowance prices and other issues. Some of the federal proposals that would require greenhouse gas emission reductions that had been submitted in Congress are summarized in Table 1 below.[3]

Table 1. Summary of Mandatory Emissions Targets in Proposals Discussed in Congress[4]

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
McCain Lieberman S.139	Climate Stewardship Act	2003	Cap at 2000 levels 2010-2015. Cap at 1990 levels beyond 2015.	Economy-wide, large emitting sources
McCain Lieberman SA 2028	Climate Stewardship Act	2003	Cap at 2000 levels	Economy-wide, large emitting sources
McCain Lieberman S 1151	Climate Stewardship and Innovation Act	2005	Cap at 2000 levels	Economy-wide, large emitting sources
National Commission on Energy Policy (basis for Bingaman-Domenici legislative work)	Greenhouse Gas Intensity Reduction Goals	2005	Reduce GHG intensity by 2.4%/yr 2010-2019 and by 2.8%/yr 2020-2025. Safety-valve on allowance price	Economy-wide, large emitting sources
Jeffords S. 150	Multi-pollutant legislation	2005	2.050 billion tons beginning 2010	Existing and new fossil-fuel fired electric generating plants > 15 MW
Carper S. 843	Clean Air Planning Act	2005	2006 levels (2.655 billion tons CO_2) starting in 2009, 2001 levels (2.454 billion tons CO_2) starting in 2013.	Existing and new fossil-fuel fired, nuclear, and renewable electric generating plants > 25 MW
Feinstein	Strong Economy and Climate Protection Act	2006	Stabilize emissions through 2010; 0.5% cut per year from 2011-15; 1% cut per year from 2016-2020. Total goal would be 7.25% below current levels.	Economy-wide, large emitting sources

[3] Table 1 is an updated version of Table ES-1 on page 5 of Exhibit DAS-3.
[4] More detailed summaries of the bills that have been introduced in the U.S. Senate in the 110th Congress are presented in Exhibit DAS-2.

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Rep. Udall - Rep. Petri	Keep America Competitive Global Warming Policy Act	2006	Establishes prospective baseline for greenhouse gas emissions, with safety valve.	Energy and energy-intensive industries
Carper S.2724	Clean Air Planning Act	2006	2006 levels by 2010, 2001 levels by 2015	Existing and new fossil-fuel fired, nuclear, and renewable electric generating plants > 25 MW
Kerry and Snowe S.4039	Global Warming Reduction Act	2006	No later than 2010, begin to reduce U.S. emissions to 65% below 2000 levels by 2050	Not specified
Waxman H.R. 5642	Safe Climate Act	2006	2010 – not to exceed 2009 level, annual reduction of 2% per year until 2020, annual reduction of 5% thereafter	Not specified
Jeffords S. 3698	Global Warming Pollution Reduction Act	2006	1990 levels by 2020, 80% below 1990 levels by 2050	Economy-wide
Feinstein- Carper S.317	Electric Utility Cap & Trade Act	2007	2006 level by 2011, 2001 level by 2015, 1%/year reduction from 2016-2019, 1.5%/year reduction starting in 2020	Electricity sector
Kerry-Snowe	Global Warming Reduction Act	2007	2010 level from 2010-2019, 1990 level from 2020-2029, 2.5%/year reductions from 2020-2029, 3.5%/year reduction from 2030-2050, 65% below 2000 level in 2050	Economy-wide
McCain-Lieberman S.280	Climate Stewardship and Innovation Act	2007	2004 level in 2012, 1990 level in 2020, 20% below 1990 level in 2030, 60% below 1990 level in 2050	Economy-wide
Sanders-Boxer S.309	Global Warming Pollution Reduction Act	2007	2%/year reduction from 2010 to 2020, 1990 level in 2020, 27% below 1990 level in 2030, 53% below 1990 level in 2040, 80% below 1990 level in 2050	Economy-wide
Olver, et al HR 620	Climate Stewardship Act	2007	Cap at 2006 level by 2012, 1%/year reduction from 2013-2020, 3%/year reduction from 2021-2030, 5%/year reduction from 2031-2050, equivalent to 70% below 1990 level by 2050	US national
Bingaman–Specter S.1766	Low Carbon Economy Act	2007	2012 levels in 2012, 2006 levels in 2020, 1990 levels by 2030. President may set further goals ≥60% below 2006 levels by 2050 contingent upon international effort	Economy-wide

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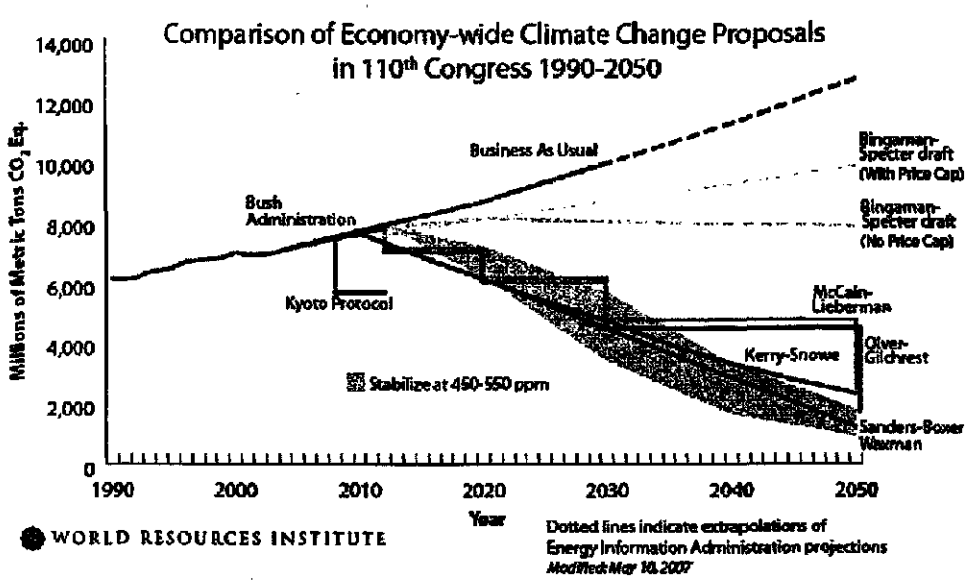
In addition, Senators Lieberman and Warner have issued a set of discussion principles for proposed greenhouse gas legislation. This legislation would mandate 2005 emission levels in 2012, 10% below 2005 levels by 2020, 30% below 2005 levels by 2030, 50% below 2005 levels by 2040, and 70% below 2005 levels by 2050.

The emissions levels that would be mandated by the bills that have been introduced in the current Congress are shown in Figure 1 below:

Figure 1: Emissions Reductions Required under Climate Change Bills in Current US Congress



The shaded area in Figure 1 above represents the 60% to 80% range of emission reductions from current levels that many now believe will be necessary to stabilize atmospheric CO_2 concentrations by the middle of this century.

Many of the bills that have been introduced in the 110th Congress call for emissions reductions to levels that are far below the levels that Entergy Louisiana considered in the development of its base and high CO_2 price forecasts.

Q. Are individual states also taking actions to reduce greenhouse gas emissions?

A. Yes. A number of states are taking significant actions to reduce greenhouse gas emissions. Table 2 below lists the emission reduction goals that have been adopted by states in the U.S. Regional action also has been taken in the Northeast and Western regions of the nation.

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Table 2: Announced State and Regional Greenhouse Gas Emission Reduction Goals

State	GHG Reduction Goal	Western Climate Initiative member (15% below 2005 levels by 2020)	Regional Greenhouse Gas Initiative member (Cap at current levels 2009-2015, reduce this by 10% by 2019)
Arizona	2000 levels by 2020; 50% below 2000 levels by 2040	yes	
California	2000 levels by 2010; 1990 levels by 2020; 80% below 1990 levels by 2050	yes	
Connecticut	1990 levels by 2010; 10% below 1990 levels by 2020; 75-85% below 2001 levels in the long term		yes
Delaware			yes
Florida	2000 levels by 2017, 1990 levels by 2025, and 80 percent below 1990 levels by 2050		
Hawaii	1990 levels by 2020		
Illinois	1990 levels by 2020; 60% below 1990 levels by 2050		
Maine	1990 levels by 2010; 10% below 1990 levels by 2020; 75-80% below 2003 levels in the long term		yes
Maryland			yes
Massachusetts	1990 levels by 2010; 10% below 1990 levels by 2020; 75-85% below 1990 levels in the long term		yes
Minnesota	15% by 2015, 30% by 2025, 80% by 2050		
New Hampshire	1990 levels by 2010; 10% below 1990 levels by 2020; 75-85% below 2001 levels in the long term		yes
New Jersey	1990 levels by 2020; 80% below 2006 levels by 2050		yes
New Mexico	2000 levels by 2012; 10% below 2000 levels by 2020; 75% below 2000 levels by 2050	yes	
New York	5% below 1990 levels by 2010; 10% below 1990 levels by 2020		yes
Oregon	Stabilize by 2010; 10% below 1990 levels by 2020; 75% below 1990 levels by 2050	yes	
Rhode Island	1990 levels by 2010; 10% below 1990 levels by 2020; 75-80% below 2001 levels in the long term		yes
Utah		yes	
Vermont	1990 levels by 2010; 10% below 1990 levels by 2020; 75-85% below 2001 levels in the long term		yes
Washington	1990 levels by 2020; 25% below 1990 levels by 2035; 50% below 1990 levels by 2050	yes	

Q. Is it reasonable to believe that the prospects for passage of federal legislation for the regulation of greenhouse gas emissions have improved as a result of last November's federal elections?

A. Yes. As shown by the number of proposals being introduced in Congress and public statements of support for taking action, there certainly are an increasing numbers of legislators who are inclined to support passage of legislation to regulate the emissions of greenhouse gases.

Nevertheless, my conclusion that significant greenhouse gas regulation in the U.S. is inevitable is not based on the results of any single election or on the fate of any single bill introduced in Congress.

Q. Have recent polls indicated that the American people are increasingly in favor of government action to address global warming concerns?

A. Yes. A summer 2006 poll by Zogby International showed that an overwhelming majority of Americans are more convinced that global warming is happening than they were even two years ago. In addition, Americans also are connecting intense weather events like Hurricane Katrina and heat waves to global warming.[5] Indeed, the poll found that 74% of all respondents, including 87% of Democrats, 56% of Republicans and 82% of Independents, believe that we are experiencing the effects of global warming.

The poll also indicated that there is strong support for measures to require major industries to reduce their greenhouse gas emissions to improve the environment without harming the economy – 72% of likely voters agreed such measures should be taken.[6]

Other recent polls reported similar results. For example, a Time/ABC/Stanford University poll issued in the spring of 2006 found 68 percent of Americans are in

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[5] "Americans Link Hurricane Katrina and Heat Wave to Global Warming," Zogby International, August 21, 2006, available at www.zogby.com/news.

[6] Id.

1 favor of more government action to address climate change.[7] In addition, a
2 September 2006 telephone poll, conducted by NYU's Brademas Center for the
3 Study of Congress, reported that 70% of those polled stated that they were
4 worried about global warming.[8]

5 At the same time, according to a recent public opinion survey for the
6 Massachusetts Institute of Technology, Americans now rank climate change as
7 the country's most pressing environmental problem—a dramatic shift from three
8 years ago, when they ranked climate change sixth out of 10 environmental
9 concerns.[9] Almost three-quarters of the respondents felt the government should do
10 more to deal with global warming, and individuals were willing to spend their
11 own money to help.

12 **Q. What CO_2 prices has Energy Louisiana used in its modeling of the proposed**
13 **Little Gypsy repowering project?**

14 A. Entergy Louisiana presented a "Reference Case Analysis" that assumed $0/ton
15 CO_2 prices.[10] The Company also prepared sensitivity analyses assuming what it
16 calls base CO_2 and high CO_2 emissions allowance prices.[11]

17 **Q. Is it prudent and reasonable to assume no CO_2 emissions allowance prices in**
18 **the Reference Case Analysis?**

19 A. No. It is not prudent to project that there will be no regulation of greenhouse gas
20 emissions at any point over the next thirty or more years. As I will discuss later in
21 this testimony, federal regulation of greenhouse gas emissions is highly likely in
22 the near future. States also have started to take actions to reduce greenhouse gas

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7 "Polls find groundswell of belief in, concern about global warming." Greenwire, April 21, 2006, Vol. 10 No. 9. See also Zogby's final report on the poll which is available at http://www.zogby.com/wildlife/NWFfinalreport8-17-06.htm.

8 Kaplun, Alex: "Campaign 2006: Most Americans 'worried' about energy, climate;" Greenwire, September 29, 2006.

9 *MIT Carbon Sequestration Initiative, 2006 Survey,* http://sequestration.mit.edu/research/survey2006.html

10 Exhibit APW-11.

11 Direct Testimony of Anthony P. Walz, at page 34, lines 3-8.

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emissions both on their own and as part of regional initiatives. Moreover, given all of their public statements about the dangers posed by global climate change and the necessity of addressing that threat, I find it hard to accept that Entergy believes that this is a reasonable scenario.

Q. Have you seen any projections of what Entergy's future CO_2 emissions would be under the Company's reference case assumption that there will be no regulation of greenhouse gas emissions?

A. Yes. As shown in Figure 2 below, the results of the PROSYM analysis discussed by Entergy Louisiana witness Walz show that Entergy's CO2 emissions would **[Redacted]** in the scenario with Little Gypsy Unit 3 repowered as a CFB:

Figure 2: Entergy CO_2 Emissions Trajectory with Little Gypsy Unit 3 Repowered as a CFB Coal-Fired Plant

Q. What CO_2 prices did Entergy Louisiana assume in its base and high CO_2 sensitivities?

A. Entergy's base and high CO2 price forecasts are presented in Table 3 below:

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Table 3: Entergy Louisiana CO_2 Price Forecasts

	Entergy Louisiana Base CO_2 Prices Nom$	Entergy Louisiana Base CO_2 Prices 2005$	Entergy Louisiana High CO2 Prices Nom$	Entergy Louisiana High CO2 Prices 2005$
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				

Q. How do these forecasts change after 2030?

A. The Company's base CO_2 forecast would [**REDACTED**] [12] Entergy's high CO_2 price forecast would [**REDACTED**].[13]

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12 *CO2 Point of View*, Entergy Corporation, December 13, 2005, provided in the Response to Question AAE 1-2, at pages 27 and 28.

13 Response to Question LPSC 1-30, at page LR168. A copy of this response is included in Exhibit DAS-8.

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Q. How did Entergy Louisiana develop its base CO_2 price forecast?

A. Entergy Louisiana witness Walz has testified that "The base CO_2 cost assumptions were developed by reviewing various consulting forecasts for CO_2 costs. As such, the base CO_2 assumptions represent a consensus forecast."[14]

Q. When was this base CO_2 price forecast prepared?

A. It appears that this base CO_2 price forecast was developed in [**Redacted**].[15]

Q. How do the annual prices in Entergy's base CO_2 forecast compare to the forecasts on which the Company has said it relied based?

A. Figure 3 below compares Entergy Louisiana's base CO_2 forecast with the other "consulting" forecasts on which the Company has indicated it relied. As can be seen, Entergy's base CO_2 forecast is significantly lower than all but one of the other forecasts. Thus, it makes no sense to say that Entergy's base CO_2 price forecast represents a consensus with the other forecasts, as Mr. Walz testifies.

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[14] Direct Testimony of Anthony P. Walz, at page 34, lines 11-13.

[15] *CO2 Point of View*, Entergy Corporation, December 13, 2005, provided in the Response to Question AAE 1-2, at pages 27 and 28.

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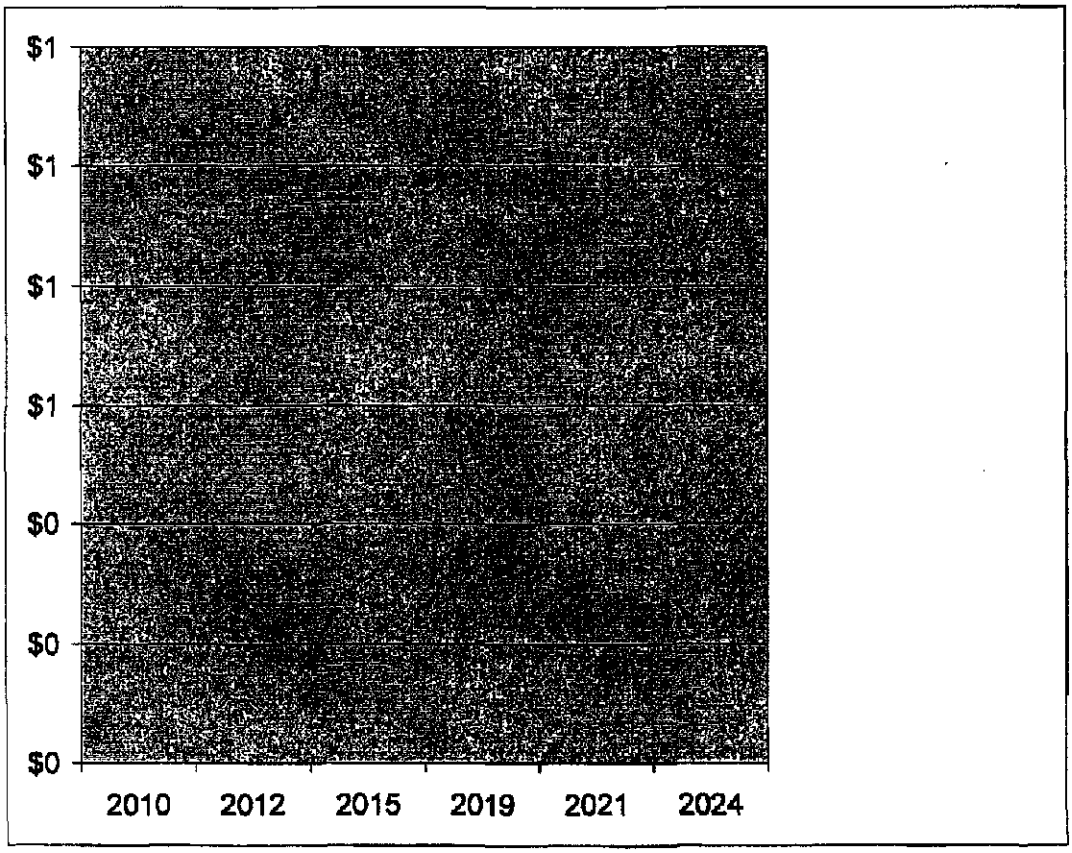
Figure 3: Entergy base CO2 Prices vs. Other Forecasts Considered by Entergy.



Q. How do the emissions levels assumed by Entergy in its base CO_2 forecast compare to the emissions target levels in the bills that have been introduced in the current U.S. Congress?

A. Entergy's base CO_2 price forecast assumes that starting [

REDACTED] These emissions levels are substantially less stringent than the emissions target levels in the bills that have been introduced in the current U.S. Congress. For example, as shown in Table 1 above, the current McCain-Lieberman bill, Senate Bill 280, would mandate that emissions be at 1990 levels by 2020 and 20% below 1990 levels by 2030. Similarly, the legislation proposed by Senators Feinstein and Carper,

Senate Bill 317, would require CO_2 emissions be reduced to 2001 levels by 2015 and 13% below 2001 levels by 2026. Even the legislation recently proposed by Senators Bingaman and Specter, which include safety-valve prices, would require that emission levels be reduced to 1990 levels by 2030.

Q. Entergy Louisiana witness Schott has testified concerning reductions in greenhouse gas emissions intensity and has presented as an exhibit a March 2006 EIA report entitled "*Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals.*"[16] Are you aware of any major bill being considered in the current Congress that would regulate the greenhouse gas intensity of power plant emissions rather than mandating that overall emissions levels be reduced?

A. No. The draft proposal that was circulated by Senator Bingaman in 2006 would have regulated greenhouse gas emission intensity. However, this approach was abandoned in the bill that Senators Bingaman and Specter actually introduced in July 2007. This bill would require that overall greenhouse gas emissions levels be capped at 2012 levels in 2012 and then be reduced to 2006 levels in 2020 and 1990 levels by 2030.

Q. Is it reasonable to consider this Entergy forecast a "base" CO_2 price forecast, as Entergy Louisiana has claimed?

A. No. It is much too low to be a base CO_2 price forecast. It might be reasonable as a low CO_2 price forecast except for the fact that it assumes that CO_2 emissions allowance prices [**REDACTED**].[17]

Q. How did Entergy develop its high CO_2 price forecast?

A. Entergy Louisiana's high CO_2 price forecast is based on an [**REDACTED**].[18]

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16 Direct Testimony of Matthew J. Schott, Jr., at page 25, line 17, to page 26, line 2.
17 *CO2 Point of View*, Entergy Corporation, December 13, 2005, provided in the Response to Question AAE 1-2, at pages 27 and 28.

Q. Is this a reasonable "high" CO_2 price forecast?

A. No. Although the forecast is far more reasonable than the Company's base CO_2 price forecast, it still is too low to be considered the high end of a reasonable range of possible future CO_2 emissions allowance prices. In particular, Entergy's high CO_2 price forecast does not reflect the emissions allowance prices that could result from a number of the bills that have been introduced in Congress which propose very significant emissions reductions.

Q. What carbon dioxide values are being used by utilities in electric resource planning?

A. Table 6.1 on page 41 of 63 of Exhibit DAS-3 presents the carbon dioxide costs, in \$/ton CO_2, that were being used as of 2006 by a number of utilities for both resource planning and modeling of carbon regulation policies.

Q. Are you aware of any recent regulatory commission decisions concerning the levels of carbon dioxide emissions prices that utilities should consider when planning how to supply energy to their customers?

A. Yes. The New Mexico Public Regulation Commission recently ordered that utilities should consider a range of CO_2 prices in their resource planning. This range runs from \$8 to \$40 per metric ton, beginning in 2010 and increases at the overall 2.5 percent rate of inflation. This range includes significantly higher CO_2 prices than the base and high CO_2 prices used by Entergy Louisiana in its analyses of the Little Gypsy repowering project.[19]

Q. Has Synapse developed a carbon price forecast that would assist the Commission in evaluating the proposed repowering of Little Gypsy Unit 3?

A. Yes. Synapse's forecast of future carbon dioxide emissions prices are presented in Figure 4 below.

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18 Response to LPSC 1-30, at page LR167.
19 A copy of the New Mexico Public Regulation Commission Order is included as Exhibit DAS-4.

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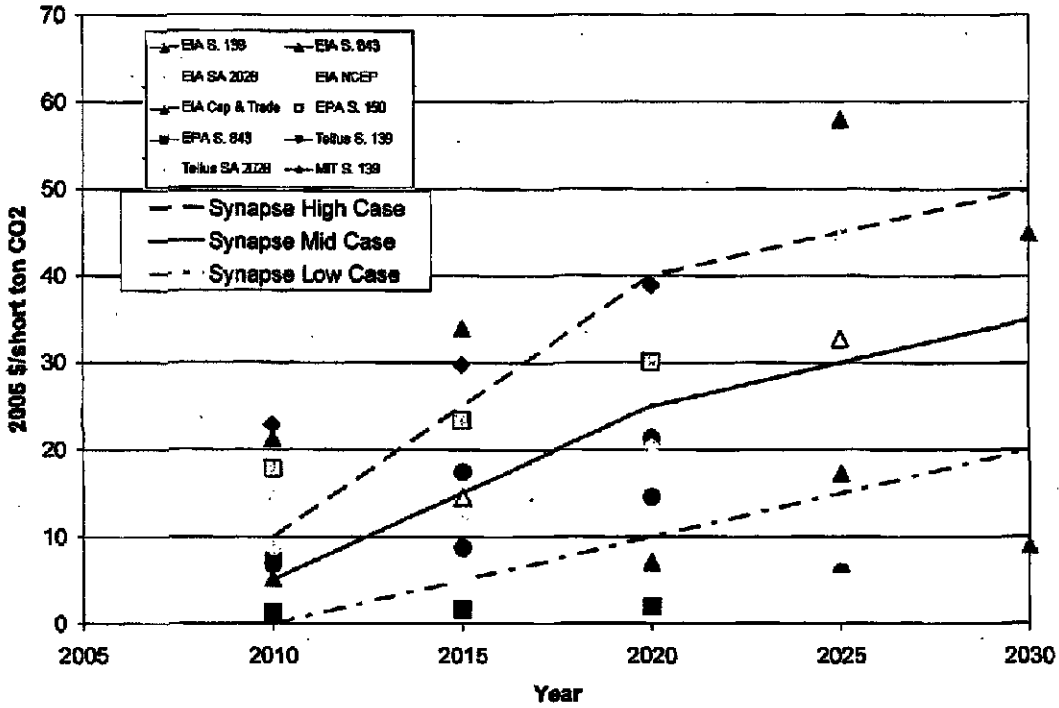
Figure 4. Synapse Carbon Dioxide Prices



Q. What is Synapse's carbon price forecast on a levelized basis?

A. Synapse's forecast, levelized[20] over 20 years, 2011 – 2030, is provided in Table 4 below.

Table 4: Synapse's Levelized Carbon Price Forecast (2005$/ton of CO_2)

Low Case	Mid Case	High Case
$8.23	$19.83	$31.43

Q. When were the Synapse CO_2 emission allowance price forecasts shown in Figure 4 developed?

A. The Synapse CO_2 emission allowance price forecasts were developed in the Spring of 2006.

Q. How were these CO_2 price forecasts developed?

A. The basis for the Synapse CO_2 price forecasts is described in detail in Exhibit DAS-3, starting on page 41 of 63.

In general, the price forecasts were based, in part, on the results of economic analyses of individual bills that had been submitted in the 108th and 109th Congresses. We also considered the likely impacts of state, regional and international actions, the potential for offsets and credits, and the likely future trajectories of both emissions constraints and technological program.

Q. Are the Synapse CO_2 price forecasts shown in Figure 4 based on any independent modeling?

A. Yes. Although Synapse did not perform any new modeling to develop our CO_2 price forecasts, our CO_2 price forecasts were based on the results of independent modeling prepared at the Massachusetts Institute of Technology ("MIT"), the Energy Information Administration of the Department of Energy ("EIA"), Tellus, and the U.S. Environmental Protection Agency ("EPA").[21]

Q. Do the triangles, squares, circles and diamond shapes in Figure 4 above reflect the results of all of the scenarios examined in the MIT, EIA, EPA and Tellus analyses upon which Synapse relied?

A. As a general rule, Synapse focused our attention either on the modeler's primary scenario or on the presented high and low scenarios to bracket the range of results.

For example, the blue triangles in Figure 4 represent the results from EIA's modeling of the 2003 McCain Lieberman bill, S.139. Synapse used the results from EIA's primary case which reflected the bill's provisions that allowed: (a)

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[20] A value that is "levelized" is the present value of the total cost converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation).

[21] See Table 6.2 on page 42 of 63 of Exhibit DAS-3.

allowance banking; (b) use of up to 15 percent offsets in Phase I (2010-2015) and up to 10 percent offsets in Phase II (2016 and later years). The S.139 case also assumed commercial availability of advanced nuclear plants and of geological carbon sequestration technologies in the electric power industry.

Similarly, the blue diamonds in Figure 4 represent the results from MIT's modeling of the same 2003 McCain Lieberman bill, S.139. MIT examined 14 scenarios which considered the impact of factors such as the tightening of the cap in Phase II, allowance banking, availability of outside credits, and assumptions about GDP and emissions growth. Synapse included the results from Scenario 7 which included allowance banking and zero-cost credits, which effectively relaxed the cap by 15% and 10% in Phase I and Phase II, respectively. Synapse selected this scenario as the closest to the S.139 legislative proposal since it assumed that the cap was tightened in a second phase, as in Senate Bill 139.

At the same time, some of the studies only included a single scenario representing the specific features of the legislative proposal being analyzed. For example, SA 2028, the Amended McCain Lieberman bill set the emissions cap at constant 2000 levels and allowed for 15 percent of the carbon emission reductions to be met through offsets from non-covered sectors, carbon sequestration and qualified international sources. EIA presented one scenario in its table for this policy. The results from this scenario are presented in the green triangles in Figure 4.

Q. Do you believe that technological improvements and policy designs will reduce the cost of CO_2 emissions?

A. Yes. Exhibit DAS-3 identifies a number of factors that will affect projected allowance prices. These factors include: the base case emissions forecast; whether there are complimentary policies such as aggressive investments in energy efficiency and renewable energy independent of the emissions allowance market; the policy implementation timeline; the reduction targets in a proposal;

program flexibility involving the inclusion of offsets (perhaps international) and allowance banking; technological progress; and emissions co-benefits.[22] In particular, Synapse anticipates that technological innovation will temper allowance prices in the out years of our forecast.

Q. Could carbon capture and sequestration be a technological innovation that might temper or even put a ceiling on CO_2 emissions allowance prices?

A. Yes.

Q. Does Entergy see carbon capture technology as a currently commercially viable way to mitigate CO_2 emissions from pulverized coal plants like the Little Gypsy project?

A. No. Entergy has expressed the following position concerning the technical feasibility of both CO_2 capture and CO_2 sequestration for the emissions from the Little Gypsy project:

> To date, carbon capture and sequestration has not been demonstrated commercially on any power plant in the United States. Even today, pilot scale projects are only now being developed in the United States. The Company does not believe that this technology is commercially and reliably viable on a utility scale at the current level of technology development. Significant research and development in the performance, cost, and reliability of carbon capture technology remains to be completed. In addition, further research is also required on underground sequestration of carbon, including costs, permitting, and technological advancement such as appropriate geological formations and appropriateness for long term storage of carbon dioxide and the transportation of CO_2 gas.[23]

Q. Do you agree with this assessment?

A. I agree with this view of the current status of carbon capture and sequestration technology although I would note that there is some experience with the piping of

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[22] Exhibit DAS-3, at pages 46 to 49 of 63.
[23] Response to Question No. LPSC 1-18. A copy of this response in included in DAS-8.

CO_2 gas for enhanced oil recovery and industrial use in certain geographical areas.

Q. Is there any consensus when carbon capture and sequestration technology will become commercially viable for plants like a repowered Little Gypsy Unit 3?

A. No. I have seen estimates that carbon capture and sequestration technology may be proven and commercially viable from as early as 2015 to 2030 or later.

Q. What are the currently estimated costs for carbon capture and sequestration at pulverized coal facilities?

A. Hope has been expressed concerning potential technological improvements and learning curve effects that might reduce the estimated cost of carbon capture and sequestration. However, I have seen recent estimates that the cost of carbon capture and sequestration could increase the cost of producing electricity at coal-fired power plants by 60-80 percent, on a $/MWh basis. A very recent study by the National Energy Technology Laboratory ("NETL") projects that the cost of carbon capture and sequestration would be $75/tonne[24] of CO_2 avoided, in 2007 dollars, for pulverized coal plants. This translates in to $65/ton of CO_2 avoided, in 2005 dollars. The March 2007 "Future of Coal Study" from the Massachusetts Institute of Technology estimated that the cost of carbon capture and sequestration would be about $28/ton although it also acknowledged that there was uncertainty in that figure.[25] The tables in that study also indicated significantly higher costs for carbon capture for pulverized coal facilities, in the range of about $40/ton and higher.[26]

However, even when the technology for CO_2 capture matures, there will always be significant regional variations in the cost of storage due to the proximity and

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[24] A tonne or metric ton is a measurement of mass equal to 1,000 kilograms or 1.1 tons.
[25] *The Future of Coal, Options for a Carbon-Constrained World*, Massachusetts Institute of Technology, March 2007, at page xi.

quality of storage sites. [

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].[27]

Q. Has Entergy included any carbon capture and sequestration equipment or features in the current design for the repowered Little Gypsy facility?

A. No.[28]

Q. Do the Synapse CO_2 price forecasts reflect the potential for the inclusion of domestic offsets and, perhaps, international offsets in U.S. carbon regulation policy?

A. Yes. Even the Synapse high CO_2 price forecast is consistent with, and in some cases lower than, the results of studies that assume the use of some levels of offsets to meet mandated emission limits. For example, as shown in Figure 4, the highest price scenarios in the years 2015, 2020 and 2025 were taken from the EIA and MIT modeling of the original and the amended McCain-Lieberman proposals. Each of the prices for these scenarios shown in Figure 4 reflects the allowed use of offsets.

Q. How do the Synapse CO_2 price forecasts compare to the forecast used by Entergy Louisiana in its recent analyses of the proposed repowering of Little Gypsy?

A. The Synapse and Entergy Louisiana CO_2 price forecasts are shown in Figure 5 below. As this Figure demonstrates, the Company's base CO_2 price forecast is similar to our Synapse low forecast and the Company's high CO_2 price forecast is similar to our mid-forecast.

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26 Id, at page 19.
27 Response to LPSC 1-30, at page LR168.
28 Response to AAE 1-47.

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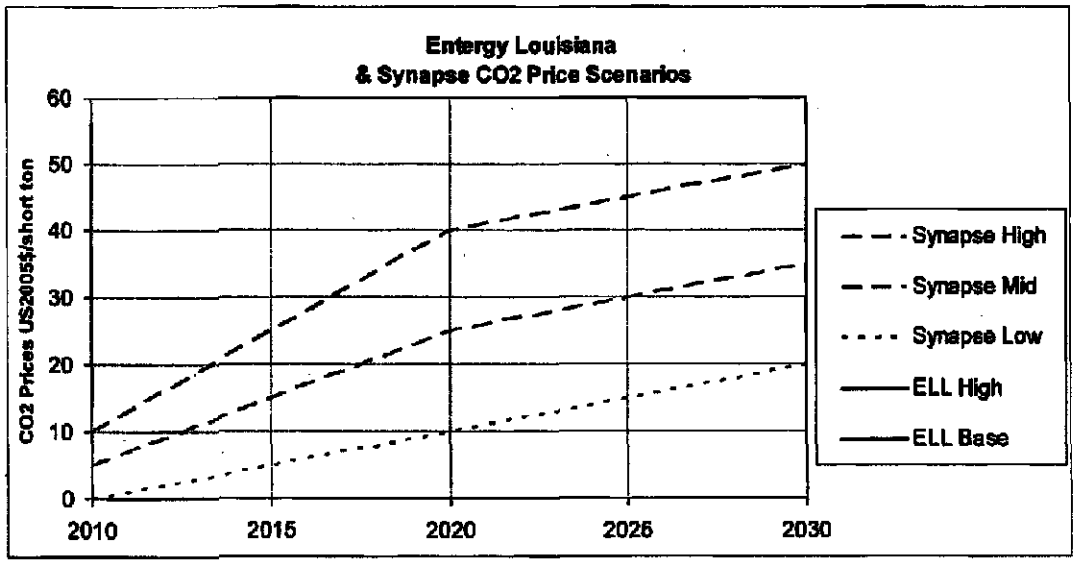
Figure 5: Synapse and Entergy Louisiana CO_2 Price Forecasts



Q. Have you seen any recent independent forecasts of future CO_2 emissions prices that are similar to the Synapse forecast?

A. Yes. The recent MIT study on *The Future of Coal* contained a set of assumptions about high and low future CO_2 emission allowance price. Figure 6 below shows that the CO_2 price trajectories in the MIT study are very close to the high and low Synapse forecasts.

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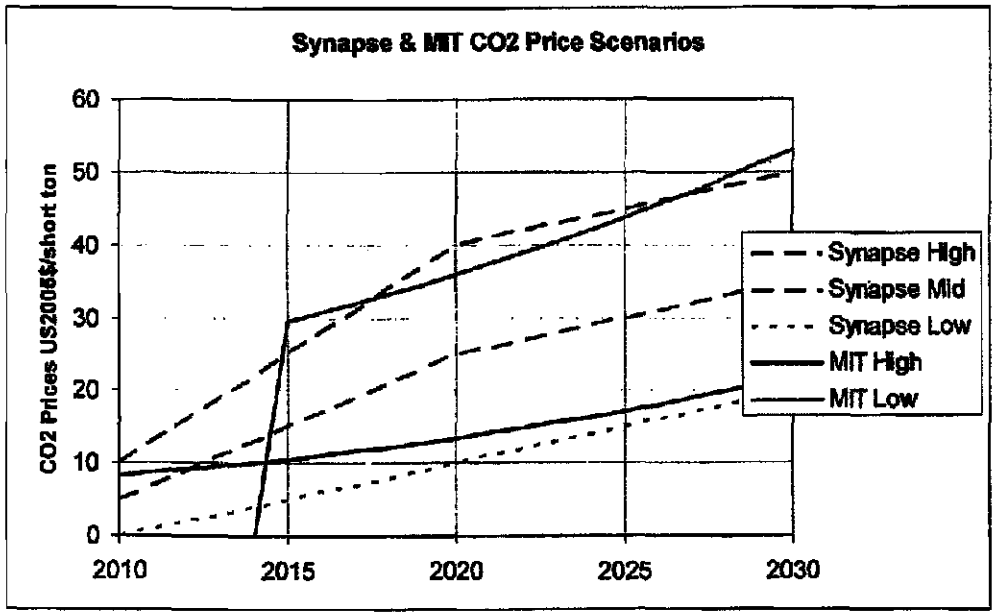
Figure 6: CO_2 Price Scenarios – Synapse & MIT March 2007 Future of Coal Study



Q. Do you believe that the Synapse CO_2 price forecasts remain valid despite being based, in part, on analyses from 2003-2005 which examined legislation that was proposed in past Congresses?

A. Yes. Synapse believes it is important for the Commission to rely on the most current information available about future CO_2 emission allowance prices, as long as that information is objective and credible. The analyses upon which Synapse relied when we developed our CO_2 price forecasts were the most recent analyses and technical information available when Synapse developed its CO_2 price forecasts in the Spring of 2006. However, new information shows that our CO_2 prices remain valid even though the original bills that comprised part of the basis for the forecasts expired at the end of the Congress in which they were introduced.

Most importantly, many of the new greenhouse gas regulation bills that have been introduced in Congress are significantly more stringent than the bills that were being considered prior to the spring of 2006. As I will discuss below, the

increased stringency of current bills can be expected to lead to higher CO_2 emission allowance prices. The higher forecast natural gas prices that are being forecast today, as compared to the natural gas price forecasts from 2003 or 2004, also can be expected to lead to higher CO_2 emissions allowance prices.

Q. Do the Synapse carbon price forecasts presented in Figures 4 and 6 reflect the emission reduction targets in the bills that have been introduced in the current Congress?

A. No. Synapse developed our price forecasts late last spring and relied upon bills that had been introduced in Congress through that time. The bills that have been introduced in the current US Congress generally would mandate much more substantial reductions in greenhouse gas emissions than the bills that we considered when we developed our carbon price forecasts. Consequently, we believe that our forecasts are conservative.

Q. Have you seen any analyses of the CO_2 prices that would be required to achieve the much deeper reductions in CO_2 emissions that would be mandated under the bills currently under consideration in Congress?

A. Yes. An *Assessment of U.S. Cap-and-Trade Proposals* was recently issued by the MIT Joint Program on the Science and Policy of Global Change. This *Assessment* evaluated the impact of the greenhouse gas regulation bills that are being considered in the current Congress.

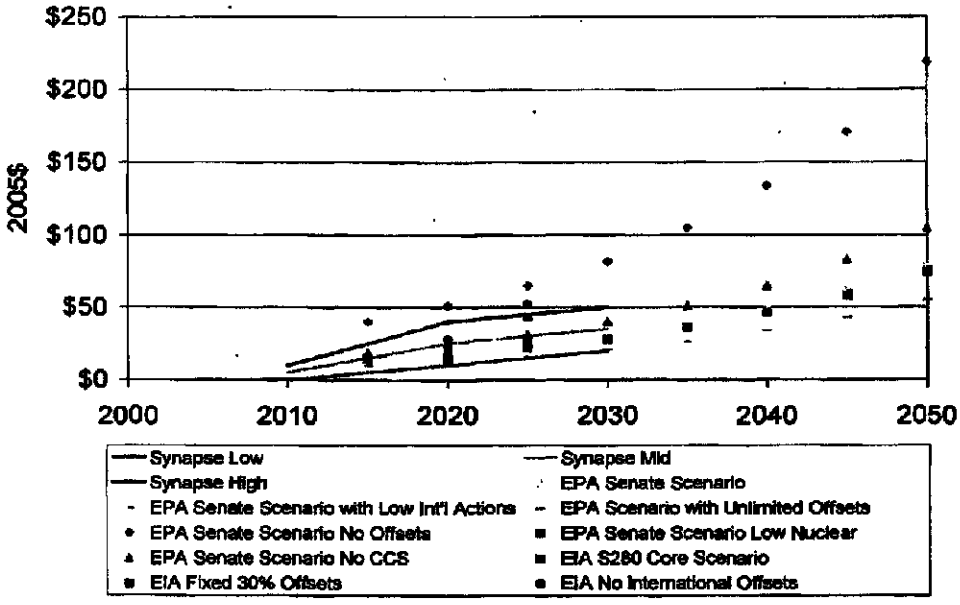
Twenty nine scenarios were modeled in the *Assessment*. These scenarios reflected differences in such factors as emission reduction targets (that is, reduce CO_2 emissions 80% from 1990 levels by 2050, reduce CO_2 emissions 50% from 1990 levels by 2050, or stabilize CO_2 emissions at 2008 levels), whether banking of allowances would be allowed, whether international trading of allowances would be allowed, whether only developed countries or the U.S. would pursue

greenhouse gas reductions, whether there would be safety valve prices adopted as part of greenhouse gas regulations, and other factors.[29]

In general, the ranges of the projected CO_2 prices in these scenarios were higher than the range of CO_2 prices in the Synapse forecast. For example, twelve of the 29 scenarios modeled by MIT projected higher CO_2 prices in 2020 than the high Synapse forecast. Fourteen of the 29 scenarios (almost half) projected higher CO_2 prices in 2030 than the high Synapse forecast.

Figure 7 below compares the three Core Scenarios in the MIT *Assessment* with the Synapse CO_2 price forecasts.

Figure 7: CO_2 Price Scenarios – Synapse and Core Scenarios in April 2007 MIT *Assessment of U.S. Cap-and-Trade Proposals*



[29] The scenarios examined in the MIT *Assessment of U.S. Cap-and-Trade Proposals* are listed in Exhibit DAS-5.

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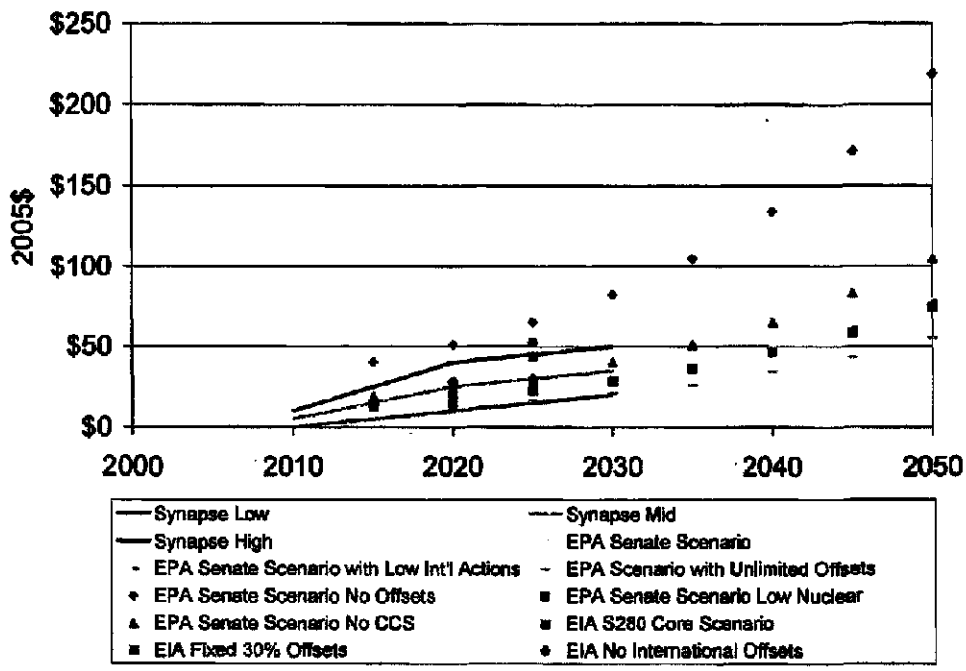
Q. Have you compared the Synapse CO_2 emissions allowance price forecasts to any other assessments of current bills in Congress?

A. Yes. Both EPA and the Energy Information Agency (EIA) of the Department of Energy have analyzed the impact of the current version of the McCain-Lieberman legislation (Senate Bill 280).[30] Figure 8 below shows that the Synapse CO_2 price forecasts are consistent with the range of scenarios examined in the EPA and EIA assessments:

Figure 8: Synapse CO_2 Price Forecasts and Results of EPA and EIA Assessment of Current McCain Lieberman Legislation

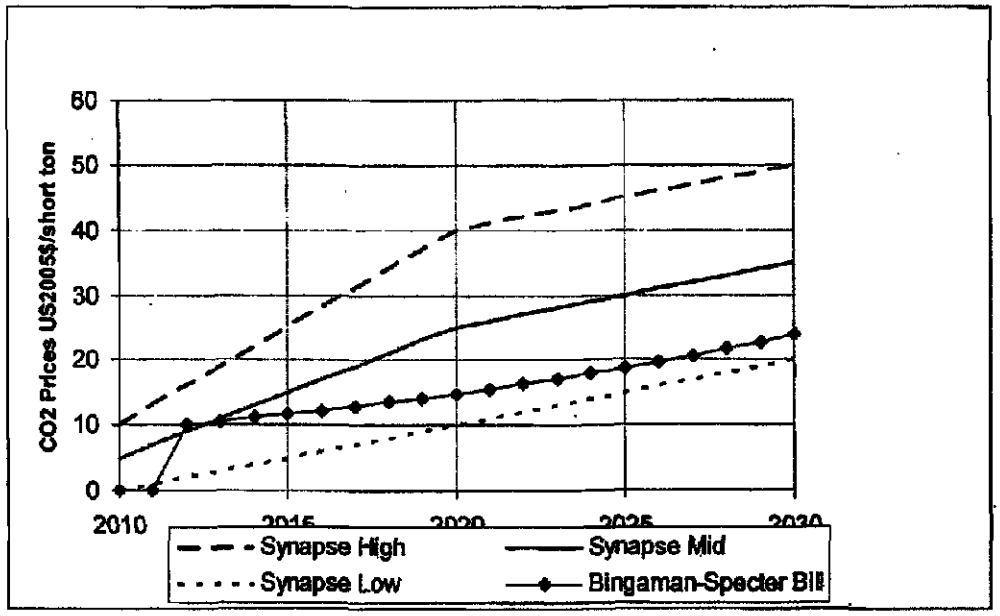


[30] *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007*, Energy Information Administration, July 2007 and *EPA Analysis of the Climate Stewardship and Innovation Act of 2007, S. 280 in 110th Congress*, July 16, 2007.

Q. How do the Synapse CO_2 forecasts compare to the safety valve prices in the bill introduced by Senators Bingaman and Specter?

A. As shown in Figure 9 below, the safety valve prices in the legislation introduced by Senators Bingaman and Specter fall between the Synapse mid and low forecasts.

Figure 9: Synapse CO_2 Price Forecasts and Safety Valve Prices in Bingaman-Specter Legislation in 110th Congress



Q. What are you recommendations concerning the CO_2 prices that the Commission should use in evaluating the proposed repowering of Little Gypsy Unit 3 as a CFB?

A. Given the uncertainty associated with the legislation that eventually will be passed by Congress, we believe that the Commission should use the wide range of forecasts of CO_2 prices shown in Figure 4 above to evaluate the relative economics of the proposed Repowering Project.

Q. How much additional CO_2 would the repowered Little Gypsy Unit 3 emit into the atmosphere?

A. The repowered Little Gypsy Unit 3 would emit approximately 4 million tons of CO_2 annually.[31]

Q. What would be the annual costs of greenhouse gas regulations to Entergy Louisiana and its ratepayers under the Synapse CO_2 price forecasts if the Company proceeds with its plan to repower Little Gypsy Unit 3 as a CFB plant?

A. The range of the incremental annual, levelized cost to the Company and its ratepayers from greenhouse gas regulations would be:

Synapse Low CO_2 Case: 4 million tons of CO_2 · \$8.23/ton = \$33 million

Synapse Mid CO_2 Case: 4 million tons of CO_2 · \$19.83/ton = \$79 million

Synapse High CO_2 Case: 4 million tons of CO_2 · \$31.43/ton = \$126 million

3. The Probable Economic Impact of the Proposed Repowering Project

Q. Do the results of the Fundamental Analysis presented by Entergy Louisiana witness Walz show that repowering Little Gypsy Unit 3 as a CFB is the lowest cost, lowest risk option for the Company and its ratepayers?

A. No. The Fundamental Analysis is critically flawed in a number of ways that result in its being biased in favor of the repowering alternative:

- All of the Reference Case comparisons in the Fundamental Analysis that assume \$0/ton CO_2 prices (that is, no federal or state regulation of greenhouse gas emissions) are extremely unrealistic and unlikely.
- Entergy Louisiana did not evaluate any demand side management or renewable resources as part of a portfolio of alternatives to the repowering of Little Gypsy Unit 3.

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[31] This reflects an 85 percent average annual capacity factor and CO_2 emissions of 2150 lbs/MWh.

- As I explained earlier, given the uncertainties concerning future CO_2 prices the range reflected in the two CO_2 forecasts considered as sensitivities in the Fundamental Analysis is too narrow. In particular, the Company's "base" and "high" sensitivity CO_2 price forecasts are unreasonably low.

- The current cost estimate for the Repowering Project assumes the use of a number of existing site facilities. However, the cost estimate for the alternative CCGT facility does not. Instead, the Company assumes that the alternative CCGT facility would be built at a Greenfield site.

Q. Did Entergy Louisiana include any costs for carbon capture and sequestration in its Fundamental Analysis for either the Repowering Project or the CCGT alternative?

A. No.

Q. Did Entergy Louisiana reflect in the Fundamental Analysis any of the performance penalties that can be expected from the addition and use of carbon capture technology for either the Repowering Project or the CCGT alternative?

A. No. It is generally accepted that the addition and operation of carbon capture equipment is expected to have an adverse impact on power plant performance. For example, operation of carbon capture equipment is expected to require substantial amounts of energy. As a result, the power plant is expected to experience an energy penalty of between 10 percent and 29 percent as a result of adding the carbon capture technology resulting in a significant decrease in the plant's net power output.[32] However, Entergy Louisiana did not reflect any such performance penalties in its Fundamental or PROSYM analyses.

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[32] For example, see *Update on Clean Coal Technologies and CO2 Capture &* Storage, a June 27, 2007 presentation to the Oregon Public Utility Commission by Neville Holt, EPRI Technical Fellow, Advanced Coal Generation Technology. Available at http://www.puc.state.or.us/PUC/meetings/pmemos/2007/062707/OregonPUCCCTCCS62707.ppt

Q. Have you seen any evidence that Entergy Louisiana considered demand side management or renewable resources as potential alternatives, even in part, for the repowering of Little Gypsy Unit 3?

A. No. Entergy Louisiana essentially has focused on fossil alternatives. I have seen no evidence that it seriously considered and in detail investments in demand side management or renewable options as part of the resource planning for the repowering project. Indeed, the Company has indicated that it has not even studied the potential for energy efficiency or renewable resources in its service territory at any time in the past decade.[33]

Q. What is the significance of this failure to seriously consider demand side management and renewal resources?

A. Because Entergy Louisiana has failed to consider a wide range of alternatives, the Company cannot demonstrate that there is not a lower cost, lower risk alternative than repowering Little Gypsy Unit 3. Such lower cost, lower risk plans might include a portfolio of additional investments in demand side management, some self-build or purchased wind or renewable resources, and some natural gas-fired capacity.

Q. Has Entergy Louisiana estimated the savings associated with construction the Little Gypsy Project as a repowering of Unit 3 rather than constructing the unit as a stand-alone CFB project?

A. No. Entergy Louisiana has said that it has not prepared an estimate that compares the cost of the Little Gypsy Repowering Project with the cost of a Greenfield CFB project.[34] However, the Company generally believes that a repowering project

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[33] Responses to Questions AAE 1-16 and AAE 1-17. Copies of these responses are included in Exhibit DAS-8.

[34] Response to Question LPSC 1-10. A copy of this response is included in Exhibit DAS-8.

would be less costly than a Greenfield CF project because certain systems and components of the existing facility will be reused.[35]

Q. Does the Company's estimate for the cost of the alternative CCGT facility similarly reflect savings from the reuse of existing facilities at the Little Gypsy site?

A. No.[36]

Q. Has the Company studied the potential cost of repowering Little Gypsy Unit 3 as a CCGT facility?

A. No.[37]

Q. Is it reasonable to expect that the cost of repowering Little Gypsy Unit 3 as a CCGT would be lower than the cost of building a new CCGT unit at a greenfield site?

A. Yes. In general, for the same reasons that Entergy Louisiana expects savings in the cost of the repowering project, it is reasonable to expect that the cost of repowering Little Gypsy as a CCGT would be lower than the cost of building a new unit at a greenfield site.

Q. Is it reasonable to expect that the cost of the Repowering Project will increase above the current $1.55 billion estimate?

A. Yes. Entergy Louisiana witness Long has noted that rising commodities and labor prices have led to significant increases in power plant construction costs in recent years.[38] It is reasonable to expect that the worldwide demand for power plant design and construction resources which underlies much of these

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35 Id.
36 Response to Question AAE 1-19. A copy of this response is included in Exhibit DAS-8.
37 Response to Question AAE 1-20. A copy of this response is included in Exhibit DAS-8.
38 Direct Testimony of Jonathan E. Long, at page 29, lines 4-7, and at page 29, line 17, to page 30, line 5.

commodity and labor price increases, will continue to lead to further cost increases in the future.

Q. Is it generally accepted that domestic U.S. and worldwide competition for power plant design and construction resources, commodities, and manufacturing capacity have led to significant increases in power plant construction costs in recent years?

A. Yes. Soaring power plant construction costs have been the subject of a number of studies, assessments and articles in papers and magazines, as well as testimony sponsored by companies that are proposing to build new fossil-fired generating plants.

For example, in testimony filed at the North Carolina Utilities Commission on November 29, 2006, Duke Energy Carolinas emphasized the significant impact that the competition for resources had been having on the costs of building new power plants. This testimony was presented to explain the approximate 47 percent ($1 billion) increase in the estimated cost of Duke Energy Carolinas' proposed coal-fired Cliffside Project that the Company announced in October 2006.

In fact, Duke Energy Carolinas' witness noted in testimony to the North Carolina Utilities Commission that:

> The costs of new power plants have escalated very rapidly. This effect appears to be broad based affecting many types of power plants to some degree. One key steel price index has doubled over the last twelve months alone. This reflects global trends as steel is traded internationally and there is international competition among power plant suppliers. Higher steel and other input prices broadly affects power plant capital costs. A key driving force is a very large boom in U.S. demand for coal power plants which in turn has resulted from unexpectedly strong U.S. electricity demand growth and high natural gas prices. Most integrated U.S. utilities have decided to pursue coal power plants as a key component of their capacity expansion plan. In addition, many foreign companies are also expected to add large amounts of new coal power plant capacity. This global boom is straining supply. Since coal power plant equipment suppliers and bidders also supply other types of

> plants, there is a spill over effect to other types of electric generating plants such as combined cycle plants.[39]

Mr. Rose further noted that the actual coal power plant capital costs as reported by plants already under construction exceed government estimates of capital costs by "a wide margin (i.e., 35 to 40 percent). Additionally, current announced power plants appear to face another increase in costs (i.e., approximately 40 percent addition."[40] Thus, according to Mr. Rose, new coal-fired power plant capital costs have increased approximately 90 to 100 percent since 2002.

A June 2007 report by Standard & Poor's, *Increasing Construction Costs Could Hamper U.S. Utilities' Plan to Build New Power Generation*, similarly noted:

> As a result of declining reserve margins in some U.S. regions ... brought about by a sustained growth of the economy, the domestic power industry is in the midst of an expansion. Standing in the way are capital costs of new generation that have risen substantially over the past three years. Cost pressures have been caused by demands of global infrastructure expansion. In the domestic power industry, cost pressures have arisen from higher demand for pollution control equipment, expansion of the transmission grid, and new generation. While the industry has experienced buildout cycles in the past, what makes the current environment different is the supply-side resource challenges faced by the construction industry. A confluence of resource limitations have contributed, which Standard & Poors' Rating Services broadly classifies under the following categories
>
> - Global demand for commodities
> - Material and equipment supply
> - Relative inexperience of new labor force, and
> - Contractor availability
>
> The power industry has seen capital costs for new generation climb by more than 50% in the past three years, with more than 70% of this increase resulting from engineering, procurement and

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39 Direct Testimony of Judah Rose for Duke Energy Carolinas, North Carolina Utilities Commission Docket No. E-7, SUB 790, at page 4, lines 2-14. Mr. Rose's testimony is available on the North Carolina Utilities Commission website.

40 Ibid, at page 6, lines 5-9, and page 12, lines 11-16.

> construction (EPC) costs. Continuing demand, both domestic and international, for EPC services will likely keep costs at elevated levels. As a result, it is possible that with declining reserve margins, utilities could end up building generation at a time when labor and materials shortages cause capital costs to rise, well north of $2,500 per kW for supercritical coal plants and approaching $1,000 per kW for combined-cycle gas turbines (CCGT). In a separate yet key point, as capital costs rise, energy efficiency and demand side management already important from a climate change perspective, become even more crucial as any reduction in demand will mean lower requirements for new capacity.[41]

More recently, the president of the Siemens Power Generation Group told the New York Times that "There's real sticker shock out there."[42] He also estimate that in the last 18 months, the price of a coal-fired power plant has risen 25 to 30 percent.

A September 2007 report on *Rising Utility Construction Costs* prepared by the Brattle Group for the EDISON Foundation similarly concluded that:

> Construction costs for electric utility investments have risen sharply over the past several years, due to factors beyond the industry's control. Increased prices for material and manufactured components, rising wages, and a tighter market for construction project management services have contributed to an across-the-board increase in the costs of investing in utility infrastructure. These higher costs show no immediate signs of abating.[43]

The report further found that:

- Dramatically increased raw materials prices (e.g., steel, cement) have increased construction cost directly and indirectly through the higher cost of manufactured components common in utility infrastructure projects. These cost increases have primarily been due to high global demand for commodities and manufactured goods, higher production and

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41 *Increasing Construction Costs Could Hamper U.S. Utilities' Plans to Build New Power Generation*, Standard & Poor's Rating Services, June 12, 2007, at page 1. A copy of this report was provided in response to Question LPSC 1-4 and is included in Exhibit DAS-8.

42 "Costs Surge for Building Power Plants, *New York Times*, July 10, 2007.

43 *Rising Utility Construction Costs: Sources and Impacts*, prepared by The Brattle Group for the EDISON Foundation, September 2007, at page 31. A copy of this report is attached as Exhibit DAS-6.

transportation costs (in part owing to high fuel prices), and a weakening U.S. dollar.

- Increased labor costs are a smaller contributor to increased utility construction costs, although that contribution may rise in the future as large construction projects across the country raise the demand for specialized and skilled labor over current or project supply. There also is a growing backlog of project contracts at large engineering, procurement and construction (EPC) firms, and construction management bids have begun to rise as a result. Although it is not possible to quantify the impact on future project bids by EPC, it is reasonable to assume that bids will become less cost-competitive as new construction projects are added to the queue.

- The price increases experienced over the past several years have affected all electric sector investment costs. In the generation sector, all technologies have experienced substantial cost increases in the past three years, from coal plants to windpower projects.... As a result of these cost increases, the levelized capital cost component of baseload coal and nuclear plants has risen by $20/MWh or more – substantially narrowing coal's overall cost advantages over natural gas-fired combined-cycle plants – and thus limiting some of the cost-reduction benefits expected from expanding the solid-fuel fleet.

- The rapid increases experienced in utility construction costs have raised the price of recently completed infrastructure projects, but the impact has been mitigated somewhat to the extent that construction or materials acquisition preceded the most recent price increases. The impact of rising costs has a more dramatic impact on the estimated cost of proposed utility infrastructure projects, which fully incorporates recent price trends. This has raised significant concerns that the next wave of utility investments may be imperiled by the high cost environment. These rising construction costs have also motivated utilities and regulators to more actively pursue energy efficiency and demand response initiatives to reduce the future rate impacts on consumers.[44]

[44] Id, at pages 1-3.

Q. Do you agree that with these reviews of the current market conditions affecting the costs of proposed coal-fired power plants like the Little Gypsy Repowering Project?

A. Yes. These reviews of the factors affecting the estimated costs of new coal-fired generating facilities appears reasonable and are consistent with other information we have seen.

Q. Is it reasonable to expect that these same current market conditions also will lead to increases in the estimated costs of other supply-side alternatives such as natural gas-fired or wind facilities?

A. Yes.

Q. Entergy Louisiana Exhibit APW-18 shows that a 10% increase in the cost of the Repowering Project would reduce the net present value benefit of the Repowering Project versus the CCGT alternative in the Fundamental Analysis by $190 million.[45] Is it reasonable to expect that the construction cost of the Repowering Project could increase by more than 10%?

A. Yes. Although the current project cost estimate does increase some contingencies, we believe that given recent history of large construction projects and current market conditions, it is reasonable to assume that the actual cost of completing the Little Gypsy Repowering Project may be more than 10 percent higher than the current cost estimate. This is especially true because all project bids have not been let and construction has not even started.

Q. What would be the results of the Fundamental Analysis if all of the flaws that you have identified were corrected?

A. Unfortunately, we have not had enough time to redo the Fundamental Analysis to reflect the inclusion of demand side management and renewable resources as part

[45] Exhibit APW-18.

of a portfolio of alternatives to the Repowering Project. Nor have we had the time or the information to estimate the cost of repowering Little Gypsy as a CCGT.

However, Table 5 below shows what the results of the Fundamental Analysis would be if we made the modest assumption that the construction costs of both the Repowering Project and CCGT alternative facility increase by 10 percent and 20 percent and/or if we assume that future CO_2 prices will be moderately higher (that is, $10/ton) than the Company's high CO_2 price sensitivity.

Table No. 5: Results of the Fundamental Analysis Assuming Increased Construction Costs and Alternative CO_2 Prices

Scenario	No CO_2 Costs	Company Base CO_2 Price Sensitivity	Company High CO_2 Price Sensitivity	Alternative CO_2 Price Sensitivity
	Benefit/(Cost) to Repowering Project			
	(millions 2006$)			
$5.00/mmBtu Gas Price	($424)	($80)	($1,330)	($1,630)
$5.00/mmBtu Gas Price + 10% increase in cost of Repowering Project and CCGT Alternative	($564)	($220)	($1,470)	($1,770)
$5.00/mmBtu Gas Price + 20% increase in cost of Repowering Project and CCGT Alternative	($704)	($360)	($1,610)	($1,910)
$7.00/mmBtu Gas Price	$461	$82	($443)	($743)
$7.00/mmBtu Gas Price + 10% increase in cost of Repowering Project and CCGT Alternative	$320	($60)	($580)	($880)
$7.00/mmBtu Gas Price + 20% increase in cost of Repowering Project and CCGT Alternative	$180	($200)	($720)	($1,020)
$8.00/mmBtu Gas Price	$904	$530	$0	($300)
$8.00/mmBtu Gas Price + 10% increase in cost of Repowering Project and CCGT Alternative	$760	390	($140)	($440)
$8.00/mmBtu Gas Price + 20% increase in cost of Repowering Project and CCGT Alternative	$620	$250	($280)	($580)

Each of the figures in the parentheses in Table 5 means that the Repowering Project would be more expensive in that scenario, in 2006 dollars, than the alternative CCGT facility. Thus, as can be seen from this Table, there are a large

number of reasonable scenarios in which the Repowering Project would be a significantly higher cost option. Clearly, the Company's Fundamental Analysis shows that there is a substantial economic risk associated with pursuing the Repowering Project.

Q. Haven't you just presented a series of worst case analyses in Table 5 above?

A. Not at all. Given the very high cost escalation that has been experienced by power construction costs in recent years, it is not unreasonable to expect that the cost of both the Repowering Project and the CCGT alternative could increase by significantly more than 20 percent by the time that design, procurement and construction actually are completed by 2011/2012. It also is possible that future CO_2 emissions allowance prices will be higher than that alternative prices that underlie the figures shown in the right-hand column of Table 5.

Q. Have you seen any evidence that the levelized Fundamental Analysis presented by Entergy Louisiana witness Walz overstates the economic benefits of the proposed Repowering Project?

A. Yes. The reference case in the Fundamental Analysis, with a $7/mmBtu gas price and a $0/ton CO_2 price shows a $461 million net present value benefit to the repowering of Little Gypsy Unit 3 as compared to the CCGT alternative.[46] However, the results of the Company's PROSYM analysis, which appear to reflect the same main assumptions, shows only a $94 million net present value benefit to the Repowering Project.[47]

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[46] Exhibit APW-11.
[47] Exhibit APW-19.

Q. Is it reasonable to expect that the difference in the results of the two analyses in due to the differences in the length of the analyses, that is 30 years for the levelized Fundamental Analysis and 25 years for the PROSYM analysis?

A. No. The difference in the number of years considered in each analysis might have some effect but would not result in such a startling difference between the two analyses. It is more likely that the PROSYM simulation modeling more accurately reflects the Entergy Louisiana system and, consequently, the relative costs of the different projects than the simplistic levelized methodology used in the Fundamental Analysis.

Q. Do the results of the PROSYM Analysis presented by Entergy Louisiana witness Walz then show that repowering Little Gypsy Unit 3 as a CFB is the lowest cost, lowest risk option for the Company and its ratepayers?

A. No. The single scenario presented by Mr. Walz is significantly flawed in several ways. First, the PROSYM analysis does not reflect any CO_2 emissions allowance prices.[48] As I have discussed earlier in this testimony, it is reasonable to assume that there will be federal regulation of greenhouse gas emissions in the near future. The costs of such greenhouse gas regulations should be considered in any evaluation of the economics of pursuing fossil-fired generating alternatives. Second, the PROSYM analysis presented by Mr. Walz does not examine the potential for including energy efficiency and/or renewable resources as part of a portfolio of alternatives to repowering Little Gypsy Unit 3 as a CFB. Third, Mr. Walz only presents the results of a single PROSYM base case comparison that does not reflect the risk of higher fuel costs or higher construction costs for either the repowering of Little Gypsy Unit 3 or the CCGT alternative.

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[48] Direct Testimony of Anthony P. Walz, at page 42, line 1.

Q. Did Entergy Louisiana include any costs for carbon capture and sequestration in the PROSYM Analysis for either the Repowering Project or the CCGT alternative?

A. No.

Q. Did Entergy Louisiana reflect in the PROSYM Analysis any of the performance penalties that can be expected from the addition and use of carbon capture technology for either the Repowering Project or the CCGT alternative?

A. No.

Q. Do you have any other observations about the results of the single PROSYM analysis presented by Mr. Walz?

A. Yes. I have two other observations. First, the results of Mr. Walz' PROSYM analysis are present valued to 2011 dollars. The $94 million net present value benefit for the Little Gypsy Repowering Project would translate into about $65-70 million in 2006 dollars.

In addition, as shown on Table 6 below, although the results of the PROSYM analysis show an overall net present value benefit to the Repowering Project, the CCGT alternative actually would be the less expensive option until the year 2031, or for the first 19 years of the analysis.

Public Version - Protected Materials Redacted

Table 6: PROSYM Break-even Analysis (in 000$)

	With Little Gypsy			With CCGT					
Year	Total PROSYM Fuel and Purchased Power	Incremental Non-fuel Revenue Requirement	Total	Total PROSYM Fuel and Purchased Power	Incremental Non-fuel Revenue Requirement	Total	Benefit/(Cost) of Little Gypsy over CCGT	Annual Present Value Benefit (Cost)	Cumulative Present Value Benefit (Cost)
					(000$)				
2012	4,730,986	245,874	4,976,860	4,861,385	59,992	4,921,377	(55,483)	($51,089)	($51,089)
2013	5,045,099	241,976	5,287,075	5,171,743	58,839	5,230,582	(56,493)	($47,900)	($98,989)
2014	5,333,784	234,650	5,568,435	5,463,829	56,881	5,520,711	(47,724)	($37,261)	($136,249)
2015	5,645,756	227,719	5,873,475	5,775,373	55,015	5,830,388	(43,087)	($30,976)	($167,226)
2016	5,999,053	221,152	6,220,204	6,143,604	53,234	6,196,838	(23,366)	($15,458)	($182,684)
2017	6,349,523	214,924	6,564,447	6,496,735	51,533	6,548,268	(16,179)	($9,862)	($192,556)
2018	6,858,595	209,011	7,067,606	7,015,509	49,905	7,065,414	(2,192)	($1,230)	($193,786)
2019	7,358,647	203,391	7,563,038	7,522,847	48,345	7,571,192	8,154	$4,214	($189,572)
2020	7,718,341	198,042	7,916,383	7,885,442	46,849	7,932,291	15,908	$7,571	($182,001)
2021	8,143,810	192,751	8,336,561	8,319,821	45,366	8,365,187	28,626	$12,545	($169,456)
2022	8,638,338	187,474	8,825,812	8,823,774	43,885	8,867,660	41,847	$16,887	($152,569)
2023	9,072,190	223,213	9,295,403	9,260,730	52,036	9,312,766	17,362	$6,451	($146,118)
2024	9,567,306	217,966	9,785,273	9,764,396	50,562	9,814,958	29,685	$10,157	($135,961)
2025	10,095,273	213,737	10,309,010	10,300,341	49,326	10,349,667	40,657	$12,809	($123,152)
2026	10,592,794	208,522	10,801,316	10,807,107	47,858	10,854,965	53,649	$15,564	($107,589)
2027	11,217,218	204,325	11,421,543	11,440,854	46,628	11,487,482	65,939	$17,614	($89,974)
2028	11,850,089	199,144	12,049,233	12,080,559	45,167	12,125,727	76,494	$18,816	($71,159)
2029	12,369,227	194,980	12,564,207	12,607,545	43,945	12,651,490	87,282	$19,769	($51,389)
2030	13,144,046	189,834	13,333,880	13,389,429	42,491	13,431,921	98,041	$20,447	($30,942)
2031	13,758,743	184,707	13,943,450	14,015,212	41,041	14,056,253	112,803	$21,663	($9,279)
2032	14,319,249	180,597	14,499,846	14,580,151	39,830	14,619,980	120,134	$21,244	$11,966
2033	15,001,530	177,075	15,178,605	16,270,528	38,755	15,309,283	130,678	$21,279	$33,244
2034	15,691,512	176,142	15,867,654	15,969,328	38,288	16,007,616	139,962	$20,986	$54,230
2035	16,301,806	174,228	16,476,035	16,583,457	37,591	16,621,048	145,013	$20,021	$74,251
2036	17,051,901	173,335	17,225,236	17,344,543	37,132	17,381,675	156,439	$19,888	$94,140
				Net Present Value					
	$81,821,143	$2,174,120	$83,995,262	$83,575,446	$513,956	$84,089,402	$94,140		

Q. Given these results, is it reasonable to assume that the resource plan that includes the CCGT alternative would have been the lower cost plan in the PROSYM if Entergy Louisiana had included CO_2 emissions allowance prices?

A. Yes. The PROSYM analysis should properly be rerun to reflect reasonable forecasts of CO_2. However, there has not been time or resources for us to do that in this case.

Nevertheless, it is possible to approximate the effect of including CO_2 prices by multiplying the corrected annual CO_2 emissions for the Repowering and CCGT alternative plans looked at by Entergy Louisiana by the annual CO2 price assumed by the Company in its base and high CO_2 price forecasts. The results of this calculation are shown in Exhibit DAS-7.

As shown in Exhibit DAS-7, the Company's plan that includes the repowering of Little Gypsy as a CFB plant would be more expensive than building a new CCGT facility by $247 million, net present value, under the Company's base CO_2 price forecast and by $682 million, net present value, under the Company's high CO_2 forecast.

Q. Why do you say that you included the "corrected" annual CO_2 emissions under the Repowering and alternative CCGT plans considered by Entergy Louisiana in its PROSYM analysis?

A. When we looked at the input and output files for the PROSYM analysis, we discovered that Entergy had input a very, very low CO_2 emission rate/MWh for the repowered Little Gypsy plant. We revised this assumption to reflect the information from Entergy Louisiana that indicated that the repowered plant would emit a much higher 2151 lbs of CO_2 per MWh.

Q. Entergy Louisiana witness Walz discusses the benefits of the proposed repowering of the Little Gypsy Unit for supply diversity.[49] Do you agree that supply diversity is an issue that the Commission should consider as it evaluates the proposed repowering project?

A. Yes. I think supply diversity is a very important consideration. However, I don't believe that repowering Little Gypsy Unit 3 as CFB coal-fired plant is a reasonable option for increasing Entergy's supply diversity.

Q. Why is considering a company's generation mix the appropriate way to evaluate its fuel diversity?

A. Because the issue of fuel diversity is a matter of the amount of each type of fuel that the company burns, and the cost consequences of burning that fuel. Simply

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[49] For example, see pages 14 through 16 of the Direct Testimony of Anthony P. Walz.

looking at its capacity mix does not offer any information about the utilization of that capacity.

Q. Is fuel diversity a broader issue than merely deciding whether to build a coal- or gas-fired generating unit?

A. Yes, it should be. Implementing demand side management programs and building or buying power from low carbon-emitting renewable resource facilities also would increase a company's supply diversity. Investments in demand side management and renewable resources would provide real benefits in terms of supply diversity by reducing Entergy's dependency on coal, oil and gas.

Q. Entergy Louisiana stresses the uncertainties associated with the price of natural gas. Are there any similar uncertainties associated with the building and operation of new coal-fired generating facilities?

A. Yes. There are a number of potential uncertainties associated with coal-fired facilities that the Commission should consider as it evaluates the proposed Repowering Project. The primary uncertainty is associated with the potential for greenhouse gas regulations. As I have noted earlier in this testimony, there is a significant potential that substantial CO_2 emissions allowance prices will be set as part of a cap-and-trade plan for reducing carbon dioxide emissions by perhaps 60% to 80% by the middle of this century.

Rising power plant construction costs also are a significant uncertainty associated with adding new coal-fired generating units such as a repowered Little Gypsy Unit 3.

Q. Does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF MASSACHUSETTS

COUNTY OF MIDDLESEX

NOW BEFORE ME, the undersigned authority, personally came and appeared, David Schlissel, who after being duly sworn by me, did depose and say:

The above and foregoing in his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any stated on information and belief, and that as to those matters and things, he verily believes them to be true.

David A. Schl

SOWRN TO AND SUBSCRIBED BEFORE ME
THIS 14th **DAY OF** September, **2007**

Melissa Dawn Whited
NOTARY PUBLIC

My commission expires January 10, 2014

The Commonwealth of Massachusetts

On this 14th day of September 2007 before me, the undersigned notary public, personally appeared David A. Schlissel proved to me through satisfactory evidence of identification, which was Driving to be the person whose name is signed on the preceding or attached document and acknowledged to me that he/she signed it voluntarily for its stated purpose.

Melissa Dawn Whited
MELISSA DAWN WHITED, Notary Public
My Commission Expires January 10, 2014

Rising Utility Construction Costs:

Sources and Impacts

Prepared by:

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The Brattle Group

Prepared for:

The EDISON FOUNDATION

SEPTEMBER 2007

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Table of Contents

Introduction and Executive Summary

In *Why Are Electricity Prices Increasing? An Industry-Wide Perspective* (June 2006), *The Brattle Group* identified fuel and purchased-power cost increases as the primary driver of the electricity rate increases that consumers currently are facing. That report also noted that utilities are once again entering an infrastructure expansion phase, with significant investments in new baseload generating capacity, expansion of the bulk transmission system, distribution system enhancements, and new environmental controls. The report concluded that the industry could make the needed investments cost-effectively under a generally supportive rate environment.

The rate increase pressures arising from elevated fuel and purchased power prices continue. However, another major cost driver that was not explored in the previous work also will impact electric rates, namely, the substantial increases in the costs of building utility infrastructure projects. Some of the factors underlying these construction cost trends are straightforward—such as sharp increases in materials cost—while others are complex, and sometimes less transparent in their impact. Moreover, the recent rise in many utility construction cost components follows roughly a decade of relatively stable (or even declining) real construction costs, adding to the "sticker shock" that utilities experience when obtaining cost estimates or bids and that state public utility commissions experience during the process of reviewing applications for approvals to proceed with construction. While the full rate impact associated with construction cost increases will not be seen by customers until infrastructure projects are completed, the issue of rising construction costs currently affects industry investment plans and presents new challenges to regulators.

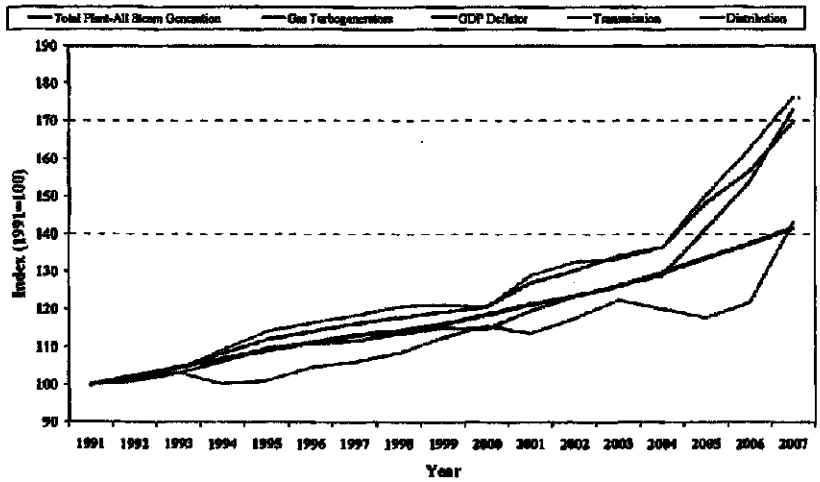
The purpose of this study is to a) document recent increases in the construction cost of utility infrastructure (generation, transmission, and distribution), b) identify the underlying causes of these increases, and c) explain how these increased costs will translate into higher rates that consumers might face as a result of required infrastructure investment. This report also provides a reference for utilities, regulators and the public to understand the issues related to recent construction cost increases. In summary, we find the following:

- Dramatically increased raw materials prices (*e.g.*, steel, cement) have increased construction cost directly and indirectly through the higher cost of manufactured components common in utility infrastructure projects. These cost increases have primarily been due to high global demand for commodities and manufactured goods, higher production and transportation costs (in part owing to high fuel prices), and a weakening U.S. dollar.
- Increased labor costs are a smaller contributor to increased utility construction costs, although that contribution may rise in the future as large construction projects across the country raise the demand for specialized and skilled labor over current or projected supply. There also is a growing backlog of

project contracts at large engineering, procurement and construction (EPC) firms, and construction management bids have begun to rise as a result. Although it is not possible to quantify the impact on future project bids by EPC firms, it is reasonable to assume that bids will become less cost-competitive as new construction projects are added to the queue.

- The price increases experienced over the past several years have affected all electric sector investment costs. In the generation sector, all technologies have experienced substantial cost increases in the past three years, from coal plants to windpower projects. Large proposed transmission projects have undergone cost revisions, and distribution system equipment costs have been rising rapidly. This is seen in Figure ES-1, which shows recent price trends in generation, transmission and distribution infrastructure costs based on the Handy-Whitman Index© data series, compared with the general price level as measured by the gross domestic product (GDP) deflator over the same time period.[1] As shown in Figure ES-1, infrastructure costs were relatively stable during the 1990s, but have experienced substantial price increases in the past several years. Between January 2004 and January 2007, the costs of steam-generation plant, transmission projects and distribution equipment rose by 25 percent to 35 percent (compared to an 8 percent increase in the GDP deflator). For example, the cost of gas turbines, which was fairly steady in the early part of the decade, increased by 17 percent during the year 2006 alone. As a result of these cost increases, the levelized capital cost component of baseload coal and nuclear plants has risen by $20/MWh or more—substantially narrowing coal's overall cost advantages over natural gas-fired combined-cycle plants—and thus limiting some of the cost-reduction benefits expected from expanding the solid-fuel fleet.

Figure ES-1
National Average Utility Infrastructure Cost Indices

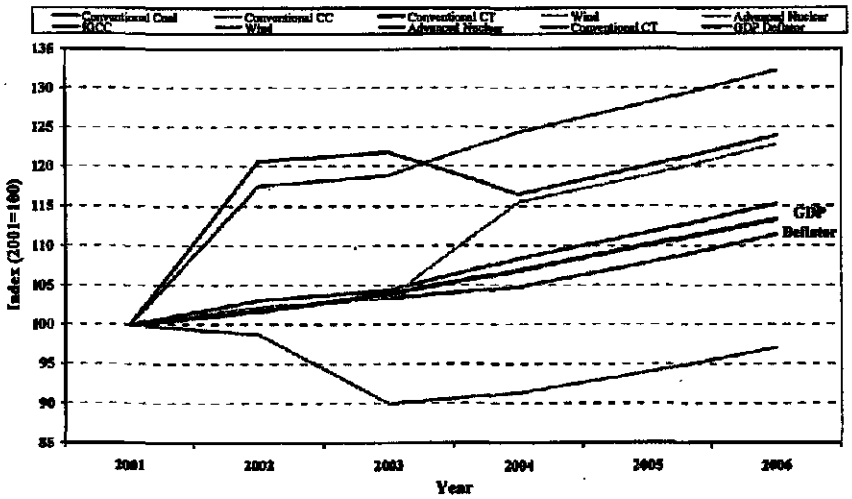


Source: The Handy-Whitman© Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indexes for the specified components.

[1] The GDP deflator measures the cost of goods and services purchased by households, industry and government, and as such is a broader price index than the Consumer Price Index (CPI) or Producer Price Index (PPI), which track the costs of goods and services purchased by households and industry, respectively.

- The rapid increases experienced in utility construction costs have raised the price of recently completed infrastructure projects, but the impact has been mitigated somewhat to the extent that construction or materials acquisition preceded the most recent price increases. The impact of rising costs has a more dramatic impact on the estimated cost of proposed utility infrastructure projects, which fully incorporates recent price trends. This has raised significant concerns that the next wave of utility investments may be imperiled by the high cost environment. These rising construction costs have also motivated utilities and regulators to more actively pursue energy efficiency and demand response initiatives in order to reduce the future rate impacts on consumers.
- Despite the overwhelming evidence that construction costs have risen and will be elevated for some time, these increased costs are largely absent from the capital costs specified in the Energy Information Administration's (EIA's) 2007 *Annual Energy Outlook* (AEO). The AEO generation capital cost assumptions since 2001 are shown in Figure ES-2. Since 2004, capital costs of all technologies are assumed to grow at the general price level—a pattern that contradicts the market evidence presented in this report. The growing divergence between the AEO data assumptions and recent cost escalation is now so substantial that the AEO data need to be adjusted to reflect recent cost increases to provide reliable indicators of current or future capital costs.

Figure ES-2
EIA Generation Construction Cost Estimates



Sources: Data collected from the U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2002 to 2007* and from the U.S. Bureau of Economic Analysis.

Projected Investment Needs and Recent Infrastructure Cost Increases

Current and Projected U.S. Investment in Electricity Infrastructure

The electric power industry is a very capital-intensive industry. The total value of generation, transmission and distribution infrastructure for regulated electric utilities is roughly $440 billion (property in service, net of accumulated depreciation and amortization), and capital expenditures are expected to exceed $70 billion in 2007.[2] Although the industry as a whole is always investing in capital, the rate of capital expenditures was relatively stable during the 1990s and began to rise near the turn of the century. As shown in *Why Are Electricity Prices Increasing? An Industry-Wide Perspective* (June 2006), utilities anticipate substantial increases in generation, transmission and distribution investment levels over the next two decades. Moreover, the significant need for new electricity infrastructure is a world-wide phenomenon: According to the *World Energy Investment Outlook 2006*, investments by power-sector companies throughout the world will total about $11 trillion dollars by 2030.[3]

Generation

As of December 31, 2005, there were 988 gigawatts (GW) of electric generating capacity in service in the U.S., with the majority of this capacity owned by electric utilities. Close to 400 GW of this total, or 39 percent, consists of natural gas-fired capacity, with coal-based capacity comprising 32 percent, or slightly more than 300 GW, of the U.S. electric generation fleet. Nuclear and hydroelectric plants comprise approximately 10 percent of the electric generation fleet. Approximately 49 percent of energy production is provided by coal plants, with 19 percent provided by nuclear plants. Natural gas-fired plants, which tend to operate as intermediate or peaking plants, also provided about 19 percent of U.S. energy production in 2006.

The need for installed generating capacity is highly correlated with load growth and projected growth in peak demand. According to EIA's most recent projections, U.S. electricity sales are expected to grow at an annual rate of about 1.4 percent through 2030. According to the North American Electric Reliability Corporation (NERC), U.S. non-coincident peak demand is expected to grow by 19 percent (141 GW) from 2006 to 2015. According to EIA, utilities will need to build 258 GW of new generating capacity by 2030 to meet the

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[2] Net property in service figure as of December 31, 2006, derived from Federal Energy Regulatory Commission (FERC) Form 1 data compiled by the Edison Electric Institute (EEI). Gross property is roughly $730 billion, with about $290 billion already depreciated and/or amortized. Annual capital expenditure estimate is derived from a sample of 10K reports surveyed by EEI.

[3] Richard Stavros. "Power Plant Development: Raising the Stakes." *Public Utilities Fortnightly*, May 2007, pp. 36-42.

projected growth in electricity demand and to replace old, inefficient plants that will be retired. EIA further projects that coal-based capacity, that is more capital intensive than natural gas-fired capacity which dominated new capacity additions over the last 15 years, will account for about 54 percent of total capacity additions from 2006 to 2030. Natural gas-fired plants comprise 36 percent of the projected capacity additions in *AEO 2007*. EIA projects that the remaining 10 percent of capacity additions will be provided by renewable generators (6 percent) and nuclear power plants (4 percent). Renewable generators and nuclear power plants, similar to coal-based plants, are capital-intensive technologies with relatively high construction costs but low operating costs.

High-Voltage Transmission

The U.S. and Canadian electric transmission grid includes more than 200,000 miles of high voltage (230 kV and higher) transmission lines that ultimately serve more than 300 million customers. This system was built over the past 100 years, primarily by vertically integrated utilities that generated and transmitted electricity locally for the benefit of their native load customers. Today, 134 control areas or balancing authorities manage electricity operations for local areas and coordinate reliability through the eight regional reliability councils of NERC.

After a long period of decline, transmission investment began a significant upward trend starting in the year 2000. Since the beginning of 2000, the industry has invested more than $37.8 billion in the nation's transmission system. In 2006 alone, investor-owned electric utilities and stand-alone transmission companies invested an historic $6.9 billion in the nation's grid, while the Edison Electric Institute (EEI) estimates that utility transmission investments will increase to $8.0 billion during 2007. A recent EEI survey shows that its members plan to invest $31.5 billion in the transmission system from 2006 to 2009, a nearly 60-percent increase over the amount invested from 2002 to 2005. These increased investments in transmission are prompted in part by the larger scale of base load generation additions that will occur farther from load centers, creating a need for larger and more costly transmission projects than those built over the past 20 years. In addition, new government policies and industry structures will contribute to greater transmission investment. In many parts of the country, transmission planning has been formally regionalized, and power markets create greater price transparency that highlights the value of transmission expansion in some instances.

NERC projects that 12,873 miles of new transmission will be added by 2015, an increase of 6.1 percent in the total miles of installed extra high-voltage (EHV) transmission lines (230 kV and above) in North America over the 2006 to 2015 period. NERC notes that this expansion lags demand growth and expansion of generating resources in most areas. However, NERC's figures do not include several major new transmission projects proposed in the PJM Interconnection LLC, such as the major new lines proposed by American Electric Power, Allegheny Power, and Pepco.

Distribution

While transmission systems move bulk power across wide areas, distribution systems deliver lower-voltage power to retail customers. The distribution system includes poles, as well as metering, billing, and other related infrastructure and software associated with retail sales and customer care functions. Continual

investment in distribution facilities is needed, first and foremost, to keep pace with growth in customer demand. In real terms, investment began to increase in the mid-1990s, preceding the corresponding boom in generation. This steady climb in investment in distribution assets shows no sign of diminishing. The need to replace an aging infrastructure, coupled with increased population growth and demand for power quality and customer service, is continuing to motivate utilities to improve their ultimate delivery system to customers.

Continued customer load growth will require continued expansion in distribution system capacity. In 2006, utilities invested about $17.3 billion in upgrading and expanding distribution systems, a 32-percent increase over the investment levels incurred in 2004. EEI projects that distribution investment during 2007 will again exceed $17.0 billion. While much of the recent increase in distribution investment reflects expanding physical infrastructure, a substantial portion of the increased dollar investment reflects the increased input costs of materials and labor to meet current distribution infrastructure needs.

Construction Costs for Recently Completed Generation

The majority of recently constructed plants have been either natural gas-fired or wind power plants. Both have displayed increasing real costs for several years. Since the 1990s, most of the new generating capacity built in the U.S. has been natural gas-fired capacity, either natural gas-fired combined-cycle units or natural gas-fired combustion turbines. Combustion turbine prices recently rose sharply after years of real price decreases, while significant increases in the cost of installed natural gas combined-cycle combustion capacity have emerged during the past several years.

Using commercially available databases and other sources, such as financial reports, press releases and government documents, *The Brattle Group* collected data on the installation cost of natural gas-fired combined-cycle generating plants built in the U.S. during the last major construction cycle, defined as generating plants brought into service between 2000 and 2006. We estimated that the average real construction cost of all natural gas-fired combined-cycle units brought online between 2000 and 2006 was approximately $550/kilowatt (kW) (in 2006 dollars), with a range of costs between $400/kW to approximately $1,000/kW. Statistical analysis confirmed that real installation cost was influenced by plant size, the turbine technology, the NERC region in which the plant was located, and the commercial online date. Notably, we found a positive and statistically significant relationship between a plant's construction cost and its online date, meaning that, everything else equal, the later a plant was brought online, the higher its real installation cost.[4] Figure 1 shows the average yearly installation cost, in *nominal* dollars, as predicted by the regression analysis.[5] This figure shows that the average installation cost of combined-cycle units increased gradually from 2000 to 2003, followed by a fairly significant increase in 2004 and a very significant escalation—more than $300/kW—in 2006. This provides vivid evidence of the recent sharp increase in plant construction costs.

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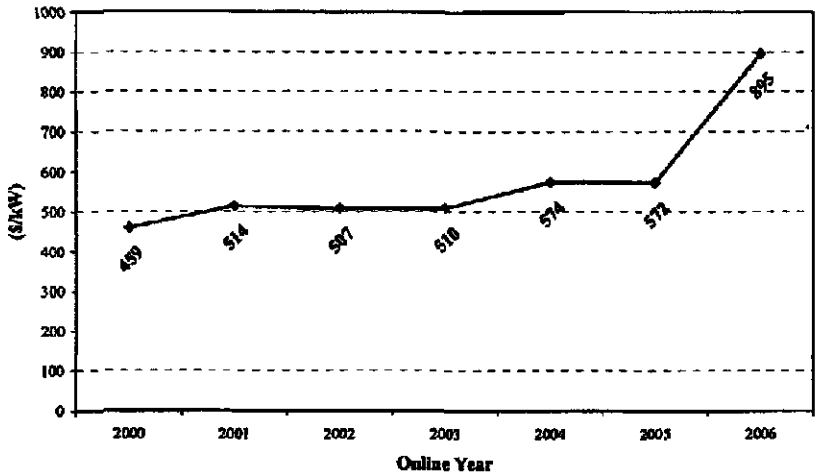
[4] To be precise, we used a "dummy" variable to represent each year in the analysis. The year-specific dummy variables were statistically significant and uniformly positive; *i.e.*, they had an upward impact on installation cost.

[5] The nominal form regression results are discussed here to facilitate comparison with the GDP deflator measure used to compare other price trends in other figures in this report.

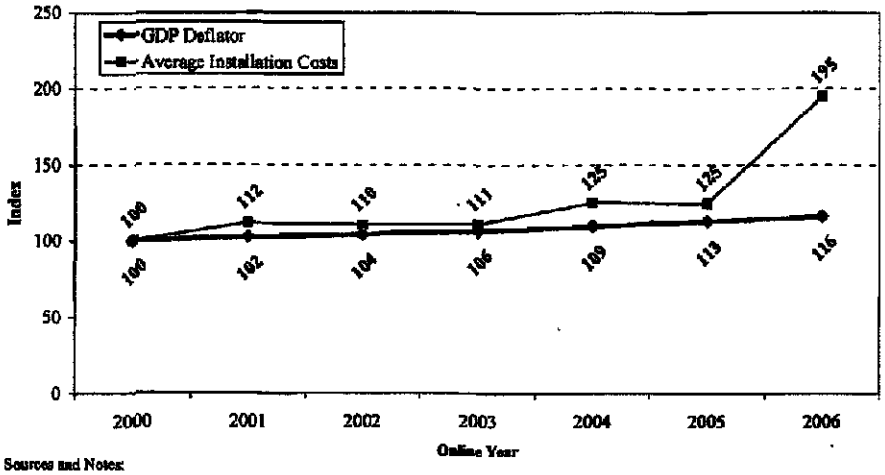
Figure 1
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year ($/kW)



Sources and Notes:
* Data on summer capacity, total installation cost, turbine technology, commercial online date, and zip code for the period 2000-2006 were collected from commercially available databases and other sources such as company websites and 10k reports.

Figure 2 compares the trend in plant installation costs to the GDP deflator, using 2000 as the base year. Over the period of 2000 to 2006, the cumulative increase in the general price level was 16 percent while the cumulative increase in the installation cost of new combined-cycle units was almost 95 percent, with much of this increase occurring in 2006.

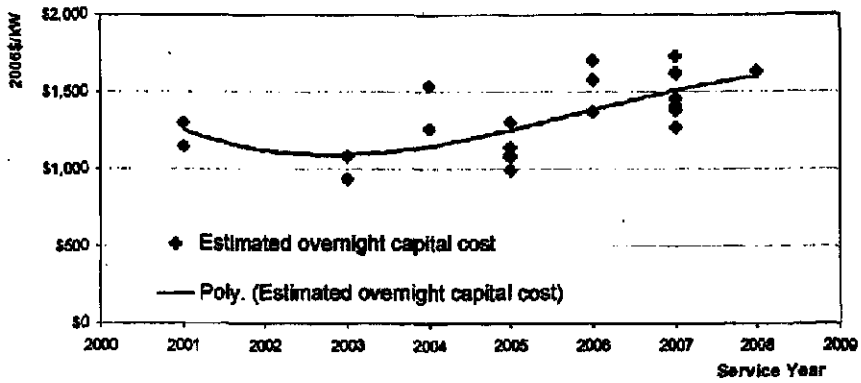
Figure 2
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year (Index Year 2000 = 100)



Sources and Notes:
* Data on summer capacity, total installation cost, turbine technology, commercial online date, and zip code for the period 2000-2006 were collected from commercially available databases and other sources such as company websites and 10k reports.
** GDP Deflator data were collected from the U.S. Bureau of Economic Analysis.

Another major class of generation development during this decade has been wind generation, the costs of which have also increased in recent years. The Northwest Power and Conservation Council (NPCC), a regional planning council that prepares long-term electric resource plans for the Pacific Northwest, issued its most recent review of the cost of wind power in July 2006.[6] The Council found that the cost of new wind projects rose substantially in real terms in the last two years, and was much higher than that assumed in its most recent resource plan. Specifically, the Council found that the levelized lifecycle cost of power for new wind projects rose 50 to 70 percent, with higher construction costs being the principal contributor to this increased cost. According to the Council, the construction cost of wind projects, in real dollars, has increased from about $1150/kW to $1300-$1700/kW in the past few years, with an unweighted average capital cost of wind projects in 2006 at $1,485/kW. Factors contributing to the increase in wind power costs include a weakening dollar, escalation of commodity and energy costs, and increased demand for wind power under renewable portfolio standards established by a growing number of states. The Council notes that commodities used in the manufacture and installation of wind turbines and ancillary equipment, including cement, copper, steel and resin have experienced significant cost increases in recent years. Figure 3 shows real construction costs of wind projects by actual or projected in-service date.

Figure 3
Wind Power Project Capital Costs



Source: The Northwest Power and Conservation Council, "Biennial Review of the Cost of Windpower" July 13, 2006.

These observations were confirmed recently in a May 2007 report by the U.S. Department of Energy (DOE), which found that prices for wind turbines (the primary cost component of installed wind capacity) rose by more than $400/kW between 2002 and 2006, a nearly 60-percent increase.[7] Figure 4 is reproduced from the DOE report (Figure 21) and shows the significant upward trend in turbine prices since 2001.

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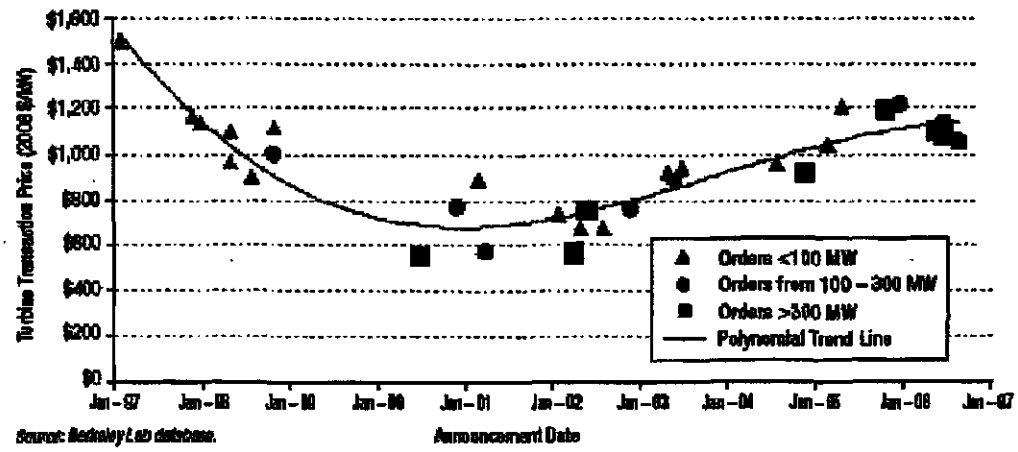
[6] The NPCC planning studies and analyses cover the following four states: Washington, Oregon, Idaho, and Montana. See "Biennial Review of the Cost of Windpower" July 13, 2006, at www.bpa.gov/Energy/N/projects/post2006conservation/doc/Windpower_Cost_Review.doc. This study provides many reasons for windpower cost increases.

[7] See U.S. Department of Energy, *Annual Report on U.S. Wind Power Installation, Cost and Performance Trends: 2006* Figure 21, page 16.

Figure 4
Wind Turbine Prices 1997 - 2007



Rising Projected Construction Costs: Examples and Case Studies

Although recently completed gas-fired and wind-powered capacity has shown steady real cost increases in recent years, the most dramatic cost escalation figures arise from *proposed* utility investments, which fully reflect the recent, sharply rising prices of various components of construction and installation costs. The most visible of these are generation proposals, although several transmission proposals also have undergone substantial upward cost revisions. Distribution-level investments are smaller and less discrete ("lumpy") and thus are not subject to similar ongoing public scrutiny on a project-by-project basis.

Coal-Based Power Plants

Evidence of the significant increase in the construction cost of coal-based power plants can be found in recent applications filed by utilities, such as Duke Energy and Otter Tail Power Company, seeking regulatory approval to build such plants. Otter Tail Power Company leads a consortium of seven Midwestern utilities that are seeking 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 seek 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 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 dramatically, largely due to higher costs for construction materials and labor.[8] Based on the most recent design refinements, the project, including transmission, is expected to cost $1.6 billion.

[8] Other factors contributing to the cost increase include design changes made by project participants to increase output and improve the unit's efficiency. For example, the voltage of the proposed transmission line was increased from 230 kV to 345 kV to accommodate more generation.

In June 2006, Duke submitted a filing with the North Carolina Utilities Commission (NCUC) seeking a certificate of public convenience and necessity for the construction of two 800 MW coal-based generating units at the site of the existing Cliffside Steam Station. In its initial application, Duke relied on a May 2005 preliminary cost estimate showing that the two units would cost approximately $2 billion to build. Five months later, Duke submitted a second filing with a significantly revised cost estimate. In its second filing, Duke estimated that the two units would cost approximately $3 billion to build, a 50 percent cost increase. The North Carolina Utilities Commission approved the construction of one 800 MW unit at Cliffside but disapproved the other unit, primarily on the basis that Duke had not made a showing that it needed the capacity to serve projected native load demands. Duke's latest projected cost for building one 800 MW unit at Cliffside is approximately $1.8 billion, or about $2,250/kW. When financing costs, or allowance for funds used during construction (AFUDC), are included, the total cost is estimated to be $2.4 billion (or about $3,000/kW).

Rising construction costs have also led utilities to reconsider expansion plans prior to regulatory actions. In December 2006, Westar Energy announced that it was deferring the consideration of 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 since the plant was first announced in May 2005.

Increased construction costs are also affecting proposed demonstration projects. For example, DOE announced earlier this year that the projected cost for one of its most prominent clean coal demonstration project, FutureGen, had nearly doubled.[9] FutureGen is a clean coal demonstration project being pursued by a public-private partnership involving DOE and an alliance of industrial coal producers and electric utilities. FutureGen is an experimental advanced Integrated Gasification Combined Cycle (IGCC) coal plant project that will aim for near zero emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), mercury, particulates and carbon dioxide (CO_2). Its initial cost was estimated at $950 million. But after re-evaluating the price of construction materials and labor and adjusting for inflation over time, DOE's Office of Fossil Energy announced that the project's price had increased to $1.7 billion.

Transmission Projects

NSTAR, the electric distribution company that serves the Boston metropolitan area, recently built two 345 kV lines from a switching station in Stoughton, Massachusetts, to substations in the Hyde Park section of Boston and to South Boston, respectively. In an August 2004 filing before ISO New England Inc. (ISO-NE), NSTAR indicated that the project would cost $234.2 million. In March 2007, NSTAR informed ISO-NE that estimated project costs had increased by $57.7 million, or almost 25 percent, for a revised total project cost of $292 million. NSTAR stated that the increase is driven by increases in both construction and material costs, with construction bids coming in 24 percent higher than initially estimated. NSTAR further explained that there have been dramatic increases in material costs, with copper costs increasing by 160 percent, core steel by 70 percent, flow-fill concrete by 45 percent, and dielectric fluid (used for cable cooling) by 66 percent.

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[9] U.S. Department of Energy, April 10, 2007, press release available at http://www.fossil.energy.gov/news/techlines/2007/07019-DOE_Signs_FutureGen_Agreement.html

Another aspect of transmission projects is land requirements, and in many areas of the country land prices have increased substantially in the past few years. In March 2007, the California Public Utilities Commission (CPUC) approved construction of the Southern California Edison (SCE) Company's proposed 25.6-mile, 500 kV transmission line between SCE's existing Antelope and Pardee Substations. SCE initially estimated a cost of $80.3 million for the Antelope-Pardee 500 kV line. However, the company subsequently revised its estimate by updating the anticipated cost of acquiring a right-of-way, reflecting a rise in California's real estate prices. The increased land acquisition costs increased the total estimate for the project to $92.5 million, increasing the estimated costs to more than $3.5 million per mile.

Distribution Equipment

Although most individual distribution projects are small relative to the more visible and public generation and transmission projects, costs have been rising in this sector as well. This is most readily seen in Handy-Whitman Index© price series relating to distribution equipment and components. Several important categories of distribution equipment have experienced sharp price increases over the past three years. For example, the prices of line transformers and pad transformers have increased by 68 percent and 79 percent, respectively, between January 2004 and January 2007, with increases during 2006 alone of 28 percent and 23 percent.[10] The cost of overhead conductors and devices increased over the past three years by 34 percent, and the cost of station equipment rose by 38 percent. These are in contrast to the overall price increases (measured by the GDP deflator) of roughly 8 percent over the past three years.

[10] Handy-Whitman© Bulletin No. 165, average increase of six U.S. regions. Used with permission.

Factors Spurring Rising Construction Costs

Broadly speaking, there are four primary sources of the increase in construction costs: (1) material input costs, including the cost of raw physical inputs, such as steel and cement as well as increased costs of components manufactured from these inputs (*e.g.*, transformers, turbines, pumps); (2) shop and fabrication capacity for manufactured components (relative to current demand); (3) the cost of construction field labor, both unskilled and craft labor; and (4) the market for large construction project management, *i.e.*, the queuing and bidding for projects. This section will discuss each of these factors.

Material Input Costs

Utility construction projects involve large quantities of steel, aluminum and copper (and components manufactured from these metals) as well as cement for foundations, footings and structures. All of these commodities have experienced substantial recent price increases, due to increased domestic and global demands as well as increased energy costs in mineral extraction, processing and transportation. In addition, since many of these materials are traded globally, the recent performance of the U.S. dollar will impact the domestic costs (see box on page 14).

Metals

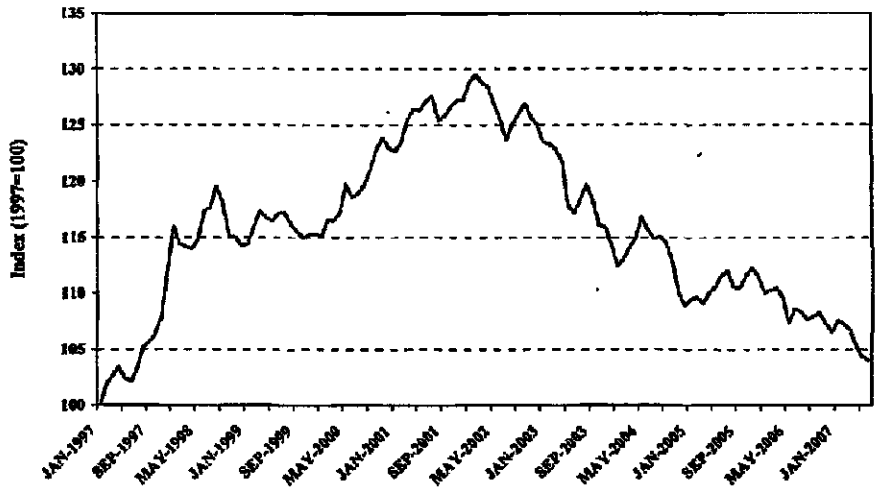
After being relatively stable for many years (and even declining in real terms), the price of various metals, including steel, copper and aluminum, has increased significantly in the last few years. These increases are primarily the result of high global demand and increased production costs (including the impact of high energy prices). A weakening U.S. dollar has also contributed to high domestic prices for imported metals and various component products.

Figure 5 shows price indices for primary inputs into steel production (iron and steel scrap, and iron ore) since 1997. The price of both inputs fell in real terms during the late 1990s, but rose sharply after 2002. Compared to the 20-percent increase in the general inflation rate (GDP deflator) between 1997 and 2006, iron ore prices rose 75 percent and iron and steel scrap prices rose nearly 120 percent. The increase over the last few years was especially sharp—between 2003 and 2006, prices for iron ore rose 60 percent and iron and scrap steel rose 150 percent.

Exchange Rates

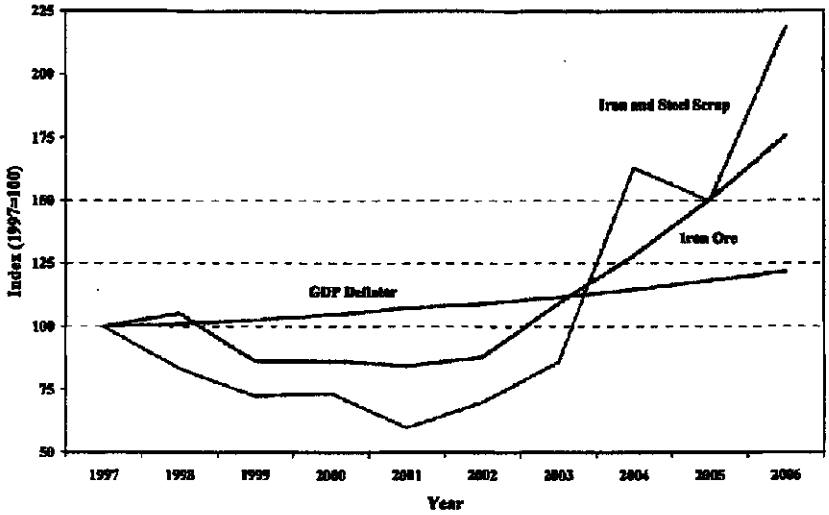
Many of the raw materials involved in utility construction projects (e.g., steel, copper, cement), as well as many major manufactured components of utility infrastructure investments, are globally traded. This means that prices in the U.S. are also affected by exchange rate fluctuations, which have been adverse to the dollar in recent years. The chart below shows trade-weighted exchange rates from 1997. Although the dollar appreciated against other currencies between 1997 and 2001, the graph also clearly shows a substantial erosion of the dollar since the beginning of 2002, losing roughly 20 percent of its value against other major trading partners' currencies. This has had a substantial impact on U.S. material and manufactured component prices, as will be reflected in many of the graphs that follow.

Nominal Broad Dollar Index



Source: U.S. Federal Reserve Board, Statistical Release, Broad Index Foreign Exchange Value of the Dollar.

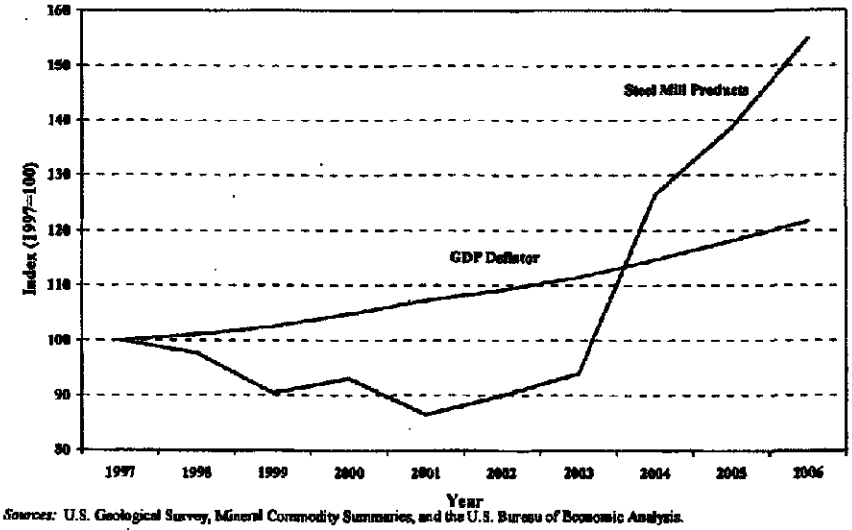
Figure 5
Inputs to Iron and Steel Production Cost Indices



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

The increase in input prices has been reflected in steel mill product prices. Figure 6 compares the trend in steel mill product prices to the general inflation rate (using the GDP deflator) over the past 10 years. Figure 6 shows that the price of steel has increased about 60 percent since 2003.

Figure 6
Steel Mill Products Price Index



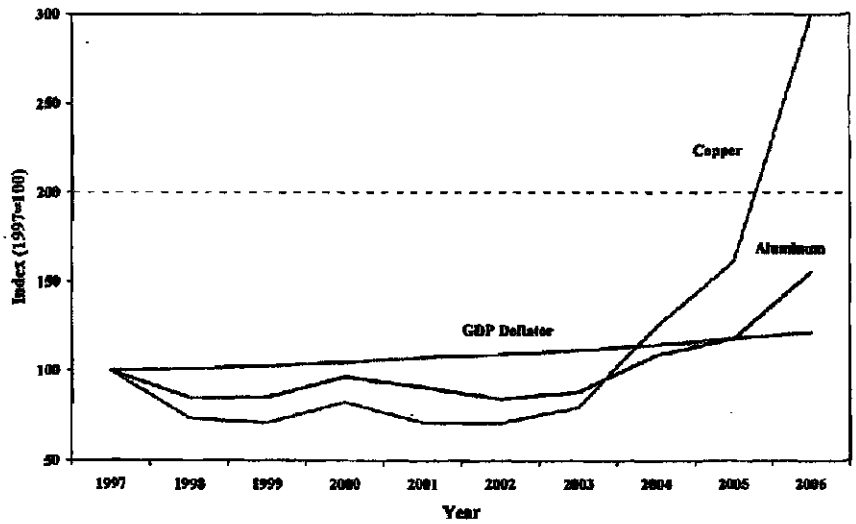
Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

Various sources point to the rapid growth of steel production and demand in China as a primary cause of the increases in both steel prices and the prices of steelmaking inputs.[11] China has become both the world's largest steelmaker and steel consumer. In addition, some analysts contend that steel companies have achieved greater pricing power, partly due to ongoing consolidation of the industry, and note that recently increased demand for steel has been driven largely by products used in energy and heavy industry, such as plate and structural steels.

From the perspective of the steel industry, the substantial and at least semi-permanent rise in the price of steel has been justified by the rapid rise in the price of many steelmaking inputs, such as steel scrap, iron ore, coking coal, and natural gas. Today's steel prices remain at historically elevated levels and, based on the underlying causes for high prices described, it appears that iron and steel costs are likely to remain at these high levels at least for the near future.

Other metals important for utility infrastructure display similar price patterns: declining real prices over the first five years or so of the previous 10 years, followed by sharp increases in the last few years. Figure 7 shows that aluminum prices doubled between 2003 and 2006, while copper prices nearly quadrupled over the same period.

Figure 7
Aluminum and Copper Price Indices

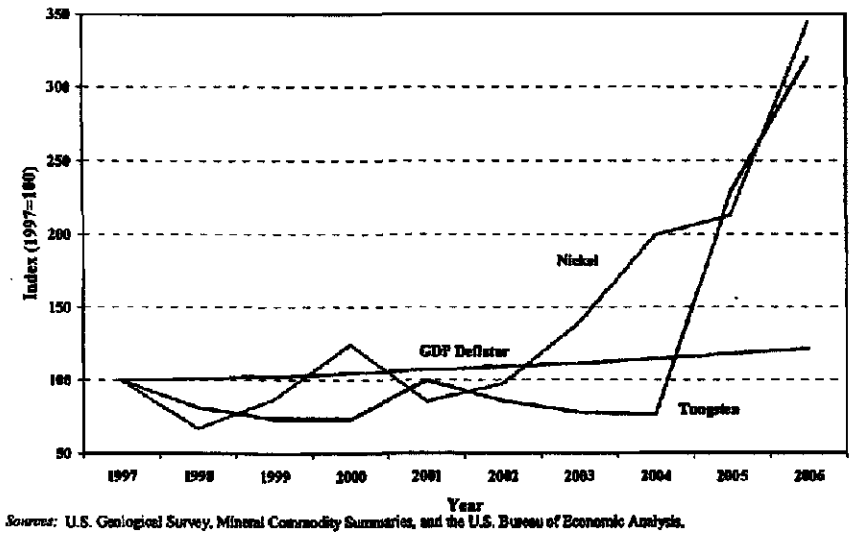


Source: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

[11] See, for example, *Steel: Price and Policy Issues*, CRS Report to Congress, Congressional Research Service, August 31, 2006.

These price increases were also evident in metals that contribute to important steel alloys used broadly in electrical infrastructure, such as nickel and tungsten. The prices of these display similar patterns, as shown in Figure 8.

Figure 8
Nickel and Tungsten Price Indices

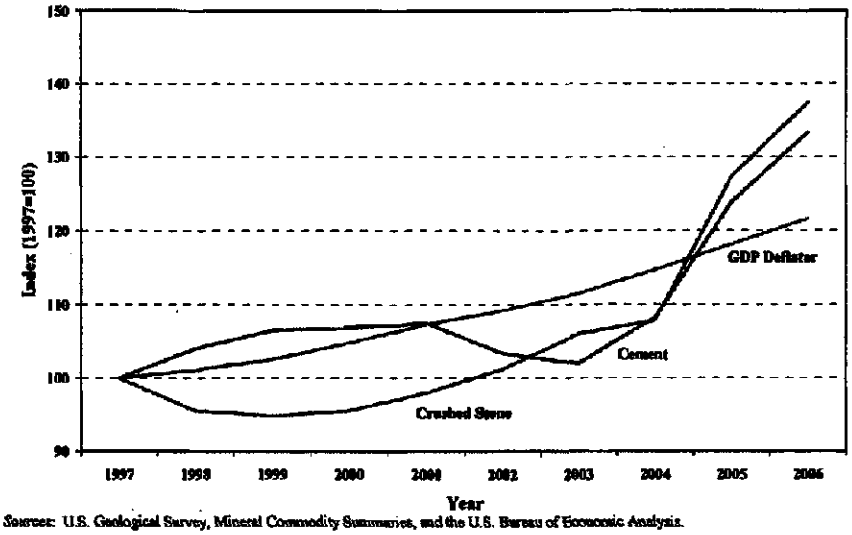


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

Cement, Concrete, Stone and Gravel

Large infrastructure projects require huge amounts of cement as well as basic stone materials. The price of cement has also risen substantially in the past few years, for the same reasons cited above for metals. Cement is an energy-intensive commodity that is traded on international markets, and recent price patterns resemble those displayed for metals. In utility construction, cement is often combined with stone and other aggregates for concrete (often reinforced with steel), and there are other site uses for sand, gravel and stone. These materials have also undergone significant price increases, primarily as a result of increased energy costs in extraction and transportation. Figure 9 shows recent price increases for cement and crushed stone. Prices for these materials have increased about 30 percent between 2004 and 2006.

Figure 9
Cement and Crushed Stone Price Indices



Source: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

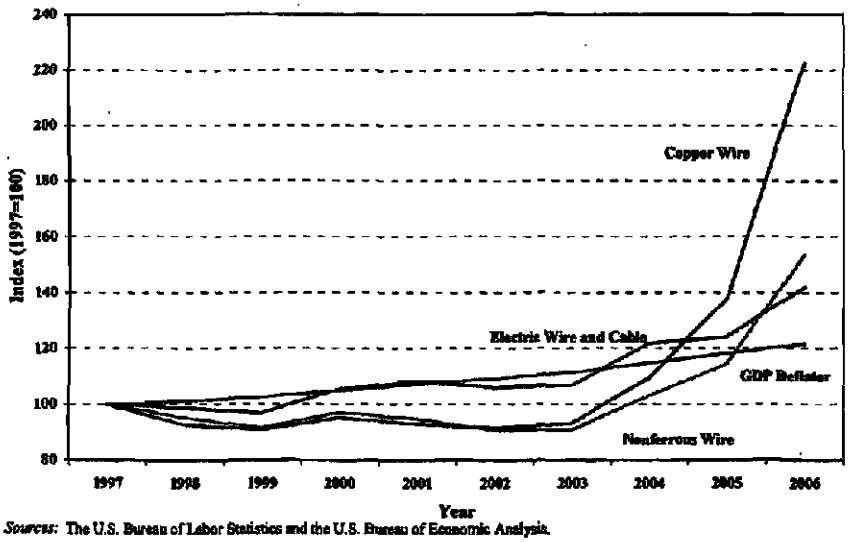
Manufactured Products for Utility Infrastructure

Although large utility construction projects consume substantial amounts of unassembled or semi-finished metal products (*e.g.*, reinforcing bars for concrete, structural steel), many of the components such as conductors, transformers and other equipment are manufactured elsewhere and shipped to the construction site. Available price indices for these components display similar patterns of recent sharp price increases.

Figure 10 shows the increased prices experienced in wire products compared to the inflation rate, according to the U.S. Bureau of Labor Statistics (BLS), highlighting the impact of underlying metal price increases.

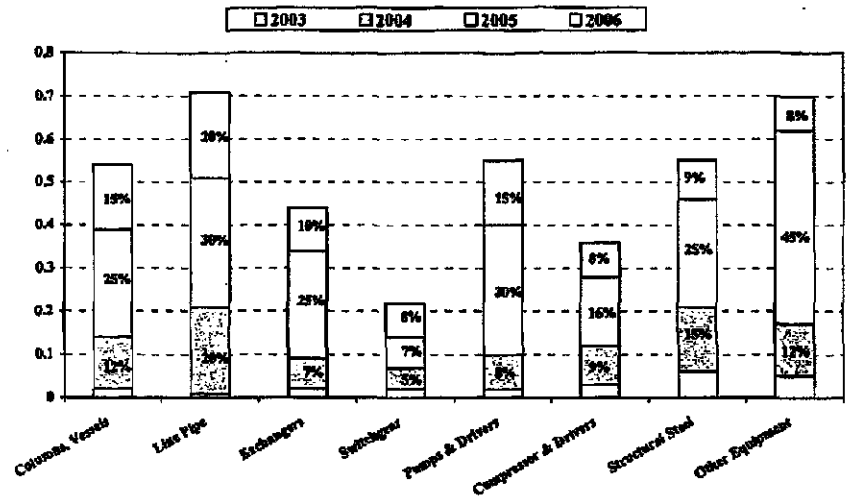
Manufactured components of generating facilities—large pressure vessels, condensers, pumps, valves—have also increased sharply since 2004. Figure 11 shows the yearly increases experienced in key component prices since 2003.

Figure 10
Electric Wire and Cable Price Indices



Sources: The U.S. Bureau of Labor Statistics and the U.S. Bureau of Economic Analysis.

Figure 11
Equipment Price Increases

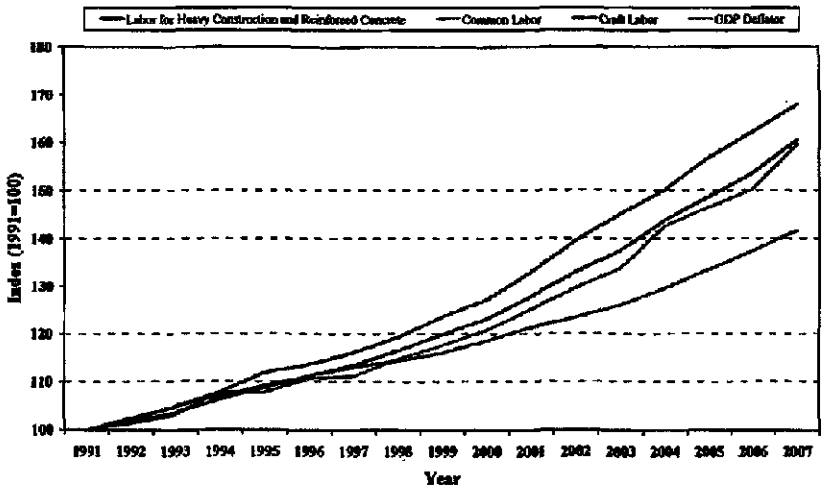


Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Labor Costs

A significant component of utility construction costs is labor—both unskilled (common) labor as well as craft labor such as pipefitters and electricians. Labor costs have also increased at rates higher than the general inflation rate, although more steadily since 1997, and recent increases have been less dramatic than for commodities. Figure 12 shows a composite national labor cost index based on simple averages of the regional Handy-Whitman Index© for common and craft labor. Between January 2001 and January 2007, the general inflation rate (measured by the GDP deflator) increased about 15 percent. During the same period, the cost of craft labor and heavy construction labor increased about 26 percent, while common labor increased 27 percent, or almost twice the rate of general inflation.[12] While less severe than commodity cost increases, increased labor costs contributed to the overall construction cost increases because of their substantial share in overall utility infrastructure construction costs.

Figure 12
National Average Labor Costs Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional labor cost indices for the specified types of labor.

Although labor costs have not risen dramatically in recent years, there is growing concern about an emerging gap between demand and supply of skilled construction labor—especially if the anticipated boom in utility construction materializes. In 2002, the Construction Users Roundtable (CURT), surveyed its members and found that recruitment, education, and retention of craft workers continue to be critical issues for the industry.[13] The average age of the current construction skilled workforce is rising rapidly, and high attrition rates in construction are compounding the problem. The industry has always had high attrition at the entry-level positions, but now many workers in the 35-40 year-old age group are leaving the industry for a variety of reasons. The latest projections indicate that, because of attrition and anticipated growth, the construction

[12] These figures represent a simple average of six regional indices, however, local and regional labor markets can vary substantially from these national averages.

[13] *Confronting the Skilled Construction Workforce Shortage*. The Construction Users Roundtable, WP-401, June 2004, p. 1.

industry must recruit 200,000 to 250,000 new craft workers per year to meet future needs. However, both demographics and a poor industry image are working against the construction industry as it tries to address this need.[14]

There also could be a growing gap between the demand and supply of electrical lineworkers who maintain the electric grid and who perform much of the labor for transmission and distribution investments. These workers erect poles and transmission towers and install or repair cables or wires used to carry electricity from power plants to customers. According to a DOE report, demand for such workers is expected to outpace supply over the next decade.[15] The DOE analysis indicates a significant forecasted shortage in the availability of qualified candidates by as many as 10,000 lineworkers, or nearly 20 percent of the current workforce. As of 2005, lineworkers earned a mean hourly wage of $25/hour, or $52,300 per year. The forecast supply shortage will place upward pressure on the wages earned by lineworkers.[16]

Shop and Fabrication Capacity

Many of the components of utility projects—including large components like turbines, condensers, and transformers—are manufactured, often as special orders to coincide with particular construction projects. Because many of these components are not held in large inventories, the overall capacity of their manufacturers can influence the prices obtained and the length of time between order and delivery. The price increases of major manufactured components were shown in Figure 11. While equipment and component prices obviously reflect underlying material costs, some of the price increases of manufactured components and the delivery lags are due to manufacturing capacity constraints that are not readily overcome in the near term.

As shown in Figure 13 and Figure 14, recent orders have largely eliminated spare shop capacity, and delivery times for major manufactured components have risen. These constraints are adding to price increases and are difficult to overcome with imported components because of the lower value of the dollar in recent years.

The increased delivery times can affect utility construction costs through completion delays that increase the cost of financing a project. In general, utilities commit substantial funds during the construction phase of a project that have to be financed either through debt or equity, called "allowance for fund used during construction" (AFUDC). All else held equal, the longer the time from the initiation through completion of a project, the higher is the financing costs of the investment and the ultimate costs passed through to ratepayers.

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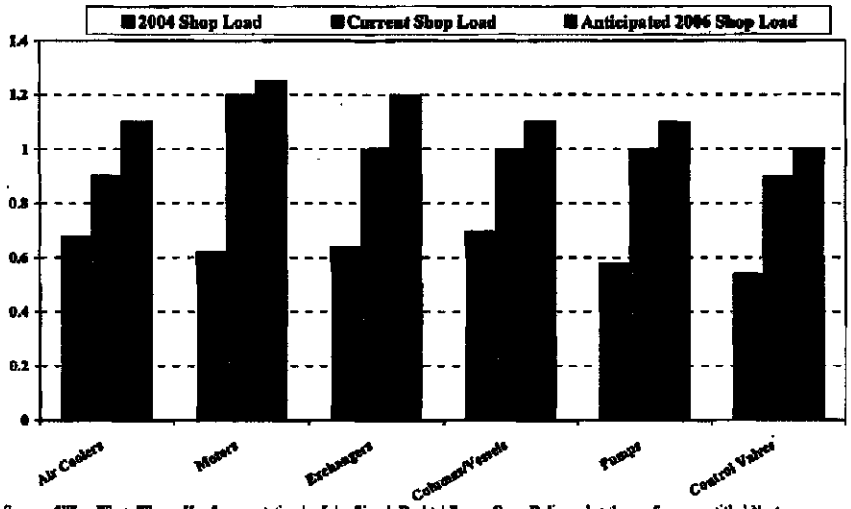
[14] *Id.*, p. 1.

[15] *Workforce Trends in the Electric Utility Industry: A Report to the United States Congress Pursuant to Section 1101 of the Energy Policy Act of 2005*. U.S. Department of Energy, August 2006, p. xi.

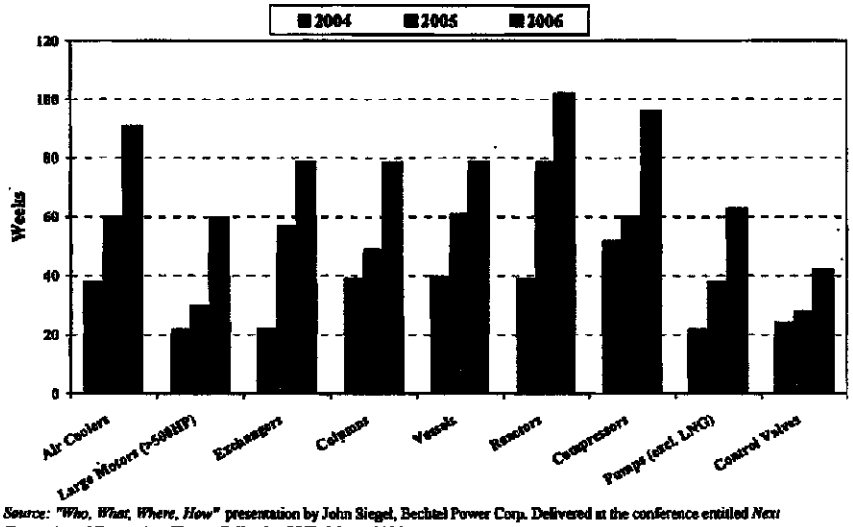
[16] *Id.*, p. 5.

Figure 13
Shop Capacity



Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Figure 14
Delivery Schedules

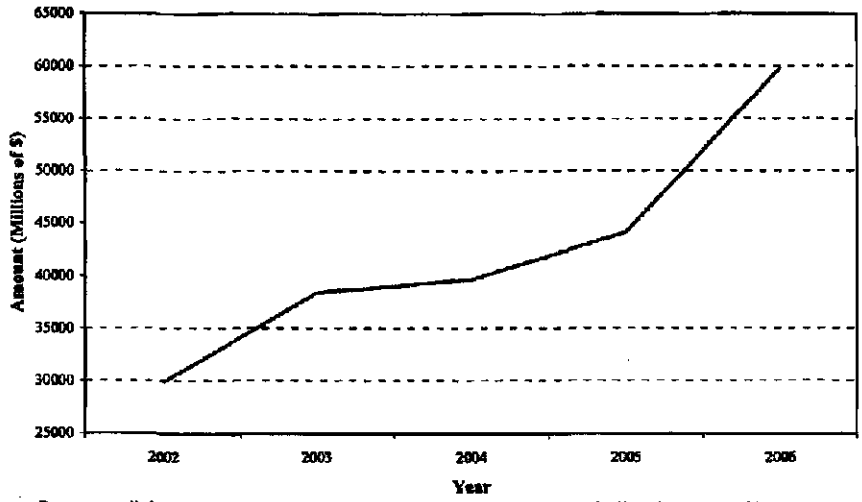


Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Engineering, Procurement and Construction (EPC) Market Conditions

Increased worldwide demand for new generating and other electric infrastructure projects, particularly in China, has been cited as a significant reason for the recent escalation in the construction cost of new power plants. This suggests that major Engineering, Procurement and Construction (EPC) firms should have a growing backlog of utility infrastructure projects in the pipeline. While we were unable to obtain specific information from the major EPC firms on their worldwide backlog of electric utility infrastructure projects (*i.e.*, the number of electric utility projects compared with other infrastructure projects such as roads, port facilities and water infrastructure, in their respective pipelines), we examined their financial statements, which specify the financial value associated with their backlog of infrastructure projects. Figure 15 shows the cumulative annual financial value associated with the backlog of infrastructure projects at the following four major EPC firms; Fluor Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd. Figure 15 shows that the annual backlog of infrastructure projects rose sharply between 2005 and 2006, from $4.1 billion to $5.6 billion, an increase of 37 percent. This significant increase in the annual backlog of infrastructure projects at EPC firms is consistent with the data showing an increased worldwide demand for infrastructure projects in general and also utility generation, transmission, and distribution projects.

Figure 15
Annual Backlog at Major EPC Firms



Data are compiled from the Annual Reports of Fluor Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd. For Bechtel, the data represent new booked work, as backlog is not reported.

The growth in construction project backlogs likely will dampen the competitiveness of EPC bids for future projects, at least until the EPC industry is able to expand capacity to manage and execute greater volumes of projects. This observation does not imply that this market is generally uncompetitive—rather it reflects the limited ability of EPC firms with near-term capacity constraints to service an upswing in new project development associated with a boom period in infrastructure construction cycles. Such constraints,

combined with a rapidly filling (or full) queue for project management services, limit incentives to bid aggressively on new projects.

Although difficult to quantify, this lack of spare capacity in the EPC market will undoubtedly have an upward price pressure on new bids for EPC services and contracts. A recent filing by Oklahoma Gas & Electric Company (OG&E) seeking approval of the Red Rock plant (a 950 MW coal unit) provides a demonstration of this effect. In January 2007, OG&E testimony indicated that their February 3, 2006, cost estimate of nearly $1,700/kW had been revised to more than $1,900/kW by September 29, 2006, a 12-percent increase in just nine months. More than half of the increase (6.6 percent) was ascribed to change in market conditions which "reflect higher materials costs (steel and concrete), escalation in major equipment costs, and a significant tightening of the market for EPC contractor services (as there are relatively few qualified firms that serve the power plant development market)."[17] In the detailed cost table, OG&E indicated that the estimate for EPC services had increased by more than 50 percent during the nine month period (from $223/kW to $340/kW).

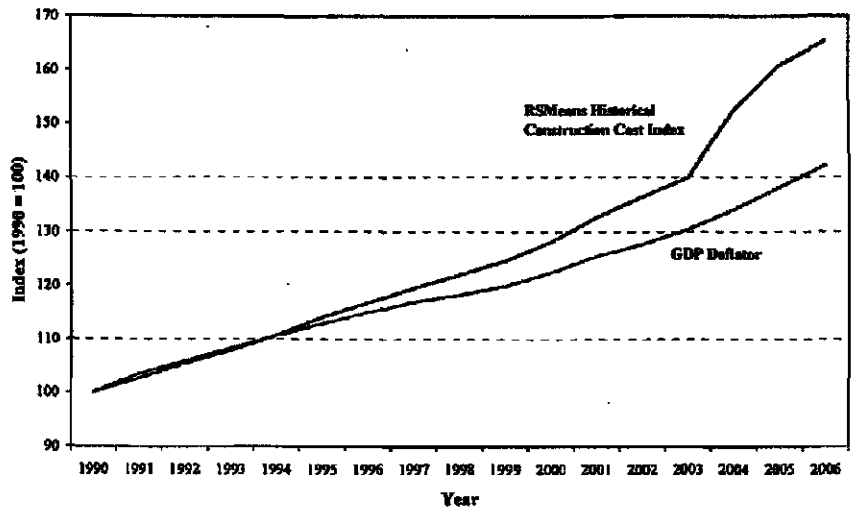
Summary Construction Cost Indices

Several sources publish summary construction cost indices that reflect composite costs for various construction projects. Although changes in these indices depend on the actual cost weights assumed *e.g.*, labor, materials, manufactured components, they provide useful summary measures for large infrastructure project construction costs.

The RSMeans Construction Cost Index provides a general construction cost index, which reflects primarily building construction (as opposed to utility projects). This index also reflects many of the same cost drivers as large utility construction projects such as steel, cement and labor. Figure 16 shows the changes in the RSMeans Construction Cost index since 1990 relative to the general inflation rate. While the index rose slightly higher than the GDP deflator beginning in the mid 1990s, it shows a pronounced increase between 2003 and 2006 when it rose by 18 percent compared to the 9 percent increase in general inflation.

[17] Testimony of Jesse B. Langston before the Corporation Commission of the State of Oklahoma, Cause No. PUD 200700012, January 17, 2007, page 27 and Exhibit JBL-9.

Figure 16
RSMeans Historical Construction Cost Index



Source: RSMeans, Heavy Construction Cost Data, 20th Annual Edition, 2006.

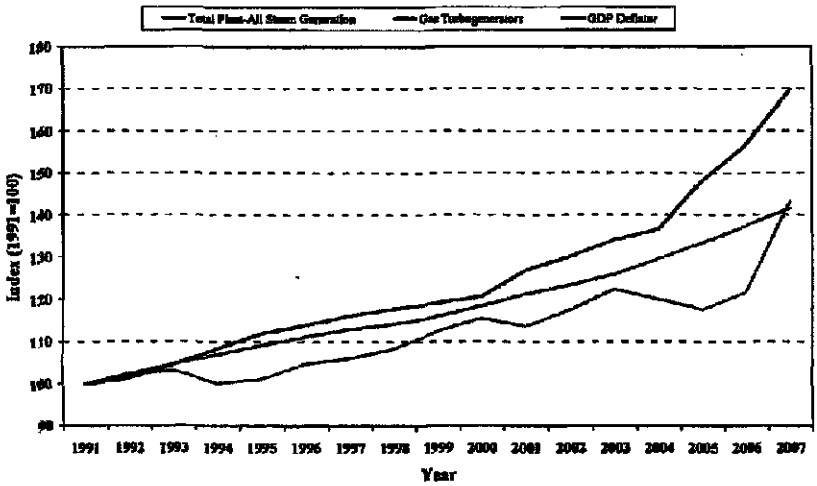
The Handy-Whitman Index© publishes detailed indices of utility construction costs for six regions, broken down by detailed component costs in many cases. Figures 17 through 19 show the evolution of several of the broad aggregate indices since 1991 compared with the general inflation index (GDP deflator).[18] The index numbers displayed on the graphs are for January 1 of each year displayed.

Figure 17 displays two indices for generation costs: a weighted average of coal steam plant construction costs (boilers, generators, piping, etc.) and a stand-alone cost index for gas combustion turbines.

As seen on Figure 17, steam generation construction costs tracked the general inflation rate fairly well through the 1990s, began to rise modestly in 2001, and increased significantly since 2004. Between January 1, 2004, and January 1, 2007, the cost of constructing steam generating units increased by 25 percent—more than triple the rate of inflation over the same time period. The cost of gas turbogenerators (combustion turbines), on the other hand, actually fell between 2003 and 2005. However, during 2006, the cost of a new combustion turbine increased by nearly 18 percent—roughly 10 times the rate of general inflation.

[18] Used with permission. See Handy-Whitman© Bulletin, No. 165 for detailed data breakouts and regional values for six regions: Pacific, Plateau, South Central, North Central, South Atlantic and North Atlantic. The Figures shown reflect simple averages of the six regions.

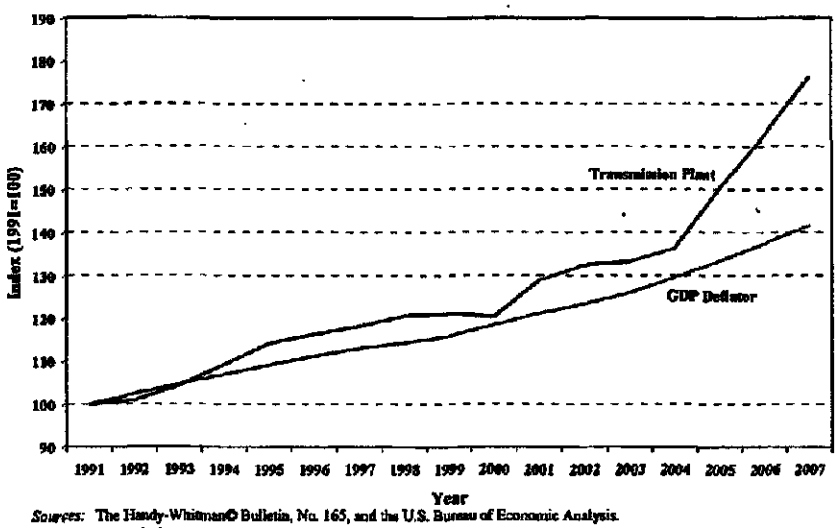
Figure 17
National Average Generation Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indices for the specified components.

Figure 18 displays the increased cost of transmission investment, which reflects such items as towers, poles, station equipment, conductors and conduit. The cost of transmission plant investments rose at about the rate of inflation between 1991 and 2000, increased in 2001, and then showed an especially sharp increase between 2004 and 2007, rising almost 30 percent or nearly four times the annual inflation rate over that period.

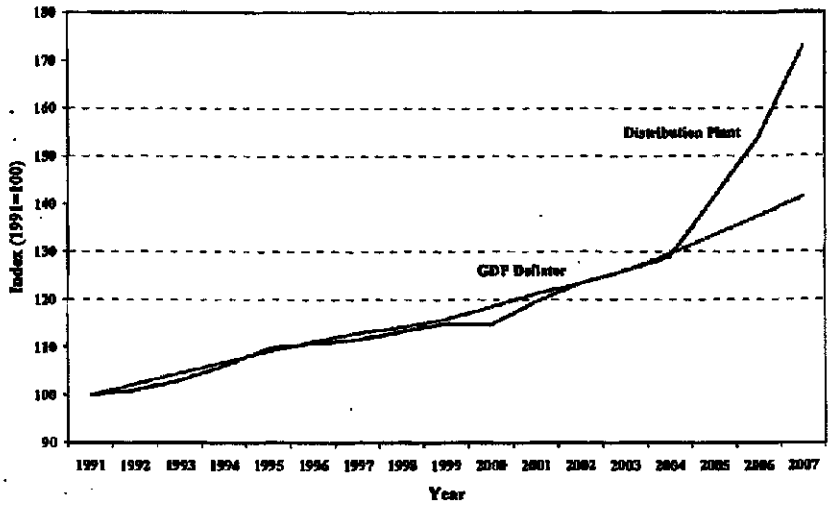
Figure 18
National Average Transmission Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional transmission cost indices.

Figure 19 shows distribution plant costs, which include poles, conductors, conduit, transformers and meters. Overall distribution plant costs tracked the general inflation rate very closely between 1991 and 2003. However, it then increased 34 percent between January 2004 and January 2007, a rate that exceeded four times the rate of general inflation.

Figure 19
National Average Distribution Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional distribution cost indices.

Comparison with Energy Information Administration Power Plant Cost Estimates

Every year, EIA prepares a long-term forecast of energy prices, production, and consumption (for electricity and the other major energy sectors), which is documented in the *Annual Energy Outlook* (AEO). A companion publication, *Assumptions to the Annual Energy Outlook*, itemizes the assumptions (*e.g.*, fuel prices, economic growth, environmental regulation) underlying EIA's annual long-term forecast. Included in the latter document are estimates of the "overnight" capital cost of new generating units (*i.e.*, the capital cost exclusive of financing costs). These cost estimates influence the type of new generating capacity projected to be built during the 25-year time horizon modeled in the AEO.

The EIA capital cost assumptions are generic estimates that do not take into account the site-specific characteristics that can affect construction costs significantly.[19] While EIA's estimates do not necessarily provide an accurate estimate of the cost of building a power plant at a specific location, they should, in theory, provide a good "ballpark" estimate of the relative construction cost of different generation

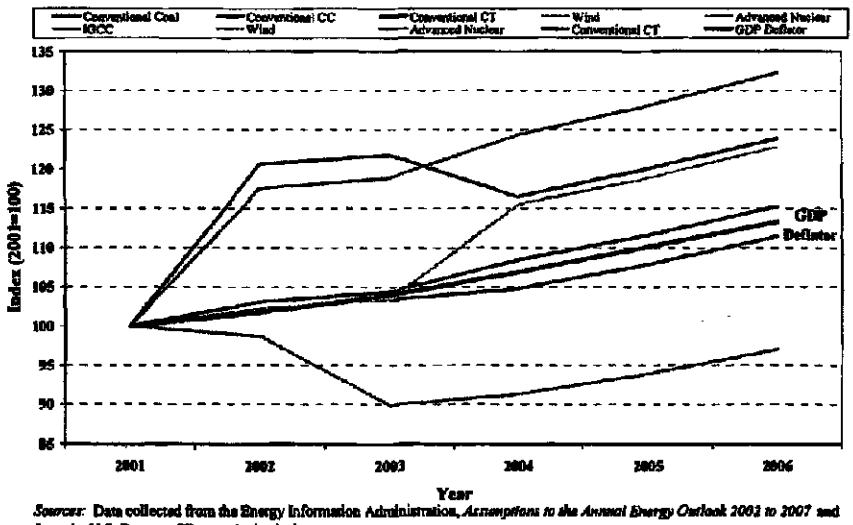
[19] EIA does incorporate regional multipliers to reflect minor variations in construction costs based on labor conditions.

technologies at any given time. In addition, since they are prepared annually, these estimates also should provide insight into construction cost trends over time.

The EIA plant cost estimates are widely used by industry analysts, consultants, academics, and policymakers. These numbers frequently are cited in regulatory proceedings, sometimes as a yardstick by which to measure a utility's projected or incurred capital costs for a generating plant. Given this, it is important that EIA's numbers provide a reasonable estimate of plant costs and incorporate both technological and other market trends that significantly affect these costs.

We reviewed EIA's estimate of overnight plant costs for the six-year period 2001 to 2006. Figure 20 shows EIA's estimates of the construction cost of six generation technologies—combined-cycle gas-fired plants, combustion turbines (CTs), pulverized coal, nuclear, IGCC, and wind—over the period 2001 to 2006 and compares these projections to the general inflation rate (GDP deflator). These six technologies, generally speaking, have been the ones most commonly built or given serious consideration in utility resource plans over the last few years. Thus, we can compare the data and case studies discussed above to EIA's cost estimates.

Figure 20
EIA Generation Construction Cost Estimates



Sources: Data collected from the Energy Information Administration, *Assumptions to the Annual Energy Outlook 2002 to 2007* and from the U.S. Bureau of Economic Analysis.

The general pattern in Figure 20 shows a dramatic change in several technology costs between 2001 and 2004 followed by a stable period of growth until 2006. The two exceptions to this are conventional coal and IGCC, which increase by a near constant rate each year close to the rate of inflation throughout the period. The data show conventional CC and conventional CT experiencing a sharp increase between 2001 and 2002. After this increase, conventional CC levels off and proceeds to increase at a pace near inflation, while conventional CT actually drops significantly before 2004 when it too levels near the rate of inflation. The

pattern seen with nuclear technology is near to the opposite. It falls dramatically until about 2003 and then increases at the same rate as the GDP deflator. Lastly, wind moves close to inflation until 2004 when it experiences a one-time jump and then flattens off through 2006.

These patterns of cost estimates over time contradict the data and findings of this report. Almost every other generation construction cost element has shown price changes at or near the rate of inflation throughout the early part of this decade with a dramatic change in only the last few years. EIA appears to have reconsidered several technology cost estimates (or revised the benchmark technology type) in isolation between 2001 and 2004, without a systematic update of others. Meanwhile, during the period that overall construction costs were rising well above the general inflation rate, EIA has not revised its estimated capital cost figures to reflect this trend.

EIA's estimates of plant costs do not adequately reflect the recent increase in plant construction costs that has occurred in the last few years. Indeed, EIA itself acknowledges that its estimated construction costs do not reflect short-term changes in the price of commodities such as steel, cement and concrete.[20] While one would expect some lag in the EIA data, it is troubling that its most recent estimates continue to show the construction cost of conventional power plants increasing only at the general rate of inflation. Empirical evidence shows that the construction cost of generating plants—both fossil-fired and renewable—is escalating at a rate well above the GDP deflator. Even the most recent EIA data fail to reflect important market impacts that are driving plant construction costs, and thus do not provide a reliable measure of current or expected construction costs.

[20] *Annual Energy Outlook 2007*, U.S. Energy Information Administration, p. 36.

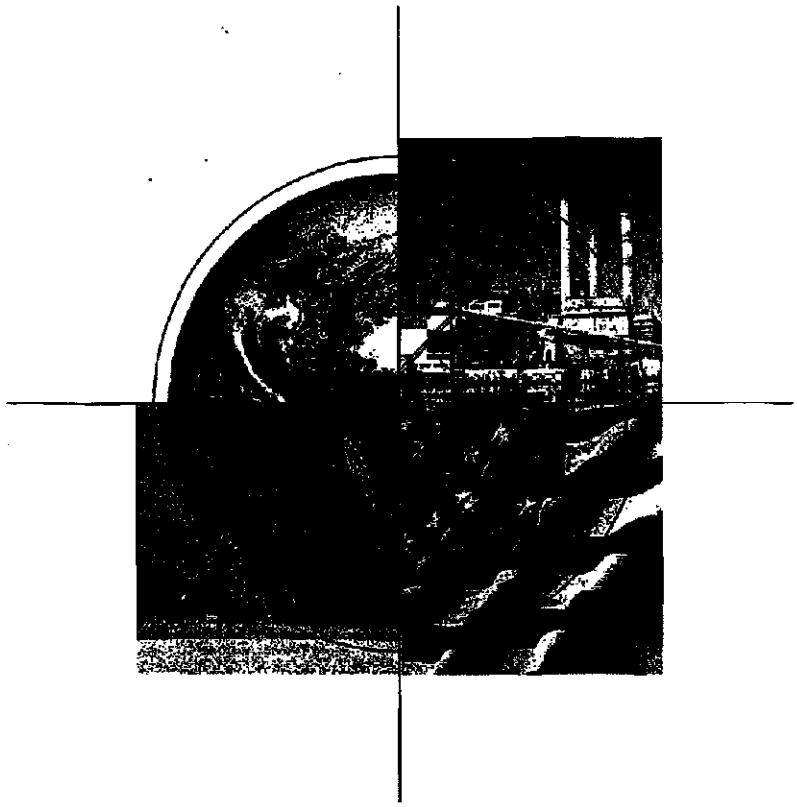
Conclusion

Construction costs for electric utility investments have risen sharply over the past several years, due to factors beyond the industry's control. Increased prices for material and manufactured components, rising wages, and a tighter market for construction project management services have contributed to an across-the-board increase in the costs of investing in utility infrastructure. These higher costs show no immediate signs of abating.

Despite these higher costs, utilities will continue to invest in baseload generation, environmental controls, transmission projects and distribution system expansion. However, rising construction costs will put additional upward pressure on retail rates over time, and may alter the pace and composition of investments going forward. The overall impact on the industry and on customers, however, will be borne out in various ways, depending on how utilities, markets and regulators respond to these cost increases. In the long run, customers ultimately will pay for higher construction costs—either directly in rates for completed assets of regulated companies, less directly in the form of higher energy prices needed to attract new generating capacity in organized markets and in higher transmission tariffs, or indirectly when rising construction costs defer investments and delay expected benefits such as enhanced reliability and lower, more stable long-term electricity prices.

Fossil Energy Power Plant Desk Reference

DOE/NETL-2007/1282



Bituminous Coal and Natural Gas to Electricity Summary Sheets

May 2007

Overview of Bituminous Baseline Study

Objective and Description

The objective of the *Cost and Performance Baseline for Fossil Energy Plants; Volume I (Bituminous Coal and Natural Gas to Electricity)* is to determine cost and performance estimates of the near-term commercial offerings for power plants, both with and without current technology for carbon capture and sequestration (CCS). The study uses consistent design requirements for all technologies examined, as well as up-to-date performance and capital cost estimates. The study timeframe focuses on plants built now and commissioned in 2010. Each plant is built at a greenfield site in the midwestern United States.

The fossil energy plant cost and performance estimates presented in the study can be used as a baseline for additional comparisons and analyses. These systems analyses are a critical element of planning and guiding Federal Fossil Energy Research and Development.

Twelve different power plant configurations are analyzed in the Bituminous Baseline Study. The list includes six integrated gasification combined-cycle (IGCC) cases utilizing General Electric Energy (GEE), ConocoPhillips (CoP), and Shell gasifiers, each with and without CCS; four pulverized coal (PC) cases, two subcritical and two supercritical, each with and without CCS; and two natural gas combined-cycle (NGCC) plants, one with and one without CCS. The study matrix is provided in Table 1.

Table 1. Study Matrix

Plant Type	Standard Conditions (psig/°F/°F)	Gas Turbine	Gasifier / Boiler	Acid Gas Removal / CO_2 Separation / Sulfur Recovery	CO_2 Capture (%)
IGCC	1,800/1,050/1,050	F-Class	GEE	Selexol/ - /Claus	–
			CoP E-Gas™	MDEA/ - /Claus	–
			Shell	Sulfinol-M/ - /Claus	–
	1,800/1,000/1,000		GEE	Selexol/Selexol/Claus	90
			CoP E-Gas™	Selexol/Selexol/Claus	88
			Shell	Selexol/Selexol/Claus	90
PC	2,400/1,050/1,050	–	Subcritical	Wet flue gas desulfurization (FGD)/ - /Gypsum	–
				Wet FGD/Econamine/Gypsum	90
	3,500/1,100/1,100		Supercritical	Wet FGD/ - /Gypsum	–
				Wet FGD/Econamine/Gypsum	90
NGCC	2,400/1,050/950	F-Class	Heat recovery steam generators	–	–
				- /Econamine/ -	90

Assumptions

Technical

The IGCC cases are dual-train gasification systems. Once the syngas is cleaned of acid gases and other contaminants, it is fed to two advanced F-Class combustion turbines (232 MWe gross output each) coupled with two heat recovery steam generators (HRSGs) and a single steam turbine to generate roughly 750 MWe gross plant output (about 630 MWe, net). The CCS cases require a water-gas-shift (WGS) and a two-stage Selexol system to capture the carbon dioxide (CO_2) and compressors to raise the CO_2 to the pipeline requirements of 15.3 MPa (2,215 psia). These systems require a significant amount of extraction steam and auxiliary power, which reduces the output of the steam turbine and reduces the net plant power to about 520 MWe. Because the IGCC system is constrained by the discrete F-Class turbine size, the system cannot be scaled to increase the net output to match that of the cases without CCS.

All four PC cases employ a one-on-one configuration comprising a state-of-the-art PC steam generator and steam turbine. The boiler is a dry-bottom, wall-fired unit that employs low-nitrogen oxides (NOx) burners with over-fire air and selective catalytic reduction for NOx control, a wet-limestone, forced-oxidation scrubber for sulfur dioxide (SO_2) and mercury (Hg) control, and a fabric filter for particulate matter (PM) control. In the cases with CCS, the PC plant is equipped with the Econamine FG Plus™ process. The coal feed rate is increased in the CCS cases to increase the gross steam turbine output and account for the higher auxiliary load of carbon capture and compression. The boiler and steam turbine industry's ability to match unit size to a custom specification has been commercially demonstrated, enabling a common net output of 550 MWe for the PC cases in this study.

Table 2. Coal Analysis

Rank	Bituminous	
Seam	Illinois No. 6 (Herrin)	
Source	Old Ben Mine	
Proximate Analysis (weight %)[1]		
	As Received	Dry
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile matter	34.99	39.37
Fixed carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
Higher heating value, Btu/lb	11,666	13,126
Lower heating value, Btu/lb	11,252	12,712

[1]The above proximate analysis assumes sulfur as a volatile matter.

An analysis of the Illinois No. 6 bituminous coal used in the IGCC and PC cases is provided in Table 2.

The NGCC cases use two F-Class turbines, each generating a gross 185 MWe. The two turbines are coupled with two HRSGs and one steam turbine generator in a multi-shaft 2x2x1 configuration. For the CCS cases, CO_2 is removed in an Econamine process that imposes a significant auxiliary power load on the system and requires significant extraction steam, reducing the steam turbine power output. Similar to the IGCC cases, the NGCC cases are constrained by the combustion turbine size. The NGCC cases have a total net power output of 560 MWe without CCS and 482 MWe with capture. In all CCS cases, the compressed CO_2 is transported 50 miles via pipeline to a geologic sequestration field for injection into a saline aquifer. In addition to transport and storage, the CO_2 is monitored for 80-years.

Table 3. Environmental Targets

Pollutant	IGCC	PC	NGCC
SO_2	0.0128 lb/MMBtu	0.085 lb/ MMBtu	<0.6 gr Sulfur /100 scf
NOx	15 ppmvd @ 15% Oxygen	0.07 lb/MMBtu	2.5 ppmvd @ 15% Oxygen
PM (filterable)	0.0071 lb/MMBtu	0.017 lb/ MMBtu	Negligible
Hg	> 90% capture	1.14 lb/TBtu	Negligible

Environmental

The environmental approach for the study was to choose environmental targets for each technology that meet or exceed regulatory requirements. The IGCC targets were chosen to match the design basis of the Electric Power Research Institute for their *CoalFleet for Tomorrow Initiative*. Best Available Control Technology was applied to each of the PC and NGCC cases, and

the resulting emissions compared to 2006 New Source Performance Standards limits and recent permit averages.

Economic

The total plant cost (TPC) for each technology was determined through a combination of vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

The cost estimates carry an accuracy of ±30 percent, consistent with the screening study level of design engineering applied to the various cases in this study. All cases were evaluated under the same set of technical and economic assumptions allowing meaningful comparisons among the cases evaluated.

Table 4. Major Economic Assumptions

Startup date	2010
Cost year (U.S. dollars)	2007
Coal cost ($/MMBtu)	1.80
Natural gas cost ($/MMBtu)	6.75
Capacity factor (%)	
IGCC	80
PC/NGCC	85
Capital charge factor (%):	
High risk (All IGCC, PC/NGCC with CO_2 capture)	17.5%
Low risk (PC/NGCC without CO_2 capture)	16.4%
Plant life (years)	20

Table 4 lists the major economic assumptions. In this study, dual trains were used only when equipment capacity required an additional train, and no redundancy was employed other than normal sparing of rotating equipment.

For those cases that feature CCS, capital and operating costs were estimated for CO_2 transport, storage, and monitoring. These costs were then levelized over a twenty-year period.

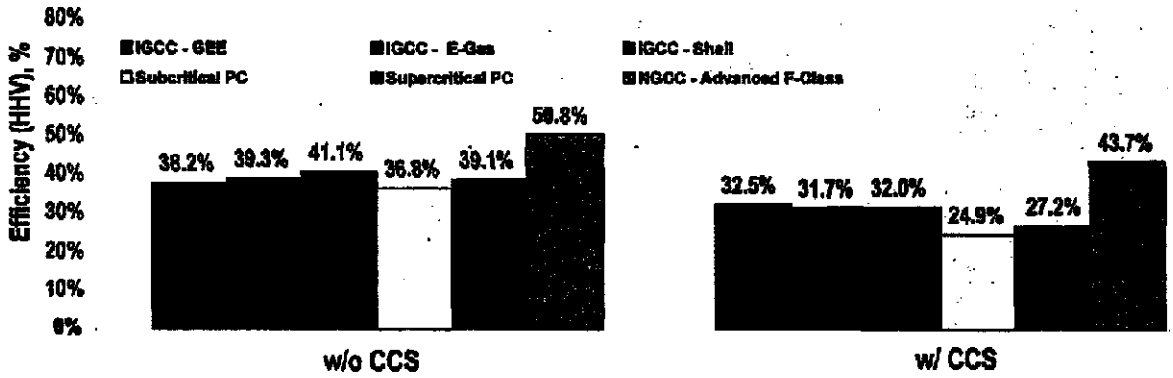
This study assumes that each new plant would be dispatched at the time it becomes available and would be capable of generating maximum capacity when online. Therefore, capacity factor (CF) is assumed to equal availability. The CF is 80 percent for IGCC cases and 85 percent for both PC and NGCC cases.

Results

Technical

The energy efficiency of NGCC cases is on the order of 50 percent (higher heating value, HHV); followed by supercritical PC and IGCC, both about 40 percent (HHV basis); and subcritical PC, with an efficiency of about 37 percent (HHV basis). Figure 1 shows the relative energy efficiency of each technology case.

Figure 1. Plant Efficiency

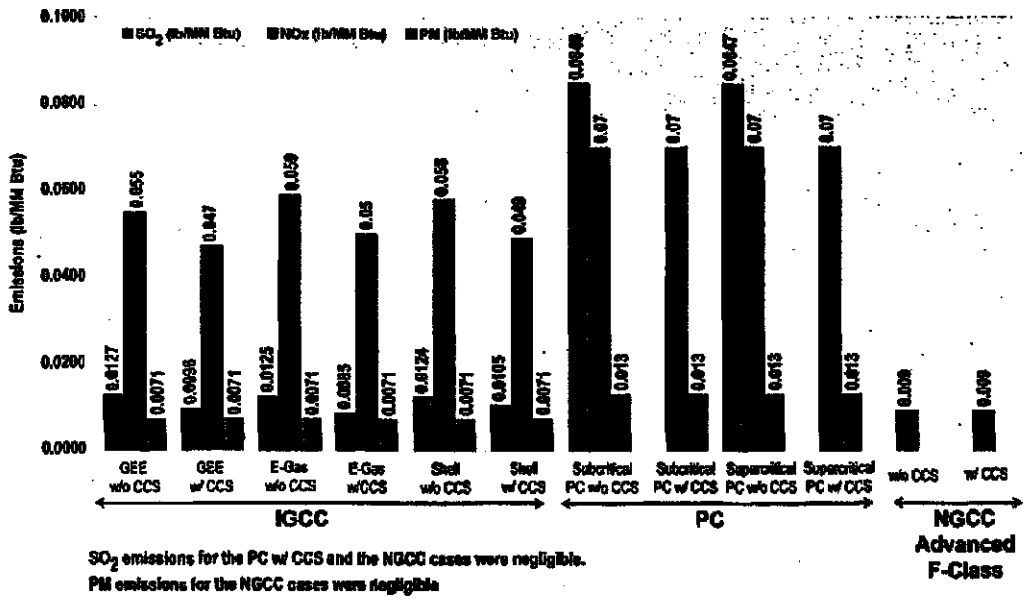


With CCS, the energy penalty is 12 percentage points for PC plants, 7 percentage points for NGCC, and 6-9 percentage points for IGCC. Even with CCS, NGCC still maintains the highest efficiency of the plants evaluated at over 40 percent (HHV basis). The significant energy penalty for the PC plants reduces the efficiency to about 26 percent (HHV basis). IGCC has an efficiency advantage over PC in the CCS cases primarily because the CO_2 is more concentrated in IGCC syngas than in PC flue gas, thus requiring less energy to capture. The efficiency of the IGCC plants with CCS is about 32 percent (HHV basis).

Environmental

All cases meet or exceed the environmental requirements set forth in the study design basis. The natural gas systems are the cleanest types of fossil power plants due to the low sulfur content and lower carbon-to-hydrogen ratio of the methane fuel. IGCC plants are the cleanest coal-based systems, with significantly lower levels of criteria pollutants than the PC plants. Figure 2 compares the results for these pollutant emissions for the various technology cases.

Figure 2. SO_2, NOx, and PM Emissions



All CCS cases were required to remove 90 percent of the carbon present in the syngas. Due to a higher methane content of the syngas in the CoP E-Gas™ case however, carbon capture was 88.4 percent. NGCC plants produce 40 percent less CO_2 than the coal-based systems. The uncontrolled coal-based systems emitted as much as 204 lb/MMBtu of CO_2, but with CCS, emissions were reduced to about 20 lb/MMBtu. Figure 3 compares the results for CO_2 emissions for the various technology cases.

All cases were required to control Hg emissions. The environmental target for Hg removal is >90 percent capture for IGCC plants and an emission rate of 1.14 lb/TBtu for PC plants. Figure 4 depicts the Hg emissions results for each case.

Water usage among the plants without CCS is lowest in the NGCC cases. The IGCC plants use about one-and-a-half times as much water as do the NGCC cases, and the PC cases use more than twice the amount of water.

In all CCS cases, water usage increases. Water usage for IGCC cases is similar to an NGCC with CCS, whereas the PC case with CCS plants requires three to four times more water. Figure 5 shows the respective water usage rates for each technology case.

Economic

Figure 3. CO_2 Emissions

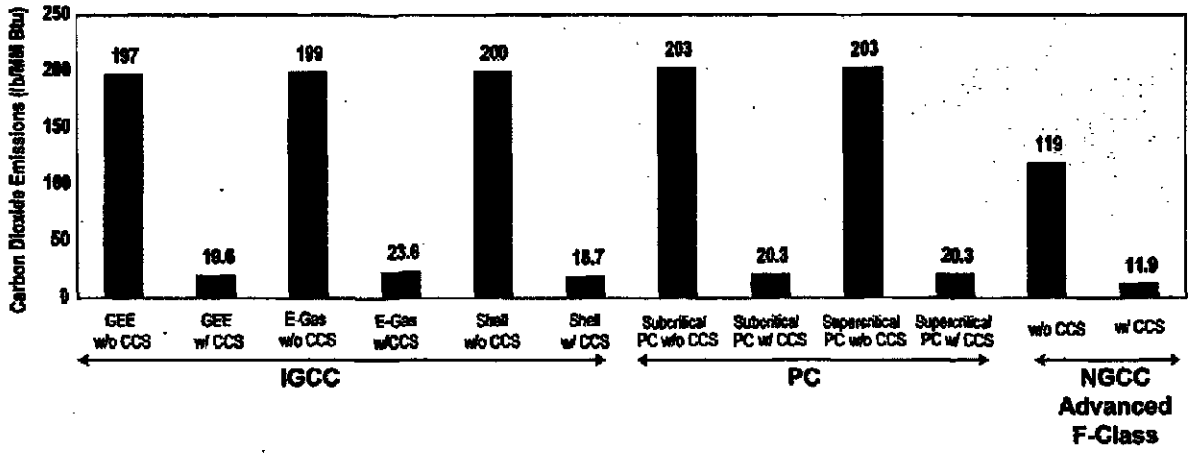
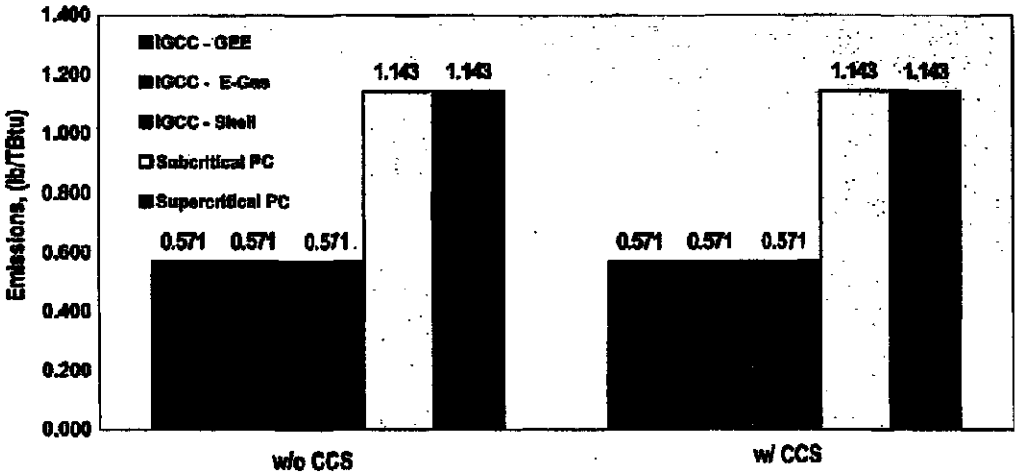


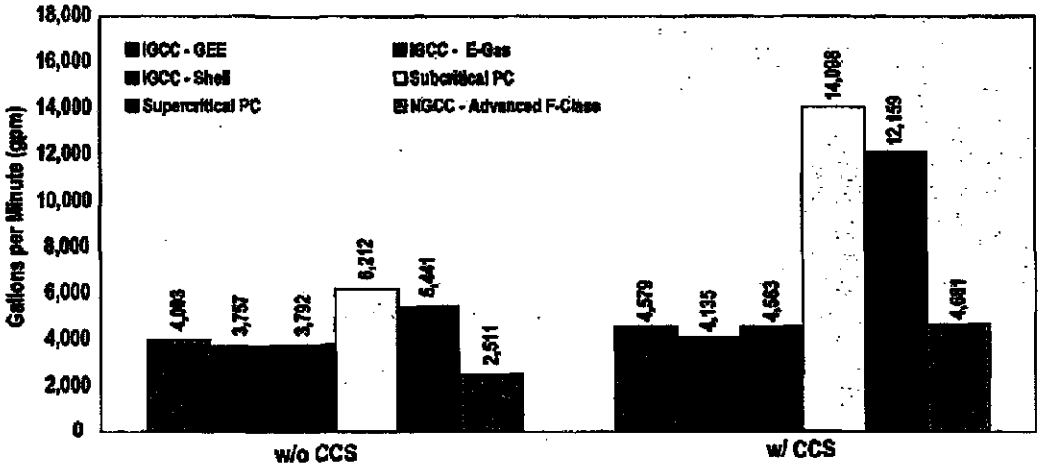
Figure 4. Mercury Emissions



Emissions for the NGCC cases were listed in the report as "Negligible."

The coal-based plants have a much higher TPC than NGCC, both with and without CCS. For IGCC, the TPC is about $1,800/kWe, varying somewhat based on the gasifier type. This is about 20 percent higher than the TPC for a PC supercritical plant, which is about $1,500/kWe.

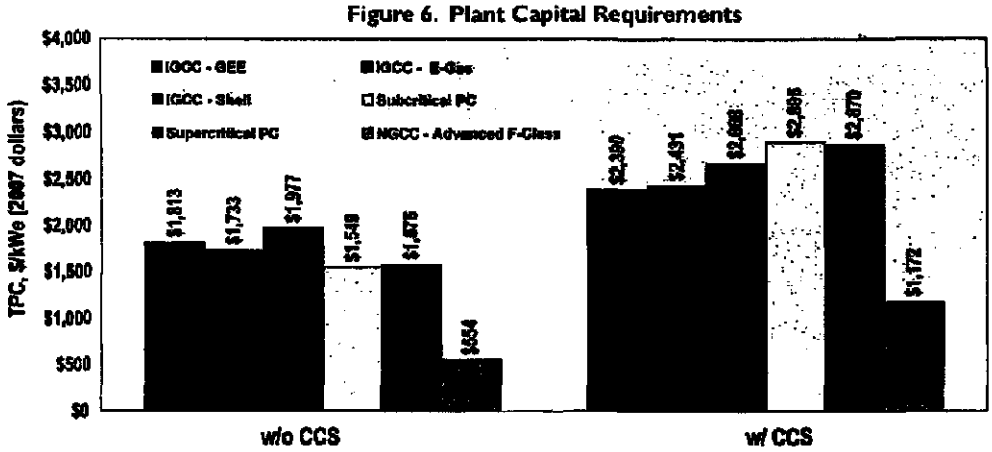
Figure 5. Plant Raw Water Usage



With CCS, the TPC for NGCC and PC plants ($/kW) increases by about 110 and 85 percent respectively. The TPC for the IGCC plant increases by around 35 percent. The NGCC plant capital requirement is over $1,000/kWe, while the IGCC plants cost approximately $2,400 to $2,600/kWe, and the PC plants cost over $2,800/kWe. Figure 6 shows the TPC for each technology case.

Cost-of-electricity (COE), which accounts for both efficiency and capital cost, is levelized over a 20-year period and expressed in mills/kWh (one mill is one-tenth of a cent). The electricity cost for cases without CCS ranges from about 63 mills/kWh for PC to 68.4 mills/kWh for NGCC and an average of 77.9 mills/kWh for IGCC.

Figure 6. Plant Capital Requirements

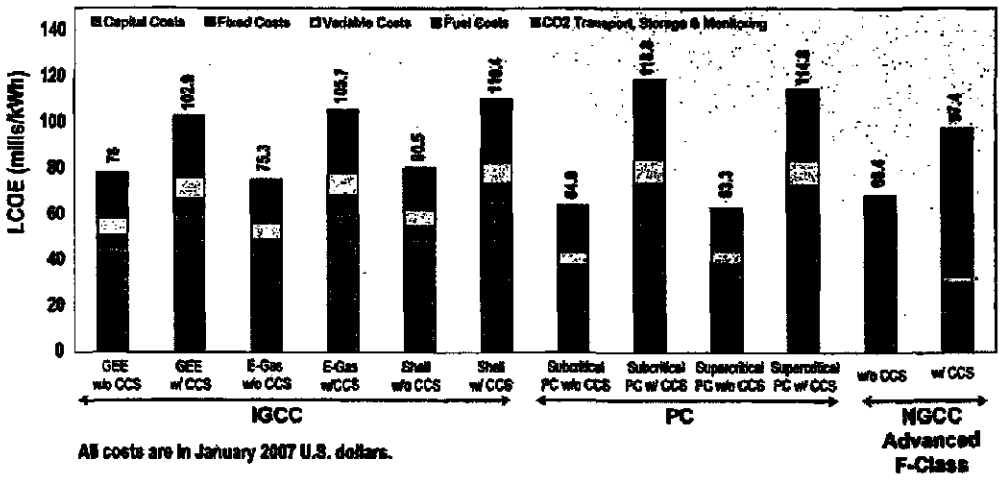


Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering, construction management, and contingencies (process and project).

With CCS, IGCC is the least expensive coal-based option for CO_2 removal with a levelized cost-of-electricity (LCOE) ranging from 102.9 mills/kWh to 110.4 mills/kWh. This is about 9 percent lower than PC plants equipped with CCS, which generate electricity at a cost of 114.8 mills/kWh to 118.8 mills/kWh. Figure 7 breaks out the LCOE costs for each technology case.

The cost of CO_2 avoided was calculated for each CCS case and is shown in Figure 8. On an avoided cost of CO_2 basis, IGCC is the least expensive option overall ($32–$42/ton) while NGCC is the most expensive option ($83/ton).

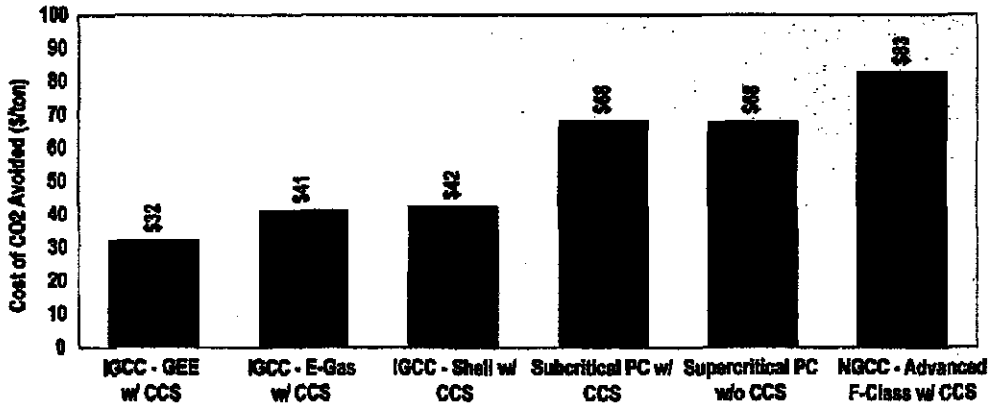
Figure 7. Levelized Cost-of-Electricity



All costs are in January 2007 U.S. dollars.

Figure 9 illustrates that at near 80 percent CF, the LCOE for PC cases is less than the LCOE for NGCC cases. With increased CF, the gap in LCOE between IGCC cases and other technologies narrows. For cases with CCS, even at higher CFs, the PC LCOE always for PC cases remains the highest.

Figure 8. Cost of CO_2 Avoided

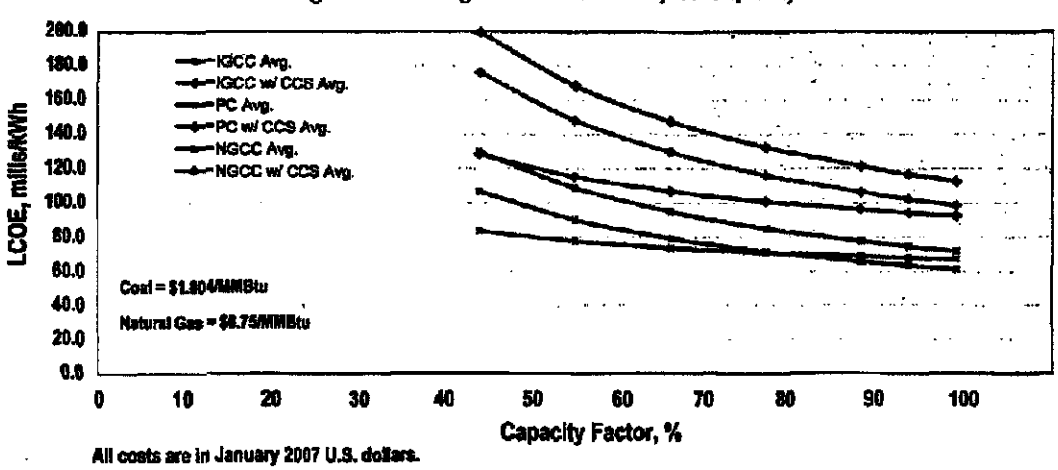


All costs are in January 2007 U.S. dollars.

The LCOE sensitivity to fuel costs for the cases with and without CCS is shown in Figure 10. The solid line is the LCOE of NGCC without CCS as a function of natural gas cost. The dashed line is the LCOE of NGCC with CCS as a function of natural gas cost. The points on the lines represent the natural gas cost that would be required to make the LCOE of NGCC equal to the respective PC or IGCC technologies at a given coal cost. The coal prices shown ($1.35, $1.804, and $2.2 5/MMBtu) represent the baseline cost and a range of ±25 percent around the baseline.

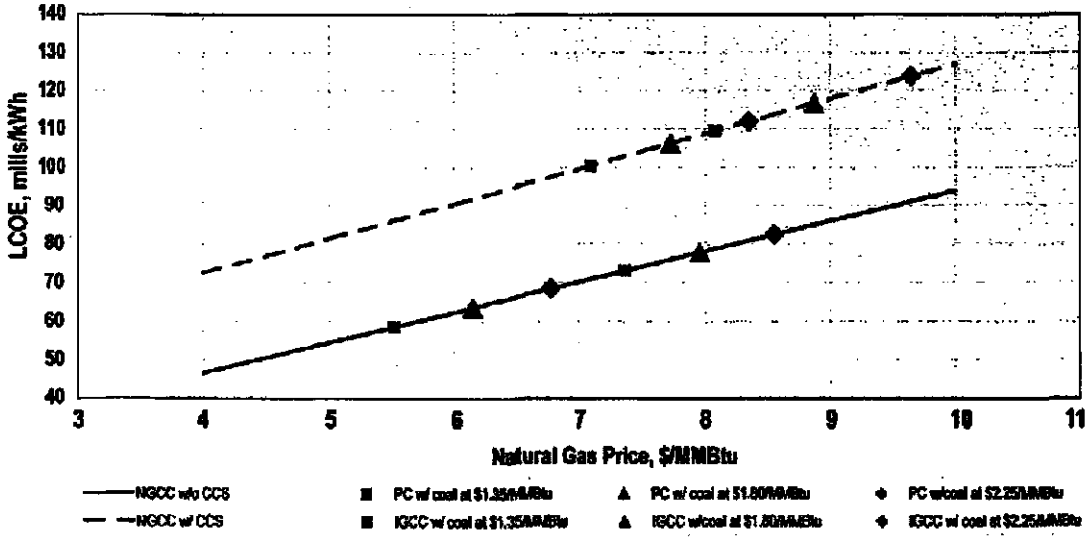
Without CCS, at the baseline coal cost of $1.80/MMBtu, the LCOE for PC cases equals that of NGCC case at a natural gas price of $6.15/MMBtu; and LCOE for IGCC cases equals that of NGCC case at a gas price of $7.96/MMBtu. With CCS, for the coal-based technologies at a baseline coal cost of $1.80/MMBtu, to be equal to the NGCC case, the cost of natural gas would have to be $7.73/MMBtu (IGCC cases) and $8.87/MMBtu (PC cases).

Figure 9. Average LCOE Sensitivity to Capacity Factor



All costs are in January 2007 U.S. dollars.

Figure 10. LCOE Sensitivity to Fuel Costs



All costs are in January 2007 U.S. dollars.

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.
Overview_050107

Senate Energy and Public Utilities Committee

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Attachment C

Technology	IGCC AVG (1)	IGCC AVG (1)	Latest IGCC Project estimate AEP & Duke (2)	Pulverized Coal (1)				Latest PC Plant Estimate (3)	Natural Gas Combined Cycle (1)		Nuclear (4)	Latest Nuclear Project Quote (5)	Wind Actual Cost (6)	Energy Efficiency (7)
Metric				Subcritical		Supercritical			2 x 7FB					
Case #	w/o CC	with CC		w/o CC	with CC	w/o CC	with CC	w/o CC	w/o CC	with CC				
$/kW	$1,841	$2,496	$4,000	$1,474	$2,626	$1,508	$2,635	$2,600	$554	$1,172	$2,000	$4,000	$1,460	$400
LCOE, Cents/kWh*	7.79	10.63		6.40	11.88	6.33	11.48		6.84	9.74	6.70		4.90	1.3 - 3.2
% Increase in COE with Capture		36.4			85.6		81.4			42.4				

Notes:

*** 20 year LEVELIZED COST OF ELECTRICITY (LCOE). Includes estimate of capital cost, fixed operating cost, variable and operating cost and fuel cost.**

1. Average of 3 IGCC designs (GE, CoP E-Gas, Shell), "Cost and Performance Baseline for Fossil Energy Plants", Exhibit ES-2, DOE, May 2007. CO2 transport, storage and monitoring adds <0.5 ¢/kWh, increase in COE ~ 3 cents/kWh (36%).
2. Based on latest IGCC estimates, see 9/10/07 Power Daily, page 5, for Duke $2.0 billion estimate and 8/18/07 $2.23 billion filing of AEP's 629 MW W. Virginia plant.
3. Based on expected cost of Longview supercritical, pulverised coal-fired generating facility in West Virginia at $1.8 billion for 695 MW, or about $2,600/kW, http://www.altassets.com/news/arc/2006/nz9491.php.
4. "The Future of Nuclear Power", Table 5.3, MIT, 2003. These figures do not include an estimated decommissioning cost of $350 million per plant.
5. "Realistic" costs of nuclear power as expressed by AEP CEO Mike Morris, "AEP not interested in nuclear plants", Bloomberg, AP and Staff Reports, 8/29/2007.
6. "Annual report on U.S. Wind Power Installation, Cost and Performance Trends: 2006, DOE. Figures are capacity weighted averages and include federal production tax credit.
7. Levelized cost of saving electricity, Martin Kushler, "The Midwest Energy Crisis and Why Energy Efficiency Should Be a Top Policy Priority", ACEEE 2005. The capacity costs are modeled after a residential direct load control program.

Attachment C