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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S PETITION TO MODIFY THE METHODOLOGY FO DETERMINING FUEL COSTS USED TO ESTABLISH PUBLISHED RATES FOR PUPRA QUALIFYING FACILITIES	CASE NO. IPC-E-07-15 EXERGY DEVELOPMENT GROUP OF IDAHO'S COMMENTS/PROTEST

COMES NOW, Exergy Development Group of Idaho LLC ("Exergy") by and through its attorney of record, Peter J. Richardson, and pursuant to that Notice of Modified Procedure issued by the Idaho Public Utilities Commission ("Commission") on September 27, 2007, and hereby lodges its Comments/Protest to Idaho Power Company's ("Idaho Power") Petition to Modify the Methodology for Determining Fuel Costs ("Petition").

I
SUMMARY OF EXERGY'S POSITION

Exergy urges the Commission to deny Idaho Power's Petition.

II
COMMISSION'S JURISDICTION AND FEDERAL AND STATE MANDATED POLICY DIRECTIVES

The Public Utility Regulatory Policies Act of 1978 (PURPA)[1] implements a broad national policy designed to help the United States achieve energy independence. It was enacted at the time of an earlier energy crises which is eerily similar to the energy situation Idaho and the country as a whole are currently facing. The States are required to implement PURPA in a manner such that traditionally reluctant utilities actually purchase power from cogeneration and small power production facilities[2]. *FERC v. Mississippi* 456 U.S. 742, 750 (1982). Utilities are required by PURPA to purchase the electricity produced by QFs at a rate equal to their full avoided costs. *Id.* No less an authority than the United States Supreme Court has ruled that utilities are reluctant when it comes to the purchase of power from QFs. It actually took federal legislation to motivate reluctant utilities, like Idaho Power, to become active participants in our nation's war for energy independence. Unfortunately, Idaho Power's actions since it first sought a moratorium on QF purchases in 2002, have certainly served to underscore the Supreme Court's finding that utilities are reluctant purchasers of QF power. Therefore, as the Commission considers Idaho Power's latest assault on PURPA it should be instructed by the national policy of requiring this reluctant utility to do its part by purchasing QF power at its full avoided cost.

In addition to Federal law and a clear statement of purpose from Congress with respect to this Commission's obligations in implementing PURPA, this Commission also has clear direction from the Idaho Legislature regarding the development of renewable resources. The

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[1] 16 U.S.C. 824a

[2] Cogeneration and small power production facilities that meet strict fuel use and source guidelines and/or generate power with renewable resources are called Qualifying Facilities or QFs for short.

2007 Idaho Energy Plan, issued just this spring, declares that "It is Idaho policy to encourage the development of customer-owned and community-owned renewable energy and combined heat and power[3] facilities."[4] Energy Plan p. 55. Not only does the Idaho Energy Plan encourage the development of renewable resources, it goes much further than mere encouragement by providing specific direction to this Commission with respect to its priorities for implementation of the plan:

> Local renewable resources also provide fuel diversity and help create jobs in Idaho. Consequently, the Committee establishes conservation, energy efficiency and demand response as the highest-priority resource for Idaho, and local renewable resources as the second-highest priority. The Committee further urges the PUC . . .to ensure that their policies are consistent with this resource priority order...

2007 State Energy Plan, p. 55.

When it comes to energy resources, the Legislature has established, as this Commission's second highest priority, the development of local renewable energy resources. This is a new directive that must now be considered by this Commission as it makes policy decisions relative to PURPA and QFs. Policies that are consistent with the Legislature's findings are policies that encourage the development of QFs in Idaho. It is necessary, as we delve into the detail of how avoided cost rates are set, to be cognizant of, and faithfully implement, these broad policy directives.

III
DEATH BY A THOUSAND CUTS
OR
VIOLATION OF THE SINGLE ISSUE RATE CASE DOCTRINE

[3] A combined heat and power facility is an alternative way to describe a cogeneration facility.

[4] *2007 Idaho Energy Plan* Idaho Legislature, Energy, Environment and Technology Interim Committee, March 14, 2007.

Single issue rate cases are frowned upon in utility ratemaking and are not used when addressing an issue that may have broader implications as to the validity of a utility's overall rates or rate of return. *See* Scates v. Arizona Public Corp. Comm'n, 118 Ariz. 531, 578 P.2d 612 (1978). The Idaho Commission has allowed single rate cases in situations where the single issue is narrow in scope and where the single issue does not affect the reasonableness of the overall rates or the return earned by the utility. *See:* The Matter of the Application of Idaho Power for Authority to Offset the Gain from the Sale of the Hailey Turbine Against the Revenue Requirement Increase Caused by Changes in Federal Tax Rates Order No. 25339. *See also:* In the Matter of the Investigation of the Effects of Revisions of the Federal Income Tax Code, Case No. U-1500-164

In its Petition, Idaho Power is seeking to lower its avoided cost rates from what they otherwise would be by changing the methodology for calculating the fuel cost input to the avoided cost rate model. Currently, the fuel cost input is adjusted whenever the Northwest Power Planning and Conservation Council updates its natural gas forecast. It is important to keep in mind that the updated natural gas forecast is used to update the numbers (inputs) in the existing avoided cost model. The resulting avoided cost rate is calculated using the updated numbers via the existing model. The updates are therefore not controversial as the forecasted gas price is produced by a third party and the model is not changed.

The methodology for incorporating each updated forecast was set in Order No. 29124 in 2002. The model is very complex and its inputs were the subject of intense litigation. The complexity of the model and the degree of controversy over its inputs can be easily discerned by looking at page five of Order No. 29124. (Attached as Attachment A). At page five of Order No. 23124, the Commission created a matrix of the various issues that were litigated in establishing

the model. It also indicates the various parties' positions on those issues. There are seventeen interdependent variables that were litigated by the nine parties to that docket. The methodology for calculating the fuel cost was litigated as part of the overall decision of determining the methodologies and inputs for the other fifteen interdependent variables that make up Idaho Power's avoided cost rate.

It should come as no surprise, especially in light of the Supreme Court's warning about the reluctance of utilities to purchase QF power, that the single issue Idaho Power is asking the Commission to address results in a dramatic reduction in the pending increase in the avoided cost rates. Ignored by Idaho Power are multiple inputs that would have the effect of increasing the avoided cost rates. For example, no one in the utility industry today can seriously state that a gas fired turbine can be constructed for $679 a kW which is in the existing SAR methodology. Idaho Power's 2006 IRP estimates the cost of a CCCT at $726 in 2006 dollars. In addition, commodity prices for items such as steel, concrete and copper have skyrocketed in the last two years, making a 2006 estimate suspect today. Interest rates have increased dramatically from the unprecedented low rates in effect in 2002 when the SAR rate was established. All of which suggests that if one input in the avoided cost model is updated, then all of the other inputs must also be updated.

Attached to these comments is a recent report prepared for the Edison Foundation by the Brattle Group (Attachment B) showing that utility construction costs have skyrocketed in the last two years. Of particular interest is Figure 17 on page 26 which is described thusly in the narrative on page 25

> 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.

While Exergy believes the current avoided cost rates that are produced by the existing model are by and large fair and reasonable, it would be a clear violation of the single issue rate case doctrine for Idaho Power to be allowed to cherry pick the one issue it believes will result in lower avoided cost rates while ignoring other issues that would have counterbalancing effects.

IV
POWER PLANNING COUNCIL'S GAS FORECASTS HAVE BEEN HISTORICALLY LOW

It is worth noting that the Power Planning Council's forecasts have proven to be extremely conservative. For example, the 2002 forecast predicted that natural gas prices in 2005 would be $3.60, however, the actual number was $7.62. The same forecast predicted the 2006 gas price would be $3.71, in reality it was $6.50. Despite the huge difference in actual gas prices, all QF contracts signed based on the 2002 forecast are stuck with the avoided cost rate that is dramatically lower than it would have been had the forecast been accurate. Idaho Power treats the Power Planning Council's forecast as if it were "real". It is nothing more than a prediction that should not dictate whether the Commission's avoided cost rate is, overall, fair, just and reasonable. The issue of single issue rate is implicated by assuming the gas forecast is etched in stone and reflects an accurate vision of the future. The price of gas will fluctuate due to influences we can not know at this time. The Commission must look at the all of the inputs to determine if the rate is a reasonable one, and not be painted into a corner by the fiction of a forecast gas price that will inevitably be proven wrong. As one former Idaho Commissioner was fond of saying, "a forecast is like a broken clock – it is right twice a day."

For the foregoing reasons, Exergy respectfully requests this Commission issue its order denying Idaho Power's petition and implement the new avoided cost rates based on the current model using the natural gas price forecast it has historically used.

Respectfully submitted this 23th day of October 2007.

RICHARDSON & O'LEARY PLLC

By _____
Peter J. Richardson
Attorneys for Exergy Development Group of Idaho

ATTACHMENT A

EXERGY DEVELOPMENT GROUP, LLC'S
COMMENTS/PROTESTS

addressed all the variables. Some variables were deemed to be more critical than others, i.e., current year fuel cost, fuel escalation rate and first deficit year. The following matrix depicts the changes in variables proposed by the parties:

COMPARISON OF PROPOSED VARIABLES

Data Type	Current Variables	Staff	Avista	Idaho Power	PacifiCorp	IEPI	Plummer/ Potlatch	Avista Rebuttal	PacifiCorp Rebuttal	IEPI Rebuttal
Surplus Energy Cost (mil/kWh):	19.00	Abandon	22.12 to 30.73	28.28	33.54	Abandon		22.12 to 30.73	33.54	Abandon
Surplus Cost Base Year:	1994	Abandon	2002	2002	2002	Abandon		2002	2002	Abandon
First Deficit Year:	2010/ 1998/1999	Abandon	2007	2005	2008	Abandon	2000/ NA/NA	2007	2008	Abandon
"SAR" Plant Life (Years):	30	No Change	No Change	No Change	No Change			No Change	No Change	
"SAR" Plant Cost ($/kW):	$667	$679	$577	$686/ $729	$632			$669	$632	
Base Year of "SAR" Cost:	1994	2000	2000	2002	2002			2002	2000	
"SAR" Capacity Factor (%):	92%	No Change	89.5%		No Change			91.38	No Change	
"SAR" Fixed O&M ($/kW):	$7.43	$10.70	$14.75	$9.45	$7.00			$9.04	$8.10	
"SAR" Variable O&M (mil/kWh):	1.65	2.80	2.80	3.27	1.61			2.69	2.80	
Current Yr Fuel Cost ($/MMBtu):	$5.23	$3.19	NWPPC	$2.79	$3.95	$3.84		NWPPC	$3.19	$3.91
Base Year, O&M Expenses:	1994	2000	2000	2002	2002			2002	2000	
Escalation Rate; "SAR" (%):	3.60%	2.10%	2.40%		0.47% thru 2007 2.5% after			2.26%	2.10%	
Escalation Rate; Surplus (%):	4.50%	Abandon	see above	5.90%	4.80			see above	4.80%	
Escalation Rate; O&M (%):	3.21%	2.70%	2.40%		2.50%			2.53%	2.70%	
Escalation Rate; Fuel (%):	6.0% nom	4.4% nom	NWPPC	2.62% nom	1.97%	3.10%		3.27% NWPPC	3.10% NWPPC	3.60%
"Tilting" Rate (%):	3.60%	2.10%	2.40%		2.50%			2.38%	2.10%	
Heat Rate (Btu/kWh):	7350	7100	7340	6899/ 6994	7074			7127	7100	

Avista, on rebuttal, recommends averaging the recommendations made for capital cost, O&M cost, heat rate, and escalation rates. Avista also accepts Staff's proposal to use a five-year rolling

ATTACHMENT B

EXERGY DEVELOPMENT GROUP, LLC'S
COMMENTS/PROTESTS

Rising Utility Construction Costs:

Sources and Impacts

Prepared by:

Marc W. Chupka
Gregory Basheda

The Brattle Group

Prepared for:

The EDISON FOUNDATION

SEPTEMBER 2007

The EDISON FOUNDATION

The Edison Foundation is a nonprofit organization dedicated to bringing the benefits of electricity to families, businesses, and industries worldwide.

Furthering Thomas Alva Edison's spirit of invention, the Foundation works to encourage a greater understanding of the production, delivery, and use of electric power to foster economic progress; to ensure a safe and clean environment; and to improve the quality of life for all people.

The Edison Foundation provides knowledge, insight, and leadership to achieve its goals through research, conferences, grants, and other outreach activities.

The Brattle Group

The Brattle Group provides consulting services and expert testimony in economics, finance, and regulation to corporations, law firms, and public agencies worldwide. Our principals are internationally recognized experts, and we have strong partnerships with leading academics and highly credentialed industry specialists around the world.

The Brattle Group has offices in Cambridge, Massachusetts; San Francisco; Washington, D.C.; Brussels; and London.

Detailed information about *The Brattle Group* is available at www.brattle.com.

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Table of Contents

Introduction and Executive Summary **1**

Projected Investment Needs and Recent Infrastructure Cost Increases **5**

Current and Projected U.S. Investment in Electricity Infrastructure 5

Generation 5

High-Voltage Transmission 6

Distribution 6

Construction Costs for Recently Completed Generation 7

Rising Projected Construction Costs: Examples and Case Studies 10

Coal-Based Power Plants 10

Transmission Projects 11

Distribution Equipment 12

Factors Spurring Rising Construction Costs **13**

Material Input Costs 13

Metals 13

Cement, Concrete, Stone and Gravel 17

Manufactured Products for Utility Infrastructure 18

Labor Costs 20

Shop and Fabrication Capacity 21

Engineering, Procurement and Construction (EPC) Market Conditions 23

Summary Construction Cost Indices 24

Comparison with Energy Information Administration Power Plant Cost Estimates 27

Conclusion **31**

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.

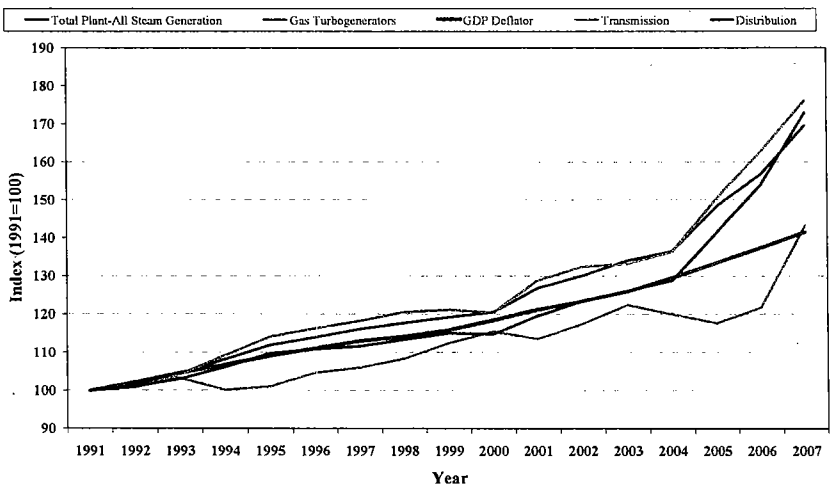
The purpose of this study is to a) document recent increases in the construction cost of utility infrastructure (generation, transmission, and distribution), b) identify the underlying causes of these increases, and c) explain how these increased costs will translate into higher rates that consumers 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

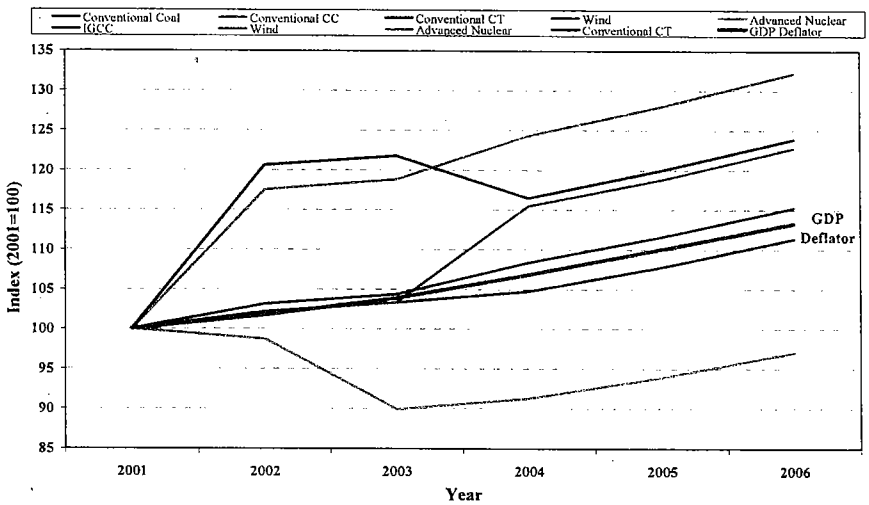


Sources: The Handy-Whitman© Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indexes for the specified components.

[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.

(page 4 intentionally left blank)

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

---

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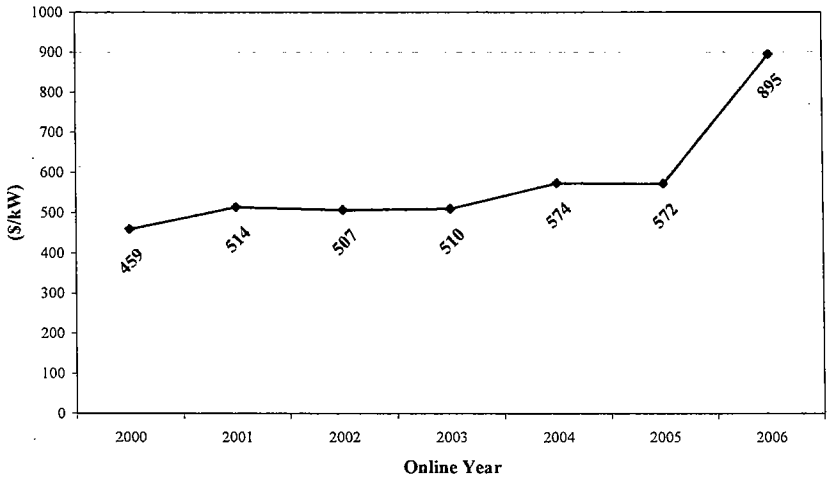
[4] To be precise, we used a "dummy" variable to represent each year in the analysis. The year-specific dummy variables were statistically significant and uniformly positive; *i.e.*, they had an upward impact on installation cost.

[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.

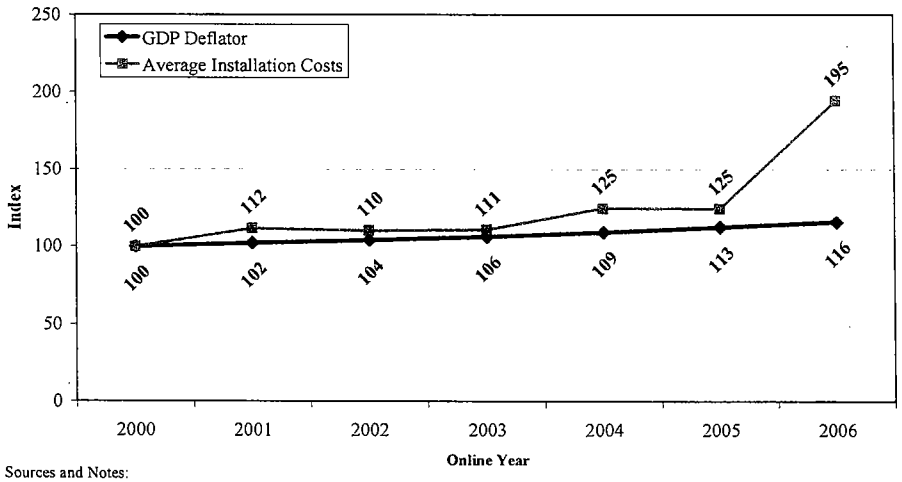
Figure 1
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year ($/kW)



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.

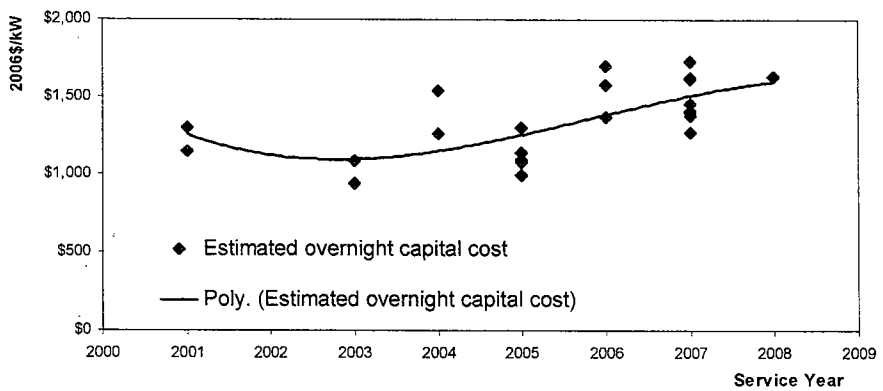
Figure 2
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year (Index Year 2000 = 100)



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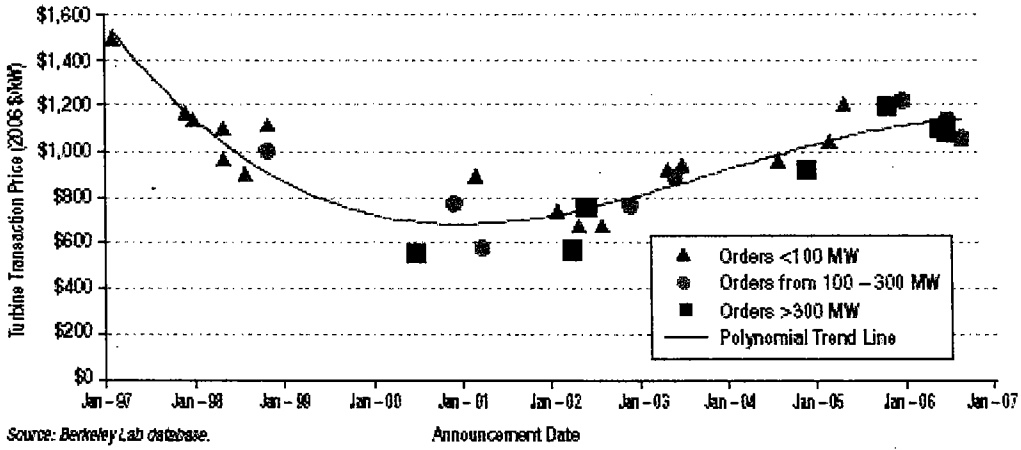
[6] The NPCC planning studies and analyses cover the following four states: Washington, Oregon, Idaho, and Montana. See "Biennial Review of the Cost of Windpower" July 13, 2006, at www.bpa.gov/Energy/N/projects/post2006conservation/doc/Windpower_Cost_Review.doc. This study provides many reasons for windpower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

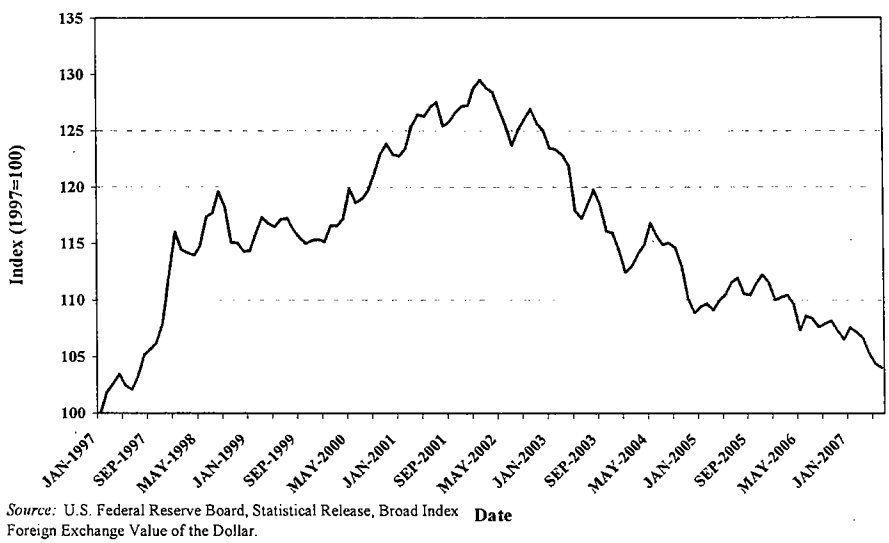
After being relatively stable for many years (and even declining in real terms), the price of various metals, including steel, copper and aluminum, has increased significantly in the last few years. These increases are primarily the result of high global demand and increased production costs (including 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

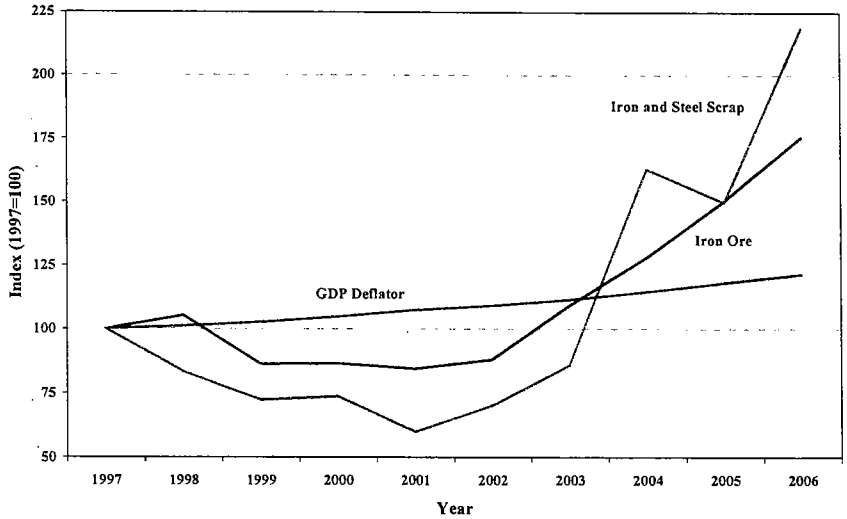
Many of the raw materials involved in utility construction projects (e.g., steel, copper, cement), as well as many major manufactured components of utility infrastructure investments, are globally traded. This means that prices in the U.S. are also affected by exchange rate fluctuations, which have been 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.

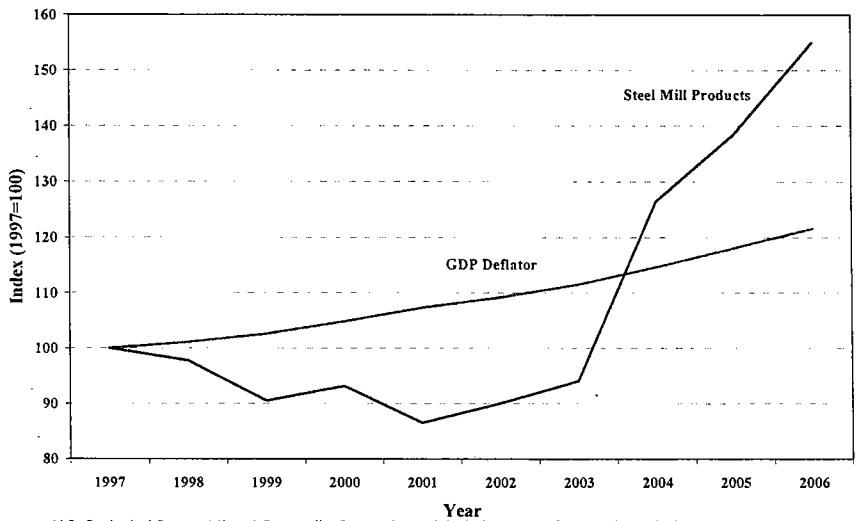
Figure 5
Inputs to Iron and Steel Production Cost Indices



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



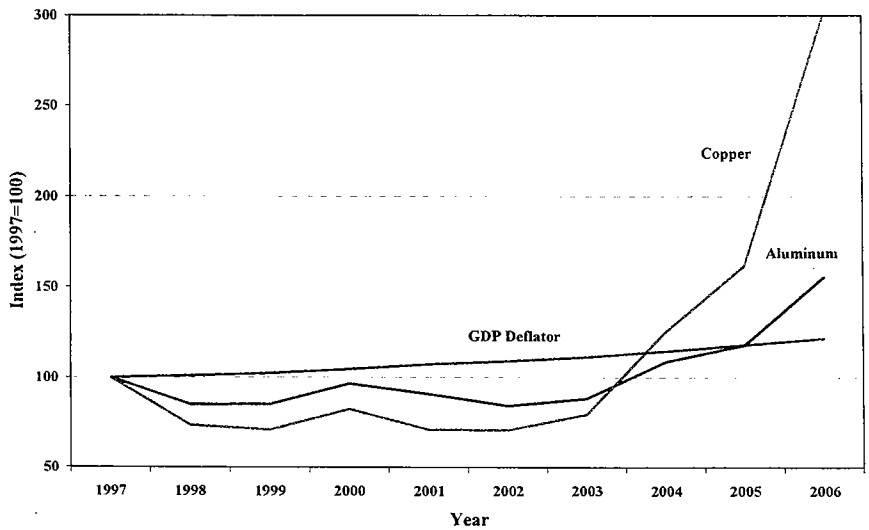
Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

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

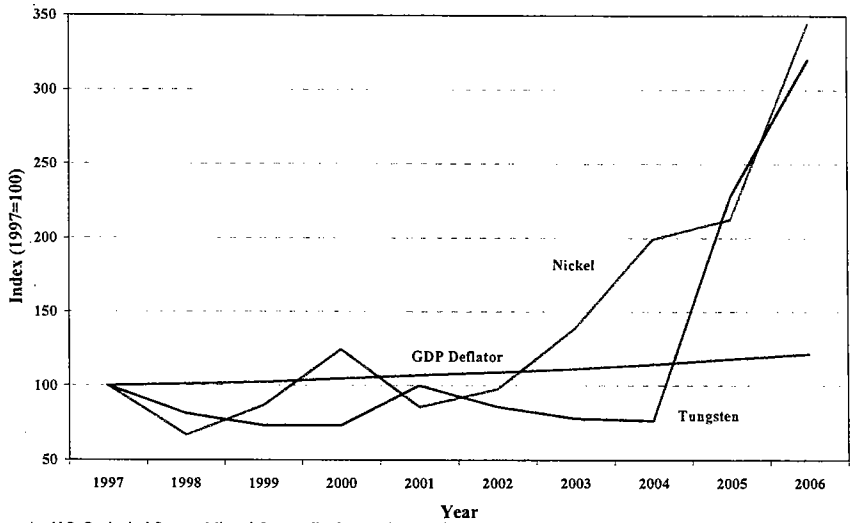


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

[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

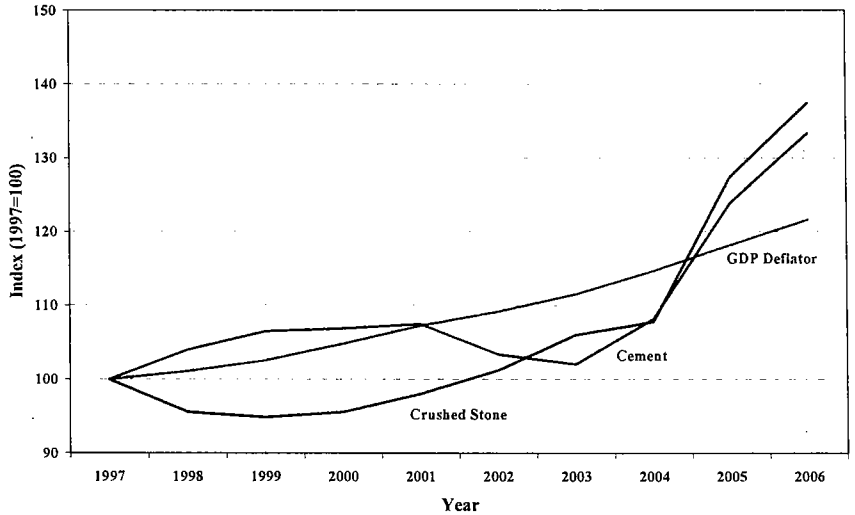


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

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



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

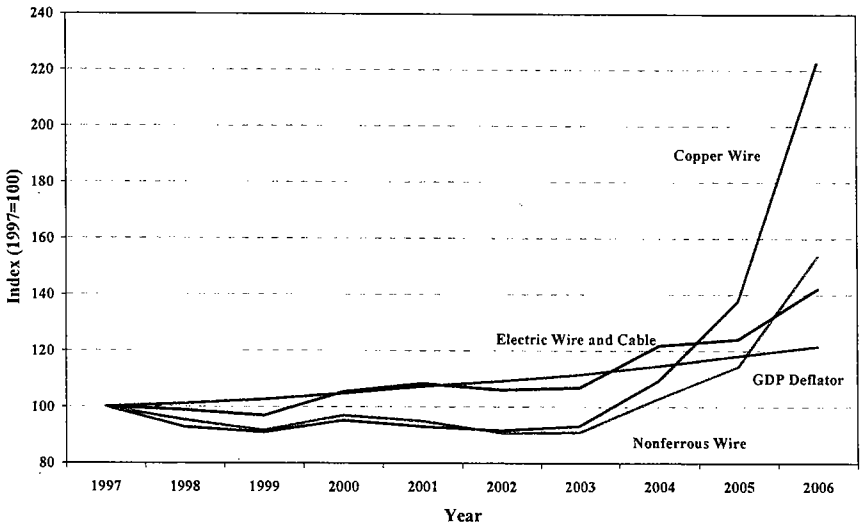
Manufactured Products for Utility Infrastructure

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.

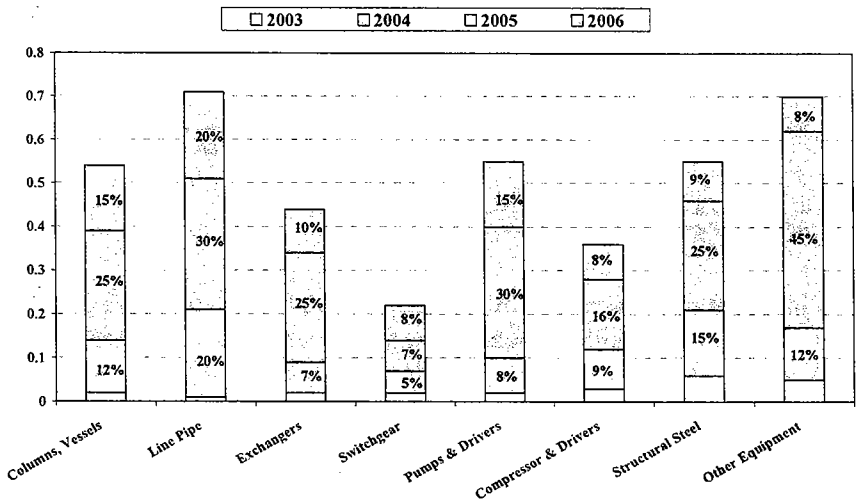
Manufactured components of generating facilities—large pressure vessels, condensers, pumps, valves—have also increased sharply since 2004. Figure 11 shows the yearly increases experienced in key component prices since 2003.

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

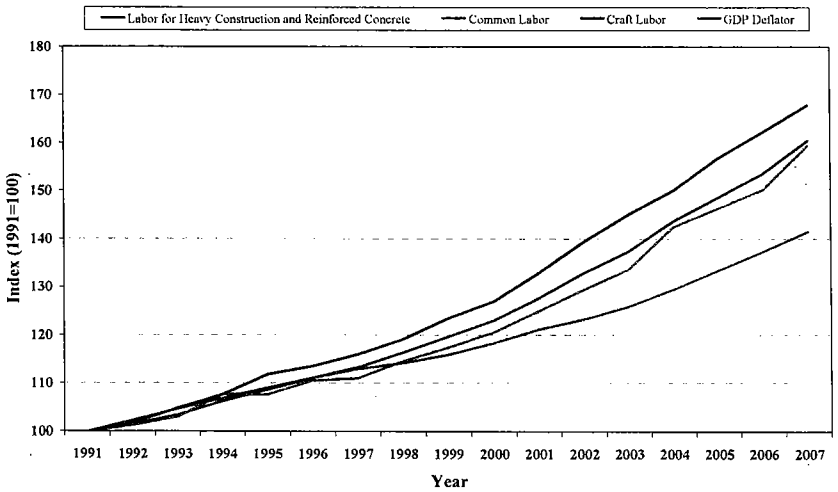


Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

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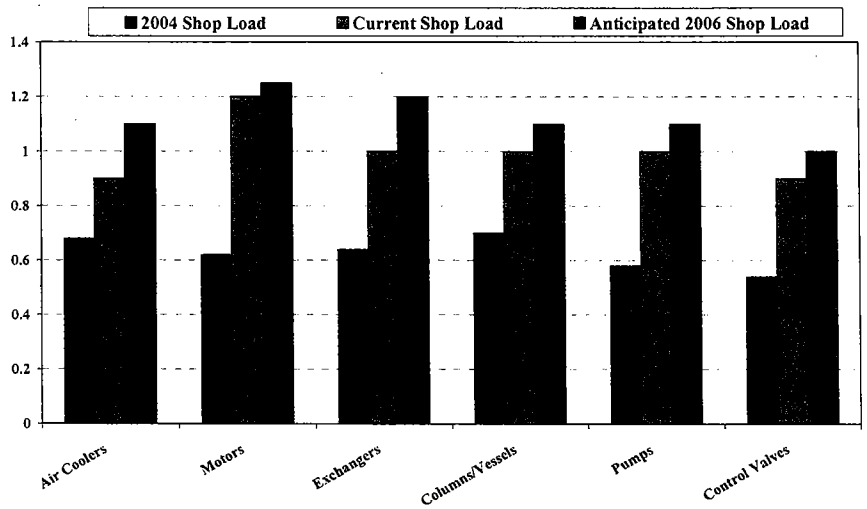
[14] *Id.*, p. 1.

[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.

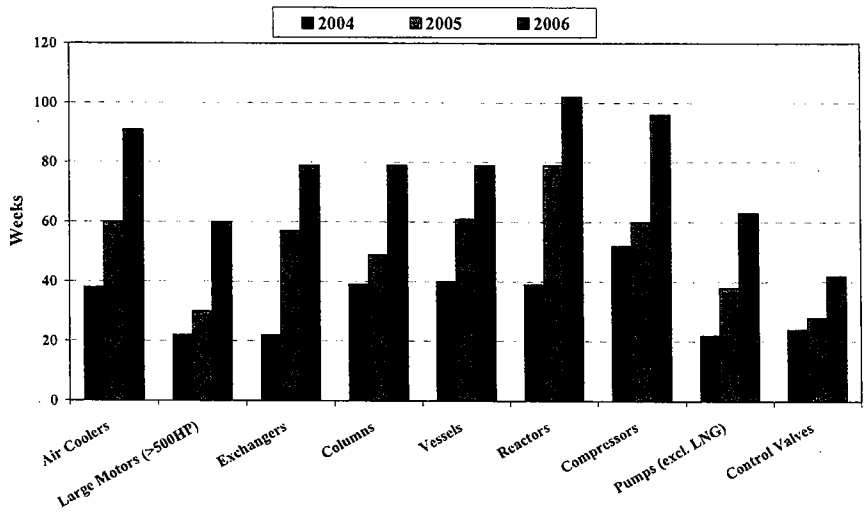
[16] *Id.*, p. 5.

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

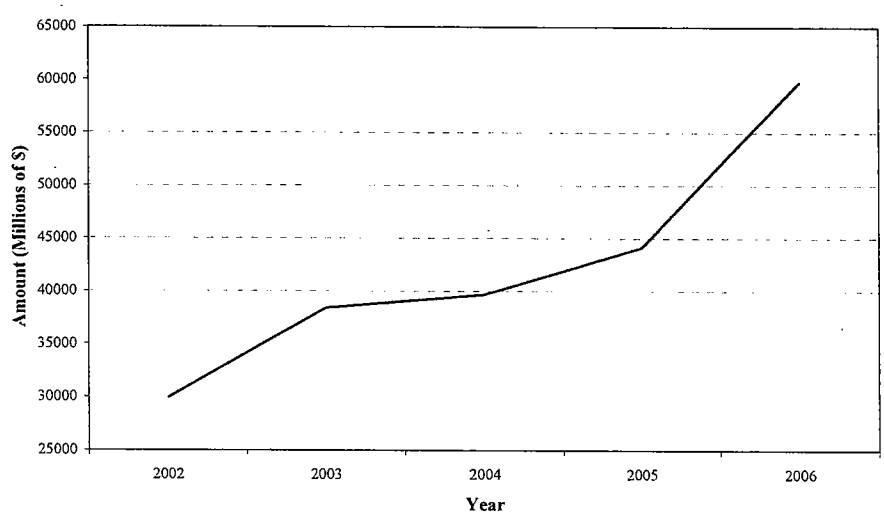


Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

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).

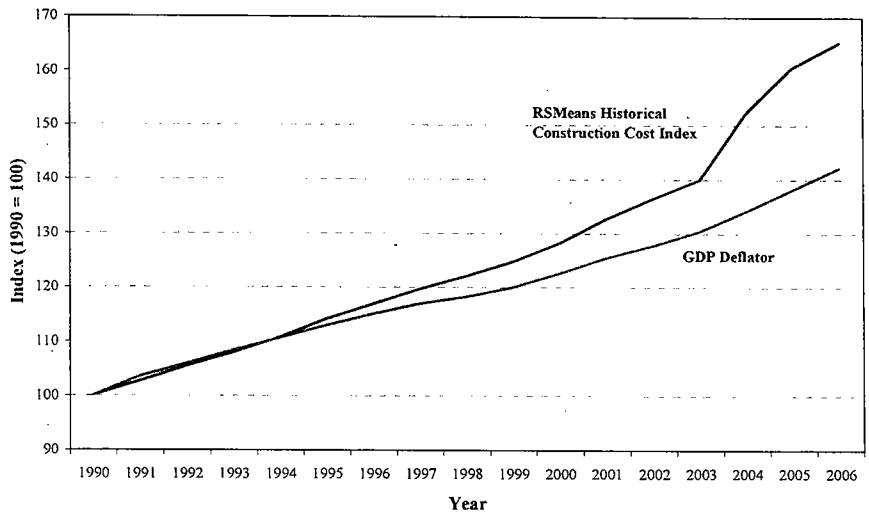
Summary Construction Cost Indices

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.

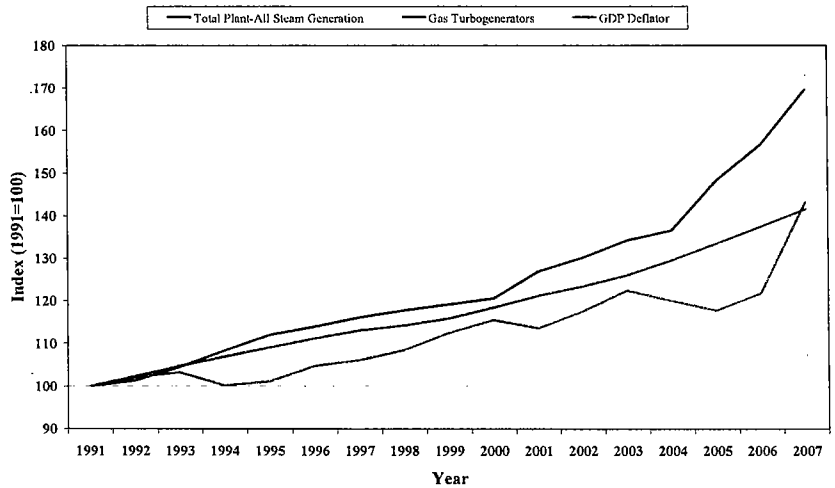
The Handy-Whitman Index© publishes detailed indices of utility construction costs for six regions, broken down by detailed component costs in many cases. Figures 17 through 19 show the evolution of several of the broad aggregate indices since 1991 compared with the general inflation index (GDP deflator).[18]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

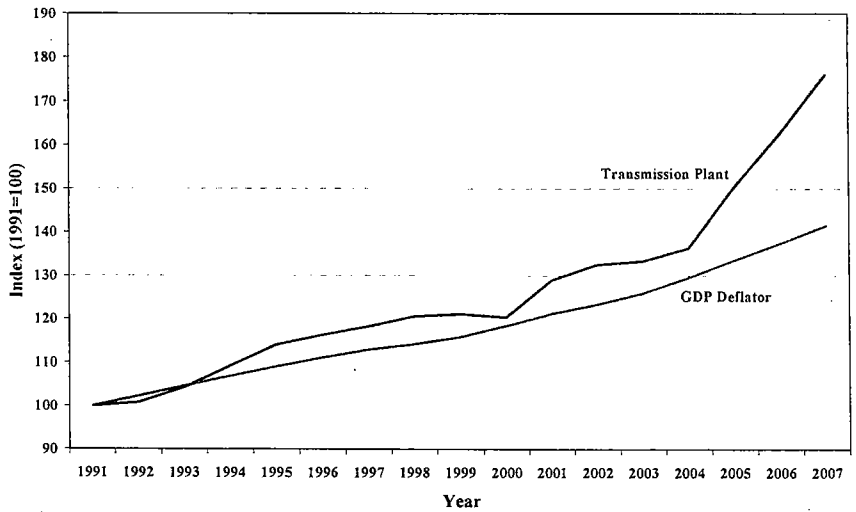
Figure 17
National Average Generation Cost Index



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.

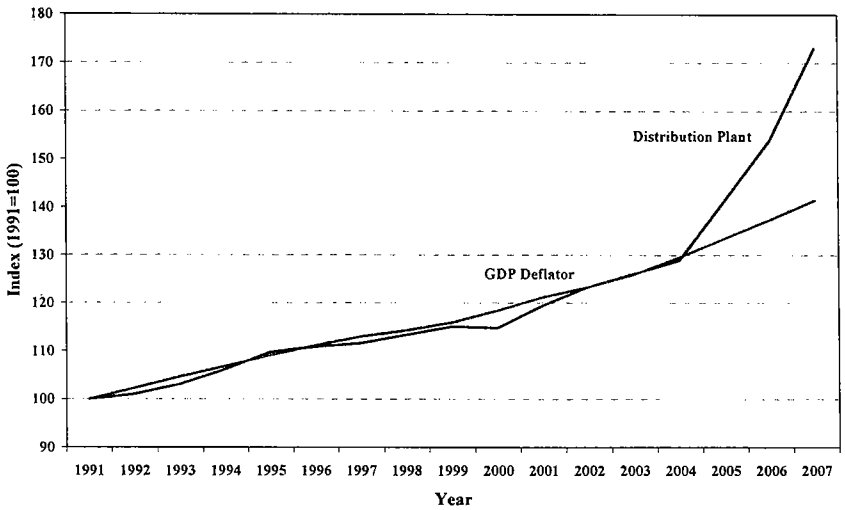
Figure 18
National Average Transmission Cost Index



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

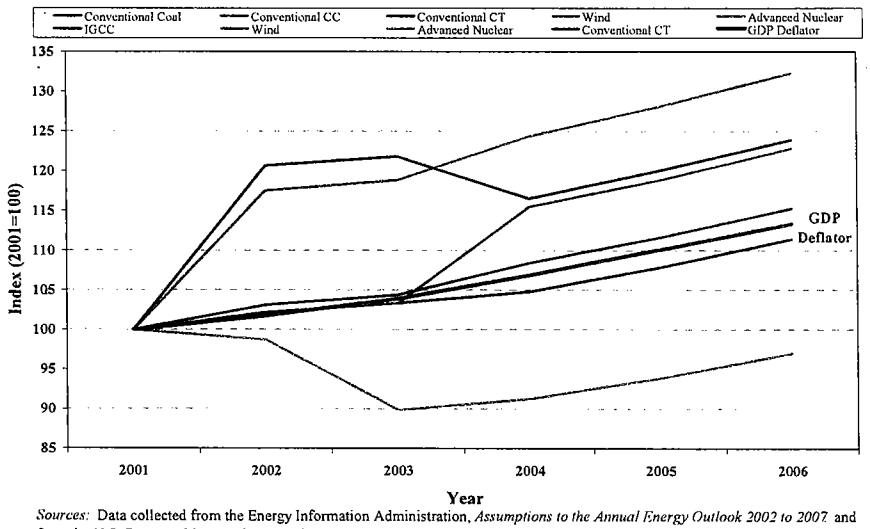
[19] EIA does incorporate regional multipliers to reflect minor variations in construction costs based on labor conditions.

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.