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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	CASE NO. AVU-E-08-01 CASE NO. AVU-G-08-01 DIRECT TESTIMONY OF DAVE B. DEFELICE

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

I. INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Dave B. DeFelice. I am employed by Avista Corporation as a Senior Business Analyst. My business address is 1411 East Mission, Spokane, Washington.

Q. Please briefly describe your education background and professional experience.

A. I graduated from Eastern Washington University in June of 1983 with a Bachelor of Arts Degree in Business Administration majoring in Accounting. I have served in various positions within the Company, including Analyst positions in the Finance Department (Rates section and Plant Accounting) and in Marketing/Operations Departments, as well. In 1999, I accepted the Senior Business Analyst position that focuses on economic analysis of various project proposals as well as evaluations and recommendations pertaining to business policies and practices.

Q. As a Senior Business Analyst, what are your responsibilities?

A. As a Senior Business Analyst I am involved in activities ranging from financial analysis of numerous projects with various departments such as Engineering, Operations, Marketing/Sales and Finance. Also, a portion of my job tasks involve advisory and informal training of employees pertaining to regulatory finance and ratemaking concepts.

Q. What is the scope of your testimony?

A. My testimony and exhibits in this proceeding will cover the Company's proposed regulatory treatment of capital investments in utility plant through 2008.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit No. 11, Schedule 1 ("Rising Utility Construction Costs: Sources and Impacts" study from The Brattle Group), Schedule 2 (Capital Expenditures), and Schedule 3 (2008 Capital Additions Detail), which were prepared under my direction.

II. CAPITAL INVESTMENT RECOVERY

Q. What does the Company's request for rate relief include regarding new investment in utility plant to serve customers?

A. In this filing, we are proposing to include in retail rates the costs associated with utility plant that is in-service, and will be used to provide energy service to our customers during the 2009 pro forma rate year. This is consistent with prior ratemaking practice in the State of Idaho.

The utility plant investment that we have included in this filing represents utility plant that will be "used and useful" in providing service to customers during the approximate period that new retail rates from this filing will be in effect. The costs associated with the investment will be "known and measurable," and finally, including the costs associated with this investment in retail rates provides a proper "matching" of revenues from customers, with the costs associated with providing service to customers (including the cost of utility plant to serve customers).

In the IPUC's Order No. 29602, in Case Nos. AVU-E-04-1 and AVU-G-04-1, dated October 8, 2004, the Commission stated, at page 10, that:

> "Once a test year is selected, adjustments are made to test year accounts and rate base to reflect known and measurable changes so that test year totals accurately reflect anticipated amounts for the future period when rates will be in effect. The Idaho Supreme Court has described "rate base" as "the utility's capital investment amount." *Industrial Customers of Idaho Power v. Idaho PUC* 134 Idaho 285, 291, 1 P.3d 786, 792 (2000). Adjustments to test year accounts generally fall into three categories: 1) normalizing adjustments made for unusual occurrences, like one-time events or extreme weather conditions, so they do not unduly affect the test year; 2) annualizing adjustments made for events that occurred at some point in the test year to average their effect as if they had been in existence during the entire year; and 3) known and measurable adjustments made to include events that occur outside the test year but will continue in the future to affect Company income and expenses."

If utility plant investment that is being used to serve customers is not reflected in retail rates then the retail rates will not be "just, reasonable, and sufficient," i.e., it would not be just or reasonable for customers to receive the benefit provided by the utility investment without paying for it, and the retail rates would not provide revenues "sufficient" to provide recovery of the costs associated with providing service to customers.

Q. Is the Company's application of these ratemaking principles in this filing consistent with prior general rate cases?

A. Yes. In prior cases, the objective has been the same -- to include in retail rates the investment, or rate base, that is providing service to customers, and ensure that there is a proper matching of revenues and expenses during the period that rates are in effect.

Q. How does new investment in utility plant change rate base over time for ratemaking purposes?

A. Historically, the annual dollars spent by the Company on new utility plant has generally been relatively close to the level of depreciation expense, with the exception of years where the Company has invested in major new utility projects.[1] I will use an example to illustrate, in general terms, how new investment in utility plant changes rate base over time. Let's assume that the Company's rate base (adjusted net plant in service used to serve customers) at the beginning of Year 1 is $1.5 billion. Also assume that depreciation expense in Year 1 is $80 million, and the Company's new investment in utility plant in Year 1 is also $80 million. During Year 1, rate base increased by $80 million (new investment), and decreased by $80 million (depreciation), and ended up at the same level of $1.5 billion at the end of the year. In this simplified example, the Company's rate base is $1.5 billion, both at the beginning of Year 1, and at the end of Year 1. For ratemaking purposes, the $1.5 billion of rate base is representative of the level of plant investment used to serve customers, both at the beginning of the year and at the end of the year. Over time, if depreciation expense continues to be approximately equal to new plant investment, rate base would continue at a relatively constant $1.5 billion. Under these circumstances, the use of the $1.5 billion rate base amount from a prior year, i.e., a historical test year, would be adequate for setting rates for the upcoming year (pro forma rate year), because

[1] Recognizing that a portion of the costs associated with capital additions are offset by additional revenues.

there is little change in the net plant investment used to serve customers.

In a similar manner, in prior general rate cases we have used a rate base amount from a historical test year as the starting point for the pro forma rate year. If there were no major plant additions between the historical test year and the upcoming pro forma rate year, the historical test year rate base amount would be used for the pro forma rate year as being representative of the net plant used to serve customers. If there were known major plant additions that would be in service for the pro forma rate year, such as the recent addition of Coyote Springs II for Avista, the major transmission upgrades, and the hydroelectric upgrades, then rate base for the pro forma rate year is adjusted for these major investments, so that rate base for the pro forma rate year is representative of the level of investment used to serve customers.

Q. Is Avista's new investment in utility plant exceeding its annual depreciation expense, causing an increase in rate base?

A. Yes. Avista's investment in plant in 2007 and 2008, is well above the annual depreciation expense, and will result in an increase in net plant in service (rate base) that will be used to serve customers in the 2009 pro forma rate year. Much of this new investment in plant for

2007 and 2008 is spread among many different utility plant categories, as opposed to a few major plant additions. Therefore, the Company's pro forma adjustment for new investment in plant in this filing involves a more detailed analysis of the net change in rate base from the historical test period to the pro forma rate year. The end result, however, is the same in this case as in prior cases - to reflect in retail rates the level of net plant investment that is used to serve customers during the pro forma rate year, and to have a proper matching of revenues and expenses.

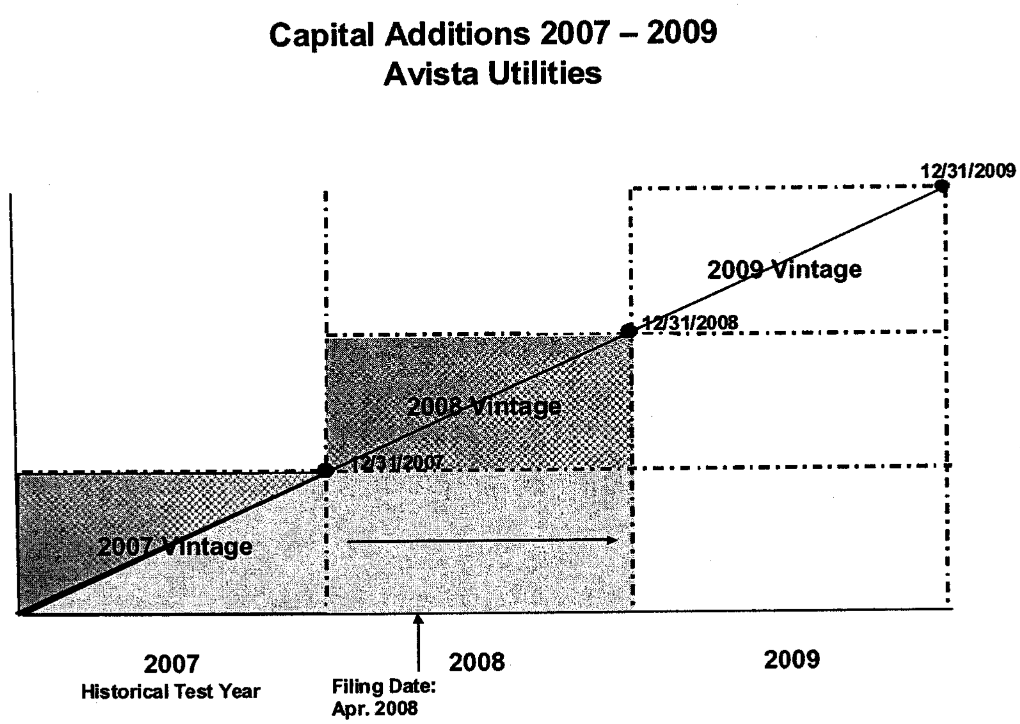
Q. How was rate base for the pro forma rate year developed for this filing?

A. As in prior rate cases, Avista started with rate base for the historical test year, which for this case is the calendar year 2007. Adjustments were made to reflect new additions and accumulated depreciation through December 2008, such that the proposed rate base reflects the net plant in service that will be used to serve customers during the 2009 pro forma rate year. Later in my testimony I will provide the details of the adjustments to rate base.

Although there is a strong case to be made that the new capital investment in 2009 will be used to serve customers during the 2009 rate year, and should be reflected in this case, the Company has only included new investment through December 2008.

The capital additions through 2008 will be in-service at the approximate time new rates become effective from this rate filing, and customers will be receiving benefits from this investment. The following chart illustrates the 2007 historical test period and the April 2008 filing of this case. The chart also illustrates that the capital additions for 2007 and 2008 will be completed and in service prior to January 1, 2009. During 2009 customers will receive the benefit from the full investment in 2007 and 2008, and it is appropriate for this investment to be reflected in the retail rates for 2009.

Illustration 1



As illustrated by the chart, if the proposed rates in this case go into effect near the end of 2008, the 2007 plant additions will be entering their <u>third year</u> of service during calendar year 2009, and the 2008 capital additions will be in their <u>second year</u> of service in 2009. Clearly the 2007 and 2008 investment will be providing service to customers, and would reflect the true cost of funding assets that are necessary, and used and useful, to provide service to customers during the year that new rates will be in effect. It would result in a mismatch of revenues and expense during 2009 if the costs associated with these investments are not reflected in new retail rates.

Q. You stated earlier that new utility investment in 2007 and 2008 will be substantially higher than the annual depreciation expense. What is driving the significant investment in new utility plant?

A. The Company is currently being required to add significant new transmission and distribution facilities, including strengthening the "back bone" of our system, due in part to customer growth in our service area, reliability requirements, and capacity upgrades. Other issues driving the need for capital investment include an aging infrastructure, physical degradation, and municipal compliance issues (i.e., street/highway relocations), etc.

While the overall economy is slowing on a national basis, Kootenai County is still growing. In 2007, employment growth in Kootenai County ranked in the top 5% of all metropolitan areas.

In addition, the cost of raw materials, including concrete, steel, copper, aluminum and other materials, have sky-rocketed in recent years, causing the cost of these new facilities to be significantly higher than in the past. Because the cost of adding new facilities is significantly higher than the existing facilities, the investment in new facilities will be significantly higher than the annual depreciation expense on the existing facilities.

Q. What is causing the substantial increase in raw materials for Avista, and the utility industry in general?

A. In September 2007, The Edison Foundation commissioned a study from The Brattle Group titled, "Rising Utility Construction Costs: Sources and Impacts," which identified cost trends specifically related to the utility industry pertaining to critical materials and equipment, as well as labor support services used for building capital infrastructure. This study is attached as Exhibit No. 11, Schedule 1. The study identifies the reasons for drastic cost increases in critical raw materials, such as global competition and an aging domestic utility infrastructure as well as the need for additional infrastructure to accommodate growth in the near future.

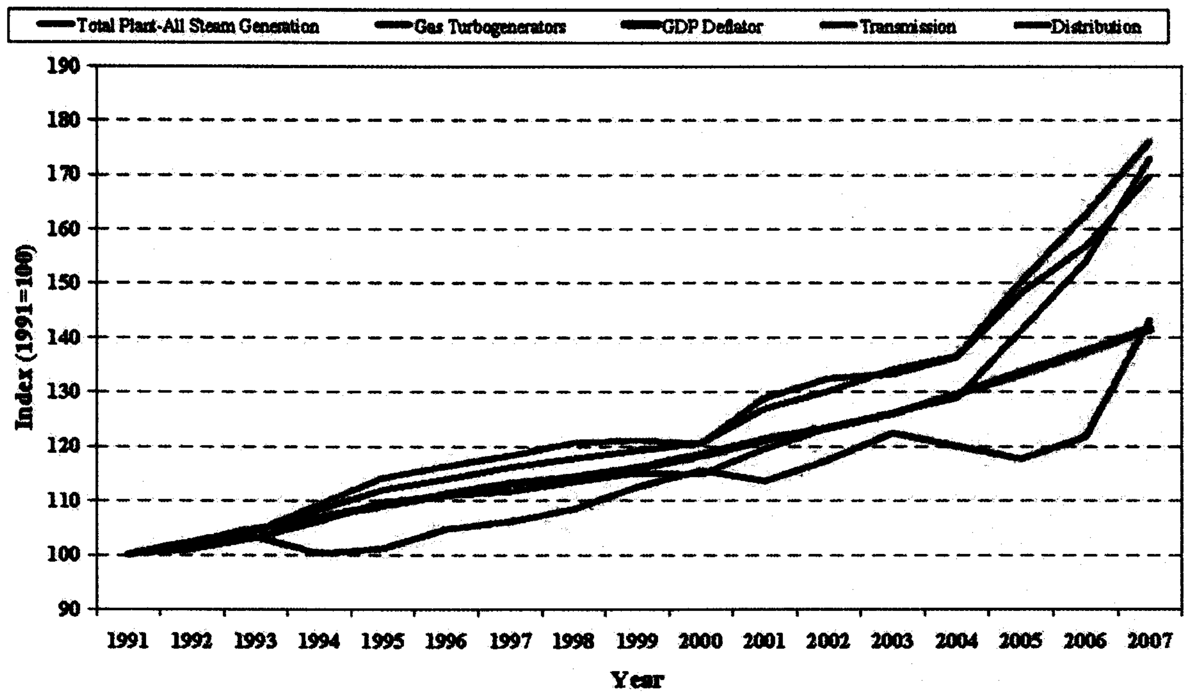
Q. What are some of the key cost drivers that are cited in the study?

A. The study, at page 16, cites four major cost drivers, "(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." The study goes on to compare cost trends for various raw materials, critical equipment and labor services relative to the general inflation rate (GDP deflator). In addition, a cost trend is summarized by three key utility functional plant categories, including generation, transmission, and distribution plant. The study concludes that these inflation impacts have been outside the utility industry's control and there are no immediate indications of cost relief in the near future.

Illustration 2 below depicts what has occurred to infrastructure costs nationally. From the chart, it is apparent that starting in 2003, costs of distribution, transmission and generation infrastructure increased at a far more significant rate than the overall economy, as measured by the GDP deflator.

<u>**Illustration 2**</u>

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. "Rising Utility Construction Costs: Sources and Impacts" Prepared by The Brattle Group for The Edison Foundation, September 2007

Q. Is there specific evidence that Avista is experiencing cost escalations similar to that indicated in the study?

A. Yes. A sample was compiled of some materials and equipment that Avista routinely uses in order to support various infrastructure construction efforts that are part of the Company's annual capital requirements of purchases made from 2003 through 2008. The sample of materials was grouped into categories for typical electric and gas distribution capital projects as well as major electric substation projects. The cost summary indicated that the cost of the materials reviewed has risen sharply in most categories from 2003 to 2008. For the distribution group of materials, the average annual escalation impact from 2003 through 2007 is approximately 37%, which is equal to a cumulative increase over the four-year period of 178%. The escalation for the substation group of materials and equipment has been approximately 12% per year for the purchases Avista has made from 2003 to 2008, or a cumulative increase of 55%.

Q. What is the historical and projected level of annual capital spending for Avista?

A. Avista's capital requirements have steadily increased from approximately $100 million to $200 million over the last several years. Exhibit No. 11, Schedule 2 reflects this trend that Avista has experienced and what is planned for in the near future. This clearly shows that the amount of capital projects is well in excess of revenue-supported capital expenditures to connect new customers, and beyond the level of revenues that is being collected from customers related to existing plant. The difference between the total capital requirements, less the new revenue related capital, and allowed revenues represent a significant discrepancy that is negatively impacting the Company.

Q. What is the likelihood that Avista's capital investment will continue at this level?

A. There are many factors that will influence capital expenditures going forward. One factor is the cost of raw materials is expected to continue to inflate over time and the fact that there is more demand for capital projects for such things as compliance work with municipal highway and road projects, sewer projects, etc. Also, as critical systems age, there will be more utility plant that will be reaching the end of physical life and, in some cases, plant may be replaced prior to the end of its physical life based on power efficiency improvements that can be recognized.

III. DESCRIPTION OF CAPITAL PROJECTS

Q. For the 2008 capital projects pro formed in this filing, please provide a description of the projects.

A. Exhibit No. 11, Schedule 3 details the capital projects that will be transferred to plant in service in 2008 and included in this filing. A short description of these projects follows:

Generation:

Thermal - Colstrip Capital Additions - $3,424,000
There will be a planned outage on Unit #4 so the Company can install NOX (pollution control equipment) to be in compliance with state and federal mandates. Further, there will be a replacement of a cooling tower.

Thermal - Kettle Falls Capital Projects - $1,131,000
The primary project at the Kettle Falls Generating Station is the re-roofing of the power house. Other smaller projects include: replacement of wood screw conveyors which feeds wood into the hopper, replacement of electronic recip. controllers, and replacement of the 4160 protective relays.

Thermal - Other Small Projects - $130,000
Please refer to the workpapers of Mr. DeFelice for detailed listing of projects.

Hydro - Cabinet Gorge Bypass Tunnel Project - $5,353,000
Feasibility study pertaining to the Company's FERC mandated license obligation regarding gas super-saturation issues within the Clark Fork River License Agreement for the Cabinet Gorge Dam. This study will be completed in August 2008. Company witness Mr. Vermillion discusses this study further in his testimony.

Hydro - Clark Fork Implement PME Agreement - $2,243,000
Over twenty projects are planned for 2008 as part of the protection, mitigation and enhancement (PME) plan. These projects were agreed to as part of the settlement agreement and FERC license received in 2001.

Hydro - Noxon Capital Projects - $1,628,000
Projects include finishing the replacement of the stator frame, stator core, and stator windings on unit #5. Further, after spring runoff, the #1 turbine will be upgraded, including a complete mechanical overhaul, upgraded high efficiency turbine, stator core and stator winding.

Hydro - Other Small Projects - $1,461,000
The primary other small project involves the replacement of the duct bank that runs from the Post Street Substation to the Upper Falls Generating Facility. Further, the 80 year old cables which have had two recent failures will be replaced. Please refer to the workpapers of Mr. DeFelice for detailed listing of projects.

Coyote Springs 2 (CS2) Joint Share Projects - $2,200,000
The primary Joint Share project is the hot gas path overhaul. This includes the replacement of the 1st stage rotating and stationary blades and 1st stage nozzles. This work is part of the long term service agreement with General Electric.

Coyote Springs 2 (CS2) Capital Projects - $1,400,000
The primary project is the replacement of duct burners on the heat recovery steam generator, which will result in more generation output from the turbine.

Other Small Projects - $807,000
The control system at the Northeast Combustion Turbine will be upgraded for standby reserve. Further, the failed Mark 5 controller and low voltage bus duct between the step transformer and the generator breaker will be replaced, as they failed in 2007.

Electric Transmission:

West Plains Transmission Reinforcement Project - $1,993,000
This item includes constructing 4.7 miles of 115 kV transmission lines from the Airway Heights substation to the existing South Fairchild tap west of Spokane. The line is required to reduce thermal loading on area transmission lines and is the first phase of a multi-phase project.

Power Transformer - Transmission - $1,595,000
The primary project in this category is the purchase and installation of a new 230/115 kV auto-transformer at the Benewah Substation. The existing auto-transformer has reached its end of life.

Spokane/Coeur d'Alene 115 kW Line Relay Upgrades - $1,247,000
Improvements to the Spokane-Coeur d'Alene area 115 kV line protection schemes are required in order to improve system reliability. This project includes the installation of high speed communications between area substations and the replacement of protective relays for improved fault clearing.

Nez Perce 115 kV Sub-Inst Capacitor Bank - $751,000
This project involves the installation of a 15 MVAR capacitor bank at the Nez Perce substation and the installation of a 15 MVAR capacitor bank at the Grangeville substation. These capacitor banks are needed to provide area voltage support during peak load conditions.

Beacon 230 Bus Convert to DB-DB - $750,000
This project will add a sectionalizing breaker at the Beacon 230 kV substation to meet national reliability compliance standards. Currently there is a 230 kV bus tie breaker, which could be a single point of failure for the entire substation.

Lolo 230 - Rebuild 230 kV Yard - $737,000
As a result of the 5-Year Transmission Upgrade Project, fault duties at the Lolo substation have increased. The substation is being rebuilt to meet Company operating standards.

Transmission Air Switch Ground Mat - $697,000
This safety project involves the installation of above ground switch platforms to all 115 kV line air switches. The platforms will allow company personnel to operate switches safely.

Other Small Projects - $4,316,000
Please refer to the workpapers of Mr. DeFelice for detailed listing of projects.

Electric Distribution:

Electric Distribution Minor Blanket Projects - $5,800,000
Replace crossarms and poles on distribution lines as required, due to storm damage, fires, or obsolescence.

Wood Pole Mgmt Capital - $4,923,000
The distribution wood-pole management program is the strength evaluation of a certain percentage of the pole population each year. Depending on the test results for a given pole, that pole is either considered satisfactory, reinforced with a steel stub, or replaced.

Electric Underground Replacement - $3,000,000
Replace high and low voltage underground cable as required.

T&D Line Replacement - $2,250,000
Relocation of transmission and distribution lines as required.

Power Transformer - Distribution - $1,755,000
Installation of distribution power transformers as required.

Failed Electric Plant - $1,750,000
Installation of distribution plant for failed plant as required.

Distribution Reliability and Energy Efficiency Program (DREEP) - $1,500,000
This new process at Avista analyzes many aspects of the distribution system, including distribution feeder lengths, optimum amperage levels, phase balancing, conservation voltage reduction, etc., in order to evaluate how the system can be made more efficient.

Plummer - Increase Capacity/Rebuild - $1,425,000
This project is required to replace the existing deteriorated wood substation, and increase transformer capacity to meet system demand during all operating conditions.

C & W Kendall Project - $3,050,000
This project involves the relocation and replacement of transmission and distribution facilities for the Kendall Yards project in Downtown Spokane from the Post Street substation to the College and Walnut substation.

Indian Trail 115-13kV Sub-Construct New Sub - $2,275,000
This project involves the construction of a new 115-13 kV substation in the Indian Trail area to meet capacity demands in northwestern Spokane. This will be a 20 MVA, 2 feeder (13 kV) substation.

Critchfield 115 Sub-Construct - $1,614,000
This project involves the construction of a new South Clarkston 115-13 kV substation (20 MVA transformer and 2 feeders) to reduce loading on other area transformers, which are reaching full capacity.

Spokane Electric Network Incr Capacity - $1,445,000
These projects are associated with the Downtown Spokane electric network. The projects involve the installation of vaults, cables, network transformers and protectors as required to serve new network customers, and to maintain service to existing customers by replacing overloaded and deteriorated equipment.

WSDOT Highway Franchise Consolidation - $800,000
In order to operate our electric system within State highway rights of way, the Company needs to establish new Franchises. Existing franchises have expired and Avista must seek new agreements with the State or risk penalties or non-approval by the State.

Other Small Projects - $4,737,000
Please refer to the workpapers of Mr. DeFelice for detailed listing of projects.

General:

Computer/Network Hardware/Software - $9,225,000
Projects for replacement of obsolete technology according to Avista's refresh cycles that are generally driven by hardware/software manufacturer and industry trends. Further investment includes hardware and software investments that address capacity and performance constraints due to technology consumption and growth. Finally, the Company will have technology investments that support business initiatives generally relating to back-office automation, reliability/safety/compliance for electric and gas infrastructure, and systems that service the Customer.

HVAC Renovation Project - $4,990,000
The heating, ventilating, and air conditioning systems throughout the Spokane Central Operating Facilities are approximately fifty years old and are in need of replacement. The project involves replacing central air handling units and distribution systems in three buildings - the Spokane Service Center, the general office building, and the cafeteria auditorium building. The building envelope of the general office building will also be renovated with high efficiency glass and insulation. New controls will also be installed which will enable energy conservation.

Backup Control Center - $1,911,000
This project involves creating a redundant control center to meet NERC reliability standard for transmission and operations groups.

Tools Lab and Shop Equipment - $1,200,000
This request is for general replacement and additions required for capital projects.

Structures and Improvements - $1,174,000
This is a group of capital maintenance projects that Facilities Management coordinates at the Spokane Central Operating Facilities and Avista branch facilities - offices and service centers. For 2008, some of the projects include; paving employee parking at Coeur d'Alene, constructing a vehicle storage building at Pullman Service Center, remodel the Spokane Meter Shop, new carpet on General Office 4th floor, remodel of the Cafeteria/Auditorium building, and multiple small capital maintenance projects across Avista's service territory.

Other Small Projects - $4,205,000
These projects include communication and security initiatives, radio equipment, SCADA controls, telephone systems, office and other general facility upgrades.

Transportation:

Transportation Equipment - $5,985,000
Capital additions in transportation include the purchase of new fleet vehicles and heavy equipment for on-road and off-road applications.

Gas Distribution:

Gas Non-Revenue Blanket - $2,297,000
This annual project will replace sections of existing gas piping that require replacement to improve the operation of the gas system but are not directly linked to new revenue. The project includes relocation of main related to overbuilds, improvement in equipment and/or technology to improve system operation and/or maintenance, replacement of obsolete facilities, replacement of main to improve cathodic performance, and projects to improve public safety and/or improve system reliability.

Gas Replacement Street and Highways - $2,060,000
This annual project will replace sections of existing gas piping that require replacement due to relocation or improvement of streets or highways in areas where gas piping is installed. Avista installs many of its facilities in public right-of-way under established franchise agreements. Avista is required under the franchise agreements, in most cases, to relocate its facilities when they are in conflict with road or highway improvements.

Replace Deteriorated Pipe - $1,339,000
This annual project will replace sections of existing gas piping that is suspect for failure or has deteriorated within the gas system. This project will address the replacement of sections of gas main that no longer operate with reliability and/or safety. Sections of the gas system require replacement due to many factors including material failures, environmental impact, increase leak frequency, or coating problems. This project will identify and replace sections of main to improve public safety and system reliability.

Reinforce Gate Station Post Falls, ID - $1,500,000
This project will build a larger Gate Station at the existing Post Fall, ID Tap. New metering, regulation, and a line heater will be installed. Due to system growth, demand for gas in the Post Falls area has exceeded the capacity of the current Gate Station. The existing facilities are inadequate during high system demand. Rebuilding the gate station will insure continued reliable operation of the gate station facilities.

East Medford /Roseburg /Sutherlin HP Reinforcement Projects - $10,020,000
These Oregon gas distribution projects are not included in this filng.

Kettle Falls Relocation/Gate - $1,300,000
This multi-phased project will install a new gate station on the west side of Spokane to serve the existing HP distribution and future replacement pipe that is part of the Kettle Falls HP main. The existing Kettle Falls Gate Station and high pressure (HP) Kettle Falls main has experienced significant encroachment due to growth in the north Spokane area. Sections of the main will be relocated to ensure continued safe reliable operation of the pipe system. The new gate station will improve the safety and reliability of operating the high pressure main and improve the gate station delivery capacity into the Kettle Falls HP system. Future phases of this project will re-route sections of the existing HP Kettle Falls main to improve system capacity and public safety.

Qualchan Reinforcement - $1,200,000
This project will reinforce the southeast Spokane area west of Hwy 195 by looping the existing distribution system. The southeast Spokane distribution system experiences low pressures during high system demand in the winter. The area fails the gas planning model for a design day. Growth in the area has reduced Avista's ability to reliably serve gas from its existing distribution system during a design day. This project will improve delivery pressure and position the system for future growth.

Other Small Projects - $4,981,000
Please refer to the workpapers of Mr. DeFelice for detailed listing of projects.

Jackson Prairie Storage:

Jackson Prairie Storage Project - $18,056,000
Avista and its partners started an expansion project at Jackson Prairie for deliverability that will be in service in the Fall of 2008. Mr. Vermillion describes this project in his testimony in this case.

IV. ADJUSTMENT METHODOLOGY

Q. What was the general approach to computing the pro forma adjustments for investment in capital projects?

A. The Company chose to track the 2007 and 2008 capital investments separately to simplify the computation and to make it easier to follow. For each vintage, capital additions, depreciation and DFIT were computed to derive rate base at December 31, 2007 and December 31, 2008 and to compute operating expenses in the pro forma rate year.

Q. What reports or data were used in the computation?

A. The Company maintains results of operations reports that are prepared for each service and jurisdiction on an average of monthly averages (AMA) basis and on an end of period (EOP) basis that were used in this computation. Actual 2007 plant additions were used from the plant accounting system to determine the month of addition and the amount of additions that were for revenue producing projects. Capital additions for 2008 (described above) were based on specific capital requirements for 2008. Capital additions for 2008 that were for revenue producing projects were separated out and excluded. The Company did not include any 2009 capital additions in this filing.

Q. Are the computations for all services and jurisdictions the same?

A. Yes, they are. Because of this, only the Idaho electric data will be used below to describe the methodology for computing the adjustments. The adjustments for Idaho gas were computed in a similar manner.

Q. Please explain in detail the computation of the adjustment as it relates to rate base.

A. There are three steps to determine the rate base adjustment at December 31, 2007 and December 31, 2008, as follows:

Step 1 - Adjust AMA 2007 to EOP December 31, 2007
(Pro Forma Capital Additions 2007 Adjustment)

The first step was to determine an adjusted December 31, 2007 EOP net plant balance that includes only the AMA revenue producing capital. The Company's December 31, 2007 EOP results of operations reports was the starting point.

The gross plant at December 31, 2007 at EOP includes all revenue producing capital added in 2007. It is necessary to remove only the average of monthly averages of those additions, since 2007 test year includes AMA customers and revenue (this is explained further below). To accomplish this, all revenue producing capital additions were deducted from the EOP balance and then the AMA additions were added back. The EOP gross plant at December 31, 2007 was computed as follows:

	($000's)
EOP Gross Plant at 12/31/07 per Results of Operations	$912,978
Less: EOP 2007 Revenue Producing Capital Additions	($9,637)
Add: AMA 2007 Revenue Producing Capital Additions	$4,138
EOP Adjusted Gross Plant at 12/31/07	$907,479

The pro forma capital additions 2007 adjustment in Company witness Ms. Andrews' testimony at Exhibit No. 13, Schedule 1, page 8, for gross plant of $27,983,000 was computed by subtracting the AMA gross plant balance used in the filing of $879,496,000 from the calculated EOP adjusted gross plant balance of $907,479,000. Additional details regarding these adjustments are provided in Ms. Andrews' workpapers.

This same process was used for both accumulated depreciation and deferred income taxes, to arrive at EOP adjusted amount at December 31, 2007 for the 2007 vintage plant assets. The pro forma capital additions adjustment for accumulated depreciation of $8,449,000 was computed by subtracting the AMA accumulated depreciation balance used in the filing of $300,320,000 from the calculated EOP adjusted accumulated depreciation balance of $308,769,000. The pro forma capital additions adjustment for DFIT of ($1,758,000) was computed by subtracting the AMA DFIT balance used in the filing of ($80,527,000) from the calculated EOP adjusted DFIT balance of ($82,285,000).

Step 2 - Adjust 2007 Vintage Plant to EOP December 31, 2008 (Pro Forma Capital Additions 2008 Adjustment - Part A)

The second step was to determine rate base at December 31, 2008 for the 2007 vintage plant assets. Only accumulated depreciation and deferred taxes are impacted. Depreciation expense of $24,241,000 was computed on gross plant at December 31, 2007, adjusted for projected 2008 retirements, using the average effective depreciation rates by functional plant group. Depreciation expense of $269,000 on the 2007 revenue producing capital additions was removed, for a net increase to accumulated depreciation of $23,972,000. The deferred tax impact on the 2007 vintage plant assets, adjusted for the revenue producing capital additions, was ($3,726,000). These changes to rate base at December 31, 2008 are added to the 2008 vintage plant additions (discussed below) to derive the pro formal capital additions adjustment for 2008, detailed in Ms. Andrews' testimony at Exhibit No. 13, Schedule 1, page 8. Additional details regarding these adjustments are provided in Ms. Andrews' workpapers.

Step 3 - Add 2008 Vintage Plant to EOP December 31, 2008 (Pro Forma Capital Additions 2008 Adjustment - Part B)

The capital additions for 2008 were summarized by functional plant categories and either directly assigned or allocated to the services and jurisdictions based on standard Company practices. The amount of revenue producing capital additions in 2008 by service and jurisdiction was excluded. The additions were further summarized by the month they are expected to be transferred to plant in service. Using the average effective depreciation rates by functional plant group, AMA depreciation expense was computed in order to include the partial year convention of depreciation that will actually be recorded in 2008.

For the Idaho electric service, plant additions were $29,475,000, depreciation expense was $542,000 and DFIT was ($519,000). These 2008 costs are added to the 2007 vintage plant 2008 costs (discussed above) to derive the pro forma capital additions adjustment to rate base for 2008.

A summary of the pro forma capital additions 2008 adjustment follows:

($000's)	Part A 2007 Vintage Plant	Part B 2008 Vintage Plant	Total Adjustment to Rate Base
Plant in Service	$0	$29,475	$29,475
Accumulated Depreciation	$23,972	$542	$24,514
DFIT	($3,726)	($519)	($4,245)

Q. What other impact does the 2007 and 2008 capital additions have on this case in addition to the rate base impact?

A. Depreciation expense and property taxes have been computed for the 2007 and 2008 plant vintages for the pro forma rate year.

The pro forma capital additions 2007 pre-tax depreciation adjustment of $185,000 is computed as follows:

	($000's)
Estimated full-year of depreciation expense in 2009 on the 2007 vintage plant balance at December 31, 2008	$24,082
Less: Depreciation expense on 2007 revenue producing capital additions	($268)
Total Depreciation Expense	$23,814
2007 test year depreciation expense, adjusted for the depreciation true-up adjustment.	$23,627
State Taxes	$2
Pro forma Capital Additions 2007 Adjustment – Depreciation Expense	$185

The pro forma capital additions 2008 pre-tax depreciation and property tax adjustment of $1,563,000 is computed as follows:

	($000's)
Estimated full-year of depreciation expense in 2009 on the 2008 vintage plant balance at December 31, 2008, net of revenue producing capital additions	$1,144
Estimated full-year of property taxes in 2009 on the 2008 vintage plant balance at December 31, 2008, net of revenue producing capital additions	$435
State Taxes	$16
Pro Forma Capital Additions 2008 Adjustment - Depreciation and Property Tax Expense	$1,563

V. OTHER CONSIDERATIONS

Q. Did the Company consider the impact of 2009 capital additions?

A. Yes, it did. A similar process was used by the Company to compute the adjustment that would be necessary to include the AMA capital additions for 2009, and to adjust both the 2007 and 2008 vintage plant to June 30, 2009 (which represents an AMA 2009 net rate base balance for all plant through 2009.) Although there is a case to be made that the AMA 2009 level of net rate base will be used and useful and providing service to customers (i.e. customers will be receiving benefit from the investment) and therefore should be reflected in this case, the Company has opted to only include the net effect of adjusting net rate base to a pro forma December 31, 2008 level.

Q. What is the rationale behind the removal of capital expenditures for connecting new customers?

A. The pro forma capital expenditures for 2008 that the Company included in this filing excludes distribution related capital expenditures made that are associated with connecting new customers to the Company's system. The Company recognizes the fact that new customers provide incremental revenue that helps offset the revenue requirements of the distribution related capital additions that the Company incurs to provide service to those customers. These adjustments completely eliminated the AMA 2007 and EOP 2008 capital activity related to new customer connections in order to avoid an unintended mismatch of revenues exceeding the cost to serve customers.

Q. In addition to excluding new customer related capital additions, does the Company address the 2009/2007 revenue difference in other ways?

A. Yes. The production property adjustment (discussed in Company witness Ms. Knox's testimony) addresses the production and transmission related retail revenue that would be produced by the change in retail load expected in 2009 compared to the 2007 normalized test year. All production and transmission rate base and operating expenses, including those from these capital additions adjustments, are reduced in order to reflect the amount needed to be recovered from 2007 sales volumes.

VI. CONCLUSION

Q. What is the impact of the pro forma adjustment?

A. The proposed adjustment will result in a closer matching of revenues to cost of service to customers at the time new rates go into effect at the conclusion of this general rate proceeding. Without the proposed adjustment, the Company would not have the opportunity to earn its allowed rate of return on investment during the rate year.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-08-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-08-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 11
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	DAVE B. DEFELICE
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

Rising Utility Construction Costs:

Sources and Impacts

Prepared by:

Marc W. Chupka
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The Brattle Group

Prepared for:

The EDISON FOUNDATION

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SEPTEMBER 2007

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.

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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.

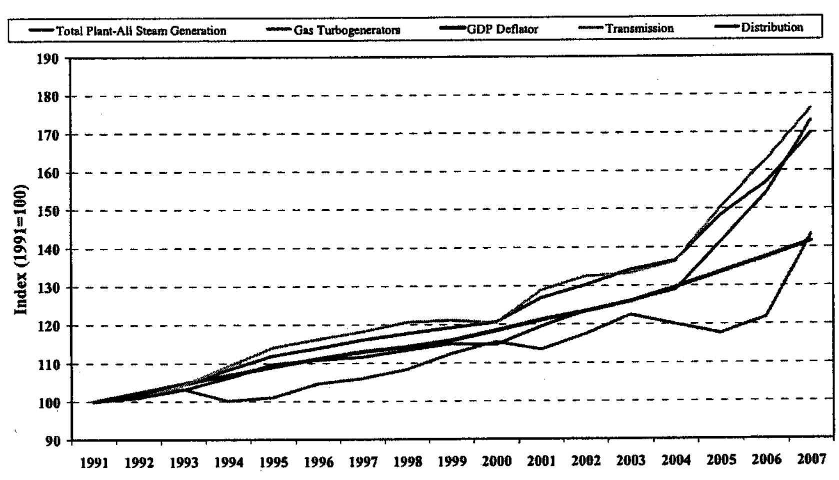
The purpose of this study is to a) document recent increases in the construction cost of utility infrastructure (generation, transmission, and distribution), b) identify the underlying causes of these increases, and c) explain how these increased costs will translate into higher rates that consumers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

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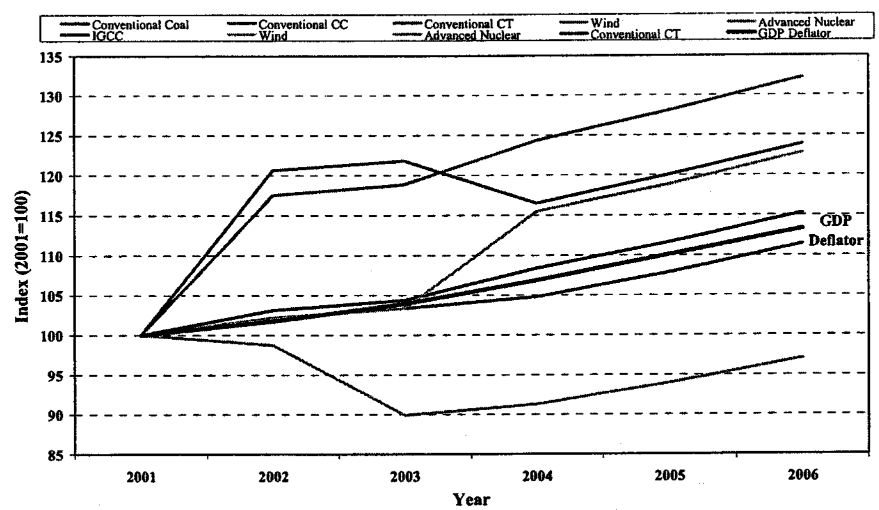
- The rapid increases experienced in utility construction costs have raised the price of recently completed infrastructure projects, but the impact has been mitigated somewhat to the extent that construction or materials acquisition preceded the most recent price increases. The impact of rising costs 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

---

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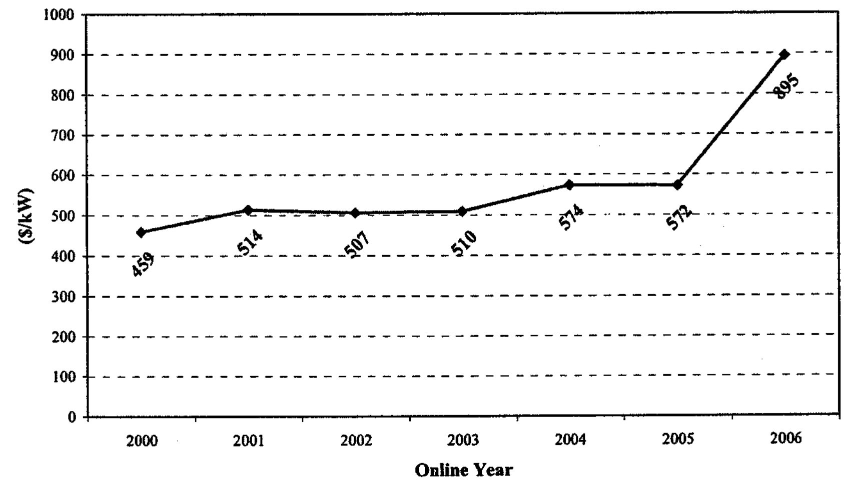
[4] To be precise, we used a "dummy" variable to represent each year in the analysis. The year-specific dummy variables were statistically significant and uniformly positive; *i.e.*, they had an upward impact on installation cost.

[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.

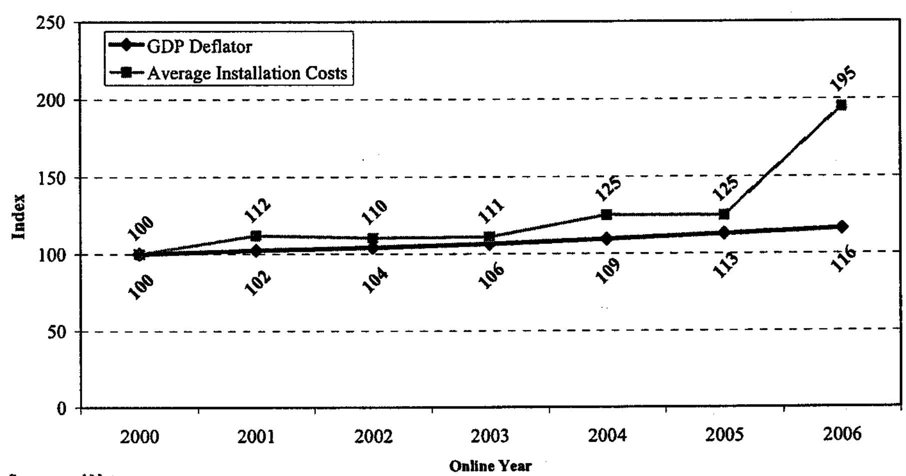
Figure 1
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year ($/kW)



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.

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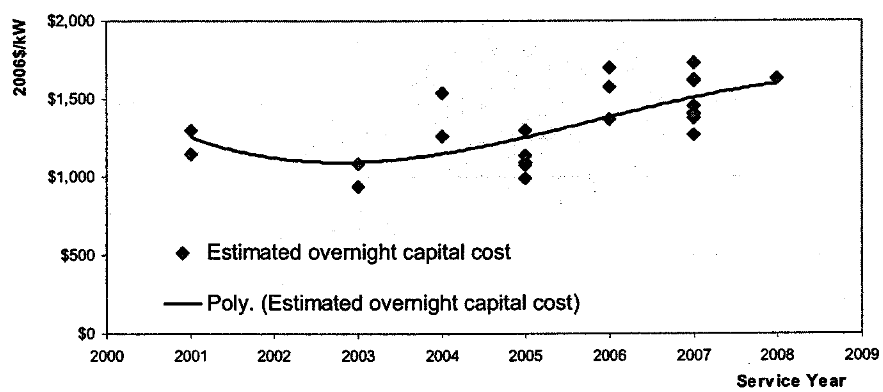
Another major class of generation development during this decade has been wind generation, the costs of which have also increased in recent years. The Northwest Power and Conservation Council (NPCC), a regional planning council that prepares long-term electric resource plans for the Pacific Northwest, 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



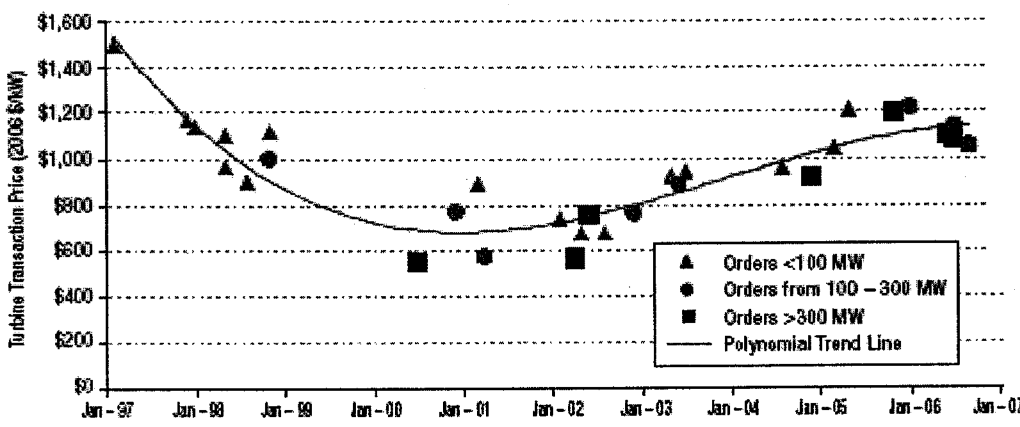
Source: The Northwest Power and Conservation Council, "Biennial Review of the Cost of Windpower" July 13, 2006.

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.

[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



Source: Berkeley Lab database.

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.

[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

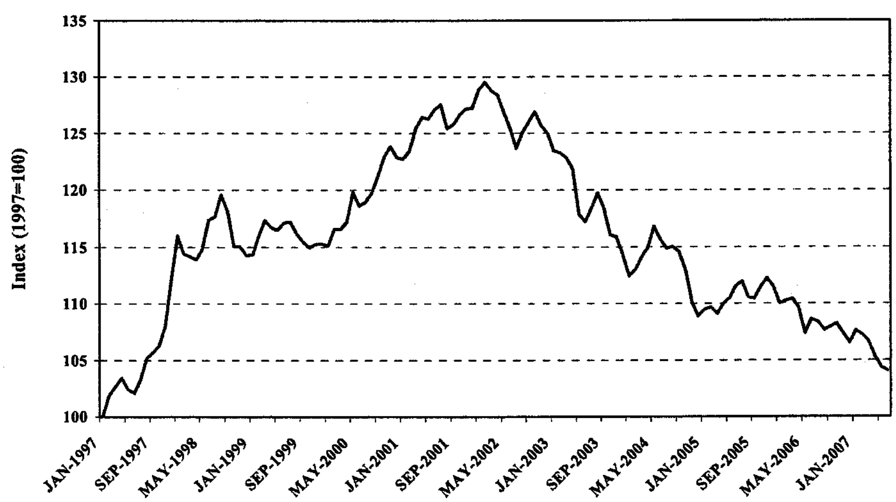
After being relatively stable for many years (and even declining in real terms), the price of various metals, including steel, copper and aluminum, has increased significantly in the last few years. These increases are primarily the result of high global demand and increased production costs (including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

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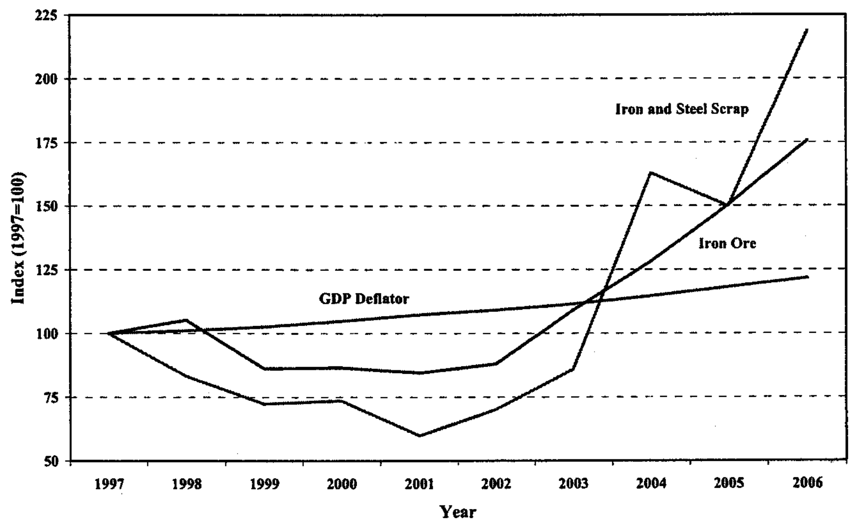
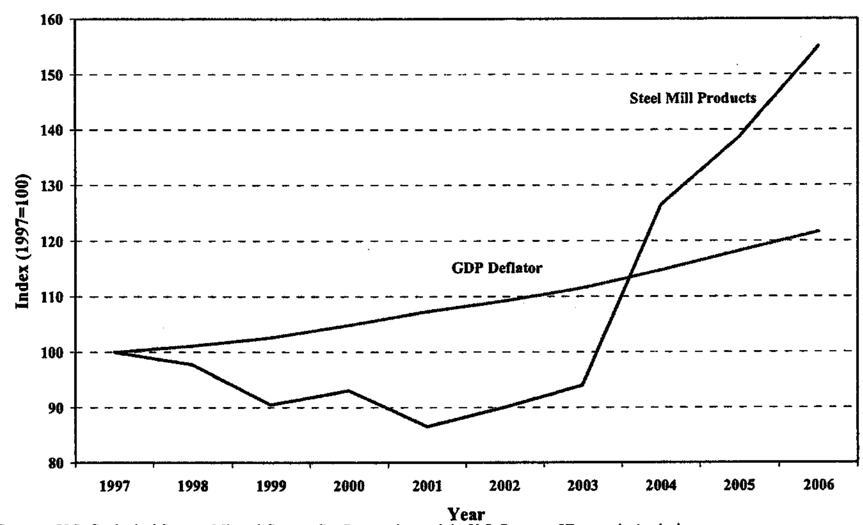
Figure 5
Inputs to Iron and Steel Production Cost Indices



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



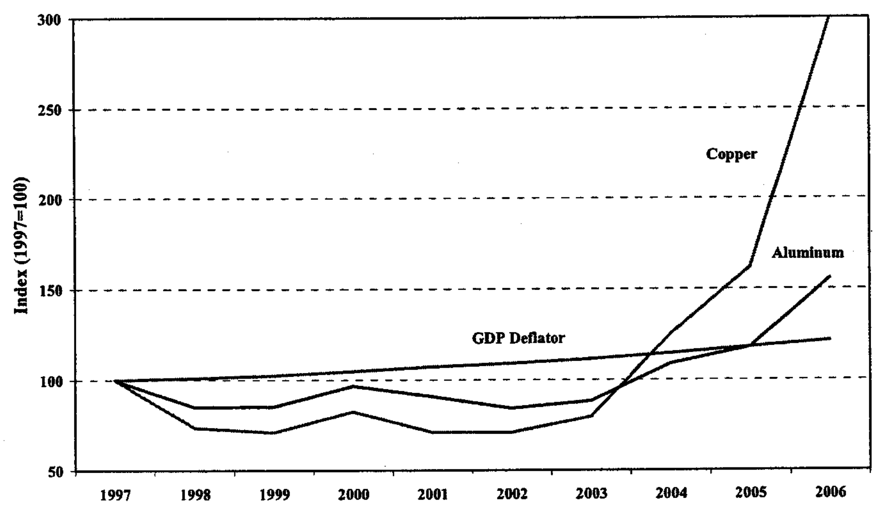
Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

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.

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

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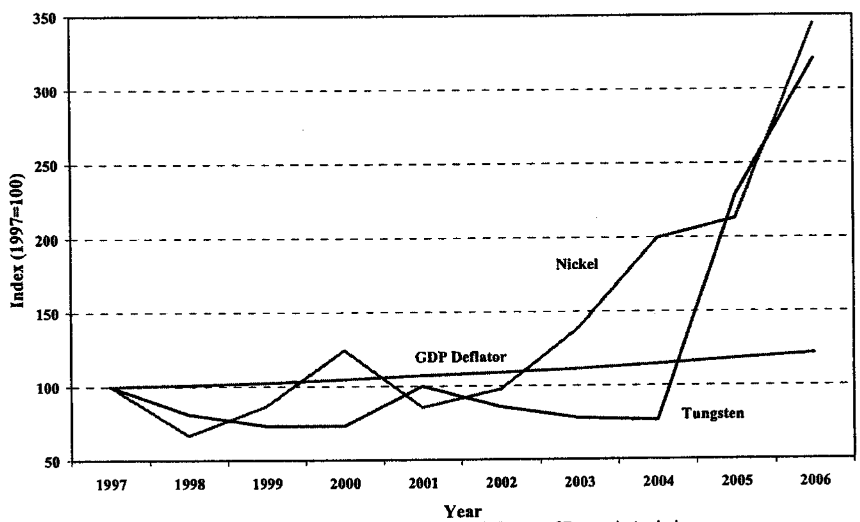
These price increases were also evident in metals that contribute to important steel alloys used broadly in electrical infrastructure, such as nickel and tungsten. The prices of these display similar patterns, as shown in Figure 8.

Figure 8
Nickel and Tungsten Price Indices

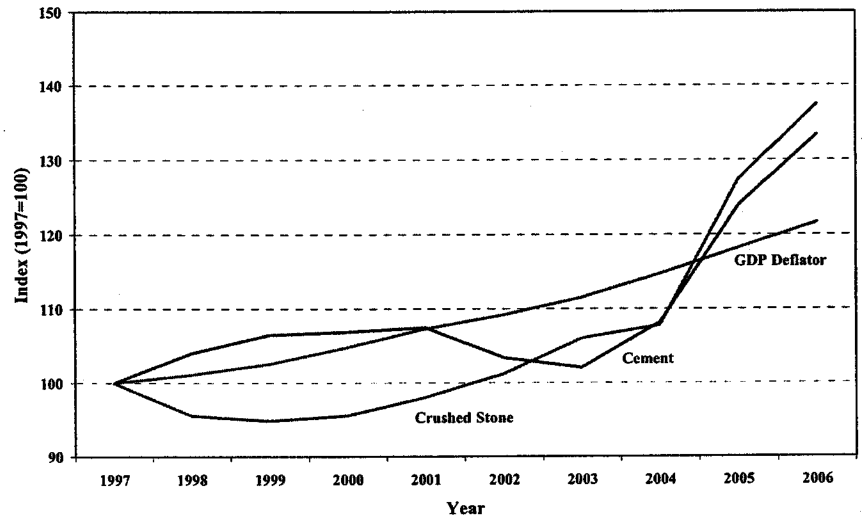


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

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.

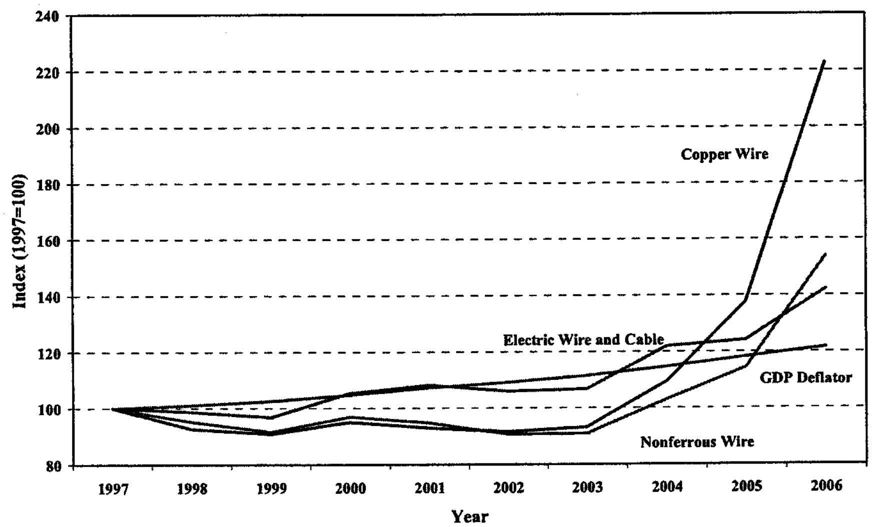
Manufactured Products for Utility Infrastructure

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.

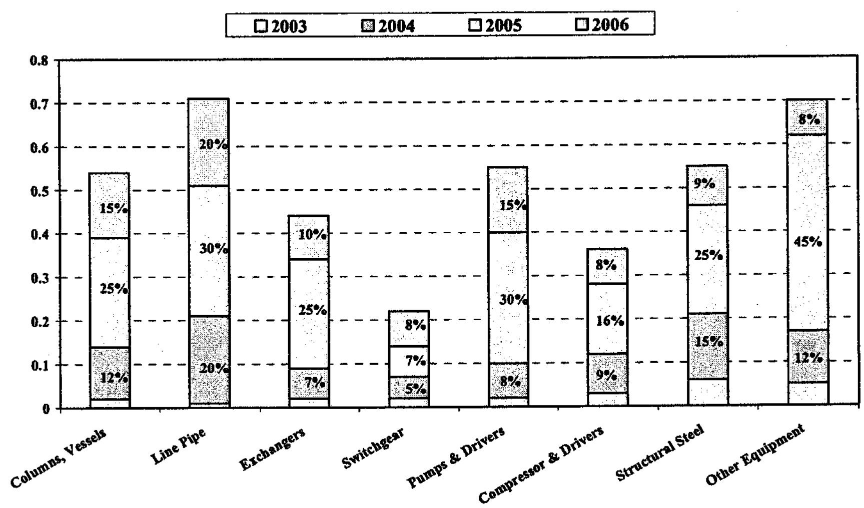
Manufactured components of generating facilities—large pressure vessels, condensers, pumps, valves—have also increased sharply since 2004. Figure 11 shows the yearly increases experienced in key component prices since 2003.

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.

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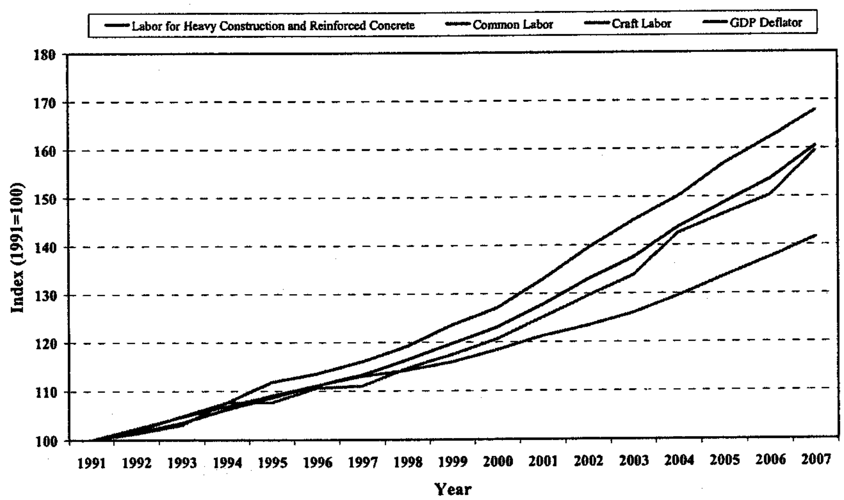
Labor Costs

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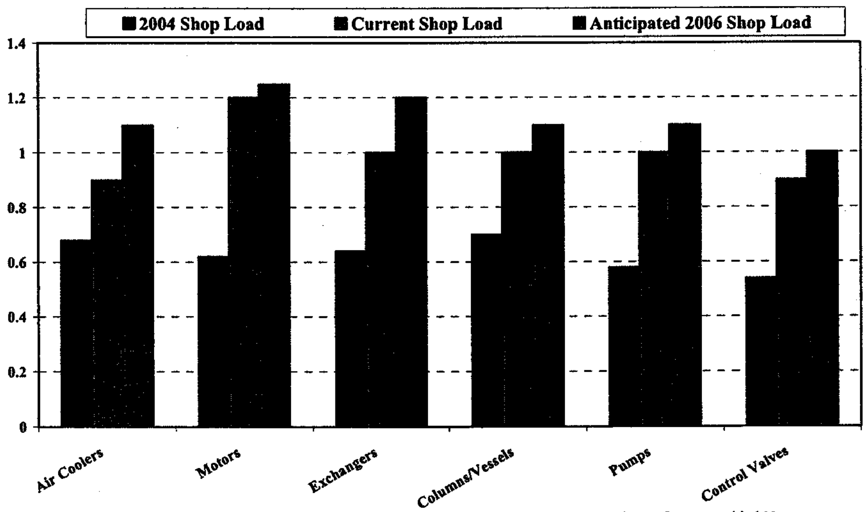
[14] *Id.*, p. 1.

[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.

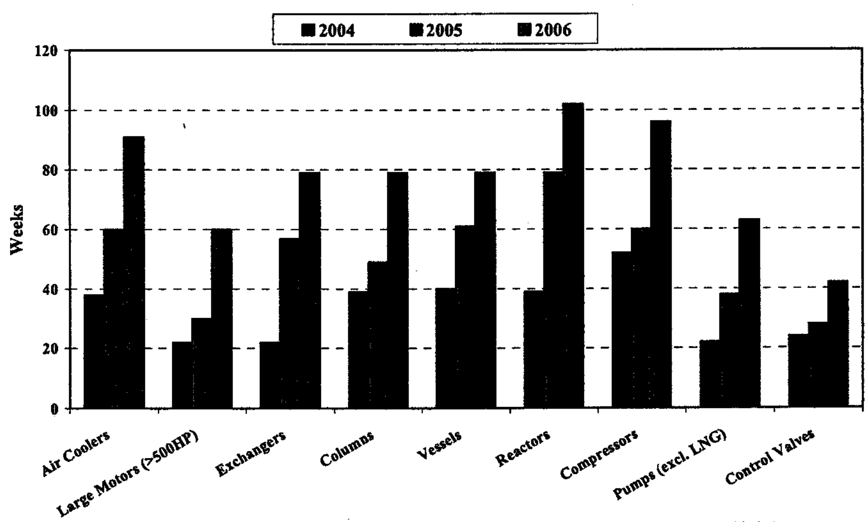
[16] *Id.*, p. 5.

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.

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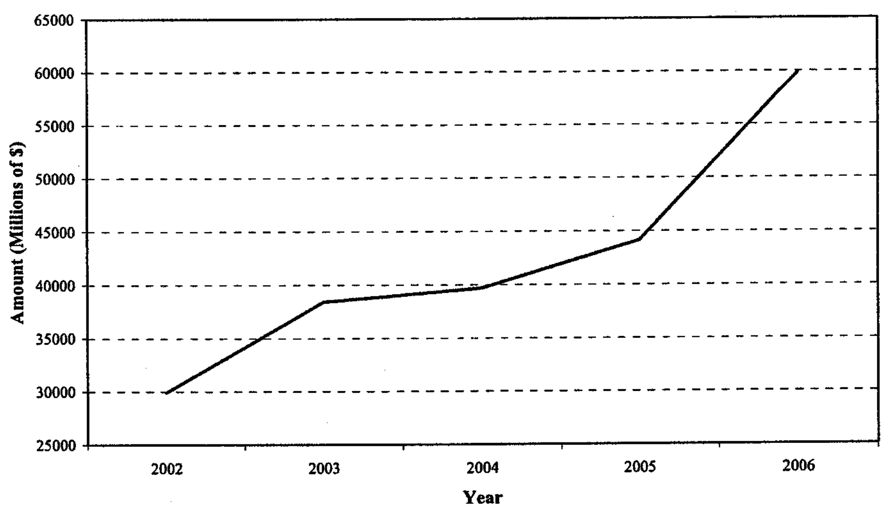
Engineering, Procurement and Construction (EPC) Market Conditions

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).

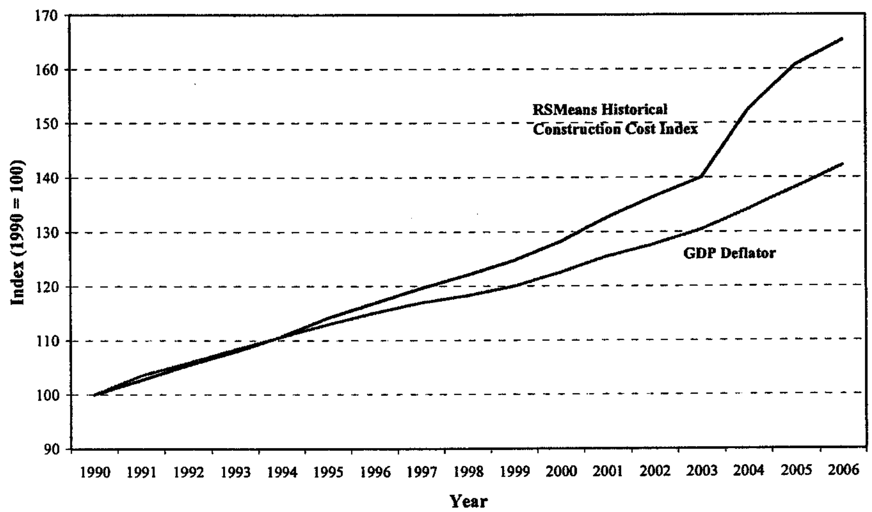
Summary Construction Cost Indices

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.

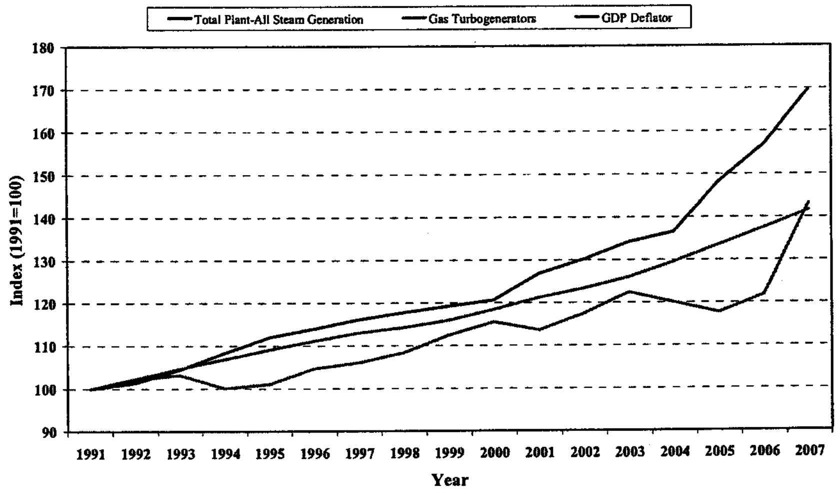
The Handy-Whitman Index© publishes detailed indices of utility construction costs for six regions, broken down by detailed component costs in many cases. Figures 17 through 19 show the evolution of several of the broad aggregate indices since 1991 compared with the general inflation index (GDP deflator).[18]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

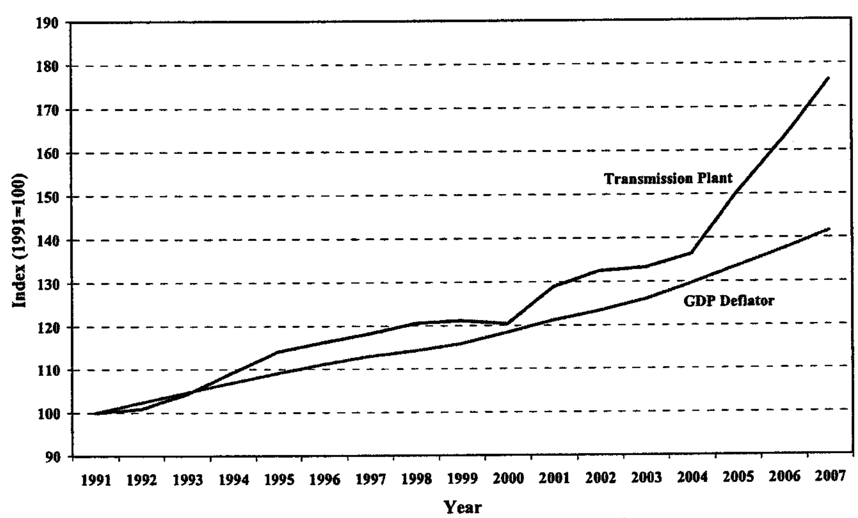
Figure 17
National Average Generation Cost Index



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.

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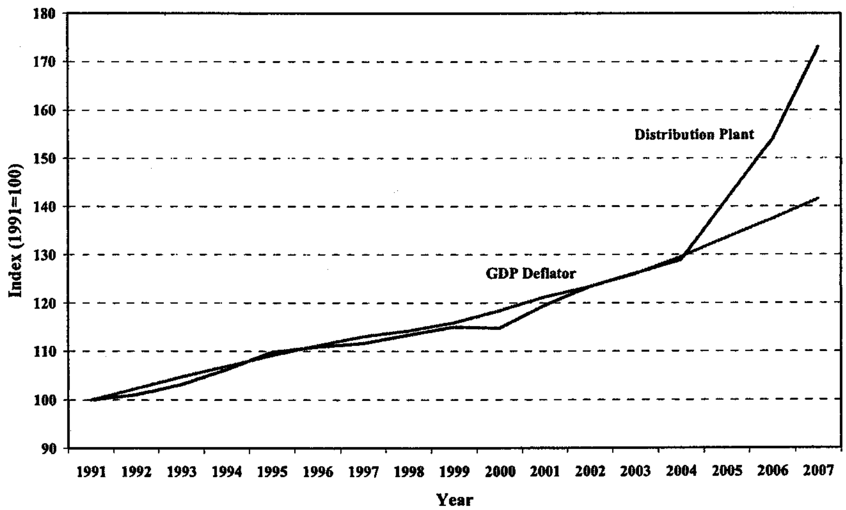
Figure 19 shows distribution plant costs, which include poles, conductors, conduit, transformers and meters. Overall distribution plant costs tracked the general inflation rate very closely between 1991 and 2003. However, it then increased 34 percent between January 2004 and January 2007, a rate that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

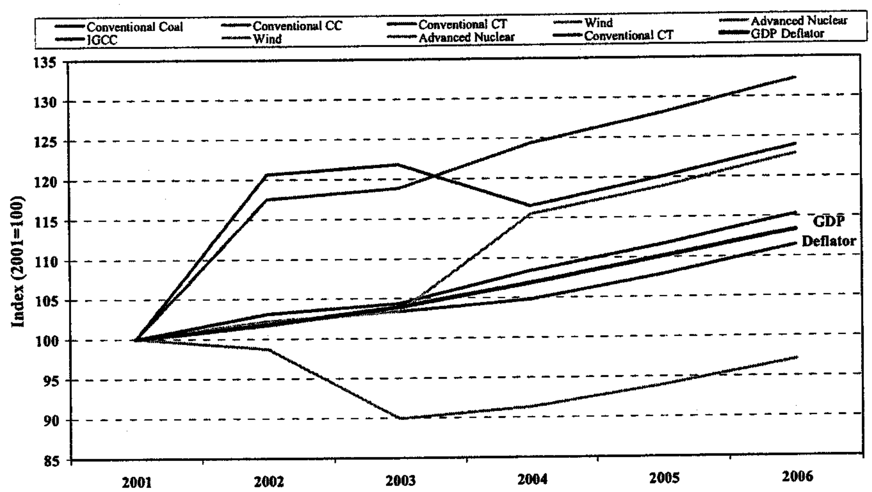
[19] EIA does incorporate regional multipliers to reflect minor variations in construction costs based on labor conditions.

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.

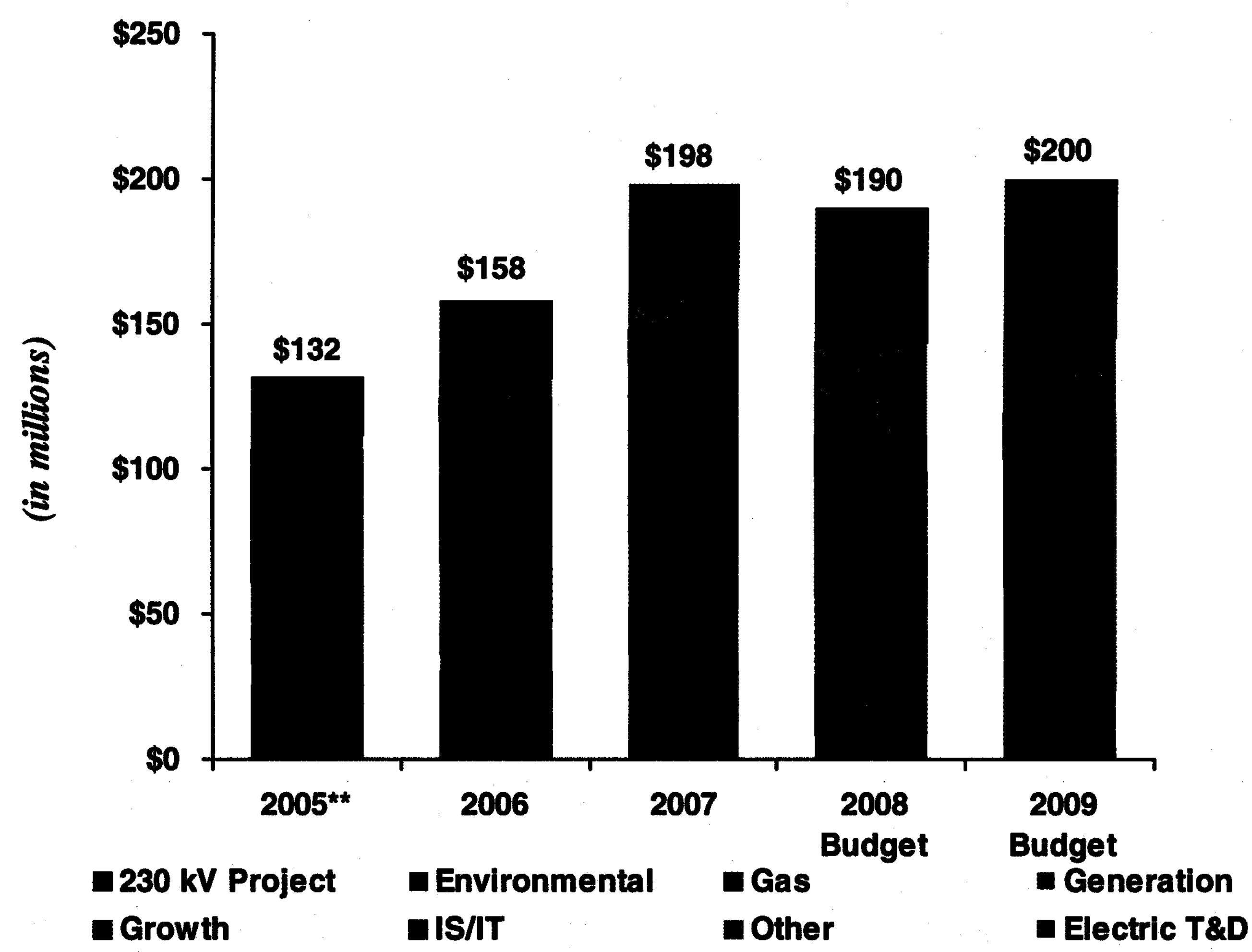
Conclusion

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.

AVISTA Corp.

Capital Expenditures



** 2005 excludes $57.5 for the purchase of the second half of Coyote Springs 2 and $17.8 for the office building purchase.

Exhibit No. 11
Case Nos AVU-E-08-01 &
AVU-G-08-01
D. DeFelice, Avista
Schedule 2, p. 1 of 1

Avista 2008 Capital Additions Detail (System)

	$ (000's)
Generation:	
Thermal - Colstrip Capital Additions	3,424
Thermal - Kettle Falls Capital Projects	1,131
Thermal - Other small projects	130
Hydro - Cabinet Gorge Bypass Tunnel Study	5,353
Hydro - Clark Fork Implement PME Agreement	2,243
Hydro - Noxon Capital Projects	1,628
Hydro - Other small projects	1,461
CS2 Joint Share Projects	2,200
CS2 Capital Projects	1,400
Other small projects	807
	19,778
Electric Transmission:	
West Plains Transmission Reinforce	1,993
Power Xfmr-Transmission - Benewah	1,595
Spokane-CDA 115 kV Line Relay Upgrades	1,247
Nez Perce 115 Sub-Inst Capacitor Bank	751
Beacon 230 Bus Convert to DB-DB	750
Lolo 230 - Rebuild 230 kV Yard	737
Xsmn Air Switch Ground Mat	697
Other small projects	4,316
	12,086
Electric Distribution:	
Electric Distribution Minor Blanket	5,800
Wood Pole Mgmt	4,923
Electric Underground Replacement	3,000
T&D Line Relocation	2,250
Power Xfmr-Distribution	1,755
Failed Electric Plant-Unknown	1,750
DREEP:Dist Reliability & Energy Efficiency Project	1,500
Plummer-Increase Capacity/Rebuild	1,425
C&W Kendall Project	3,050
Indian Trail 115-13kV Sub-Cnstrct New Sub	2,275
Critchfield 115 Sub-Construct	1,614
Spokane Electric Network Incr Capacity	1,445
WSDOT Highway Franchise Consolidation	800
Other small projects	4,737
	36,323

	$ (000's)
General:	
Computer/Network Hardware	5,176
Computer Software	4,049
HVAC Systems Improvement Project	4,990
Backup Control Center	1,911
Tools Lab & Shop Equipment	1,200
Structures & Improvement	1,174
Other small projects	4,205
	22,705
Transportation:	
Transportation Equipment	5,985
Gas Distribution:	
Gas Distribution Non-Revenue Blanket	2,297
Gas Replace-St&Hwy	2,060
Replace Deteriorating Gas System	1,339
Reinforce Gate Station Post Falls Idaho	1,500
East Medford Reinforcement	7,520
Roseburg Reinforcement	1,700
Sutherlin HP Reinforcement	800
Re-Rte Kettle Falls Fdr & Gate Station	1,300
Qualchan Reinforcement, Spokane WA	1,200
Other small projects	4,981
	24,699
Gas Storage:	
Jackson Prairie Storage	18,056
Total Non-Revenue Capital	139,632
Growth/Revenue - Producing	43,262
Total Capital Additions in 2008	182,894