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ELECTRIC TRANSMISSION & DISTRIBUTION INFRASTRUCTURE:

Powerful Spending Trend Forecast to Extend Well Into the Next Decade

Industrial & Basic Materials

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TABLE OF CONTENTS

All relevant disclosures and certifications appear on page 35 of this report.

Overview

- Spending on U.S. electric transmission and distribution (T&D) infrastructure has fallen far short of growth in demand for nearly 30 years, leading to inadequate capacity. As much as 30%–50% of the T&D network is 40–50 years old and many components of the system have useful lives of only 40–50 years. As a result, instances of power outages are rising due to component and equipment failure. All utilities have a "run to fail" policy: replace something when it fails and causes a power outage. There are no programs in place to systematically upgrade the grid.

- **In our view, investment in transmission infrastructure will occur in three phases.**

  1. 2007–12 Focus on projects to relieve congestion.
  2. 2009–15+ New transmission to support new generation.
  3. 2009–15+ Upgrade and replacement cycle begins and gains momentum.

- **We forecast strong spending growth on electric transmission and distribution of 12%+ annually over the next five years.**

- **We forecast annual T&D spending growth continuing at a 10%+ rate into the middle of the next decade.**

- **We forecast that the available market for outsourced network services will grow at a 15%–20% annual rate over the next five years due to a greater percentage of outsourced work.**

- **We expect supply constraints that include**: 1) trained electricians and specialized equipment regarding network maintenance and construction, and 2) manufacturing capacity regarding components and equipment to produce very favorable market conditions for T&D suppliers during the next five or more years.

- **Federal and state governments are taking action to attract T&D investment through** 1) higher investment returns on T&D spending, and 2) private equity capital.

- Our current T&D infrastructure research coverage includes Hubbell, Inc. (HUB'B - $49.20) rated Buy, Thomas & Betts (TNB - $49.01) rated Buy, Quanta Services (PWR - $20.79) rated Buy, General Cable Corporation (BGC - $43.23) rated Buy, and InfraSource Services (IFS - $22.50) rated Hold.

Electric T&D Universe

Company	Ticker	Rating	Price	Target Prices		% Appreciation Potential		Market Cap	T&D Exposure
			2/5/07	1-year	3-years	1-year	3-years	(Millions)	% revenues
T&D Network Services									
InfraSource Services	IFS	Hold	$22.50					**$907**	**61%**
Quanta Services	PWR	**Buy**	**$20.79**	**$24.00**	**$32.00**	**15.4%**	**53.9%**	**$2,952**	**67%**
T&D Components/Equipment									
General Cable Corporation	BGC	**Buy**	**$43.23**	**$53.00**	**$70.00**	**22.6%**	**61.9%**	**$2,274**	**39%**
Hubbell Inc.	HUB'B	**Buy**	**$49.20**	**$62.00**	**$80.00**	**26.0%**	**62.6%**	**$3,006**	**20%**
Thomas & Betts	TNB	**Buy**	**$49.01**	**$66.00**	**$84.00**	**34.7%**	**71.4%**	**$2,960**	**20%**

Source: Company data and Stifel Nicolaus estimates

Investment Summary

The period 1975–2003 was marked by underinvestment in the transmission and distribution grid by the electric utility industry.

- During 1975–1999, real spending on electric transmission steadily declined, followed by a modest upturn through 2003.
- Transmission miles/electric demand (MW) declined 19% during the period 1992–2002. This resulted in a significant increase in transmission congestion to the worrisome levels of today.
- During 1975–2003, real spending on electric distribution grew 1.6% per year versus demand at 2.4% per year.
- During 1994–2004, electric generation has dominated utility spending, cumulatively amounting to five times the amount of transmission spending.
- We believe spending trends on both transmission and distribution support the conclusion that nearly all spending has been in support of demand growth and replacement, or restoration of failed components and equipment that have resulted in power outages. Minimal spending has been made to replace worn out components and equipment.

T&D spending has fallen far short of growth in demand for nearly 30 years, leading to inadequate capacity. The fact that total T&D spending has not supported demand growth suggests that the entire network has been undermaintained. As much as 30%–50% of the T&D network is 40–50 years old. Many of the components of T&D equipment generally have 40–50-year useful lives. As a result, instances of power outages are rising due to component and equipment failure. All utilities have a "run to fail" policy: replace something when it fails and causes a power outage. There are no programs in place to systematically upgrade the grid.

Current Transmission Forecasts are Flawed, Distribution Forecasts Nonexistent

Current transmission spending forecasts are simple extrapolations of historical data.

The North American Electric Reliability Council (NERC), the primary source for transmission forecasts, focuses on only a portion of the transmission grid. NERC only follows and forecasts ultra-high voltage projects (235 kV and above), ignoring the 69 kV to <235 kV market, which is expected to experience strong investment. NERC's current Electric Supply and Demand database identifies 470 planned transmission projects with an average length of 23 miles.

NERC's database of planned transmission projects is missing as much as 80% of planned projects. A July 2005, commissioned study by the Edison Electric Institute ("Meeting U.S. Transmission Needs"), performed by Energy Security Analysis, Inc., identified over 3,000 transmission projects under discussion or in development. The study was an intensive analysis of every region within the transmission grid.

NERC's definition of system reliability is flawed, in our view, reflecting only "adequacy". In our opinion, reliability has no reflection on the condition of the system. NERC's annual Long Term Reliability Assessments during 1996–2004 leave much to be desired, in our opinion. In these assessments, reliability has been defined as power generation capacity available to meet peak projected summer demand. Not once in 10 years has NERC mentioned the condition of the aged T&D network, the minimal spending to maintain the condition of the system, or the increasing power outages due to component and equipment failure during the periods of extreme stress to the system (July 2006).

Edison Electric Institute, the electric utility association, publishes data and forecasts regarding only publicly-owned utilities.

Current Industry Forecasts for T&D Spending

NERC transmission forecast. NERC forecasts new transmission miles growing 3.4% during 2004–09 and 5.9% during 2004–14. These increases fall dramatically short of current forecasts for planned generation capacity and electric demand.

In our view, NERC compounds the underestimation because it significantly underestimates generation capacity that will come on-line, forecasting an 8.2% increase in generation capacity during 2006–14 when demand is forecast to grow 15%–19% over the same period. This is important because new generation requires new transmission.

We are not currently aware of any forecasts for distribution spending.

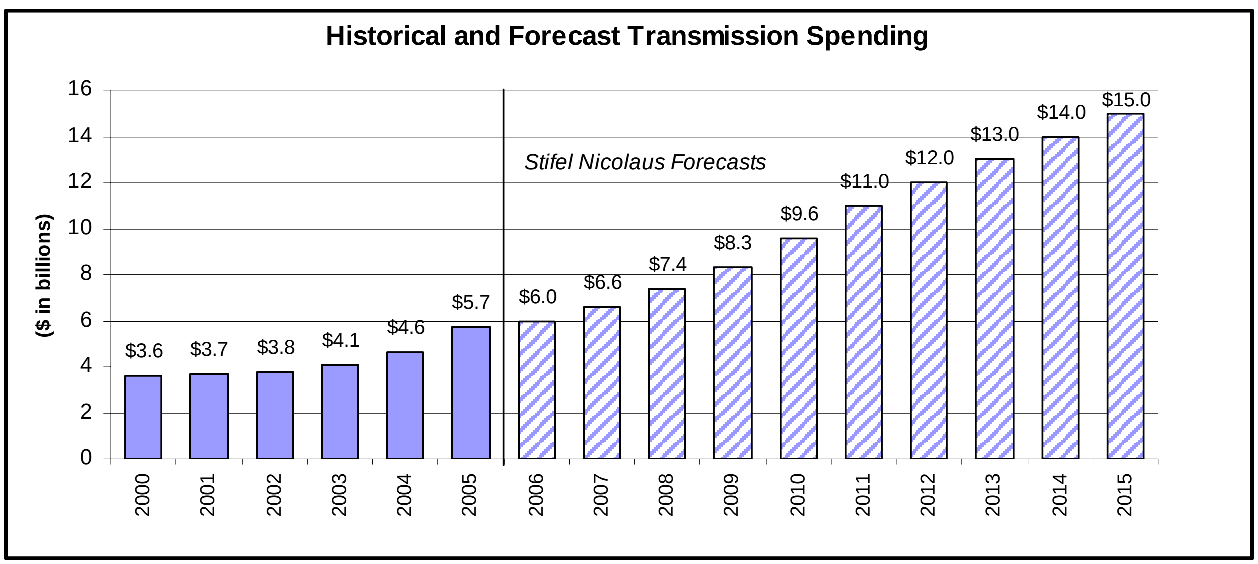
Drivers to Strong T&D Spending Growth During 2006–15

1. Strong growth in electric transmission spending to relieve a congested network.
2. Transmission expansion to support the next surge in power generation capacity (2009–15).
3. Spending on maintenance and replacement of a worn-out grid, both transmission and distribution.
4. Greater amount of outsourcing could expand available market growth at a 50% greater rate than spending.
5. Escalating costs of components and construction/maintenance spending due to supply constraints will likely exceed general inflation measures meaningfully.

The Unfolding Electric Transmission Spending Cycle

1. **2007–12** **Focus on projects to relieve congestion.**
2. **2009–15+** **New transmission to support new generation.**
3. **2009–15+** **Upgrade and replacement cycle begins and gains momentum.**

Exhibit 1
Electric Transmission and Distribution
Historical and Forecast Transmission Spending



Source: EEI reports and Stifel Nicolaus estimates

Focus on projects to relieve congestion. The significant increase in transmission congestion occurred during 1999–2005. During this period, annual growth in new transmission miles averaged 0.9% while annual growth in electric demand was approximately 2.0% (including a recession). This expansion equaled a 1% annual shortfall from demand. We assume, therefore, that incremental 1% mileage growth above base demand growth is needed during 2007–12 to alleviate congestion levels.

New transmission to support new generation. We expect significant new power plant construction starting in 2009 and lasting through at least 2015, adding 12%–15% growth in new capacity (see **Exhibit 2**). This translates into 1.6%–2.0% annual growth in new transmission mileage to keep pace.

Upgrade and replacement cycle begins and gains momentum. According to the DOE, 70% of transmission lines are over 25 years old, 70% of power transformers are over 25 years old, and 60% of circuit breakers are over 25 years old. More than 50% of the high voltage transformers in the PJM Interconnection are over 30 years old. We estimate that 50% of the wooden poles are 30–50 years old. We assume that as reliability pressures mount to address power outages from component and equipment failures, particularly during the summer, the industry will begin to replace 0.5% of the transmission mileage annually by the early part of the next decade and building to 1% or more by the middle of the next decade, sustaining at this level on a long-term basis.

We estimate the upgrade spending using the following two approaches.

- During 2003–04, transmission mileage grew by approximately 1% and transmission spending totaled $4 billion. Therefore, replacement of 1% of the system should run $3.0 billion–$3.5 billion, allowing for maintenance and restoration.
- Alternatively, there are 283,000 transmission miles in North America. The replacement of 1%, or 2,830 miles, would cost an estimated $3 billion at $1 million per mile.

Transmission spending summary. Transmission spending has totaled about $4 billion annually to grow new transmission mileage 1%. <u>We estimate that during 2009–15, transmission mileage will grow 2.5%–3% annually to meet demand and reduce congestion. This translates into annual transmission spending of $10 billion–$12 billion in real 2006 dollars.</u>

In addition, we estimate that eventual replacement of 1% of worn-out transmission sections annually could add another $3 billion to spending.

In summary, we forecast the need for transmission spending reaching and sustaining a level of $10 billion–$12 billion annually in real 2006 dollars by 2010, or 65%–100% above the 2006 level of about $6.0 billion. This translates to annual spending growth of 13.5%–19.0%. Upgrade spending of the worn-out grid could boost the annual transmission spending in the next decade to $13 billion–$15 billion by the early part of the next decade, sustaining 12%–15% spending growth for six to seven years.

<u>Electric Distribution Spending Forecast</u>

Background. At over 2.2 million miles, the local distribution network represents 89% of the T&D system and is 8x as large as transmission. We believe that the average age of the distribution system is older than the transmission system. Long-term spending on electric distribution has grown 1.6% annually in real dollars. Since distribution spending has significantly lagged electric demand and there were not the system inefficiencies as in transmission, we believe it is obvious that minimal spending has been made in maintenance and upgrade. Electric utilities have long operated their distribution systems on a "run to fail" basis.

Current spending trends. During 1998–2003, distribution spending grew 2%–3% on average. In 2004 and 2005, distribution spending increased about 12% annually. We believe that there were two reasons for the stronger spending. First, utilities responded to increased pressure from state PUCs to spend more on "reliability." Second, utilities were replenishing inventory levels depleted during the financial strains of 2002–03. Current distribution spending is estimated at about $18 billion.

Distribution spending forecast. The primary growth drivers are (1) demand growth (1.5%–2% annually) and (2) upgrading worn-out system components and equipment, in our view.

We estimate the upgrade spending on distribution networks as follows:

- There are 2,200,000 distribution miles in North America. The replacement of 1.0%–2.0%, or 22,000–44,000 miles per year at an estimated cost of $140,000 per mile would total $3.0 billion–$6.0 billion per year. Currently aerial construction is estimated at $120,000 per mile and underground installation at nearly $1 million per mile. Utilities are increasingly being directed to place new or existing distribution lines underground.
- We estimate that upgrade spending could produce spending growth of 4%–5% annually in constant dollars, or 7%–9% in current dollars.

Distribution spending summary. <u>We forecast total electric distribution spending growth at 8.5%–11.5% annually over the next five years</u>.

<u>Outsourced Network Services</u>

Background. Electrical utilities adopted an outsourcing model in the 1990s. During 1994–2004, the total utility workforce declined by 20%. During 2002–2004, the electric utility workforce declined by about 10%. The average age of electrical linemen at utilities is 48 and many will likely retire at 55–60. Most utilities stopped lineman training programs during the 1990s, although we understand some training programs have been reinitiated.

A recent industry survey concluded the following.

- Skilled trades would experience the highest percentage of retirements in the near future.
- Skilled trades would be the most difficult to replace.
- 77% of utilities responded that there was no formal plan to meet workforce needs.

Electrical utilities currently outsource over 90% of their transmission work and 35% of their distribution work, or approximately 50% of total T&D work.

Summary outsourcing forecast. Assuming that the electric lineman workforce at electric utilities declines by 10%–12% over the next five to six years, <u>we estimate that the available outsourcing market for network service providers would grow at a 15%–20% annual rate versus 12% for overall T&D spending</u>.

<u>Supply Constraints</u>

Electricians. A tight market for trained electricians is already developing. It requires five years of training to become a journeyman lineman. An apprentice is generally not productive for the first one to one and a half years. There are three sources of training programs: the IBEW union, technical training schools plus on-the-job training, and formal training programs by large contractors. The number of apprentice electricians in training programs is not keeping pace with demand, and there is a lag before new apprentices are productive. Most electric utilities abandoned their lineman training programs during the 1990s in favor of outsourcing programs. In the last two years, some utilities have revived their electrician training programs in view of the tight labor market that is developing.

An August 2006 report prepared by the U.S. Department of Energy entitled, “Workforce Trends in the Electric Utility Industry”, concludes “analysis indicates a significant forecasted shortage in the availability of qualified candidates by as many as 10,000 lineworkers, or nearly 20% of the current workforce.” Using information from the Bureau of Labor Statistics, the report states that the number of electric linemen has grown at a 1.6% annual rate since 1999, and that the electric linemen workforce totaled 58,020 in 2005. Projected retirements of over 3,000 linemen annually by 2010 would account for over 25% of the current workforce. The report identifies 31 lineman training programs in the U.S. with 1,360 active apprentices. Since the apprentice programs typically last two years, this indicates a coming shortage, particularly in view of the electric utility industry's strong spending plans.

Our conclusion: We expect a shortage of skilled electricians to perform the strong forecast growth that is looming immediately ahead.

Manufacturing capacity. Strong T&D spending growth has not occurred during the past 30 years. The recent strong demand has already pushed the producers of electric T&D cables and transmission towers to near capacity. Continued strong growth will likely strain the manufacturing capacity of other component and equipment producers. Oligopolies and high barriers to entry are expected to maintain very favorable market conditions over the next five years.

Conclusion. We expect tight labor and equipment markets to result in higher pricing for network services providers, driving operating margins toward 10% or better. Component and equipment producers are generally at, or approaching, record profit margins. We believe these levels are sustainable and, in many instances, could go higher.

Energy Policy Act of 2005: Facilitating T&D Investment, Attracting New Capital

The repeal of the Public Utility Holding Company Act of 1935 (PUHCA) is aimed at ushering in new capital from the private sector. New non-utility investors are expected to focus on lower costs (outsourcing).

The Energy Policy Act calls for a self-regulated reliability organization that will implement and enforce mandatory reliability standards, with Federal Energy Regulatory Committee (FERC) oversight.

FERC issued final rules that will provide specific incentives for transmission investment on a case-by-case basis that provides a rate of return that attracts investment and allows a recovery of costs for complying with new reliability standards. Recently, FERC granted incentive rate increases to American Electric Power and Allegheny Energy regarding T&D investment. FERC also accepted a proposal for a new transmission line up to 600 kV from Alberta, Canada, to Montana.

FERC completed a preliminary draft map of potential electric energy corridors on federal land in western states in June 2006. The electric corridors are expected to be determined by late 2007, which should streamline planning and commitment of new transmission lines. FERC has indicated it will review and establish new needed electric transmission corridors every three years.

Electric Power Infrastructure Overview

The electric power system in the U.S. is a vast network of interconnected power plants, transmission lines, substations, and distribution systems. Electrical infrastructure was originally built with the intention to serve local markets. Electric generating plants were built by the local utility to serve its local market, which was generally a state or a region within a state. A transmission and distribution system was then constructed to serve that local market. However, over time, utilities made agreements to purchase electric power from neighboring utilities. Various reasons for these purchases included avoiding the construction of a new generating plant, accessing lower cost electric power in some cases, and improving the reliability of the electric power system by serving as a backup source.

Since the 1970s, technological advances in electric transmission have allowed utilities to transmit electricity over longer distances at higher voltages. NERC was established in 1968 to coordinate planning, establish standards, and operate the U.S. transmission system.

In 1996, FERC Order 888 created a wholesale electricity market, which led to more congestion and more power transactions occurring over transmission lines. The deregulation of the electric generation market rapidly and significantly magnified the stress on the electric transmission system.

Power Grid Basics

Energy is generally produced at electrical generating plants at a relatively low voltage of up to 30 kV. In order to prepare this power for transport to locations throughout North America, its voltage level is increased by a high voltage transformer before it is sent along transmission lines. Transmission lines are high voltage with levels typically above 110 kV, although voltage levels can range from 69 kV to 745 kV. Increasing the transmission voltage has the effect of reducing current in the conductors, thereby reducing energy losses.

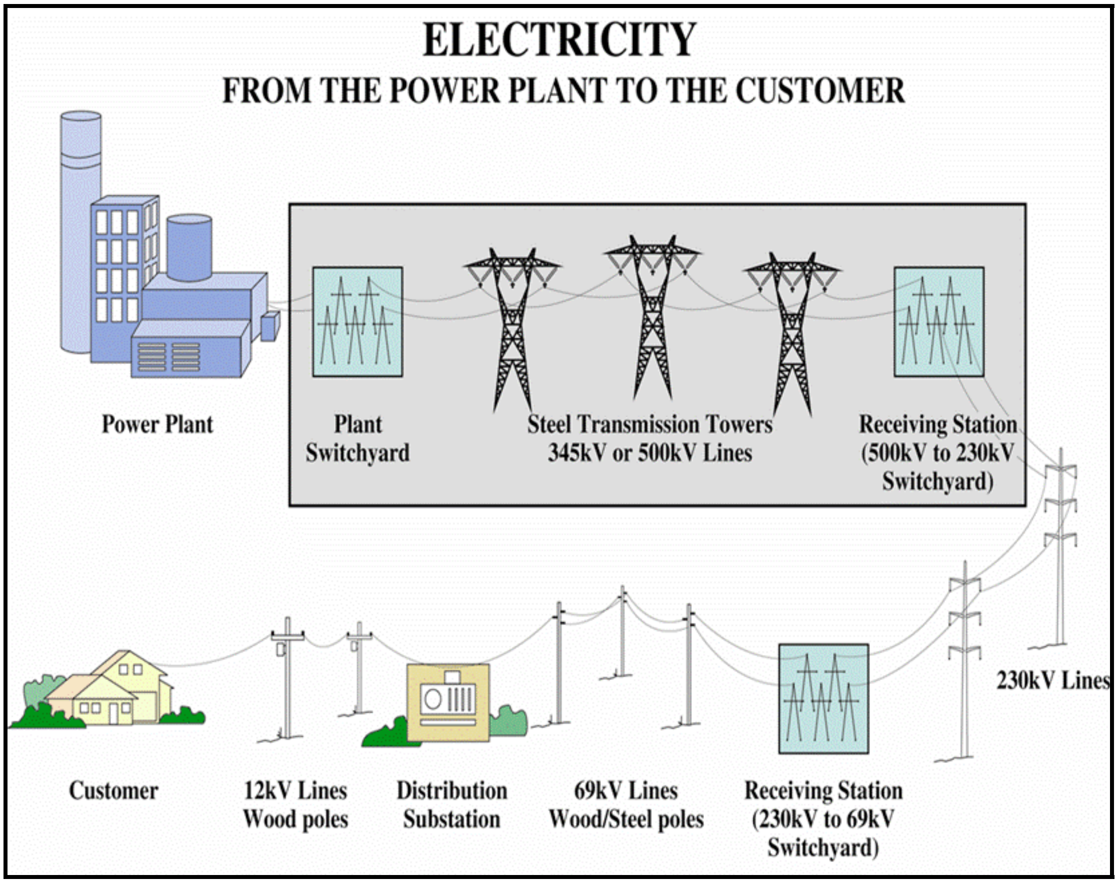
As the electricity approaches populated areas it is transported into substations, where the voltage level is reduced. Once the voltage is stepped down, electricity is sent along the low and medium voltage power lines, which make up the nation's distribution system. Distribution networks consist of low to medium voltage power lines, transformers, and meters. Distribution power lines normally have a voltage level of 37 kV and are usually below 50 kV. To reach end-use residential, commercial, and industrial customers, low voltage transformers located atop distribution lines reduce the electricity voltage level again. Energy is usually transmitted within the grid with three-phase AC.

Electricity cannot easily be stored over extended periods of time and is generally consumed less than a second after being produced. The demand load on any power grid must be matched by the supply to it and its ability to transmit that power. Any great overload of a power line, or underload/overload of a generator, can cause hard-to-repair and costly damage. Thus, the power grid is disconnected if a serious imbalance is detected.

Within the power grid, redundant paths and lines are provided so that power can be routed from any power plant to any load center, through a variety of routes, based on the economics of the transmission path and the cost of power. Much analysis is done by transmission companies to determine the maximum reliable capacity of each line, which, due to system stability considerations, may be less than the physical or thermal limit of the line. Deregulation of electricity companies in many countries has led to renewed interest in reliable economic design of transmission networks. [1]

[1] *http://en.wikipedia.org*

Exhibit 2
Electric Transmission and Distribution
Power Grid Components



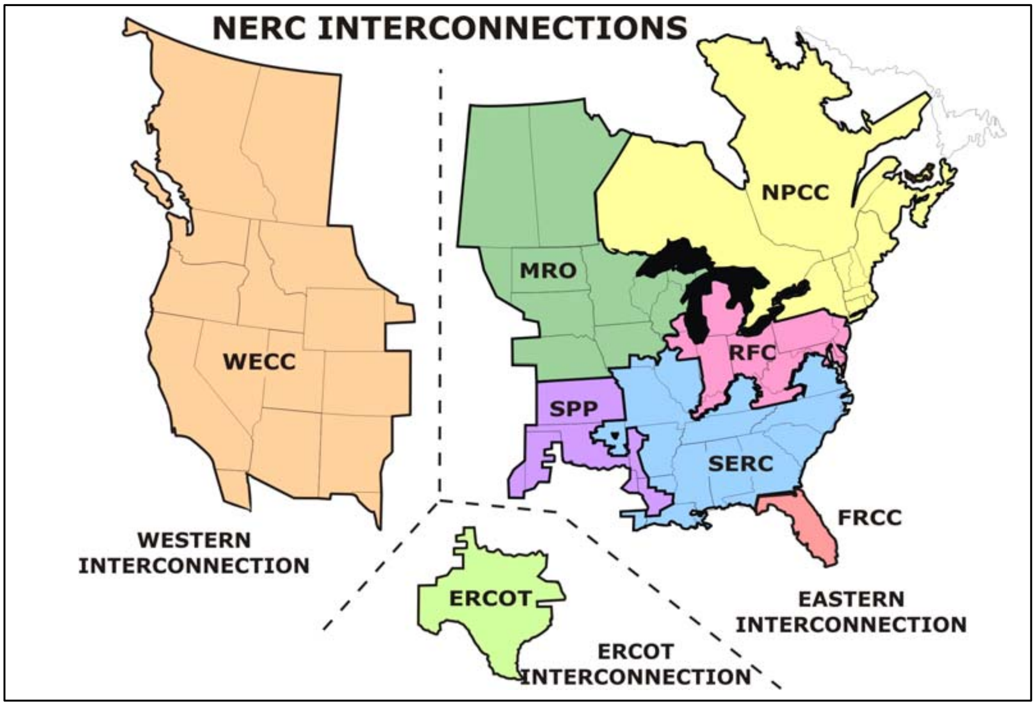
Source: APS.com

The electric power grid in the U.S. is an estimated $360 billion asset and consists of 282,850 miles of high voltage transmission cables and 2,205,853 miles of distribution (local low voltage) cable through the interconnection of roughly 3,000 public, municipal, and federal electric utilities that serve more than 300 million customers.[2] Approximately 70,000 substations within the network monitor, control, stabilize, and step-up/step-down voltage levels.[3] The high voltage transmission system, operated by NERC, consists of eight regional reliability organizations, as follows.

- Eastern Interconnection (RFC, MRO, SPP, SERC, FRCC, NPCC): 6 regions
- Western Interconnection (WECC): 1 region
- Electric Reliability Council of Texas (ERCOT): 1 region

[2] *Goulden Reports: The World Market for T&D Equipment and Systems 2005-2015 and http://www.physicstoday.org*
[3] *http://uaelp.pennnet.com*

Exhibit 3
Electric Transmission and Distribution
NERC Interconnections



Source: NERC

ERCOT	Electric Reliability Council of Texas, In	RFC	Reliability*First* Corporation
FRCC	Florida Reliability Coordinating Council	SERC	SERC Reliability Corporation
MRO	Midwest Reliabilty Organization	SPP	Southwest Power Pool
NPCC	Northeast Power Coordinating Council	WECC	Western Electricity Coordinating Council

History of the Grid/Regulation

When the electric power grid was built in the United States, its intention was to serve local markets. The regulation that was established as the power grid was built out in the 1930s was similarly oriented toward local markets. We believe an understanding of the regulatory policies in place from the 1930s to the 1990s lends insight into the drivers of systematic underinvestment in T&D assets over this time frame.

Under PUHCA, laws were established that assumed an industry's key players were state-regulated local monopolies. No policies were established for interstate siting procedures, and non-utility players were essentially barred from participation in grid investment. Transmission investment was generally designated a lower ROE than generation and distribution which encouraged utilities to expand their rate bases through the build-out of power plants. While recommended grid reliability standards were created, adherence to these standards was strictly voluntary.

In the 1970s, regulators began to believe that traditional rate of return investment incentivized overbuilding and instead shifted to a cost-avoidance model. This new approach focused on maximizing the use of existing assets; consequently; transmission investment declined every year from 1975–98.

Regulatory Policy Historically Favored Investment in Electric Generation

Over the past 10–15 years, the electric industry has undergone a restructuring phase. As energy transmission increasingly became a national issue, regulation oversight began to shift from the state level to the federal level. Federal policy changes began to move the industry toward unbundled, competitive energy services.

In 1992, Congress passed the Energy Policy Act of 1992 (amending the PUHCA of 1935), which created a framework for a wholesale competitive generation market and established a new category of electricity producer, the exempt wholesale generator (EWG). These new entities were not subject to constraints on non-utility generation specified under the PUHCA. The act also gave FERC the authority to open up the transmission system to wholesale suppliers on a case-by-case basis.[4] FERC could require open access of a utility so long as that affected utility was engaged in wholesale power sales. The legislation was designed to encourage the beginnings of competition in the electric industry without infringing on state rights. FERC was given considerable authority over access to and regulation of transmission grids, but it was forbidden from ordering retail competition. The decision to allow competitive suppliers to market power to electricity consumers was left to state legislatures and regulatory commissions.[5] In 1996, FERC Order 888 required transmission line owners to offer access to the grid at prices comparable to those they charge to themselves. The purpose of FERC Order 888 was to require equal access to transmission services, which was intended to foster competitive bulk power markets, which would, in turn, lower electricity rates. Subsequent FERC Orders 889, 2000, and 2001 further moved the U.S. toward a wholesale power market.

Implications

The deregulation of the electric generation market and the creation of a wholesale electricity market rapidly and significantly magnified the stress on the electric transmission system. As investment decisions related to electricity production shifted from utilities to competitive market forces, there were two primary outcomes.

1. Hundreds of natural gas turbine generator plants were constructed throughout the U.S. These new generator plants were sited near existing transmission facilities; enabling IPPs to access the power grid without adding any new transmission capacity.
2. An enormous market for wholesale power transactions was created within the U.S. Wholesale power transactions allow for electricity to be generated in one region of the country and, through transactions, used in another region. In 1996, more than 73% of all U.S. electricity was bought and sold in the wholesale market before it reached the consumer.[6]

Investment in electric power generation grew steadily during the period 1992–2002 while transmission infrastructure investment declined from 1975–1999 before rebounding somewhat beginning in 2000. Over the past decade, approximately $200 billion was spent on new generation and only $40 billion was invested in transmission.[7] This equates into a 5:1 ratio for generation to transmission investment.

There were three main factors responsible for this declining trend in transmission spending.

1. Siting and permitting for new transmission lines became extremely difficult to obtain (public argument for new transmission lines is ‘not in my backyard’).
2. Lack of financial incentives for utilities to invest in new transmission, particularly relative to the investment returns on generation.
3. New technology enabled more electricity to be carried on the existing electric grid.

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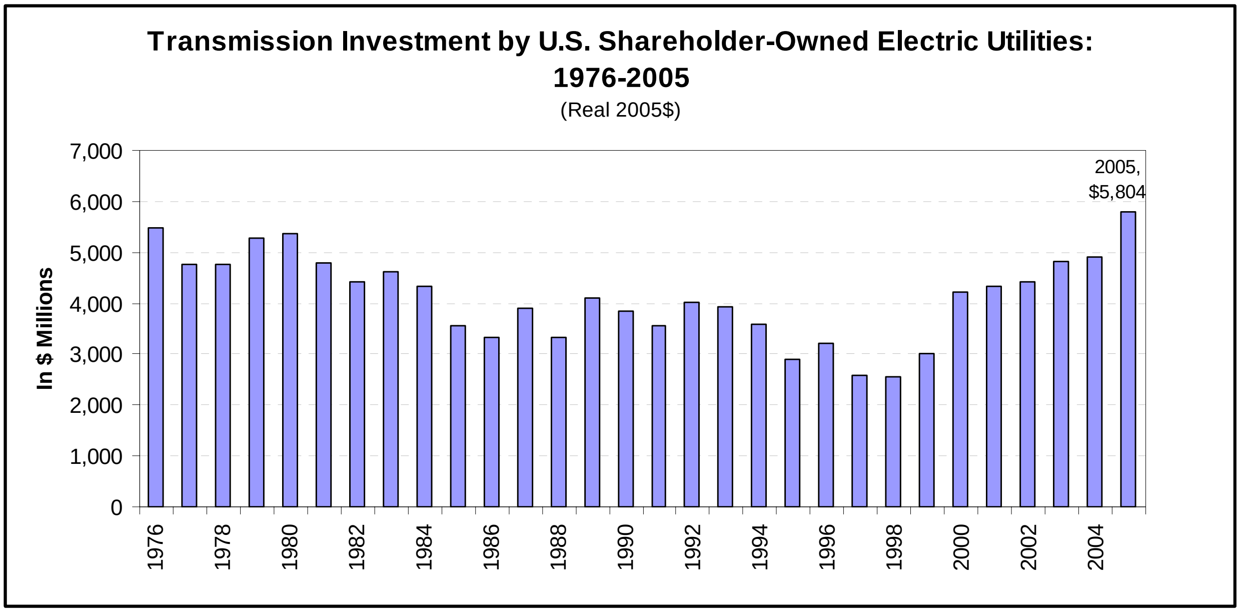
[4] http://www.eia.doe.gov
[5] http://neaap.ncat.org
[6] http://www.eia.doe.gov
[7] Edison Electric Institute: “Meeting US Transmission Needs,” http://www.eei.org

The trend in transmission investment has increased since 1998, and in 2005, investment in transmission by shareholder-owned utilities finally surpassed investment levels in 1975.

Exhibit 4
Electric Transmission and Distribution
Transmission Investment



Source: EEI

The power delivery system in the United States was not constructed to facilitate competitive regional power transactions. Antiquated regulatory policies led to a situation where energy markets evolved while energy transmission and distribution infrastructure stagnated. The increases in wholesale power transactions, electric demand, and power production over the past several years have put significant pressure on a power grid that was built only to serve local markets. A large amount of energy is being transported over an aged and antiquated system. Many of the components that make up the power grid are approaching their 30–50-year useful lives. Investment is necessary to bring the power grid up to a level of acceptable physical soundness and reliability. Looking forward, additional grid investment will be needed to connect the grid to new forms of power production such as nuclear, clean coal, wind, geothermal, and hydro-electric. New renewable generation additions will likely be located far from populated areas, requiring transmission projects that are larger in scale than we have seen historically.

Inadequacy of Current Transmission and Distribution Infrastructure

When addressing the issue of necessary investment in the U.S. power grid, the question of whether or not the grid is truly inadequate and/or unreliable inevitably arises. In our opinion, the issues of transmission constraints and aging equipment have led to both grid reliability issues and inflated energy prices. Well-planned transmission investment is a rapid and economical solution to these problems.

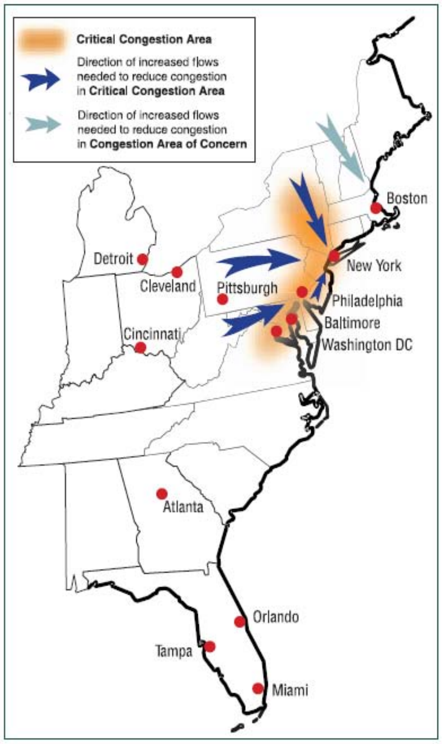
Congestion/ Transmission Bottlenecks

Transmission bottlenecks, or areas where electricity flow across a line or component of the power grid is restricted- either by the physical or electrical capacity of a line, or by operational restrictions created to protect grid security and reliability- are currently widespread.[8] According to the U.S. Department of Energy's August 2006 *National Electric Transmission Congestion* study, there are 171 transmission constraints in the Eastern Interconnection and 67 constraints in the Western Interconnection (the DOE does not perform analysis on ERCOT).

Exhibit 5
Electric Transmission and Distribution
Transmission Congestion

One Critical Congestion Area and Three Congestion Areas of Concern in the Western Interconnection

Critical Congestion Area and Congestion Area of Concern in the Eastern Interconnection



Source: U.S. Department of Energy

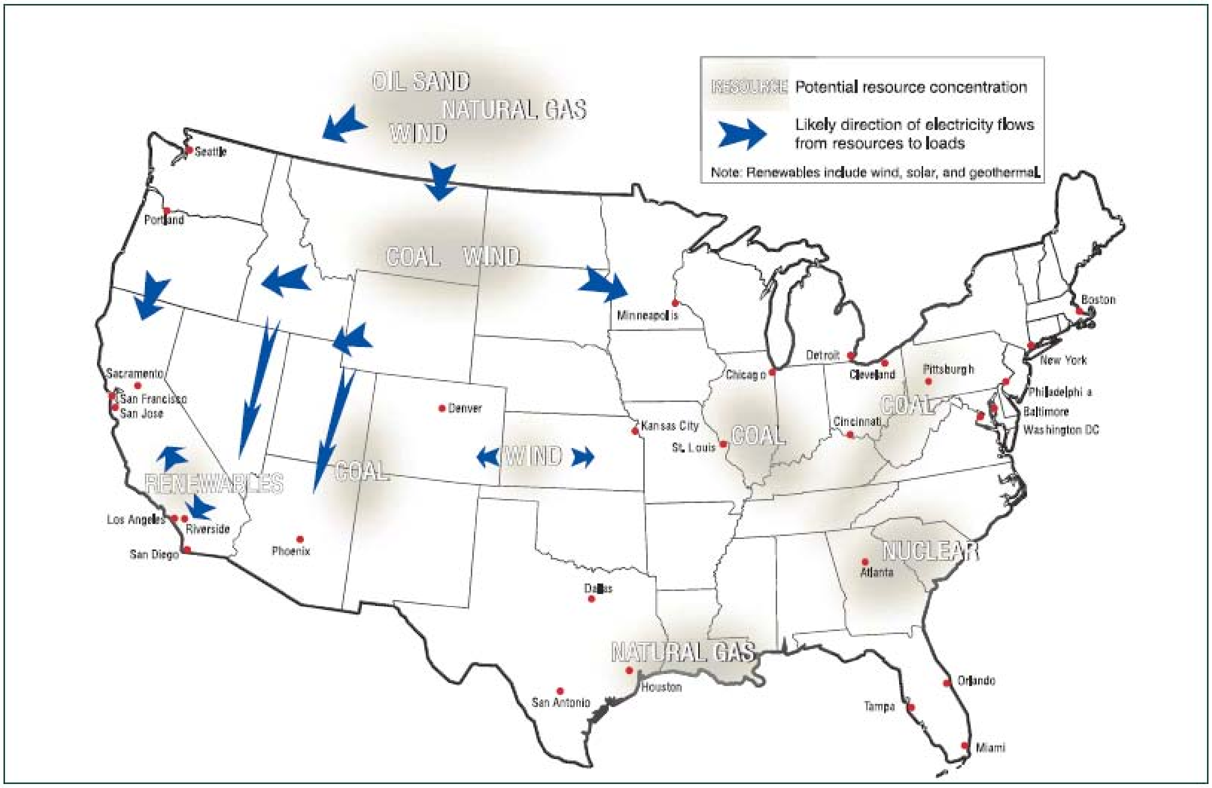
The Department of Energy has identified Southern California and the Atlantic coastal area (metropolitan New York through northern Virginia) as critical congestion areas that must be improved because current and projected effects of congestion are severe. Areas that the DOE determines as congestion areas of

[8] *http://www.oe.energy.gov*

concern include New England, the Phoenix-Tucson area, the Seattle-Portland area, and the San Francisco Bay area. These are areas where large-scale congestion problems exist or may be emerging; however, the DOE has indicated that it needs to conduct further analysis in order to determine the magnitude of the problem. The DOE also outlines conditional congestion areas, which are areas that would become significantly congested if new generation projects were undertaken without the development of relative transmission capacity. Areas that are conditionally congested are Montana-Wyoming, the Dakota's-Minnesota, Kansas-Oklahoma, Illinois, Indiana, Upper Appalachia, and the Southeast. [9]

Exhibit 6
Electric Transmission and Distribution
Conditional Constraint Areas in the U.S. as Outlined by the DOE

Conditional Constraint Areas



Source: U.S. Department of Energy

Major Regional Transmission Constraints/Bottlenecks

- *Southern California.* Southern California is currently experiencing a tight supply and demand balance of electricity, with low supply and fast growing demand. There is also a strong dependence on imports from Northern California, the Pacific Northwest, and the Southwest to meet peak demand, and generation additions over the past year are expected to barely cover load growth within the region. Since tight reserve margins exist, we believe Southern California is vulnerable to both high peak demand due to extended periods of extreme heat and unplanned outages of generation or transmission capacity, which is required to maintain imports. Resource adequacy requirements were put into place, forcing utilities to have resources equal to at least

[9] *http://www.oe.energy.gov*

115% of their forecasted monthly peak loads beginning in June 2006. This requirement, among others, should increase the level of contracting for resource adequacy and should lower the volatility of Southern California's electricity prices.[10]

- *New York/Long Island*. New York City has experienced some capacity additions; however, Long Island continues its trend of having an extremely tight supply and demand balance of electricity. Because of its reliability concerns, Long Island remains highly vulnerable to extended periods of heat and unplanned power outages. With reserves being used and supply being very tight, the retail rates on Long Island are very high. Since the New York ISO has a scarcity pricing program, prices should continue to be high until sufficient capacity and reliability concerns are addressed.

- *Southwest Connecticut.* Southwest Connecticut is also experiencing a large imbalance of supply and demand. Transmission and generation capacity is not sufficient to meet reliability requirements as well as demand. There have been no generation or transmission capacity additions since 2004. In our opinion, the power grid in southwest Connecticut is highly vulnerable to long periods of intense heat, which not only will affect their system but also the systems in which they import their electricity, causing limited supply. Although retail rates are fixed, when rate cases expire, electric bills will most likely be increased due to limited supply and relatively stable demand.

- *Ontario, Canada*. This region is also experiencing a tight balance of supply and demand. Ontario is highly dependent on importing electricity from New York and Michigan to meet demand. Last summer, Ontario had to initiate emergency control actions in order to mitigate peak demands. Since then, Ontario has actually lost some of its capacity margin. The system is exposed to extended periods of heat in the northeastern U.S., which could limit its importing capacity. A program was implemented by the Independent Electricity System Operator that is designed to alleviate disturbances of imports, which was a common trend in Ontario last summer. Also, imposed emergency control actions will affect the markets of its suppliers, Michigan and New York, by increasing the costs of balancing supply and demand.[11]

Impacts of Congestion

Transmission Load Relief Events

Within areas of congestion there are times when there is inadequate transmission capacity to accommodate all requests for electric power and also maintain adequate safety margins for reliability. When grid flow schedule inconsistencies and/or unforeseen events threaten or violate grid operating security limits, a grid operator must intervene and perform tasks to mitigate the problem. These interventions are called transmission load relief events, or TLRs. TLRs are used widely across the Eastern Interconnection and are a last resort to try and curtail transactions that could overload transmission facilities or violate operational security limits. TLRs are generally indicative of congestion levels within an area of the grid.

TLRs have increased 37.29% compounded annually since 1999. From 1999 to 2000, congestion increased 188.27%. Following a 1.18% decline in 2001, congestion increased by 46.47% in 2002, 33.2% in 2003, and 16.18% in 2004. NERC data shows that the number of TLRs increased by 3.68% in 2005. **Exhibit 7**, which represents NERC TLR data from July 1997 through November 2006, shows that peak summer congestion, as represented by number of TLR events, continues to increase; however, the level of increase is slowing down, likely due to increased system investment.

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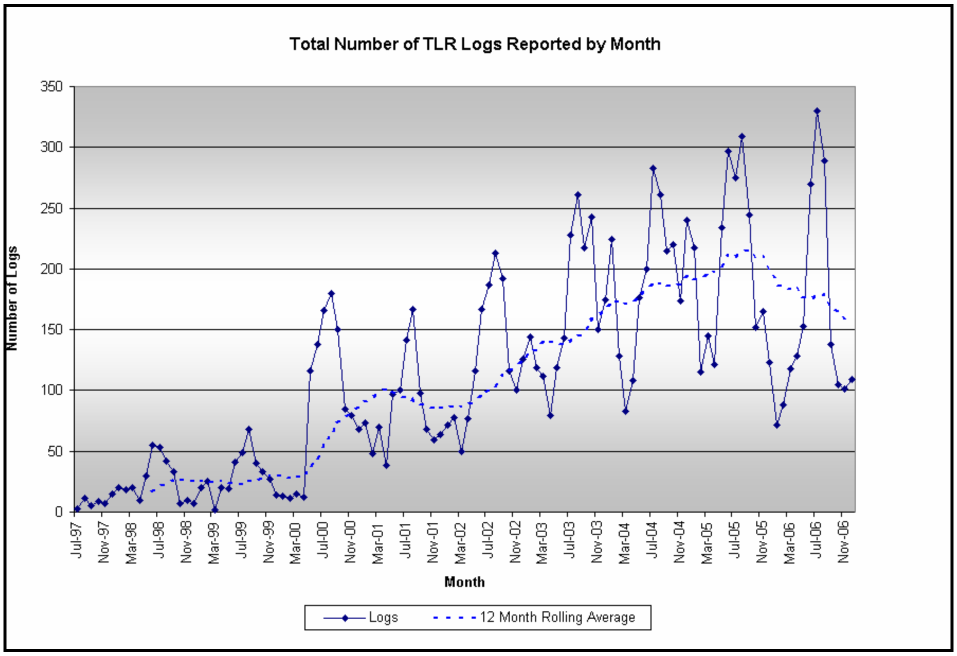
[10] *http://cdn.idc.com*

[11] *Edison Electric Institute: "Assessing Rate Trends of US Electric Utilities":http://www.eei.org*

Exhibit 7
Electric Transmission and Distribution
Transmission Load Relief Events: 1997-2006



Source: NERC

Dollar Cost of Congestion
Power marketers look to buy the least expensive energy available in order to resell it at load centers. When transmission constraints limit the amount of available electricity from the most desired source, the grid operator must find an alternative source of power. This alternative power source is more expensive than the least cost provider, and the difference is a rough estimate of the cost of congestion. In the PJM Interconnection, which manages the grid in 10 mid-Atlantic and Midwestern states, total transmission congestion costs were $750 million in 2004 and $2.09 billion in 2005, representing a 179% increase. Total congestion costs have ranged 6%–10% of total annual billings in PJM since 2000[12]

Aging Infrastructure

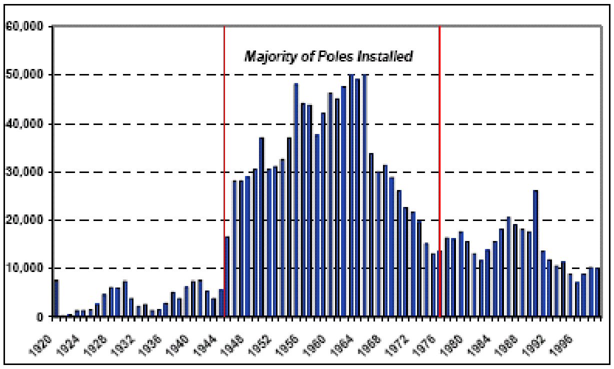
The current electric transmission and distribution infrastructure is aging. According to the DOE, 70% of transmission lines are 25+ years old, 70% of power transformers are 25+ years old, and 60% of circuit breakers are 30+ years old. Southern California Edison, a subsidiary of Edison International, has many transmission lines, transformers, and power poles that are 50 to 60 years old.[13] SCE also lost 1,345 transformers due to operating at or near capacity during July–August 2006 (SCE is budgeting $7 billion over the next five years to upgrade its distribution system[14]). Similarly, more than 50%, or 103, of the 500-230 kV transformers in the PJM Interconnection are at least 30 years old, which means that 103 high voltage transformers will need to be replaced within the next decade in the PJM Interconnection alone.[15]

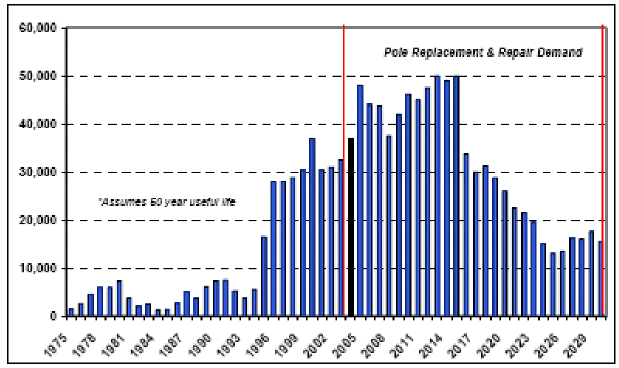
As an example, many of the wooden poles that support the power grid were installed from the mid-1940s to the mid-1970s and are now approaching an average 50 years in age. As one of the components of the grid most susceptible to the elements, they likely will require significant investment over the next two decades to maintain system stability.

[12] *http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20060411-som-web-4.pdf*
[13] *http://www.pasadenastarnews.com*
[14] *PJM*
[15] [15]*http://www.thestreet.com*

Exhibit 8
Electric Transmission and Distribution
Pole Replacement and Repair Demand as Implied by Age

# of Poles Installed By Year- Representative of a Typical Electric Utility	Implied Demand for Pole Replacement & Repair for a Typical Electric Utility





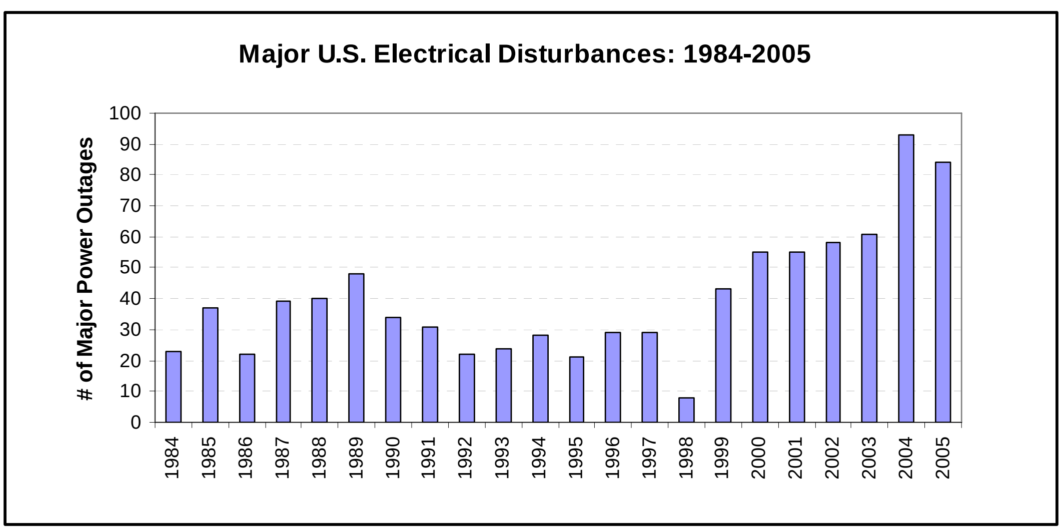
Source: Quanta Services

While older grid components are often more prone to failure due to corrosion, metal degradation, and breakage, older components are often the limiting factor that prevents a higher voltage of electricity from traveling along a specific path, thereby causing congestion. Modern capacitors and transformers are often built to handle higher voltages than components built in the middle of the century. Isolating these limiting components and replacing them can often increase the capacity of a route.

Consequences of Grid Inadequacy: Increase in Major Power Outages

The number of major electric disturbances in the U.S. has increased dramatically over the past two decades, experiencing a 265% increase in the raw number of major power outages that have occurred since 1984, or 6.4% compounded annually.

Exhibit 9
Electric Transmission and Distribution
Major U.S. Electrical Disturbances



Source: EIA

In 2005, a study conducted for the Department of Energy estimated that power outages cost the U.S. economy roughly $80 billion annually.[16] The study found an estimated $57 billion, or 73%, of power outage costs impacting the commercial sector and $20 billion, or 25%, impacting the industrial sector. Residential losses were estimated at only $1.5 billion annually, which is only 2% of total losses. Momentary power outages lasting less than five minutes attributed to $52 billion in costs, or nearly two-thirds of the total costs. Power outages that last longer than five minutes account for one-third of total costs, or $26 billion. The study points out that some utilities do not include power outages caused by natural events, such as hurricanes, in their power outage statistics. A study conducted by the Electric Power Research Institute (EPRI) claims that roughly two million businesses have been losing $46 billion per year in lost production due to power outages and another $6.7 billion annually due to power quality issues.[17] Another source states that the annual cost of power outages and power disturbances to the U.S. economy is $104 billion–$164 billion, with another $24 billion lost due to power quality phenomena.[18] This is a total loss of roughly $128 billion–$188 billion annually due to power outages.

In August 2003, North America experienced the largest power outage in its history. An estimated 10 million residents of the northeastern U.S. and eastern Canada were affected by the cascading failures, which covered an area of roughly 9,300 square miles. Estimates state that outage-related financial losses totaled more than $6 billion. A System Outage Task Force determined that the ultimate cause of the blackout was FirstEnergy Corporation's failure to trim trees in part of its Ohio service area. The outage had the impact of significantly increasing awareness of the inadequacies of current electric infrastructure and the need for utilities to adhere to reliability and maintenance standards.[19]

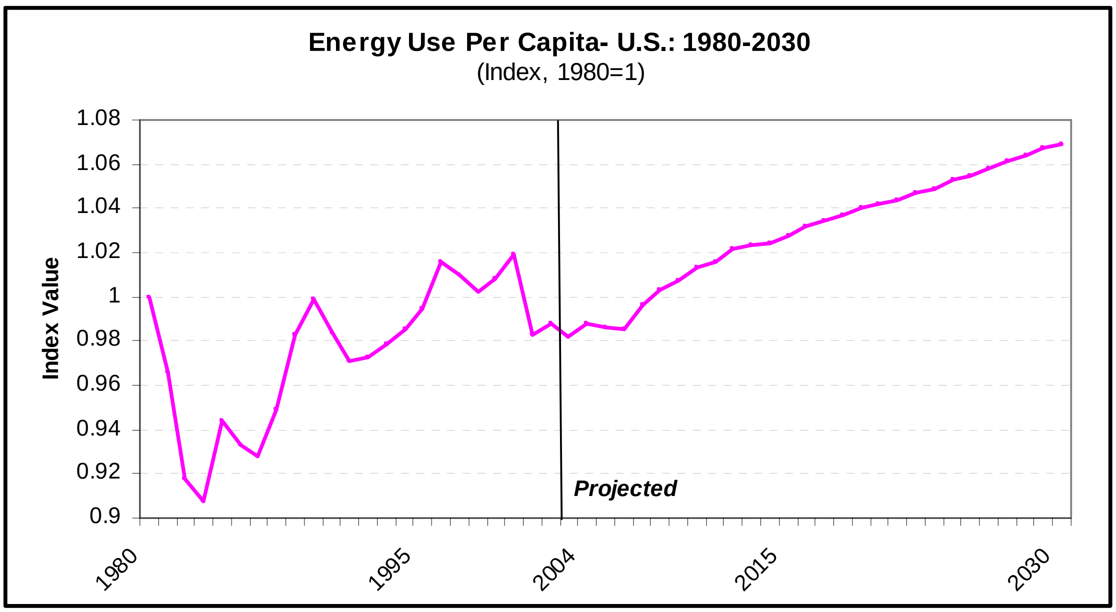
[16] http://www.lbl.gov
[17] http://www.icfi.com
[18] http://www.eatonelectrical.com
[19] http://en.wikipedia.org

Looking Forward: Strain on the Grid Will Increase

Demand for Electricity is Growing

The Energy Information Administration (EIA) projects that U.S. electricity consumption will grow by approximately 2% per year over the next 25 years. It is estimated that 10 years from now, electricity consumption will be approximately 20% greater than it is currently. EIA also projects that 350 gigawatts (GW) of new capacity will be needed to supply this increase in demand. Based on the projected 350 GW increase of electric capacity by 2030, it can be assumed that roughly 140 GW will be added within the next 10 years. This growing demand for electricity is a concern for the industry. In its 2006 Summer Assessment, NERC projected that the average annual growth rate for transmission circuit line mileage is only 0.66%, which is only one-third of the projected growth in electricity consumption. However, transmission line mileage added has exceeded what has been projected over the past six years. NERC's 2006 Summer Assessment also points out that, over the past four years, there has been a downward trend in U.S. capacity margins. This indicates that there is a general slowing of capacity additions relative to the projected growth in demand for electricity, although regional capacity margins differ from the U.S. average.

Exhibit 10
Electric Transmission and Distribution
Energy Use Per Capita



Source: EIA

On July 17 and July 18, 2006, seven large regions in the U.S. experienced record levels of electricity demand and one region in Canada had energy consumption levels just below the record set last summer, according to the *SNL Energy Power Daily* (July 19, 2006) and the *SNL Energy Electric Transmission Week* (July 24, 2006). The regions that experienced these record levels were the PJM Interconnection, the Midwest ISO, the California ISO, the Southwest Power Pool, the Electric Reliability Council of Texas, the New York ISO, and ISO New England. These regions cover 25 states and the District of Columbia and represent approximately 71% of the population within the United States.[20] Furthermore, the U.S. as a whole set record electricity demand levels in August 2006.[21] These record levels of consumption

[20] *http://www.census.gov*
[21] *http://www.eei.org*

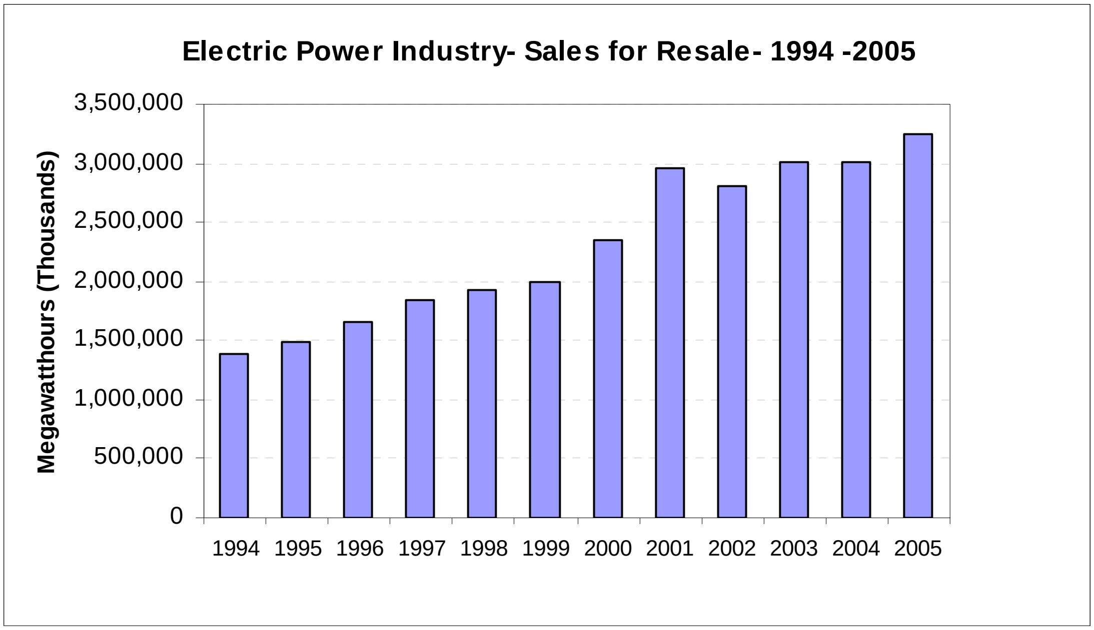
combined with a record heat wave and major storms led to several large power outages in the U.S. Queens, New York, had major power outages, affecting roughly 100,000 people.

In California, 1.2 million customers in Pacific Gas and Electric Company's service area were without power on July 25, 2006, due to extremely hot temperatures causing transformers to overheat. A PG&E spokesman disclosed that the company had underinvested in its infrastructure and that a significant portion of its system was aging and in need of upgrade.[22] On July 26, 2006, the California Independent System Operator asked its generators and transmission owners to avoid any unnecessary maintenance work in order to perform a test of the reliability of the grid. Although the grid passed the test, there were still 62,000 customers that suffered from power outages caused by the prolonged heat overwhelming local distribution systems. 765,000 customers in the service territory of Southern California Edison, a subsidiary of Edison International, lost power due to 800–900 transformers that burned out or failed to perform.

Increase in Wholesale Transactions

Wholesale power markets involve buying and selling bulk power between electric companies. Bulk power is then resold to either end-use customers or other utilities. Due to the formation of regional transmission organizations, the electric power grid experienced a 140% increase in wholesale power transactions over the past five years.[23] We believe deregulation is directly responsible for the dramatic increase in the number of transactions within the U.S. The electric power grid experienced an increase from 25,000 transactions in 1995 to two million in 1999.[24] This represents an 80-fold increase in the number of wholesale power transactions that took place from 1995 to 1999. **Exhibit 11** represents the volume of electricity sold for resale between electric utilities, independent power producers, and combined-heat-and-power plants between 1994 and 2005.

Exhibit 11
Electric Transmission and Distribution
Electricity Sales for Resale



Source: EIA

[22] *http://www.larouchepub.com*
[23] *Edison Electric Institute: 2005 Financial Review Plus 2006 Developments*
[24] *http://www.memagazine.org*

Part of the Solution: The Energy Policy Act of 2005 Marks a Regulatory Turning Point

On August 8, 2005, the President signed into law a broad energy bill entitled, Energy Policy Act of 2005, which effectively repealed the Public Utility Holding Company Act of 1935. We believe this bill is a major step toward modernizing the transmission regulation to fit the competitive market forces currently in play. The energy bill outlines the establishment of mandatory electric grid reliability standards and provides several incentives for improvement to the grid.

The Act establishes the creation of an electric reliability organization (ERO); an entity that falls under FERC's jurisdiction. The ERO's primary responsibility is to establish and enforce reliability standards for the bulk power system, which must be reviewed and approved by FERC. On July 20, 2006, the North American Electric Reliability Council (NERC) was certified by FERC as the country's electric reliability organization and is charged with the task of enforcing its 102 mandatory reliability standards, after they are reviewed and approved by FERC.[25] As the ERO, NERC has been given the legal authority to enforce reliability standards on all owners, operators, and users of the power grid, as opposed to previously relying on voluntary compliance.[26]

<u>New Incentives for Transmission and Distribution Investment</u>

With respect to electric transmission and distribution, the Act creates several key incentives for investment in the transmission and distribution infrastructure.

- FERC is required to establish rules for incentive based rates for transmission facilities; including an ROE sufficient enough to attract new investment that is a "just and reasonable rate."
- Permits the inclusion of construction works in progress in the utility rate base.
- The depreciable life of electric transmission property has been decreased from 20 years to 15 years.
- A tax deferral provided to electric utilities that sell their transmission assets to a FERC or state approved independent transmission company. Utilities have eight years to pay their taxes on gains from sale rather than paying them in the year of the sale. All sales through 2007 qualify for the eight-year tax provision.
- FERC is granted "backstop" siting authority over the states in national corridors. FERC can use its siting jurisdiction if it believes that siting promotes national energy policy or is in the best interest of the public.
- NERC can impose fines of up to $1 million per day on users, owners, or operators of the bulk power system for violating mandatory reliability standards.[27]
- On November 18, 2005, FERC issued its "Promoting Transmission Investment through Pricing Reform" notice of proposed rulemaking, which hopes to promote greater capital investment in the transmission system. FERC has proposed numerous incentives for all owners of transmission assets, including additional incentives for independent transmission companies, in order to encourage vertically integrated utilities to divest their transmission assets. The proposed incentives for utilities include the following.
    - o **An incentive-based return on equity (ROE**) — In order to receive the ROE increase, utilities/transcos must show FERC that the new facilities will improve reliability and reduce congestion.

[25] *http://www.ferc.gov*
[26] *http://www.eei.org*
[27] *Energy Policy Act of 2005*

- **Recovery of construction work-in-progress** — This provision would allow utilities to recover their costs sooner if state commissions set their rates. This should also improve cash flow during the construction phase, which would lead to reduced borrowing costs due to stronger debt ratings and coverage ratios.

- **Expensing pre-commercial costs** — Utilities would be able to expense costs associated with pre-commercial/certification activities rather than capitalizing them, which should lead to enhanced cash flow.

- **Adoption of a hypothetical capital structure** — Utilities would have increased flexibility of proposing financing structures for different projects.

- **Accelerated recovery of depreciation expense** — Accelerated depreciation of transmission assets over 15 years rather than over the useful life of the asset. This should improve cash flow and reduce borrowing time.

- **Recovery of costs associated with abandoned facilities** — 100% of incurred costs can be recovered if factors beyond the utilities' control lead to the abandonment of a project. This incentive will lessen regulatory uncertainty and assist with new investment.

- **ROE adder for joining and RTO/ISO**[28] — If a utility joins a Regional Transmission Organization (RTO) or an Independent System Operator (ISO), FERC will grant that utility a higher ROE for transmission investment than the utility would have received otherwise.[29]

Incentives for the formation of transcos include the following.

- A higher ROE for transcos than for integrated utilities — This may promote integrated utilities to divest their transmission assets.

- Recovery of accumulated deferred income taxes — This would assure cost recovery of taxes associated with the sale of transmission assets in hopes of encouraging utilities to sell their transmission assets to transcos.

- An adjustment of the book value of transmission assets being sold to a transco to remove the disincentive associated with the impact of accelerated depreciation on federal gains tax liabilities.[30]

Repeal of PUHCA Sets the Stage for Increased Industry Consolidation and Private Equity Investment

The repeal of PUHCA that took effect on August 8, 2006, is expected to have a significant effect on investment in the electric utility industry. Before this Act was repealed, non-utility companies, which include private equity firms as well as hedge funds, were essentially prohibited from investing in the electric utility industry. The repeal of PUHCA allows for investment in the industry by non-utility companies and will allow for further consolidation among electric utility companies, which will create more private investor opportunities. Also, private and institutional investors will now be able to freely invest in

[28] An ISO is a regulated, not-for-profit entity chartered to maintain system reliability and provide coordination and reliability assurance services to the users of the transmission system. An ISO has operational authority to direct the operation of the transmission system; it does not own transmission or generation assets.

[29] *Edison Electric Institute: 2005 Financial Review Plus 2006 Developments*

[30] A TransCo, or independent transmission company, is a regulated, for-profit stock company that either owns or leases under long-term contracts, all of the transmission facilities within a specified area. A TransCo is the system administrator and operator of the transmission system.

publicly traded electric utilities. Before the Act was repealed, investors had to obtain SEC approval in order to acquire 5% or more in a public utility if they already owned 5% or more of another public utility. Also, before the Act was repealed, private investors had to devise complex capital structures in order to avoid being regulated as a holding company, which is defined as owning 10% or more of the outstanding voting securities. The repeal of the Act eliminated geographic and operational restrictions as well. The Act stated that public utilities had to be physically interconnected in order to merge. This change should have a significant effect on mergers and acquisitions within the industry, especially consolidation of noncontiguous utilities. Also, private investors should begin to see investment opportunities that were previously unavailable. The repeal of PUHCA is expected to broaden the pool of potential investors for the electricity infrastructure.

Although PUHCA was repealed, it does not mean that there will be an immediate increase in utility M&A activity. According to a Capgemini survey given to international utility executives at the EEI International Utility Conference, industry executives have been unable to reach a consensus about the future outlook for utilities. 32% of respondents believe that 2006 will be remembered as the year of the utility merger, 32% of the respondents believe that most utilities do not see any benefits from merger and acquisition activity, and 28% believe that regulatory issues will delay most deals.[31] FERC now has to grant approval for the lease, purchase, or acquisition of generation facilities that are valued at over $10 million and are used for interstate wholesale transactions of electricity. FERC and state utility commissions examine relevant books and records when considering mergers and acquisitions. FERC also has been given ratemaking jurisdiction for wholesale transactions. More importantly, most mergers require state approval. A state commission can reject merger and acquisition transactions if it is concerned about the outcome of the merger. These concerns, as well as others, could be related to the transaction itself, if it is mostly debt financed, or if the intentions of the merger do not meet public service responsibilities. Another incentive for investing more capital in the industry is the two-year extension (through 2010) of the 15% federal income tax rate on qualified dividends and capital gains.

During 2005, merger and acquisition activity in the electricity and gas industry set several records. Some electric utilities found that operating efficiencies and lower costs can be achieved through acquiring other companies, as well as expanding market share. The industry has been experiencing mostly domestic consolidation, which accounted for 71% of all power deals in 2005.[32] However, global activity is seeing growth due to more infrastructure funds building global portfolios consisting of key network assets. According to the PricewaterhouseCoopers' 2005 Power Deals report, the number of deals in 2005 rose 15% over 2004, from 459 to 527, a record for the number of deals made in one year. The total value of all deals in 2005 also set a record, netting $196 billion, up 59.3% over 2004's $123 billion and almost five times the deal value in 2003. Another record set in 2005 was the number of mega deals. There were five mega deals (i.e., over $10 billion) in 2005 (compared to just one in 2004) that accounted for $78 billion, or 40% of all transactions. Recent mega deals in the U.S. include Duke-Cinergy, FPL-Constellation, MidAmerican-Pacificorp, and Exelon-Public Service Enterprise Group. In 2005, electricity deals increased 80% and gas deals decreased by 20%. Although M&A activity has seen significant growth in recent years, federal and state regulators will continue to dictate electric utility M&A in the future.

<u>FERC and RTOs/ISOs Become the Transmission Planners</u>

The prevailing view of the early 1990s was that only utilities invested in the electric transmission grid. Once the restructuring of the electric industry began, the view switched to believing only independent transmission companies would make large transmission investments because utilities would focus more on competitive generation. Now that the Energy Policy Act of 2005 has been signed into law, other sources of investment should begin to flow due to the passage of the Act and the repeal of PUHCA. These other forms of investment will depend on the project type, the investment stage, and the likely rates of return.[33] <u>Potential sources of investments include utilities, independent transmission companies, pension funds, investment firms, asset management firms, load serving entities, independent power</u>

[31] *http://www.us.capgemini.com*
[32] *http://www.pwc.com*
[33] *http://www.icfi.com*

producers, leasing companies, engineering and construction contractors, as well as structured finance that involve debt and equity mixes as well as partnerships.[34]

Facilitators of transmission investment planning are FERC, RTOs, and ISOs. FERC has the responsibility of setting wholesale rates for interstate transmission. FERC also has backstop authority over states relating to siting transmission projects. If state and local regulators cannot overcome siting issues, FERC has the authority to step in and oversee siting if it is not completed in a timely manner (i.e., within one year of the application filing). RTOs and ISOs essentially serve the same purpose and have the same responsibilities, with the only difference being that RTOs could include independently-owned, for-profit transmission companies that own transmission assets. RTOs and ISOs are not-for-profit organizations that oversee the planning and coordination of transmission investment within their region. They are separate operators of power grid facilities that are owned by other entities, usually utilities and independent transmission companies. ISOs and RTOs act as the wholesale power marketplace for interstate power transactions. The responsibilities of ISOs and RTOs are to ensure electric stability, provide open access to transmission systems, monitor and control operations moment to moment in order to manage congestion, administer transmission tariffs, and plan and approve requests for maintenance to the system.

RTOs and ISOs currently have two different ways of funding transmission projects.[35] The first method is known as **Participant Funding**. With this method, the beneficiary of the transmission project must pay for it. Parties that benefit from transmission projects could involve independent power producers and utilities. Once the project is complete, other entities have the ability to tap into the new transmission line. These entities then pay compensation to the parties that originally funded the project. Participant funding is used in the MISO, PJM, and Southwest Power Pool regions.

Socialization Funding is the other major form of raising money for transmission projects. Socialization funding distributes the costs of new transmission projects to all participants in the region, assuming that all will benefit from the increase in reliability. Therefore, every utility and every independent power producer in the region, as well as every end-use customer pays for the project through an increase in electricity rates. This type of funding is used in ISO-New England as well as ERCOT. Socialization funding has had mixed results. ERCOT maintains a reliable system while keeping retail rates slightly above the U.S. average. In the ISO-New England, which includes Massachusetts, Connecticut, Rhode Island, Vermont, New Hampshire, and Maine, each state has retail rates that far exceed the national average.

There are many other ways to fund transmission projects. For example, the Bonneville Power Administration, one of four federal power marketers, recently completed the Shultz-Wautoma project, a new 64-mile, 500 kV transmission line connecting two substations at a total cost of $175 million. In order to fund the project within its current budget, the BPA created a special purpose entity called Northwest Infrastructure Financing Corporation. NIFC issued bonds to buy the transmission lines, towers, and appropriate fixtures and leased those facilities to the BPA. The BPA owns the substations being connected, the property rights, the easements, and rights-of-way for the project. Also, BPA pays all operation and maintenance costs once the line is complete and retains the right to purchase the transmission line for one dollar ($1.00) when the lease expires. In addition to this creative financing mechanism, BPA also held two auctions in 2005 in order to obtain financing for a 79-mile line, with an estimated cost of $167 million, but was unable to secure enough commitment.[36]

[34] *http://www.icfi.com*
[35] *http://www.nrri.ohio-state.edu*
[36] *http://www.esai.com*

Beneficial Impacts of the Energy Policy Act

- **More efficient transmission siting.** The Energy Policy Act has made it more difficult for public interest and environmental groups (arguing "Not in My Backyard") to delay the approval of power lines in certain areas of the U.S. The Act gave FERC 'backstop' authority to order the acquisition and permitting of the right-of-way for siting and development of transmission projects within national interest electric corridors under certain circumstances. Triggers of FERC backstop authority include the following.
  - The state lacks authority to approve siting or to consider the interstate benefits involved with the project.
  - The applicant (company undertaking project) does not have end-use customers in the state, making it not qualified to apply for siting approval.
  - The state approval process takes longer than one year after the application is filed or the state places conditions on the project that make it economically infeasible.

Transmission projects approval was previously required by state and local agencies in all affected areas. FERC's backstop authority should streamline the process of siting new transmission lines.[37]

- **Mandatory reliability standards.** These standards call for new transmission lines, new substations and relevant equipment, new computer software and hardware, increased operator training, greater vegetation management (which keeps trees off of power lines), etc. If these standards are not met, harsher penalties can be imposed for noncompliance on utilities. Once these standards are created, approved, and enforced, they are expected to be the catalyst for billions of dollars in new transmission investment, especially in areas of the grid that are congested or have seen underinvestment.

- **Wholesale and retail rates.** FERC incentives are expected to impact wholesale and retail rates. Utilities will likely want to increase rates in order to recover costs of investing in transmission facilities to meet mandatory reliability standards. States may object to these increases. Thus, the number of rate cases and tariff changes for transmission will most likely increase.

- **Economic transmission investment**. Historically, investment in transmission has been related to reliability concerns. This Act encourages investment in transmission for economic purposes (i.e. to lower the cost of power). There may be a new trend of investment in transmission for economic reasons.

- **Merger/Acquisition activity.** Enhanced reliability and grid monitoring could be a catalyst for consolidation within the industry. Smaller utilities will likely find it more difficult to maintain their own control areas due to the increased level of investment to correct reliability issues that need to be addressed. As a result, smaller utilities may merge with other small utilities, rely on the control areas of larger utilities, or sell their grid assets outright.

The new Federal legislation will likely boost investment in the power grid significantly over the next decade. We believe we will begin to see this investment emerge in 2007–08.

[37] *http://www.icfi.com*

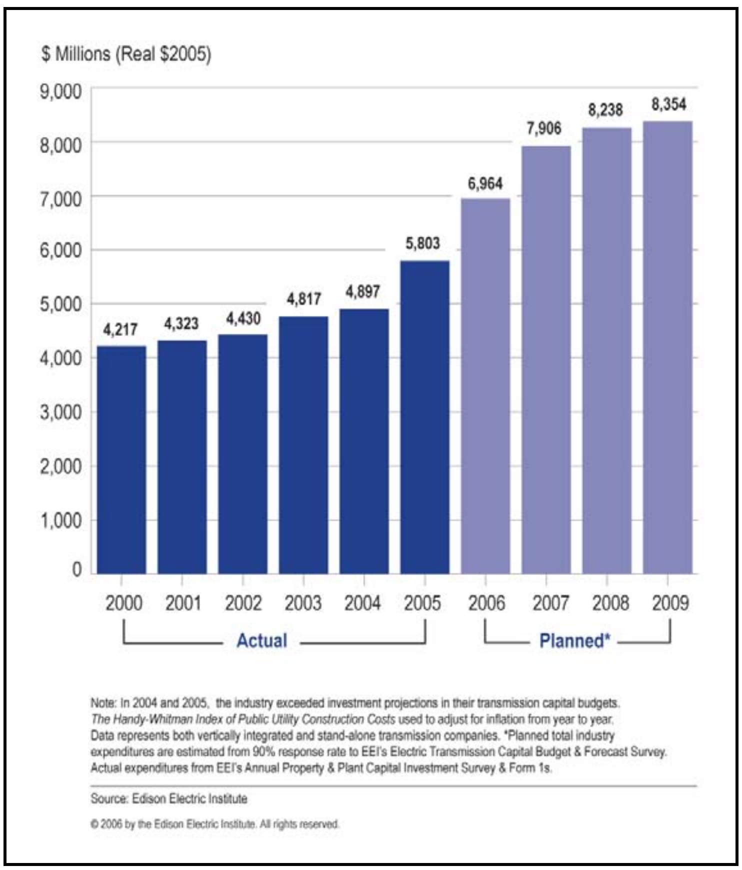
Outlook — Transmission & Distribution Spending to Increase Meaningfully

Increased Spending on Transmission Infrastructure

Since 1998, transmission investment by utilities has begun to increase following decades of decline In 2005, investment in transmission by shareholder-owned utilities reached a new record of $5.8 billion. According to Edison Electric Institute (EEI) investment in transmission infrastructure increased 116% from 1999-2005, rising from $2.688 billion in 1999 to $5.803 billion in 2005 (Real 2005$). This $5.8 billion level of transmission investment had not been seen in the industry, in real terms, since the late 1960s. Additionally, the EEI reports that transmission investment by investor-owned utilities grew a robust 18.5% from 2004 to 2005. Based on data from its most recent *Electric Transmission Capital Budget and Forecast Survey,* the EEI forecasts that total investment by electric utilities on transmission infrastructure from 2006 through 2008 will total $23.1 billion; this would represent a 31.4% increase over the 2003-2005 time period. The most recent EEI investment survey reveals that utility company forecasts for transmission investment are increasing, for in EEI's May 2005 survey, utility transmission expenditures from 2006-2008 were forecast at $18.3 billion, roughly 20% below the current forecast.

Exhibit 12
Electric Transmission and Distribution
Actual and Planned Transmission Investment

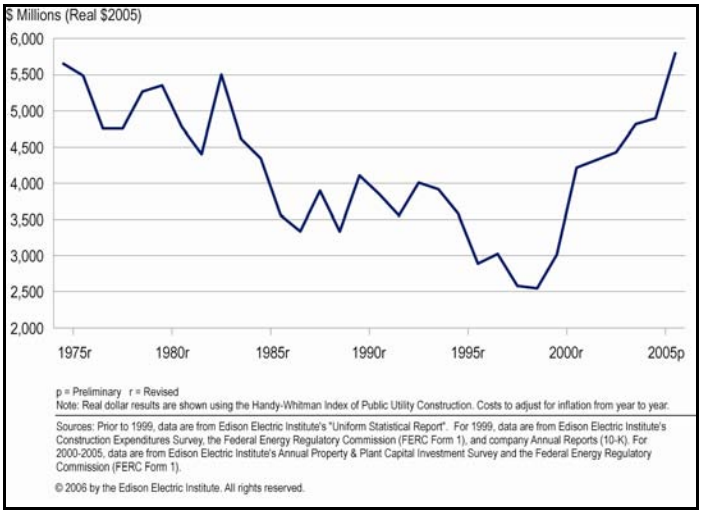
Actual and Planned Transmission Investment by Shareholder-Owned Electric Utilities (2000-2009)



Source: EEI

Exhibit 13
Electric Transmission and Distribution
Historical Transmission Expenditures

Construction Expenditures for Transmission, Shareholder-Owned Electric Utilities (1975-2005)

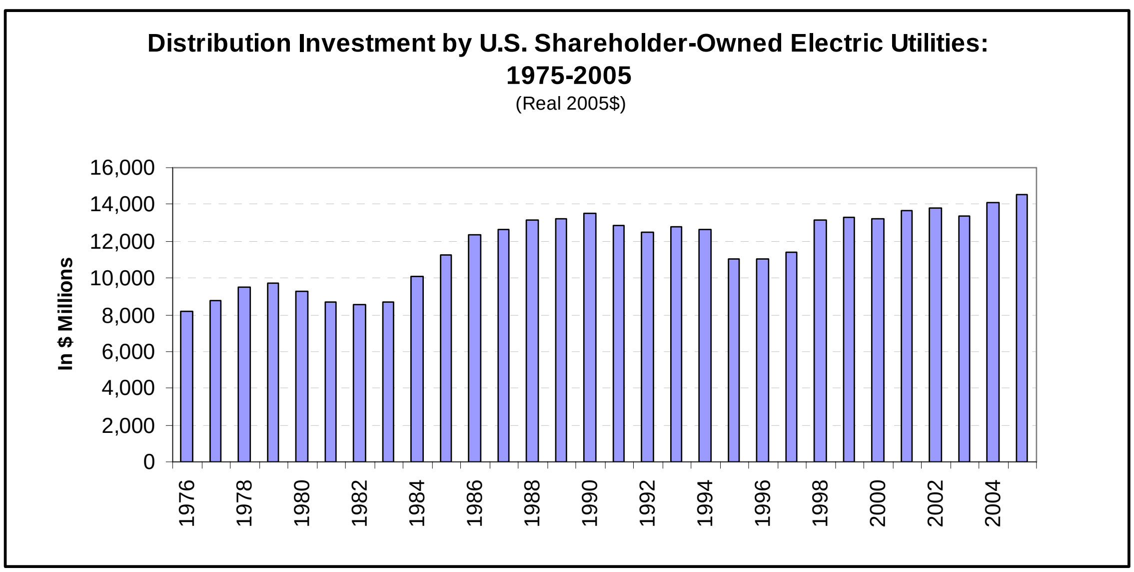


Source: EEI

The increase in transmission investment should enhance grid reliability and allow for more regional transmission capability. At this time, the current trend of increasing investment in transmission shows no signs of slowing down.

Increased Spending on Distribution Infrastructure

Exhibit 14
Electric Transmission and Distribution
Distribution Investment



Source: EEI

Investment in distribution systems is needed in order to replace aging infrastructure and to modernize the system with new technologies that advocate management and control of distribution operations. There has been a steady increase in distribution investment since 1975; the continued investment was necessary to keep pace with population growth. According to an EEI report entitled, *Rising Electricity Prices: A National Perspective*, distribution investment in 2005 by shareholder-owned electric utilities was approximately $14.566 billion.[38] Anecdotal comments from industry players suggest overall spending on distribution is currently running an average of $18 billion per year.

The distribution network is plagued with outdated equipment. Black & Veatch estimates that the industry needs to spend an additional $8 billion–$10 billion per year in addition to the current $18 billion per year to tackle the problem of obsolete and outdated equipment.

In many areas of the U.S., utilities are putting existing distribution lines underground, which is far more expensive than typical overhead lines. The average for the dollar cost/mile of underground distribution lines is $957,258 and the average for the dollar cost/mile of overhead distribution lines is $120,000.[39]

Underestimation of Transmission Project Costs

Actual costs of investment in the electric infrastructure are exceeding estimated costs in several cases. For example, AEP's 89-mile Wyoming-Jackson Ferry 745 kV transmission project was underestimated by 6.76%, or $19 million.[40] This project took 14 years and $50 million to obtain all of the necessary permits before construction started.[41] Another example is in the ISO-NE, where an assessment was made in July 2006, regarding current transmission projects greater than 345 kV. The assessment showed that the ISO-NE had underestimated the costs of all of its projects by $187 million.[42] Another project where the original anticipated costs were far below actual costs was American Transmission Company's Arrowhead-Weston project. The 220 mile, 345 kV transmission line was originally estimated by planners to cost $165 million. The new estimated cost for the project is $396 million, which is an increase of $231 million or 140%.[43] The Jefferson-Martin project undertaken by Pacific Gas & Electric Company is another project that is currently over budget. The original construction cap was $206.988 million. The new 27-mile, 230 kV transmission line is currently being built at a cost of $220 million, which is roughly $13 million and 6.3% over budget.[44] These are only a few examples of long-term transmission projects that have underestimated costs associated with them. Factors that are causing the underestimating of projected costs include delays in obtaining siting permits, acquiring state approval of the projects as well as state approvals for rate increases, and the timely completion of the project once the construction phase is underway.

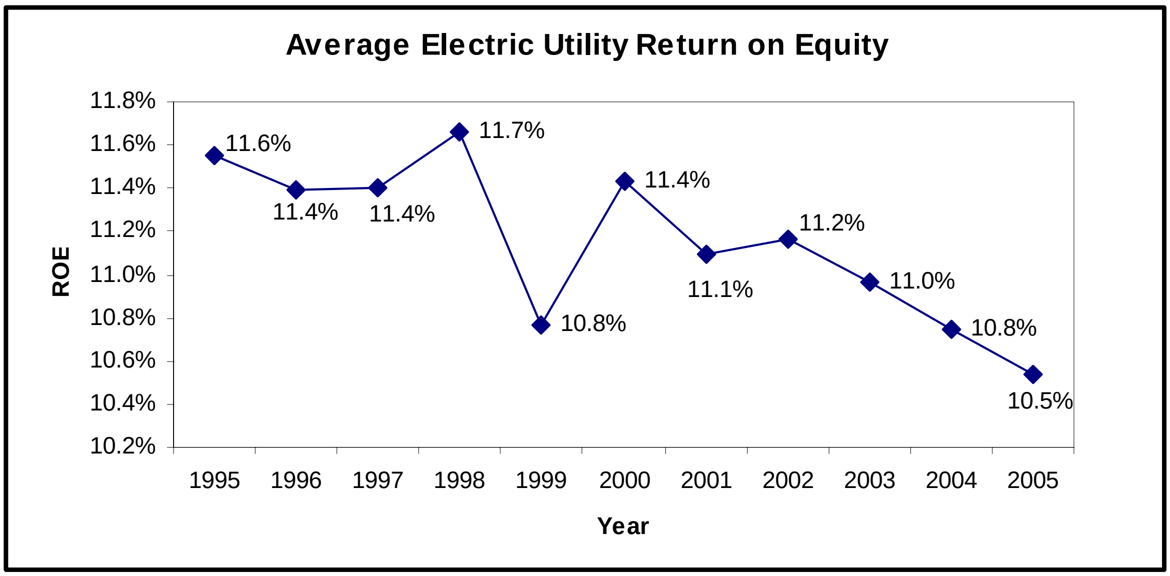
[38] *http://www.icc.illinois.gov*
[39] *http://www.eei.org*
[40] *http://www.aep.com and http://www.aep.com*
[41] *http://www.esai.com*
[42] *http://www.iso-ne.com*
[43] *http://www.jsonline.com*
[44] *http://omega.twoday.net*

Current Trends

Potential Increase in Utility ROEs

Since deregulation of the power industry began in the mid-1990s, electric utilities have seen their ROEs decrease significantly. However, with the implementation of the Energy Policy Act of 2005, electric utilities and stand-alone transmission companies should begin to receive government regulated ROEs that are sufficient to attract new investment. Provisions in the Energy Policy Act of 2005 will allow utilities and stand-alone transmission companies to receive ROE adders in addition to their allowed ROE if the company joins a RTO or an ISO, and ROE adders may become a function of the underlying interest rate.[45] MISO transmission owners just received a baseline ROE of 12.38%, along with ROE adders for certain companies. For example, ITC Holdings, the only publicly traded stand-alone transmission company, received a 13.88% ROE after asking for a 100-basis-point increase. Following in ITC's footsteps, Michigan Electric Transmission Company is asking FERC for a 150-basis-point increase of MISO's baseline rate, which would give METC a ROE of 13.88%.[46]

Exhibit 15
Electric Transmission and Distribution
Average Electric Utility ROE



Source: EEI

Rising Electricity Prices

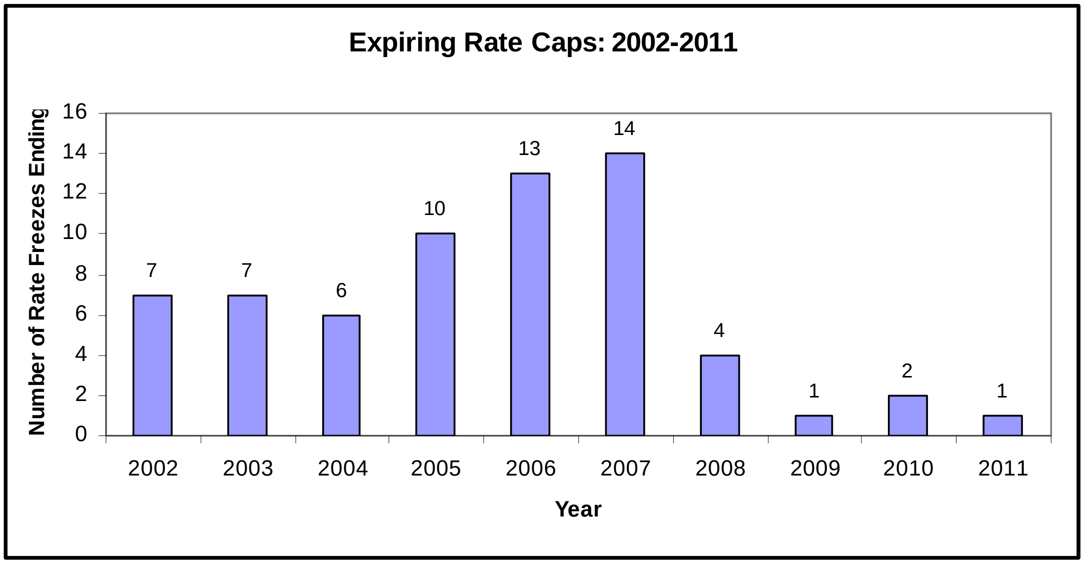
The U.S. average price for electricity is lower today than it was in 1980, when adjusted for inflation.[47] However, the U.S. has been experiencing rising electricity prices over the past five years. The primary drivers of electricity rate hikes over this time period have been higher fuel costs, which led to higher operating costs and higher construction costs for utilities.

Expiring rate caps. Outside of these increases, the general trend was toward rate freezes, or rate reductions, that were driven by the restructuring of the industry and were imposed by state public utility commissions. However, these rate freezes are expiring. Essentially, the real cost of power has not been reflected since rate caps were implemented. Once rate freezes expire, numerous electric utilities are

[45] *http://www.esai.com*
[46] *http://www.cis.state.mi.us*
[47] *Edison Electric Institute: "Assessing Rate Trends of US Electric Utilities": http://www.eei.org*

expected to apply for rate cases in which they will seek rate increases. The Public Utility Commission (PUC) of the state in which the rate case was filed will review these rate cases. The primary purpose of the rate increases is to recover the costs of purchased power expenses and prudent construction costs over the previous year.

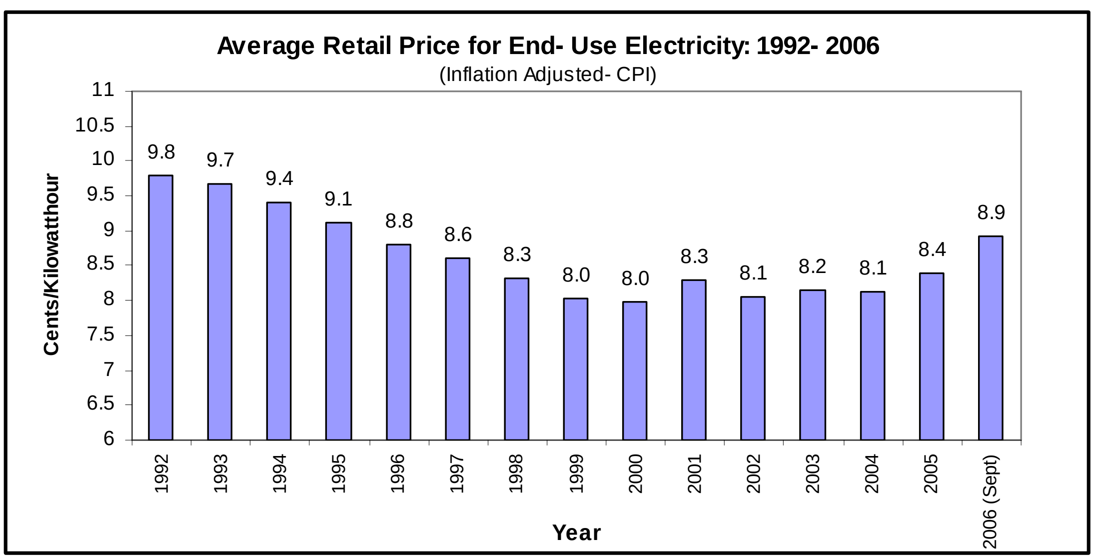
Exhibit 16
Electric Transmission and Distribution
Expiring Rate Caps



Source: EEI

Exhibit 16 represents the average retail price of electricity for all U.S. sectors combined, adjusted for inflation.

Exhibit 17
Electric Transmission and Distribution
Average Retail Prices for U.S. Electricity



Source: EIA

State Regulation versus Deregulation

After FERC Order 888 in 1996, a wholesale electricity market was created in the U.S. It was a common belief that deregulation leads to a competitive marketplace, which would, in turn, lead to lower electricity prices. However, some areas of the country have experienced record levels of high electricity rates in recent years. Furthermore, rate freezes imposed in certain areas are set to expire in the near future, and as a result, rates will likely be driven up due to higher fuel costs associated with electric delivery, resulting in filings for rate increases. At one point in the 1990s, nearly every state passed a law, or considered passing a law, that deregulated its electric power market. Since then, many states have postponed deregulation. Following is a breakdown of states that are regulated (do not allow retail access), deregulated (allow full retail access to customers), and other specifications. [48]

- **Regulated** (do not allow customers retail access) — Washington, Idaho, Utah, Wyoming, Colorado, North Dakota, South Dakota, Nebraska, Kansas, Missouri, Iowa, Minnesota, Wisconsin, Louisiana, Mississippi, Alabama, Georgia, Florida, Tennessee, South Carolina, North Carolina, Kentucky, Indiana, Vermont, Hawaii, and Alaska (26 states total)
- **Deregulated** (allows all customer groups full retail access) — Arizona, Texas, Illinois, Michigan, Ohio, Pennsylvania, Virginia, Maryland, Delaware, New Jersey, New York, Connecticut, Rhode Island, Massachusetts, New Hampshire, Maine, and Washington, D.C. (16 states total plus the District of Columbia)
- **Restructuring laws delayed/repealed** — West Virginia, Arkansas, Oklahoma, and New Mexico
- **Limited retail access** — Oregon and Nevada
- **Retail access suspended** — California
- **Residential transition period** — Montana (extended through 2027)

Electricity rate situations that have occurred this year in deregulated and regulated states

- **Deregulated States**
  - *Milford, Pennsylvania (Pike County)*: Electric rates have more than doubled since January 2006, although rate caps protect most households in Pennsylvania until 2010. Deregulation was expected to bring about competition and allow for power to be provided by the lowest cost supplier. Instead, only two power suppliers bid in an auction to serve the Pike County area with electricity.
  - *Maryland*: Baltimore Gas and Electric Co. customers have had artificially low rates since 1999 due to rate caps that were set for restructuring. Once the rate caps expired, customers received word in March 2006 about a 72% rate increase. Pepco customers in Maryland have seen a 38% increase in electricity rates since its rate cap expired.[49]
  - *Delaware:* Delmarva Power increased rates 59%, lawmakers decided to phase in the rate hikes over several years and require power companies to participate in long-term planning. Delaware had a 35% rate increase in May 2006.[50]
  - *New England (excluding Vermont):* Rate caps expired last year, and retail electricity prices have increased around 15%.
  - *New York:* Rates have increased 30%.
  - *Washington D.C.:* When Pepco Holdings lifted its rate caps a few years ago, customers in D.C. saw a 12% rate increase.
  - *Arizona:* APS was approved for a 7.6% rate increase to recover higher natural gas costs. They were also given a $0.004 per kilowatt hour power supply adjustor. Combined, residents will see rates rise 13.1%, and businesses will see electricity prices increase 14.9%.[51]
  - *Montana:* Montana had the region's lowest electricity rates. In 1997, Montana deregulated electric generation and sold off its hydro-electric dams. Those dams produced electricity for

[48] *http://www.csmonitor.com*
[49] *http://www.csmonitor.com*
[50] *http://www.washingtonpost.com*
[51] *http://www.aps.com*

$20 per megawatt hour. Now, those dams produce power for $31 per megawatt hour — a 55% increase since deregulation.
  - *Massachusetts:* 27.5% rate increase.
  - *Texas:* 24% rate increase.
  - *Nevada:* 23% rate increase.

- **Regulated States**
  - *Vermont*: Rates have remained relatively flat throughout the state.
  - *North Carolina*: Rates increased 4.4%.
  - *West Virginia*: Rates increased 23%.
  - *Oklahoma*: Rates increased 32%.
  - *Kentucky*: Rates increased 27.1%.
  - *Colorado*: Rates increased 30%.
  - *Idaho*: Rates increased 24.1%.

Regulated states. The main component causing the increase in operations and maintenance costs in regulated states are fuel expenses. To recover these costs, utilities and companies within the industry are filing with state commissions for rate hikes. Since January 2004, there have been 111 rate cases in regulated states, 51 (45.9%) of them are related to fuel cost increases. Also, since late 2005, 12 regulated states have double-digit rate increases pending. From 1997–2005, total percentage rate increases for regulated states were slightly higher than those in restructured states, increasing roughly 22% compared to restructured rates increasing by roughly 17.5%; however, this has not been the case in recent years.[52]

Restructured/Deregulated states: Utilities are facing higher purchased power costs as a result of deregulation in addition to higher fuel costs. In restructured states, there have been 125 rate situations since 2004. 63 (50.4%) of them are related to fuel cost increases. In more recent years, electricity rates in deregulated states have actually increased more than in regulated states due to expiring rate freezes and short-term procurement. Many restructured states have rate freezes that are set to expire in the near future, which should result in rates that reflect current fuel prices.

Formation of Transcos

A transco is a regulated, for-profit company that either owns or leases under long-term contracts all of the transmission facilities within a specified area. Transcos are system administrators and serve as operators of the grid. These companies are also responsible for investing in new transmission facilities. They are unlike independent system operators in that they own the transmission assets, act economically, and have their own interests over market participants. However, transcos are similar to ISOs in that they provide open access to the grid, monitor and control system operations, manage congestion, administer transmission tariffs, and provide operating reserves and voltage support. Transcos have proven to be an excellent source of transmission investment, with three transcos in the Midwest investing at five times the rate of the previous owners.[53] Currently, there is only one publicly traded stand-alone transmission company within the U.S. However, according to Edward Krapels, founder of Wakefield, Massachusetts, based Anbaric, an independent transmission development and consulting company, "ITC is the first of what ultimately will be several public entities formed to take advantage of the new incentives offered by FERC."[54] American Transmission Company, which has owned and operated the transmission grid for roughly 30 utilities in Wisconsin, Minnesota, and Illinois over the past five and a half years, is thought by some industry analysts to be the next transco to go public.

According to FERC, transcos must be independent. There may be some passive ownership of these companies, but transcos carry a 49% interest restriction. Also, transcos are not allowed to participate in

[52] *http://www.icc.illinois.gov*
[53] *http://www.esai.com*
[54] *http://yahoo.smartmoney.com/*

the power trading business. This is in order to prevent transcos from gaining upside from a transmission project by trading around it. Transcos are given incentives to buy assets from utilities, including a regulated rate of returns higher than traditional utilities. In restructured, deregulated states, investment in transcos is likely to only occur on a project-by-project basis because those utilities are focused on national acquisitions. Utilities in states that are still regulated are not likely to invest in transcos and are more likely to invest in local transmission and maintain/enhance the reliability of their own service territory. Although transmission developments will always be made for reliability purposes, even at current rates of return, there has not been an increase in economic transmission developments, or transmission projects with the intention of lowering the cost of power. There are two main reasons for the lack in economic transmission investment.

1. It is hard to capture capacity spreads for transmission projects because the cost of generating capacity varies greatly across regions.
2. There is a lack of competition for the retail segment within the power sector.

Leading Publicly- Held Companies within Electric Transmission and Distribution

We differentiate the leading publicly held companies that serve the electric T&D market into two categories: (1) network service providers, and (2) component and equipment manufacturers.

The network service providers act as an outsourcing arm for the electric utility industry, performing maintenance, repair and power restoration services on their transmission and distribution networks. In addition, the companies design and build new transmission and distribution lines and substations. Of the five or six large service providers in the U.S. that can undertake large projects, three are public — InfraSource, Pike Electric, and Quanta Services. The service providers are more pure plays on the electric T&D spending theme, with T&D exposure ranging 61% to 100% of company revenues. A large portion of the non-electric revenues at InfraSource and Quanta Services are similar network services for the telecom and natural gas industries.

The producers of electric T&D components and equipment provide a wide range of products, including transformers, switchgear, connectors, pole line hardware, cables, enclosures, bus duct systems and steel towers and poles. Often, one or two companies have very high market shares in a given product set, so that the publicly held companies listed below generally have strong market positions in electric T&D. The electric T&D producers have less total company exposure to this market segment than the network service providers, generally ranging 19%-44% of total sales (we estimate that 60%+ of Powell's electrical sales are T&D).

Exhibit 18 lists leading public T&D-related companies by percentage of sales:

Exhibit 18
Electric Transmission and Distribution
Leading Publicly-Held Electric T&D Companies

Publicly-Held Electric Transmisson & Distribution Companies		
T&D Network Services	**% Revenue**	**Description**
InfraSource Services (IFS)*	61% Electric	Focus on constructing high voltage transmission and substations. One of two largest in U.S.
	39% Other	Natural gas and telecom system construction and maintenance. Provides telecom services.
Pike Electric (PEC)	100% Electric	Maintain/construct electric transmission and distribution networks. Major storm restoration.
Quanta Services (PWR)*	66% Electric	Maintain/construct electric transmission and distribution networks. Largest in U.S.
	34% Other	Maintain/construct communication networks and transportation systems.
T&D Components/Equipment	**% Revenue**	**Description**
General Cable (BGC)*	40% Electric T&D	#1 producer of electric T&D cables in North America and est. #3 in Europe.
	60% Other	A leading producer of industrial and communication cables.
Hubbell (HUBB)*	20% Electric T&D	Broad line of T&D components, with focus on pole line hardware.
	80% of Other electric	Lighting, connectors, other electrical products
Thomas & Betts (TNB)*	19% Electric T&D	Connectors, components, switchgear. A leading producer of steel T&D poles.
	81% Other electric	Broad line of components for commercial and industrial markets and HVAC.
Cooper Industries (CBE)	19% Electric T&D	Broad line of electrical components
	66% Other electric	Broad line of electrical components
	15% Other	Industrial and consumer tools
Powell Industries (POWL)	93% Electrical power	Switchgear, bus duct systems, power control systems
	7% Other	Distribution and control systms
AZZ Inc. (AZZ)	28% Electric T&D	Switchgear, bus duct systems, enclosures, control systems
	32% Other	Electrical products, industrial lighting, tubular products; 40% steel galvanizing
Valmont (VMI)	21% Electric T&D	Steel and concrete poles and towers
	79% Other	Engineered support structures, coatings, irrigation equipment, tubing
ABB Ltd. (ABB)	44% Electric T&D	Transformers, switchgear, apparatus; electric transmission systems for grid
	56% Other	Process control systems, robotics

Source: Company data, Stifel Nicolaus estimates * Covered by Stifel Nicolaus

Electric T&D Industry Valuations

2006 Investment Performance. The 11-stock universe of public companies with electric T&D exposure achieved average stock price appreciation of 62.3% in 2006, with the service providers providing a 38.8% average investment return and the manufacturers providing a 71.1% average investment return. Within the group of manufacturers, the 3 broad-line electric companies (Hubbell, Thomas & Betts, and Cooper Industries) appreciated an average 12.3% in price while the remaining manufacturers rose an average 106.5% in price.

T&D Network Service Providers. The three service providers (PEC, PWR, IFS) are forecast to achieve rapid EPS growth averaging over 22% annually over the next five years. Following the strong 2006 stock price appreciation (+39%), the group is selling at high valuations: 22x-28x 2007 EPS and 9x-16x EV/2006 EBITDA. Two of the firms, PEC and IFS, have been public companies for only a couple of years and, therefore, have limited histories. Quanta Services, PWR, was valued at 15x-30x EPS during the past expansion of 1998-2000.

T&D Component and Equipment Manufacturers. Because the high-growth T&D sector represents only 19%-44% of total sales for seven of the eight manufacturers, 5-year forecasted EPS growth ranges 10%-20% annually, which is below that of the service providers. The valuations are correspondingly lower as well, ranging 13x-18x 2007 EPS and 10x-12x EV/2006 EBITDA. Powell Industries is the exception, having the highest exposure to electric T&D, the highest forecasted EPS growth and correspondingly, the highest valuation. The three broad-line electric companies (Hubbell, Thomas & Betts, and Cooper Industries) are valued near the low end of 10-year P/E ranges of 15x-19x forward EPS.

Exhibit 19
Electric Transmission and Distribution
Electric T&D Company Valuations

Electric Transmission & Distribution Company Valuations

Company	Ticker	Price 2/5/07	P/E 2006E	P/E 2007E	5 Yr. EPS Growth	PEG Ratio	EV/ EBITDA	Market Cap (Mil.)	T&D Exposure % revenues
T&D Network Services									
Pike Electric	PEC	$16.44	63.2	22.2	18.0%	123.4%	8.8	$546	100%
Quanta Services	PWR	$20.79	35.8	30.1	25.0%	120.5%	17.3	$3,087	66%
InfraSource Services	IFS	$22.50	32.1	28.8	24.0%	120.2%	12.3	$907	61%
Median			**43.7**	**27.1**	**22.3%**	**121.4%**	**12.8**		**75.7%**
T&D Components/Equipment									
Powell Industries	POWL	$33.10	37.2	24.0	25.0%	95.9%	16.8	$367	93%
ABB Ltd.	ABB	$18.07	26.2	20.3	17.5%	115.8%	12.9	$41,416	44%
General Cable Corporation	BGC	$43.23	18.9	14.9	20.0%	74.5%	9.5	$2,274	40%
AZZ Inc.	AZZ	$40.76	13.5	13.9	NA	NA	7.4	$240	28%
Hubbell Inc.	HUB'B	$49.20	18.5	15.1	15.0%	100.9%	10.8	$3,006	20%
Valmont Industries	VMI	$55.57	23.5	19.7	20.0%	98.5%	10.5	$1,439	21%
Thomas & Betts	TNB	$49.01	17.8	15.0	12.0%	124.9%	10.7	$2,960	19%
Cooper Industries	CBE	$92.12	17.9	15.7	9.5%	164.9%	11.7	$8,641	19%
Median			**21.7**	**17.3**	**17.0%**	**110.8%**	**11.3**		**36%**

Source: Company data and Stifel Nicolaus estimates Bolded companies- FirstCall estimates

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