EDISON ELECTRIC INSTITUTE

Meeting U.S. Transmission Needs

Prepared by:

Energy Security Analysis, Inc.

Prepared for:

Edison Electric Institute

July 2005

Attribution Notice and Disclaimer

Published by:
Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Phone: 202-508-5000
Web site: www.eei.org

TABLE OF CONTENTS

EXECUTIVE SUMMARY

The purpose of this report is to review the state of electric transmission investment in the United States. Over the last decade, studies have demonstrated that investment in transmission has lagged behind investment in generation.[1] In recent years, investment in generation has clearly diminished, but this appears not to have affected investment in transmission. To the contrary, transmission investment appears to be expanding.

Factors Promoting Growth in Transmission Investment

The pace of transmission development, however, is not readily apparent in part because so much attention has been paid instead to generation. Energy Security Analysis, Inc. (ESAI) was commissioned by the Edison Electric Institute to evaluate the state of transmission development. Our review indicates there are four factors motivating sustained or even accelerated investment in transmission.

1. State and federal regulators continue to encourage electric utilities and independent transmission developers to invest in transmission both to increase overall system reliability and robustness and to increase transfer capacity between areas. Regulators appear to agree that more investment is needed in transmission for the sake of both improving reliability and expanding trade.
2. Transmission service territories are changing in many parts of the country, resulting in broader areas of inter-regional transmission planning. In many areas, transmission investment deliberations that used to be confined to transmission owners and their regulators have now been joined by other stakeholders, including regional planning organizations, investors, generators, and developers.
3. Surplus generation developed during the construction boom of the past decade is gradually being consumed, requiring better integration of poorly located generation facilities into their regional grids. Transmission upgrades required to connect generators to the grid, and financed by those generators as part of their interconnection cost, may have declined; but baseline transmission network upgrades are increasing as it becomes more important to optimize the connections of existing generators to the grid.
4. More transparent regulations on locational reserve requirements are making the need for transmission projects that effectively migrate capacity from generation to load pockets more apparent. Thus, there are more transmission projects under discussion and under development whose essential purpose is to relieve congestion in load pockets.

Remaining Constraints on Transmission Development

While these factors are sustaining and promoting transmission development, the task of actually getting a project planned, approved, permitted, and financed remains daunting. For utilities, transmission development remains an area that competes for investment with distribution investments (which, regulated at the state level, often carry a higher rate of return than those allowed at the interstate level by the Federal Energy Regulatory Commission). Often, given that transmission projects require the expenditure of substantial amounts of political capital, these projects lose the internal battle for funding.

[1] For example, Energy Information Administration data indicate that approximately 400 Gigawatts of new generation has been built over the last decade. At an average cost of $500 per kilowatt, that represents an investment of $200 billion. At the same time, $40 billion in transmission investments were made, according to a 2004 Energy Information Administration report, *Electricity Transmission in a Restructured Industry: Data Needs for Public Policy Analysis*, page 37.

Independent projects compete for the long-term contracts without which investors are (so far) unwilling to finance transmission. Such contracts are few and far between, so while there are some success stories—Path 15, Cross Sound Cable, Neptune—there are as many projects that have failed because of their inability to secure long-term commitments.

Thus, the clear need for an increase in transmission investment exists in an investment climate that remains fragmented by different procedures, incentives, and constraints from region to region. Over time, however, the growing need for transmission investment will have to give rise to policies and incentives that enable transmission development to occur. We believe this is not an option, but a necessity, and on the basis of that necessity it is reasonable to argue that the next ten years will see a substantial increase in transmission investment in North America.

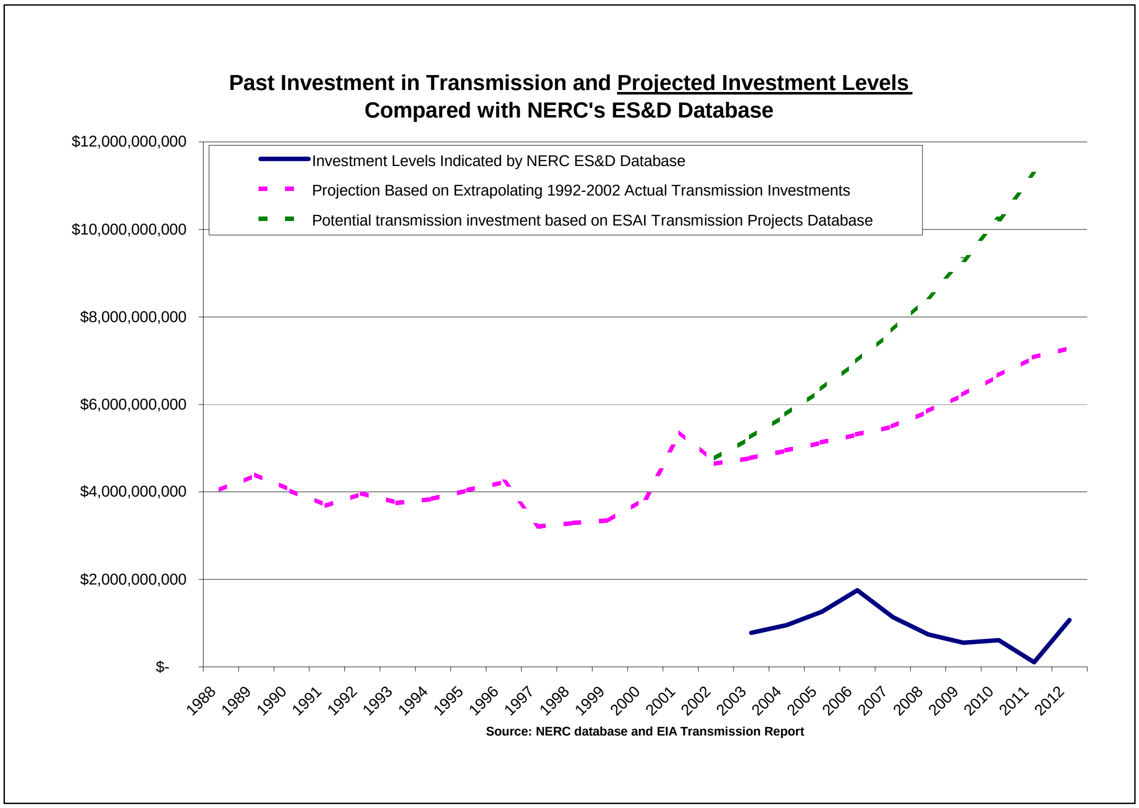
Need for Better Information

A starting point for improved understanding of the transmission outlook is better information. Unfortunately, the most readily available source of information on the pace of recent and ongoing transmission investment[2] has limitations that mask the full extent of transmission investment in the country. As shown in the chart below, during the past 10 years, investment in transmission by public utilities, investor-owned utilities, and municipal and rural cooperatives has averaged $3.6 billion per year, and in 2003–2004 increased to $5 billion per year. The most readily available source of *planned* investment in transmission is the Electric Supply and Demand (ES&D) database of planned projects issued annually by the North American Electric Reliability Council (NERC). Its current compilation of projects indicates total investment levels in the range of $500 million to $2 billion per annum.[3]

We have made a simple extrapolation of the growth rate of transmission investment over the last ten years, and compared these extrapolated results with the NERC projection of transmission investments. The results are shown in the chart above. NERC's ES&D list of future projects unintentionally implies transmission investment levels of less than $2 billion per year. The ES&D, however, is a poor indicator of the likely investment in transmission, largely because it was not intended to be a comprehensive forecast. A more comprehensive and accurate forecast of future transmission investment requires a more systematic and probing survey of all of the participants in this segment of the electric industry.

[2] The NERC data are drawn from the EIA's Form EIA-411, through which regional reliability councils submit projects that were voluntarily reported to them by utilities. This form requires disclosure of transmission projects greater than 230 kV. See the Appendix for an excerpt from the 2004 EIA report, *Electricity Transmission in a Restructured Industry: Data Needs for Public Policy Analysis*, that provides a comprehensive analysis of the transmission line and project information collected by the federal government.

[3] There are straightforward reasons why the NERC ES&D presents a limited picture of transmission development: the information in the ES&D database is drawn from the Energy Information Agency's Coordinated Bulk Power Supply Program Report (EIA-411). The Department of Energy requests that each of NERC's ten regional reliability councils voluntarily submits data provided by utilities and other electricity suppliers within their Council area. Schedule 6 of form EIA-411 asks respondents to provide information on all transmission line additions of 230 kV and above that are expected over the coming five years. The data are collected annually. Much transmission investment falls below the 230 kV level, and entails upgrades to existing facilities. As a result, the NERC ES&D likely reports on only a fraction of planned transmission investment.



Simple extrapolation of historic data indicates transmission investment levels of $5 billion per year rising to $7 billion per year over the next decade. ESAI's review of transmission expansion plans, however, suggests that the pace of transmission investment will be even higher, rising to the $10 billion and more per year level shown in the chart above. Regional transmission expansion planning by ISOs and RTOs has put into play a process that compels the building-out of their transmission systems to maintain reliability across larger and larger market footprints. The slowdown in merchant generation investment, and a growing desire to diversify the generation portfolio (or maintain a diversified portfolio) are causing utilities and their state regulators to re-evaluate the role of transmission in bringing wind, coal, and hydro resources into the generation mix. The difficulty of building generation in heavily urbanized areas has given rise to a number of AC and DC transmission projects that meet resource requirements in these markets with generation located elsewhere.

Looking ahead, ESAI has compiled a database of more than 3000 transmission projects currently under discussion, or in the early stages of development by utilities, developers, RTOs, and reliability and economic expansion study groups (like the Rocky Mountain Area Transmission Study Group). Should even a moderate number of these projects come to fruition—and that depends on how well the utility and development communities respond to current and future incentives to build transmission—the amount of annual investment in transmission is likely to grow along the path suggested in the "potential transmission investment" line shown in the chart above.

Who Will Invest in Transmission?

We cannot simply project potential increases in transmission investment without addressing the issue of who will lead the charge. The restructuring process began in the early 1990s with the prevailing view that only utilities would invest in transmission. That was replaced for a time with the opposite view, which assumed the unbundling of generation, transmission, and distribution segments of the electricity business, and envisioned that only specialized independent transmission companies (ITCs) would make transmission investments, and that with locational pricing and free markets, merchant transmission projects would materialize in large numbers.

By 2005, however, it has become clear that the scope of needed and desired transmission investments is such that they will have to be made by both utility and independent entities. Our survey of the transmission sector reveals an array of new transmission ideas and initiatives. Many of these new initiatives are by established utilities, who appear—by and large—to have re-energized their transmission development efforts. In some parts of the country, those efforts are harnessed by new regional transmission expansion plans (RTEPs) created by RTOs. In other parts of the country, the efforts are led by the incumbent utilities which are not part of RTOs.

This surge of transmission activity is not apparant to the casual observer with access only to the NERC ES&D database because the NERC transmission expansion figures report investment only in 230 kV lines and above. There is at least as much bulk transmission activity below this threshold as there is above it Moreover, the NERC data is limited to “new lines” and does not pick up system upgrades within existing corridors. But there is much activity in projects that improve system reliability and increase bulk transport of power without the construction of a new line.

Transmission expansion, therefore, is on a faster track than the NERC ES&D indicates. But there is still room for more transmission investment. In the last decade, roughly $200 billion was invested in new generation while $40 billion was invested in transmission. Given the virtual collapse in investment in generation, that 5:1 ratio may well be reversed. This report indicates that funds will flow into transmission investment under an array of strong pressures, ranging from the reliability upgrades by utilities and RTOs (which has been averaging $3–$4 billion per year), to economic projects.

How much will be invested in reliability and economic projects over the next decade? That is one of the most difficult answers in the power markets today. The industry does not yet have an authoritative transmission project database, but as this report shows, there are indications of hundreds of projects awaiting development. Unlike with generation, however, there will be no cookie-cutter approach to transmission development. Each project has its own economic, regulatory, and technical complexities. Because each power market area has developed its own market design, it will also have its own particular approach to transmission expansion. Even though there may be similarities, substantial differences remain and are likely to remain.

Part I
DRIVERS OF TRANSMISSION EXPANSION: 2004 TO 2014

As the project discussions in the second part of this report will show, the North American electric transmission grid is changing beyond what might be inferred from looking at the NERC database. If there is more to transmission than NERC suggests, how will it get done? Who will do it?

Traditionally, only utilities invested in transmission. With restructuring of the power market came the expectation that the unbundling of generation, transmission, and distribution segments of the electricity business would lead to specialized independent transmission companies making the bulk of transmission investments. Some believed that, with locational pricing and free markets, merchant transmission projects would materialize in large numbers.

Over time, it has become clear that both utilities and independent developers will be needed to take advantage of the many transmission requirements and opportunities that have emerged.

The Emerging Grid

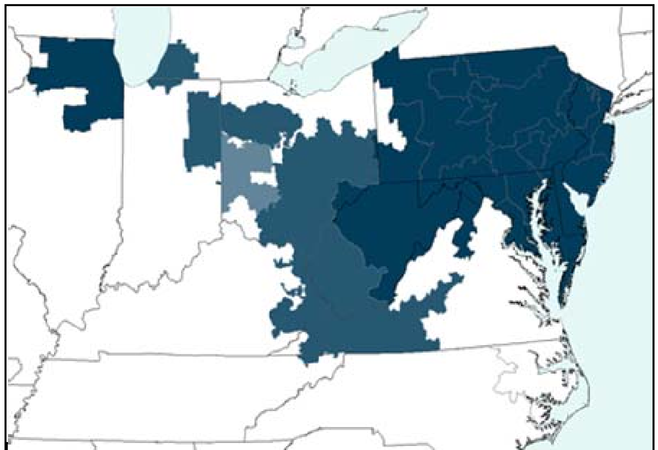
The North American transmission grid is evolving into a complex amalgamation of regions with a wide array of market designs: formalized and powerful RTOs in the Northeast, Midwest, Southwest, and California; more traditional utility structures in the Southeast and parts of the West; a diverse group of provincial markets in Canada. In this intricate array, decisions about transmission investment are being made in response to an equally intricate set of reliability requirements, economic incentives, and constraints.

The traditional transmission system allowed a modest amount of electricity trade between the distinct North American Electric Reliability Council (NERC) regions and sub-regions. The grid evolved into regions clustered into reliability councils organized decades ago. Important work has been done and will continue to be done in NERC to improve the reliability of the electric grid.

In addition, there are newer and more complicated arrays of transmission relationships. Before restructuring, and before the Public Utilities Regulatory Policy Act of 1978, utilities tended to build generation and transmission in tandem. As federal policy opened up the power generation business to non-utility generators, however, generators were often built in places inconvenient for the transmission utility.

The propensity to build generation without a great deal of attention to transmission became even more pronounced in the 1995–2003 era of exuberant construction of merchant facilities. As a result, there are generation surpluses in some markets, most notably in the Southeast. Integrating these surplus generators into the grid represents one clear area of challenge, and opportunity, for transmission planners and developers.

While NERC continues to be the locus of discussions about electric system reliability, PJM, the New York ISO, the New England ISO, ERCOT, the Midwest ISO, the SPP RTO, and the California ISO have become—in their sometimes changing geographic areas—the locus of day-to-day transmission operations, electricity trade, and of a growing amount of transmission investments by generators, independent developers, and utilities. Some of the investment is now being made pursuant to an important new regional initiative: the regional transmission expansion plans (RTEPs) of which New England and PJM are particularly noteworthy in the vision they present and the transmission planning process they are stimulating.



Source: **http://www.pjm.com/documents/maps.html**, downloaded Dec. 2, 2004.

PJM remains the poster child of this redrawing of the electric transmission map. Its expansion, whose footprint is partially sketched out in the map on the right, cuts across NERC regions and state boundaries. Its transmission planning process will ultimately encompass a power market stretching from Illinois to Virginia and New Jersey.

A similar process of redrawing traditional electric boundaries is in place in the Midwest, where the Midwest ISO's energy market is scheduled to begin operations in March 2005. In the Southwest, the Southwest Power Pool proposed an Aggregated Transmission Study Planning Process in November 2004.

In the Northeast, the boundaries of electric transmission regions are apparently not going to be redrawn, as New England and New York will remain separate ISO/RTOs. But the New England ISO is now in its third year of a comprehensive Regional Transmission Expansion Process, and in New York—where utility-level transmission planning has been particularly difficult to centralize in the ISO due to historically pronounced transmission congestion between upstate and downstate markets—a state-wide transmission planning process is underway.

Between some of these reorganizing transmission areas, meanwhile, substantial efforts are being made to reduce or eliminate tariffs and protocols that constitute seams that hinder electricity trade. The New York ISO announced at the end of November 2004 that it would eliminate "export tariffs" on transactions scheduled from its service territory to New England. While elimination of such seams can be very challenging and take months if not years of negotiations and adaptation, it is very likely that over the next five years they will be eliminated in much of the Eastern Intertie of the U.S. power market.

All this activity raises two central questions about the essence of the North American power grid: will there be substantially more transmission investment than in the past, as the first section of this report suggests? If so, what difference will it make for electricity trade?

The Drivers of Transmission Investment

Because there is no single repository on all of the transmission projects in various stages of development, opinion naturally varies on the size and durability of this investment surge. As discussed elsewhere in this report, if we relied only on the most accessible source—the NERC list of proposed projects—we would find that NERC tallies some 470 projects whose average line length is 23 miles and whose average voltage is 283 volts.

The NERC database originates in the submission of EIA-411 forms by utilities. As such, this is information given by a subset of the transmission population. Before the emergence of ISOs/RTOs and independent transmission developers, the NERC effort may have told most of the story. Today, however, it only tells a part of the story. A closer look at what the industry is actually doing, in contrast to what a subset of the industry is actually reporting, reveals the following clusters of transmission activity:

Regional Transmission Organizations: By far the most active cluster is in the New England and PJM regional transmission organizations. Their RTEP lay out comprehensive arrays of transmission projects in pursuit of various well-defined objectives:

- *Maintaining the reliability of the system:* Transmission projects aimed at maintaining reliability given projected load growth and generation additions and retirements.
- *Interconnecting generators:* Usually, generators need to build some transmission to connect their plants with a node in the host transmission system. Typically, but not always, these are modest investments and do not materially add to an area's electrical transfer capacity.
- *Generator and other interconnection-related network upgrade projects:* Beyond the interconnection point, generation and other projects sometimes require increases in the take-away or bring-into capacity of the existing transmission network. At the peak of the generation construction boom, the network upgrades required to interconnect new facilities with the network constituted a substantial amount of new transmission, albeit much of it was in the upgrade, rather than new building, category.
- *Projects aimed at reducing "unwanted" congestion:* PJM explicitly identifies nodes within its system that have "unhedgeable" congestion, and has developed a "market window" process wherein it invites offers for projects to resolve the unwanted congestion. If "the market" does not respond within a designated period of time, PJM has the right to put the project to the utility most affected by the congestion. If that utility fails to develop the project, PJM then has the right to commission others to do so and send the bill to the affected utility.

Regional Transmission Initiatives: Even where there is no RTO, there is growing awareness and activity in transmission planning. Most notably, in the West, five distinct regional transmission planning initiatives have emerged in recent years in response to pressure from state governors and others to develop a planning process in lieu of a true Western RTO (which may yet develop). Those initiatives are:

- *SSG-WI*: The Seams Steering Group-Western Interconnection process was created as a forum that would address the development of a seamless Western-wide electricity market. The SSG-WI released its first report on transmission needs in the Western Interconnection in 2003. The report presents the results of transmission modeling studies that examine three generation and transmission scenarios for 2008 and 2013. It also created a public database for evaluating the interaction of future transmission and generation development. Several sub-regional efforts within the Western Interconnection, outlined below, have also developed and moved forward.

- *STEP*: The Southwest Transmission Expansion Planning Group began work in November 2002 and has met periodically since then. Its focus is on expansion of the transmission system between Arizona, southern California, southern Nevada, and New Mexico. The group consists of utilities, independent power producers, state agency and regulatory entities, and other interested stakeholders.
- *SWAT*: The Southwest Area Transmission Group evolved from a smaller area study group, the Central Arizona Transmission System (CATS) Study Group, to cover Arizona, New Mexico, and portions of Nevada and Colorado. Within SWAT there are five smaller study areas.
- *RMATs:* The Rocky Mountain Area Transmission Study was initiated in August 2003 by Wyoming Governor Dave Freudenthal and Utah Governor Michael Leavitt. It covers the states of Colorado, Idaho, Montana, Utah, and Wyoming. The study was initiated to stimulate investment in transmission infrastructure in order to serve load growth in the Rocky Mountains and to facilitate the export of coal and wind generated power to other parts of the Western Interconnection. The latest RMAT study, which was released this September, recommends three expanded transmission projects within the five-state Rocky Mountain area and two projects that would export power to California, Arizona, and Nevada.
- *NTAC:* The Northwest Transmission Assessment Committee was formed to examine transmission expansion needs in the Pacific Northwest. The Committee is focused on economic projects that will help to reduce price volatility as opposed to reliability issues. The Committee comes under the umbrella of the Northwest Power Pool and has held joint meetings with the California ISO to initiate sub-regional planning similar to that undertaken with the STEP Process.

Financial Incentives to Existing Transmission Organizations and Independent Transmission Developers

The initial presumption of restructuring was that locational marginal pricing and its associated financial instruments (variously known as financial transmission rights [FTRs], congestion revenue rights [CRRs], and transmission congestion contracts [TCCs]) would motivate and mobilize transmission projects. While that presumption may ultimately be borne out, there are few if any examples of transmission projects that have been financed entirely on the basis of these assets.

In part, this is because of the general withdrawal of investment in the merchant power sector—neither generation nor transmission projects have gotten financing on a merchant basis since 2002. In addition, however, there are likely to be problems raising capital on FTRs because they are usually assets whose quantity is not revealed to the investor until six months before the physical facility is completed (and likely to be several years after the Feasibility, System Impact, and Facility study cycle is completed) and whose value is extremely difficult to calculate.

For that reason, independent transmission projects will tend to focus on projects between control areas, where both energy and capacity market spreads are most notable and most enduring. And, those same characteristics will tend to make many of these projects use Direct Current technology, rather than be part of the AC system.

The most likely candidates to develop AC transmission projects, therefore, are the utility transmission providers. In the current structure of the industry, we can differentiate two types of contexts for transmission expansion: within an RTO or ISO, and within/between areas that have not joined RTOs or ISOs.

Within existing RTOs, FERC generally treats transmission proposals emerging from the RTOs as independent and has expressed a willingness to consider favorable consideration in the form of adders to the regulated rate of return for such projects.[5] FERC's order granting RTO status to ISO-New England stated it "will also accept, subject to suspension, hearing, and the application of our Pricing Policy Statement (when issued), the ROE Filers' proposed 100 basis point adder attributable to new transmission investment."

As of December 2004, FERC had not yet decided whether to extend this incentive to all new transmission projects, or only to those using new technologies. FERC noted in mid-2004 that "In the PJM RTO Order [Date 2003], we held that applicants seeking this incentive adder would be required to demonstrate why the adder is needed to incent investment in new transmission facilities and whether the adder should apply to all types of transmission expansion or be more narrowly focused on transmissions expansions that utilize innovative, less expensive technologies." In the New England RTO order, FERC still had not settled on the issue. In its July 28, 2004 Order,[6] FERC noted again that it was seeking additional comments on this issue.

Among the issues are:

1. Should transmission organizations be given such adders to do something they are obligated to do anyway?
2. Are the adders necessary to maintain the credit standing and overall business position needed to attract a continuous flow of capital into the sector?
3. Should the adders be limited to new technology or specific kinds of "highway" facilities like DC projects, or should it be applied to all projects, whatever the focus?
4. Is it reasonable to argue that adders and other incentives are needed to motivate transmission organizations to spend the political capital needed to overcome the many siting and permitting obstacles that transmission projects inevitably encounter?

FERCs final decision on financial incentives for transmission is pending the outcome of federal legislation which is expected to require FERC to establish a rule in this area. Assuming a rule supporting incentives moves forward, and given the stimulative effect of RTEPs, a substantial increase in transmission investment strengthening and expanding the AC grid appears likely.[7]

Independent Transmission Projects

Finally, the Northeast and the West are home to a variety of proposed transmission projects in various stages of development by independent developers. While some of these projects were initially conceived as merchant projects—dependent upon sales of transmission rights through open seasons pursuant to FERC approvals[8]—the collapse of most merchant energy trading companies and the difficulties in financing any merchant assets (generation or transmission) has moved most of these projects into the pursuit of power purchase agreements or other forms of contractual support from creditworthy entities.

[5] 106 FERC ¶ 61,280, pp. 78–79.
[6] 104 FERC 61,124.
[7] FERC discussions of this issue are organized under docket ER04-156.
[8] See, for example, Neptune Regional Transmission System, LLC, 96 FERC ¶ 61,147 (2001).

These are sizeable projects competing for funding from utilities issuing requests for proposals. In utility RFPs for energy and capacity, transmission solutions are more and more often explicitly included in the definitions of compliant responses to solve the problem of providing both energy and capacity in load pockets.

a. New York
   i. *Cross Sound Cable:* This 330 MW DC cable was developed by TransEnergie and went into service in August 2003. It connects Connecticut and Long Island.
   ii. *Neptune:* This 660 MW HVDC cable project was selected by the Long Island Power Authority in its Spring 2004 request for proposals process. The cable will connect New Jersey and Long Island. Neptune will be project-financed.

b. California and the West
   i. *Path 15*: Construction began in September 2003 on the installation of a third 500 kV transmission line linking northern and southern California between the Los Banos and Gates substations along Path 15. The project will upgrade the South to North OTC by 1,500 MW, from 3,900 MW to 5,400 MW. In September 2003, Trans-Elect NTD closed on $200 million of financing to fund construction. The project brought together the Department of Energy's Western Area Power Administration, Pacific Gas & Electric Company, and Trans-Elect.[9]
   ii. *TransBay Cable Project*: A proposed 55-mile HVDC cable from Pittsburg, CA to San Francisco.
   iii. *TransElect's Navajo Transmission Project* (NTP) would add 470 miles of 500 kV AC transmission capability from the Four Corners area to the Las Vegas area.
   iv. *Sea Breeze* proposed an underwater HVDC merchant transmission line connecting Vancouver Island to Port Angeles, on the Olympic Peninsula in Washington State.

It is likely that independent projects like these will tend to share several characteristics. They will be inclined to use DC transmission, since that technology is more controllable than AC transmission. As such, many of the independent projects will tend to be oriented to load pockets, where energy and capacity prices are sufficiently high to merit the cost of dedicated transmission. Load pockets that are accessible by water (on either coast or on the shores of the Great Lakes) are likely to provide underwater routes that will be more amenable to development than overland routes.

On the other side of the cable, independent projects are likely to be spawned by relatively low-cost energy sources (coal, large-scale hydro, or nuclear) or favored sources (e.g., wind) that can obtain access to incentives. A number of projects will essentially be long distance generator leads. A good example is the InterMountain Power Project linking coal-fired generation in Millard County, Utah with load centers in southern California.

[9] In this project, Trans-Elect owns long-term capacity rights in the transmission line expansion. The U.S. Department of Energy's Western Area Power Administration will build and own the line. Pacific Gas & Electric is financing and building the substation expansions at Los Banos and Gates. The electricity will be controlled by the California Independent System Operator (CAISO) and available to all users of the transmission system. The project was awarded "Infrastructure Deal of the Year for the Americas" by *Project Finance International* (PFI) magazine in 2004.

Conclusions

As the preceding pages have shown, the North American electric transmission grid is evolving largely in response to the pressures and opportunities created by restructuring. While a considerable amount of investment capital has already been deployed in new transmission initiatives, much more will be required, and this is where the attention of regulators, utilities, and investors must now be focused.

Thinking about transmission investment has endured a kind of dialectic which began with the proposition that only utilities would invest in transmission. That was replaced for a time with the opposite view, which argued (1) that with the foreseen unbundling of generation, transmission, and distribution segments of the electricity business, only specialized ITCs would make these investments, and (2) that with locational pricing and free markets, merchant transmission projects would materialize in large numbers. By 2005, a synthesis has emerged. The synthesis contains part of the initial thesis—that utilities build transmission—and of the antithesis—that ITCs and merchants do the building. Transmission is no longer a business just for utilities, but it is a business in which utilities are essential. Transmission is not just a business for merchant or independent developers, but their energy, innovation, and willingness to take risks are also essential.

In this new transmission synthesis, regulators need to make transmission more interesting for utilities—adders such as FERC has begun to extend are an important first step. They also need to make transmission less difficult for developers; there are many things that could be done to streamline and facilitate independent development.

Assuming progress is made on both these fronts, this synthesis is likely to contain the necessary ingredients for substantial expansion of the North American transmission grid.

Part II
TRANSMISSION PROJECT REVIEW

The next part of this report compares the transmission projects reported by the North American Electric Reliability Council Projects in its ES&D database to the projects that are under development or under discussion in the transmission community. The information in the ES&D database is drawn from the Energy Information Agency's Coordinated Bulk Power Supply Program Report (EIA-411). The Department of Energy requests that each of NERC's 10 regional reliability councils voluntarily submits data provided by utilities and other electricity supplies within their council area. Schedule 6 of form EIA-411 asks respondents to provide information on all transmission line additions of 230 kV and above that are expected over the coming five years. The data are collected annually.

The North American electric grid is broken out in three major regions, the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT). These interconnections operate independently from one another, though a few direct current ties do link them. Within each interconnection NERC has established Regional Reliability Councils that conform to established operating and planning standards to ensure the reliable operation of the grid within each region. The Eastern Interconnection encompasses eight separate reliability areas, while the Western Interconnection or the Western Electricity Coordinating Council (WECC) and ERCOT are coterminous with the reliability councils for their interconnection. Transmission projects are reported in the EIA-411 by regional reliability council areas.

The NERC process was not initially designed to identify currently contemplated transmission additions. As with generation projects, many transmission proposals are identified, extensively studied, and never built. Thus, ESAI's review of all the transmission projects under discussion in all of the various forums for review, analysis, and development has yielded a Transmission Development Database of close to 3000 projects. Many of these transmission projects will not be developed. Nevertheless, the number of projects under consideration is a leading indicator of the number of projects that will be built.

If the objective is to present a reasonable estimate of the future expansion of the North American power grid, therefore, the answer is somewhere between the minimalist picture presented by NERC and the very expansive view created by assembling all the projects under serious development. Presenting that reasonable estimate, in other words, is not an easy research exercise.

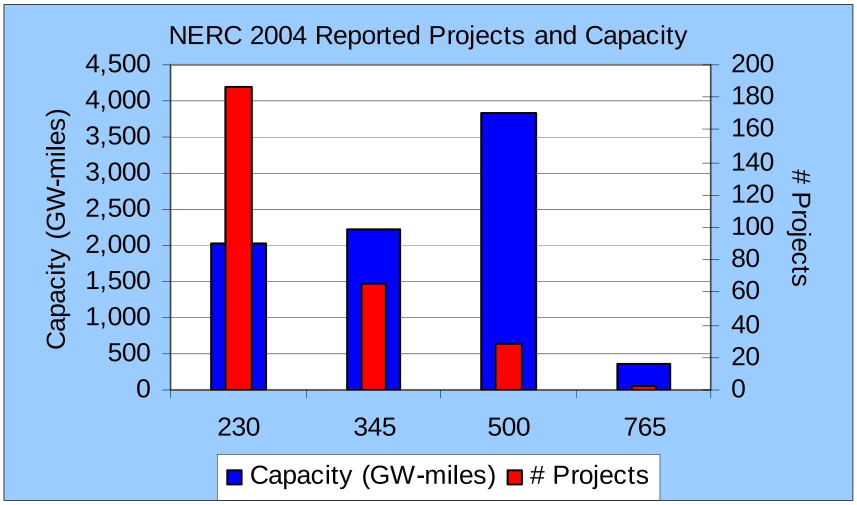
Transmission data collected in form EIA-411 is one of the three primary areas through which the federal government collects data on transmission in the U.S. Other transmission data collection tools include the EIA's Annual Electricity Financial Report (EIA-412) and the FERC's Annual Transmission Planning and Evaluation Report (FERC Form 715). Form EIA-412 is a mandatory report that must be filed annually. Owners of transmission lines with a nominal voltage of 132 kV or greater must report the existing lines in Schedule 10. Those completed in the past year are reported separately in Schedule 11.

FERC Form 715 is a more valuable tool for envisioning the future of transmission on a regional basis. It requires all utilities that operate transmission systems of 100 kV or above to submit power flow base cases. The base cases include forecasts for planned transmission lines, but only EIA-411 specifically requests data on planned new transmission lines. In no place is information specifically collected for system upgrades, such as new capacitors, switches, etc., that are not included as part of a new transmission line within existing or proposed new right-of-ways.[10]

As individual utility control areas have morphed in some parts of the country into RTOs and ISOs, these power flow base cases have become more elaborate. Increasingly, they reflect (or should reflect) the effects of ongoing "Regional Transmission Expansion Plans." While in many respects these power flow cases represent the most sophisticated and comprehensive form of future transmission development, and the source of the richest forms of visualization of their impacts on the system, they are not readily accessible to the general public. Instead, they require the observer to have a functioning power flow model that can transform the data into the kinds of transmission models discussed in Part III of this report.

While there has been a lag in the development of new transmission lines over the past 10 to 15 years, existing systems have been upgraded to meet increasing demand. Many new and advanced transmission technologies work within existing transmission corridors and utilize existing transmission lines. Plans for these types of improvements will not be picked up in EIA-411 data. In preparing this report, ESAI looked at other data sources to determine what projects are on the planning horizon that might not be contained in the EIA-411 data. Sources for this information include published regional transmission expansion plans, RTO and ISO websites, utility websites, and regulatory agency listing. The data ESAI collected for each of the NERC Reliability Council Regions is presented in the section below along with a brief discussion about the observed differences with what is reported in the EIA-411 data and information that ESAI has collected from other sources.

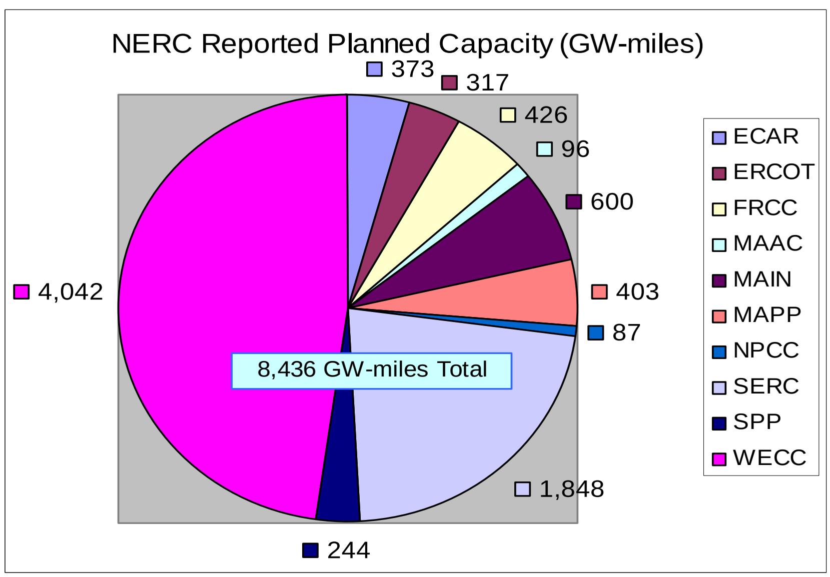
[10] The Energy Information Administration recently published a comprehensive review of its transmission reporting practices. See Energy Information Administration, *Electricity Transmission in a Restructured Industry: Data Needs for Public Policy Analysis*, November 2004.



The NERC Data: The National Picture

The NERC 2004 ES&D database lists 284 transmission projects with line voltages of 230 kV or greater. The total length of new line represented by the projects is 7,175 miles.[11] As summarized in the chart above, the projects represent 8,436 GW-miles of future transmission capacity.[12] Though EIA-411 only requests projects extending five years forward, projects were reported out as far as 2013. The greatest number of projects (187) are 230 kV lines, however, they only represent 2,030 GW-miles of new transmission capacity. The largest amount of new capacity (3,825 GW-miles) is represented by new 500 kV lines.

As shown in the chart at right, the Western Electricity Coordinating Council (WECC) has the greatest amount of planned new capacity with 4,042 GW-miles, followed by the Southeast Electricity Reliability Council (SERC) with 1,848 GW-miles.



11 ESAI did not include lines that were reported in the ES&D database that were less than 230 kV. There were 13 projects reported in MAPP that were 115 kV or 161 kV lines for a length of 233 miles.

12 ESAI estimated GW-miles of transmission capacity by multiplying line length by the Megavoltamperes (Mva) capacity provided NERC's ES&D database. When there was no Mva capacity found in the database, ESAI used thermal capacity limits for typical line lengths at different line voltages as provided in Table 1 of EEI's June 2001 report, "Transmission Planning for a Restructuring U.S. Electricity Industry," prepared by Hirst and Kirby.

Eastern Interconnection

There are eight reliability areas within the Eastern Interconnection. These are:

- NPCC—Northeast Power Coordinating Council
- MAAC—Mid-Atlantic Area Council
- FRCC—Florida Reliability Coordinating Council
- SERC—Southeast Electric Reliability Council
- MAIN—Mid-America Interconnected Network
- MAPP—Mid-Continent Area Power Pool
- ECAR—East Central Area Reliability Coordination Agreement
- SPP—Southwest Power Pool

Transmission projects presented in the NERC database are segmented into these reliability regions.

NPCC—Northeast Power Coordinating Council

The NPCC includes the New England and New York ISOs, as well as the Maritimes provinces of Canada. The NERC database reports six projects that total 119 miles of new transmission lines that are planned for NPCC for between 2005 and 2007. These are primarily 345 kV lines. There are projects for 59 miles of underground lines reported, one of which is the 36-mile DC, underwater Neptune project. There are four other underground lines listed totaling 23 miles. The projects reported in NERC total 87 GW-miles of new capacity in the NPCC. The projects are listed in the following Table.

NPCC Projects listed in NERC 2004 Database						
Company Name	**Design Voltage**	**In Service Date**	**Line Length**	**Line Type**	**Terminal From**	**Terminal To**
PSEG Power LLC	345	2005-03	8	UG	Bergen (New Station,	W. 49th Street
Atlantic Energy Partners	250	2005-03	36	UG	Sayerville (New Station)	W. 49th Street
PG&E National Energy Group	230	2006-03	1	UG	Liberty (Linden, NJ)	Goethals
New Brunswick Power Corp.	345	2006-11	60	OH	Pt. Lepreau	Maine/New Brunswick
Consolidated Edison Co-NY Inc	345	2007-07	10	UG	Mott Haven	Dunwoodie
Consolidated Edison Co-NY Inc	345	2007-07	4	UG	Mott Haven	Rainey

This small list of projects raises many of the issues that make an accurate assessment of the growth of the transmission grid such a complicated exercise.

First, several of these projects are independent initiatives of developers, rather than the result of utility planning. As discussed in Part I, such projects are typically aimed at inter-control area (or ISO) economic opportunities. Money, often substantial sums of money, will be spent on the development of such projects while they seek a contract (such as a purchase power or transmissions scheduling agreement) with a creditworthy counterparty. The PSEG and Neptune projects to New York City are independent projects not yet part of the transmission expansion plan of either the PJM RTO or New York ISO. As discussed in Part I, the Neptune Project to Long Island has obtained a contract from the Long Island Power Authority and is scheduled to go into service in mid-2007.

Second, some of these projects are initiatives from utilities that are intended to become part of the transmission rate base but are initially developed without assurance that such treatment will ultimately be obtained. The U.S. side of the New Brunswick project was initially advanced—and development money spent—without assurance that it would be incorporated into the tariff of the New England ISO. That status was achieved in 2004.

Beyond the NERC List: New York Projects

In addition to this small number of NPCC projects, however, ESAI assembled additional data and reported projects from the ISO New England 2004 RTEP and from the New York Department of Public Service's (NYDPS) Article VII filing. ESAI found several discrepancies between the projects reported in the NERC ES&D database and those listed in the other sources it consulted for project data. There were five projects (see table below) listed by the NYDPS in its November 10, 2004 report as either certified, filed, or announced that are new 230 kV lines or larger, which may be developed over the next five years that are not listed in the ES&D database. At least one of these projects (Conjunction) has since been withdrawn, and another (the Niagara Reinforcement Project) has only been announced. However, in total there is as much as 600 GW-miles of transmission capacity in New York alone that is not reported in the ES&D database. For example, the NERC database lists Atlantic Energy's Neptune project as a 36-mile 250 kV line with an estimated completion date of March 2005. That is the Manhattan leg of this project, which is not under active development. The New York Department of Public Service listing of Article VII cases lists another Neptune project with a length of 58 miles and a 600 MW transfer capability. That is the Long Island leg, which is under active development, with an estimated in-service date of May 2007.

NY Department of Public Service Article VII Cases

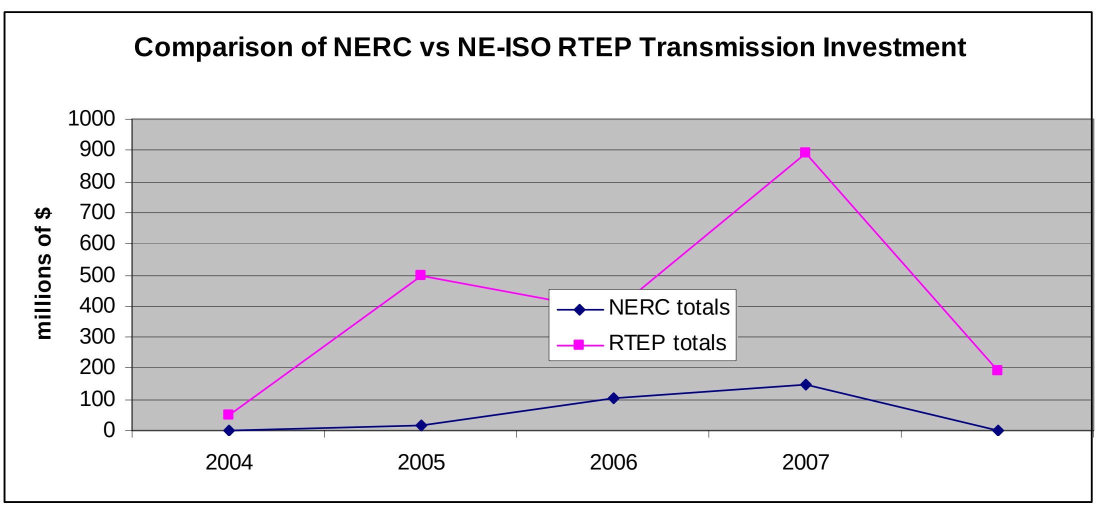
Project	Developer	Voltage Diameter	Transfer Capability (MW)	Line Length	Town/County	Estimated In-Service Date
Flat Rock	Flat Rock Wind Power	230 kV	350 (est.)	10.3	Martinsburg & Watson/ Lewis County	N/A
Neptune	Atlantic Energy	HVDC	600	58	NJ to Newbridge, LI	May-07
Besicorp	NMPC	345 kV	450	8.1	Rensselaer to North Greenbush/Rensselaer County	2005
Empire Connection	Conjunction, LLC	HVDC	1000	126	Athens, Greene County to NYC	N/A
Niagara Reinforcement Project	Pegasus Power Systems	HVDC	1200	360	Connecting Marcy, Porter & Edic Stations w/W. 49th St., NYC	N/A

Beyond the NERC List: New England Projects

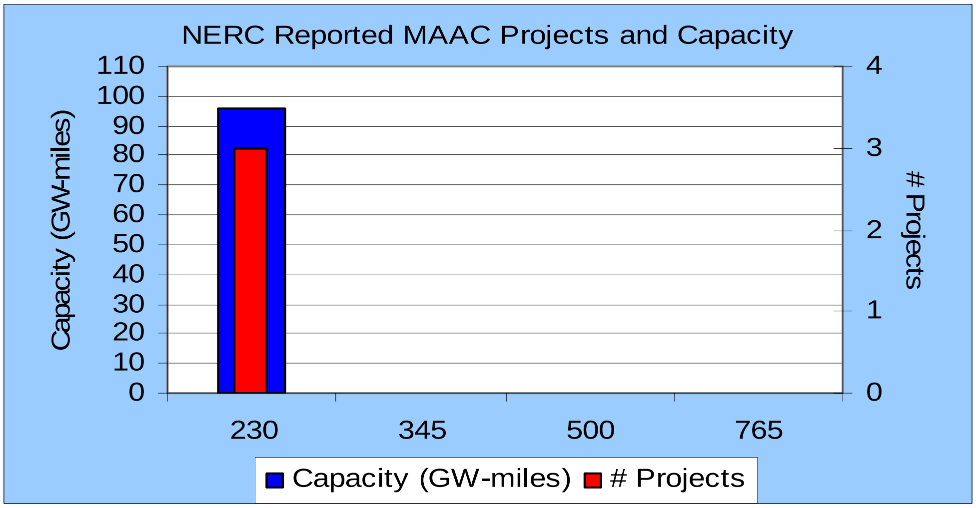
ISO-New England's 2004 RTEP lists five new 345 kV line projects that are not in the ES&D database. The projects represent at least 18 GW-miles of new transmission capacity and $217 million in transmission investment.

ISO New England RTEP Planned Projects					
Equipment Owner - Project	**Projected Year of In-Service**	**Project Description**	**Voltage**	**Line Length (miles)**	**Projected Year of In-Service**
Northeast Utilities-CT - SWCT Reliability Project	2005	Build new 345 kV OH/UG line from Plumtree Substation to Norwalk Substation	345	20	2005
NSTAR - 345 kV Reliability Project	2006	Add (1) new 345 kV UG Cables from Stoughton to Mattapan Sq.to K Street	345	-	2006
NSTAR - 345 kV Reliability Project	2007	Add 2nd 345 kV UG Cables from Stoughton to Mattapan Sq.to K Street	345	-	2007
NSTAR - 345 kV Reliability Project	2006	Add (1) new 345 kV UG Cable from Stoughton to Mattapan Sq. to Hyde Park Substation	345	-	2006
Vermont Electric Power Co - NW Vermont Reliability Project	2006	New Haven-West Rutland 345kV line	345	-	2006

These are very substantial and transformative projects under active development. They are also centerpieces of the New England ISO's RTEP. The chart below indicates the difference in the transmission investment outlook between the RTEP and the much smaller list of projects listed by NERC.



MAAC—Mid-Atlantic Area Council



The NERC database reports three projects for a total of 134 miles that are planned for MAAC between 2004 and 2006. All three are 230 KV lines. The projects reported in NERC total 96 GW-miles of new capacity. The projects are listed in the following Table.

MAAC Projects listed in NERC 2004 Database						
Company Name	**Design Voltage**	**In Service Date**	**Line Length**	**Line Type**	**Terminal From**	**Terminal To**
Conectiv	230	2004-06	44	OH	Cardiff	Oyster Creek
Conectiv	230	2006-06	47	OH	Milford	Indian River
Conectiv	230	2006-06	43	OH	Red Lion	Milford

<u>Beyond the NERC List: PJM Projects</u>

ESAI reviewed PJM's RTEP with projects updated through August 1, 2004. The projects listed in the ES&D database were consistent with those presented in the PJM's RTEP. ESAI found one project, a new 230 kV line from the South Akron to Berks substation that is projected to be in-service sometime after 2005.

The picture the NERC data paint of PJM's overall transmission activity, however, is extremely limited. Even though PJM, within the footprint of the coterminous original MAAC reliability council, was already a fairly well-integrated transmission system, its RTEP has a very large number of additional transmission projects that will further integrate not only the classic PJM but the newly joining areas from ECAR, MAIN, and SERC.

The table below presents PJM's estimate (as of November 2004) of the cost of the network upgrades associated with interconnection queues A through E.

PJM Baseline Network Upgrades (in Million $)	
Network Reinforcements	Cost Estimate (Millions)
Queue A Baseline Network Upgrades	$54.77
Queue B and C Baseline Network Upgrades	$85.00
Queue D, E, and F Baseline Network Upgrades	$31.66
Queue G, H, and I Baseline Network Upgrades	$22.25
Total Baseline Network Upgrades: Queue A - I	**$193.68**

In addition to these baseline network upgrades, PJM (like other control areas) has also seen transmission investment as a result of the interconnection of new generators to the transmission system. As of November 2004, the total identified investment in this transmission segment was $223 million, as shown in the table below. This amount includes expenditures already made in association of the development of generation in PJM's various interconnection queues (A through K), and expenditures that will be made if these projects are completed.

PJM Network Reinforcement Summary (in Million $)	
Queue A Network reinforcement summary	$91.74
Queue B Network reinforcement summary	$47.09
Queue D Network reinforcement summary	$14.10
Queue E Network reinforcement summary	$15.57
Queue G Network reinforcement summary	$39.34
Queue H Network reinforcement summary	$4.26
Queue I Network reinforcement summary	$4.37
Queue J and K Network reinforcement summary	$6.14
Total Network Reinforcements	**$222.60**

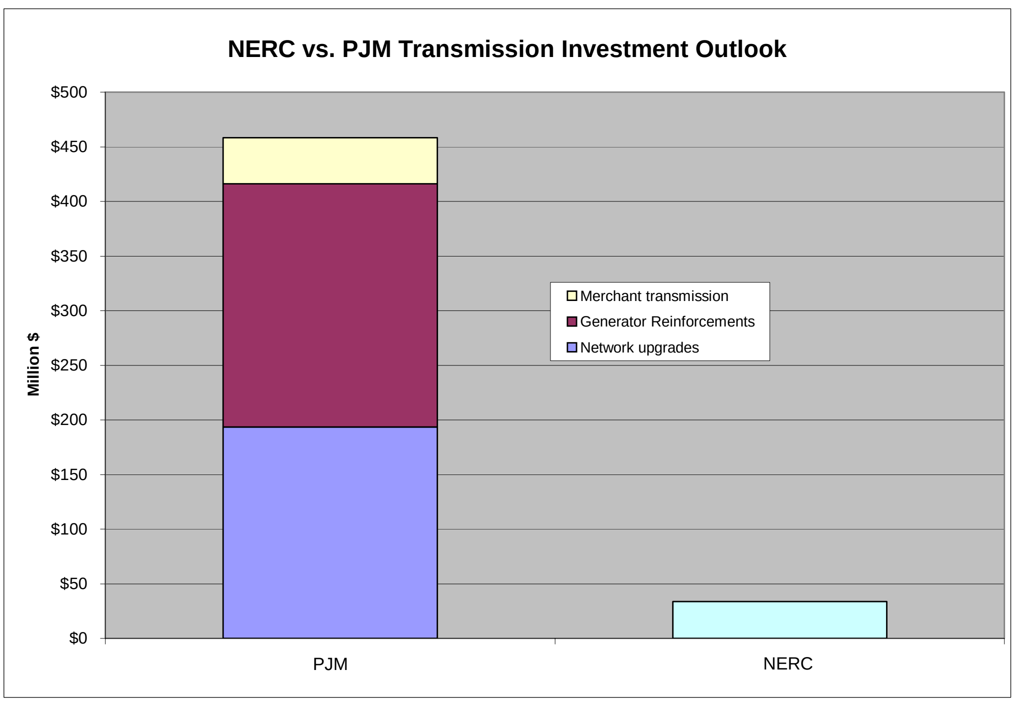
Beginning in 2003, PJM had to contend with the withdrawals of generation projects and their associated transmission investment. To that end, PJM retools its transmission baseline each year (or more frequently, if necessary). The retools can alter the allocation of transmission upgrades to the projects that have not yet executed an interconnection agreement. Thus, the withdrawal of projects B15, B16, C03, D05_W17, and E17_W26, for example, caused the reallocation of $35 million of RTEP retool costs to interconnection customers in queues B, C, D, and E.

In addition to baseline and generation network reinforcements, PJM's RTEP also lists network upgrades required to interconnect various merchant transmission projects, as shown below:

Merchant Transmission Network Reinforcement Summary	
Network Reinforcements for Project G07	Cost (Millions)
Project G07 Total	$ 6.75
Project G22 Total	$14.57
Project G32 Total	$20.50
Total Merchant Transmission Projects	**$ 41.82**

In 2004, PJM began to deal with another issue that promised to add to the transmission challenge. Some 3000 MW of generation capacity in PJM East was announced to be headed for retirement. While it remained unclear as of the end of 2004 how much would actually retire, PJM indicated that if the retirements were implemented, as much as $130 million in network upgrades would be required.[13]

PJM, therefore, has substantially more transmission activity than the four MAAC projects listed in the NERC database. As shown in the chart below, the PJM transmission investment outlook can be conservatively assessed at close to $500 million (recent indications are that the investment figure will approximate $1 billion), rather than the $35 million suggested by the NERC ES&D data.



[13] PJM, Transmission Expansion Advisory Committee, "Generator Retirement Analysis." Document created Nov. 18, 2004 and downloaded from PJM Website (www.PJM.com) on December 5, 2004, page 10.

Beyond the NERC List: The MISO Regional Transmission Expansion Plan

The Midwest ISO, like PJM, spans several traditional control areas (ECAR, MAIN, MAPP, and SPP, as shown in the adjacent chart). We will review the NERC reports on each of these control areas later in this section. As with PJM, however, the NERC reports present a minimalist view of the future of transmission in these areas. The *Midwest ISO Transmission Expansion Plan 2003* (MTEP-03) presents a much richer picture of the transmission challenges and opportunities in the area.

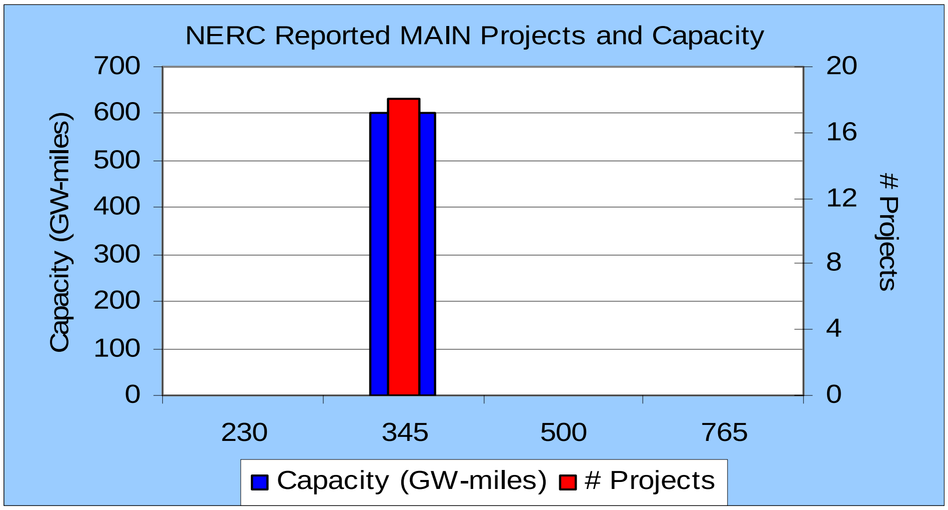
Part IV of this report presents a table of the many transmission projects listed in the MTEP-03. The table below presents one of the many possible summary scenarios from the MISO plan, showing a bundle of projects ranging from 115 kv to 345 kv with a total estimated cost of $1.6 billion.

MTEP-03 notes that $1.3 billion of the projects identified are in the "planned" category, indicating that the utilities believe the projects should proceed, largely on the basis of reliability.

Sum of Estimat	MISO Area-SPG or Other Region						
Voltage(s)(kV)	C-CSILL	C-WUMS	E-IOK	E-MIO	N-RRV	N-UMV	Grand Total
115		$ 31,824,474		$ 1,415,696	$ 41,755,592	$ 132,109,060	$ 207,104,822
138	$ 47,802,450	$ 157,623,597	$ 16,840,298	$ 45,543,493			$ 267,809,838
161	$ 29,750,700			$ 6,600,000		$ 47,170,000	$ 83,520,700
230	$ 748,000			$ 10,713,391	$ 101,885,462	$ 7,020,000	$ 120,366,853
345	$ 146,796,100	$ 376,509,000	$ 61,193,200	$ 15,186,597		$ 83,537,344	$ 683,222,241
345/115		$ 28,300,000					$ 28,300,000
345/138	$ 54,649,400	$ 64,648,400	$ 3,180,000	$ 25,473,674			$ 147,951,474
345-115						$ 14,632,805	$ 14,632,805
345-138		$ 28,000,000		$ 14,388,499			$ 42,388,499
345-230					$ 7,599,811	$ 17,788,931	$ 25,388,742
Grand Total	$ 279,746,650	$ 686,905,471	$ 81,213,498	$ 119,321,350	$ 151,240,865	$ 302,258,140	$ 1,620,685,974

Because the footprints of MISO and the four reliability areas overlap, it is very difficult to compare with any precision the overall picture of the future of the transmission systems in the Midwest. As with PJM, the outcome is likely to be somewhere between the relatively austere picture of the NERC and the expansive picture of the MISO.

MAIN—Mid-America Interconnected Network



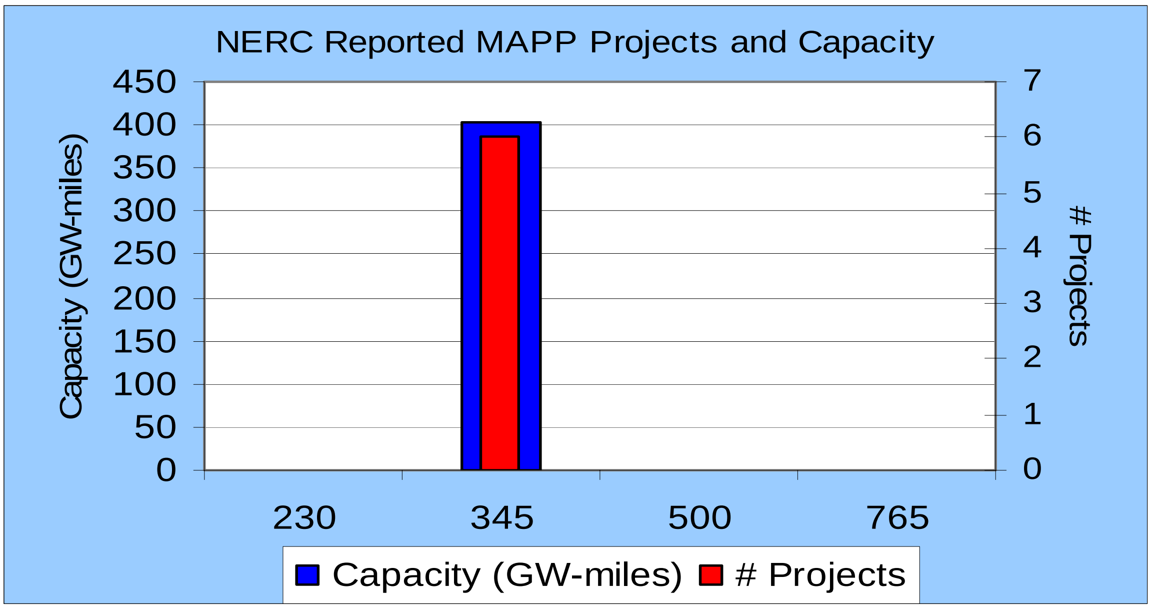
The NERC database reports 18 projects for a total of 519 miles that are planned for MAIN between 2004 and 2009. All the projects are 345 kV lines. One project is an underground project. The projects reported in NERC total 600 GW-miles of new capacity.

The projects are listed in the following table.

MAIN Projects Listed in NERC 2004 Database					
Company Name	**Design Voltage**	**In Service Date**	**Line Length**	**Terminal From**	**Terminal To**
Commonwealth Edison Co	345 (Underground)	2004-06	6.3	Garfield	Taylor
American Transmission Company	345	2004-12	11	Illinois Border	Wempletown
American Transmission Company	345	2004-12	4	Paddock	Illinois Border
American Transmission Company	345	2006-06	140	Weston	Stone Lake
Union Electric Co	345	2006-12	60	Callaway	Franks
Union Electric Co	345	2007-06	8	Cahokia	Dupo
Union Electric Co	345	2007-06	15	Loose Creek	Jefferson City
American Transmission Company	345	2008-06	9	Minnesota Border	Stinson
American Transmission Company	345	2008-06	60	Stone Lake	Stinson
Illinois Power Co	345	2008-06	1.5	Baldwin Power Plant	Prairie State PP Sub
Illinois Power Co	345	2008-06	7.5	Baldwin Power Plant	Prairie State PP Sub
Illinois Power Co	345	2008-06	26	Baldwin Power Plant	Rush Island Substati
Illinois Power Co	345	2008-06	7.5	Prairie State PP Sub	Stallings Substation

MAIN Projects Listed in NERC 2004 Database					
Company Name	**Design Voltage**	**In Service Date**	**Line Length**	**Terminal From**	**Terminal To**
Illinois Power Co	345	2008-06	1.5	Prairie State PP Sub	W. Mount Vernon Subs
American Transmission Company	345	2009-06	47	Morgan	Werner West
American Transmission Company	345	2009-06	30	Rockdale	Concord
American Transmission Company	345	2009-06	35	Rockdale	West Middleton
American Transmission Company	345	2009-06	50	Weston	Central Wisconsin

MAPP—Mid-Continent Area Power Pool

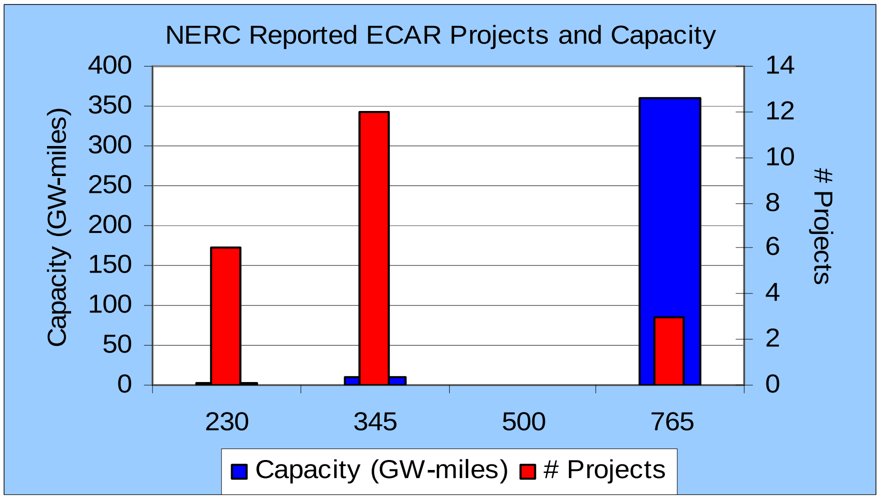


The NERC database reports 24 projects for a total of 696 miles that are planned for MAPP between 2004 and 2010. Five of these projects are Manitoba Hydro projects in Canada. There are also 15 projects that are 115 kV or 161 kV lines. There are six projects in the U.S. These are all 345 kV lines. They have a combined capacity of 403 GW-miles. All the projects are listed in the NERC database are shown in the following Table.

MAPP Projects Listed in NERC 2004 Database					
Company Name	**Design Voltage**	**In Service Date**	**Line Length**	**Terminal From**	**Terminal To**
Manitoba Hydro Electric Board	230	2004-06	1	St. Leon	St.Leon wind site
Lincoln Electric System	115	2004-10	3.5	19th & Alvo	NW 12th & Arbor

MAPP Projects Listed in NERC 2004 Database					
Company Name	**Design Voltage**	**In Service Date**	**Line Length**	**Terminal From**	**Terminal To**
Northern States Power Co	115	2004-10	6.5	Rogers Lake	Red Rock
Northern States Power Co	115	2004-11	29	Lake Yankton	Lyon County
Manitoba Hydro Electric Board	230	2005-03	28.3	Wuskwatim	Birchtree
Manitoba Hydro Electric Board	115	2005-10	45.4	Herblet Lake	Sherridon
Manitoba Hydro Electric Board	115	2005-11	4.4	Herblet Lake	Chisel Lake
Manitoba Hydro Electric Board	230	2005-11	56.6	Silver	Rosser
Northern States Power Co	161	2006-04	25	Lakefield Gen	Fox Lake
Northern States Power Co	115	2006-05	2.75	Air Lake	Vermillion River
Lincoln Electric System	115	2006-06	11	NW 68th & Holdrege	NW 12th & Arbor
MidAmerican Energy Co	345	2006-09	15	Council Bluffs	Grimes
MidAmerican Energy Co	345	2006-09	109	Council Bluffs	Grimes
Lincoln Electric System	115	2006-10	1	40th & Yankee Hill	40th & Rokeby
Northern States Power Co	115	2007-06	26	Buffalo Rodge	White
Northern States Power Co	115	2007-06	25	Chanarambie	Nobles County
Northern States Power Co	345	2007-10	95	Split Rock	Lakefield Jct.
Northern States Power Co	115	2007-12	12	Lakefield Gen	Watonwan Jct
Lincoln Electric System	345	2008-06	28.2	NW 68th & Holdrege	128th & Adams
Minnesota Power Inc	345	2008-07	12.44	Arrowhead	MN-WI State Line
Dairyland Power Coop	161	2008-12	23.4	Marshland	La Crosse Tap
Omaha Public Power District	345	2009-04	68	Sub 3458	Under Plan
Dairyland Power Coop	161	2009-12	42	Apple River	Chisago
Dairyland Power Coop	161	2010-12	25.4	Marshland	Alma

ECAR—East Central Area Reliability Coordination Agreement



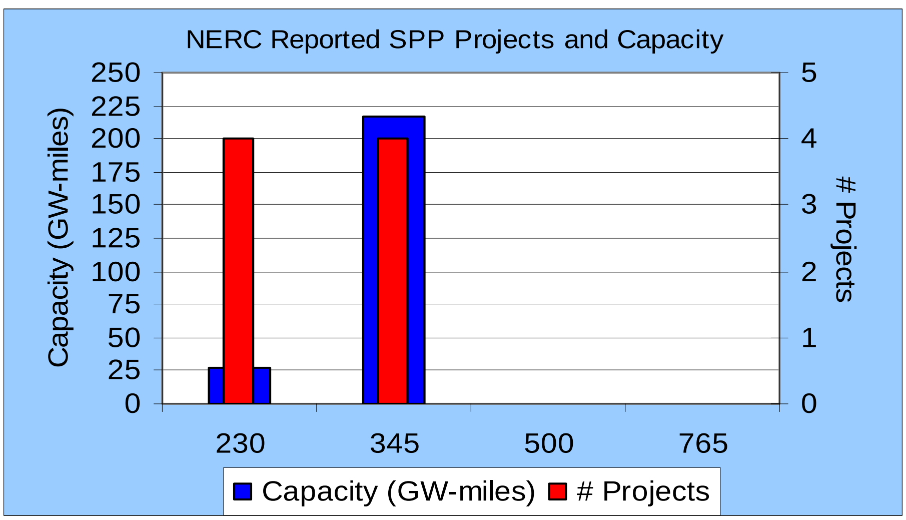
The NERC database reports 21 projects for a total of 109 miles that are planned for ECAR between 2004 and 2006. The projects range in size from 230 kV to 765 kV. One 765 kV project accounts for 90 miles of the planned new transmission. The projects reported in NERC total 373 GW-miles of new capacity.

The projects are listed in the following table.

ECAR Projects Listed in NERC 2004 Database					
Company Name	**Design Voltage**	**In Service Date**	**Line Length**	**Terminal From**	**Terminal To**
American Electric Power Inc	345	2004-04	0	Hiple	Collingwood
American Electric Power Inc	345	2004-04	0	Hiple	East Elkhart
Detroit Edison Co	230	2004-05	0	Jewell	Spokane
American Electric Power Inc	765	2004-06	0.5	Foster Falls (new)	Jacksons Ferry
American Electric Power Inc	345	2004-06	0	South Berwick (new)	Fostoria Central - G
Allegheny Power System Inc	230	2004-06	4	Urbana	MDM Tap - Montgomery
METC	345	2004-06	0.1	Gaines	Vergennes - Roosevel
American Electric Power Inc	345	2005-02	0.2	Berrien Energy(new)	Cook - Benton Harbor
American Electric Power Inc	345	2005-02	0.2	Berrien Energy(new)	Cook - Palisades
East Kentucky Power Coop Inc	345	2005-05	3.8	Spurlock	Stuart / Zimmer
American Electric Power Inc	345	2005-06	0	Barron Lake (new)	Cook - East Elkhart
American Electric Power Inc	345	2005-06	0	Barron Lake (new)	Cook - Kenzie Creek
American Electric Power Inc	765	2005-06	0.5	Lawrence	Hanging

ECAR Projects Listed in NERC 2004 Database					
Company Name	**Design Voltage**	**In Service Date**	**Line Length**	**Terminal From**	**Terminal To**
				County(new)	Rock
American Electric Power Inc	230	2005-06	0.5	Mount Zion (new)	E Danville - Rxbro 1
American Electric Power Inc	230	2005-06	0.5	Mount Zion (new)	E Danville - Rxbro 2
American Electric Power Inc	345	2005-06	1.7	South Shore (new)	Cook
American Electric Power Inc	345	2005-06	0.2	Terre Coupee (new)	Dumont - Olive
Allegheny Power System Inc	230	2005-06	2	Ridgeville	Mt. Airy - Damascus
American Electric Power Inc	345	2005-12	4.5	Lima Energy (new)	Southwest Lima
American Electric Power Inc	765	2006-06	90	Wyoming	Jacksons Ferry
Allegheny Power System Inc	230	2006-06	0.2	South Frederick	Lime Kiln - Monocacy

SPP—Southwest Power Pool

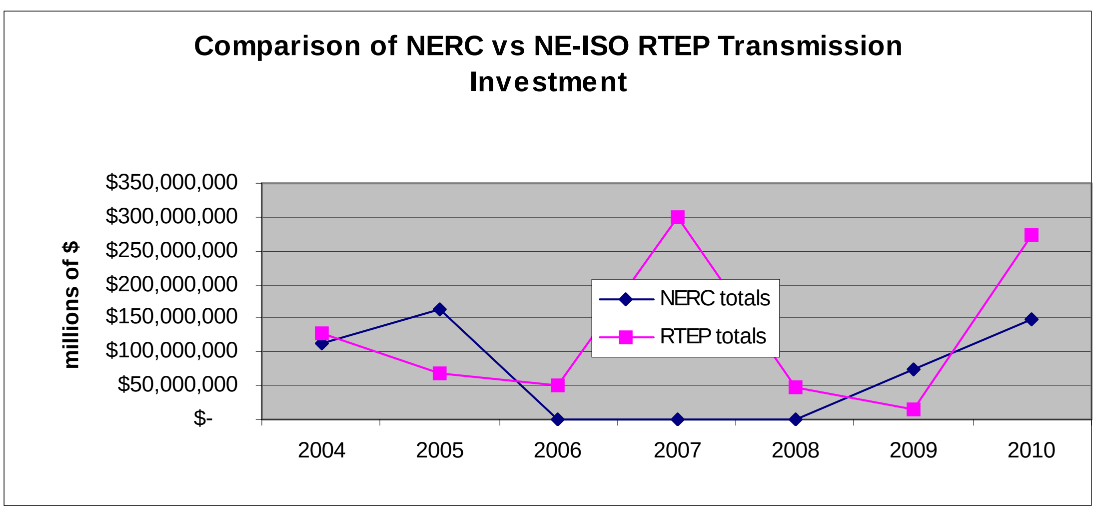


The NERC database reports 8 projects for a total of 211 miles that are planned for SPP between 2004 and 2010. The projects are both 230 kV and 345 kV lines. The projects reported in NERC total 244 GW-miles of new capacity. The projects are listed in the following table.

SPP Projects Listed in NERC 2004 Database					
Company Name	**Design Voltage**	**In Service Date**	**Line Length**	**Terminal From**	**Terminal To**
Lubbock City of	230	2004-06	3	Lubbock South Intg	Southeast Substation
Southwestern Public Service Co	230	2004-06	6	Amarillo South Intg.	Nichols Station
Southwestern Public Service Co	230	2004-06	6	Amarillo South Intg.	Switsher Co. Intg.
Southwestern Public Service Co	345	2004-12	25	Eddy Co. Intg	Seven Rivers Intg.
Southwestern Public Service Co	345	2004-12	106	Finney Co. Sw Sta.	Lamar Interchange
Southwestern Public Service Co	230	2004-12	34	Seven Rivers Intg.	Potash Jct.
Southwestern Electric Power Co	345	2007-06	14	Chamber Springs	Tontitown
Southwestern Electric Power Co	345	2010-06	17	Flint Creek	East Centerton

<u>Beyond the NERC List: The SPP RTO Regional Transmission Expansion Plan</u>

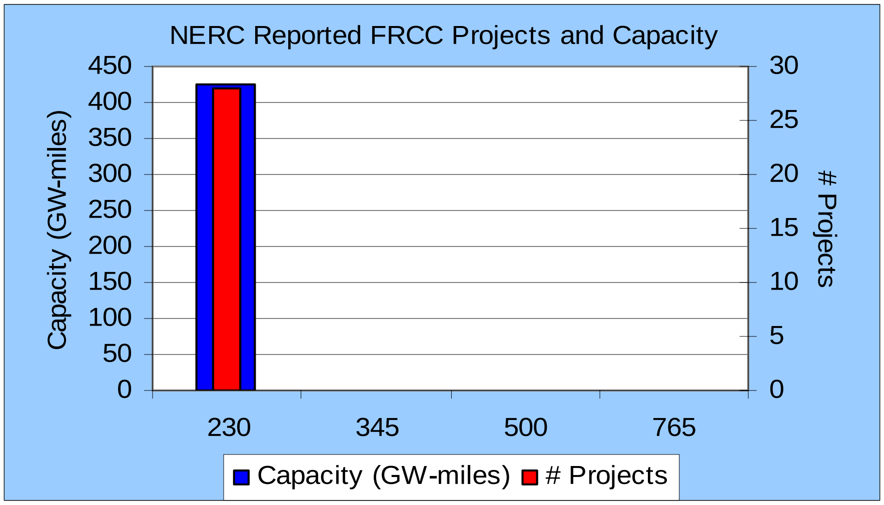
The Southwest Power Pool has developed a transmission expansion program whose database of proposed new transmission projects, transformers, and devices (capacitors, reactors, FACTS, etc.) goes well beyond the minimal number of projects that are listed in the NERC ES&D. The chart below presents a comparison of the cost estimates of the NERC projects, and those of the SPP, by year. The SPP list amounts to projects exceeding $1 billion in investment, while the NERC list amounts to roughly half that amount.



Eastern Market Areas Not Organized as RTOs

The transmission outlooks for areas not organized as RTOs is more difficult to assess, because the transmission planning process tends to be owned by the incumbent utilities, rather than subjected to the extensive discussions and public disclosure that tends to occur in RTO areas.

FRCC—Florida Reliability Coordinating Council



The NERC database reports 28 projects for a total of 440 miles that are planned for FRCC between 2004 and 2010. All the projects are 230 kV lines. The projects reported in NERC total 426 GW-miles of new capacity. The projects are listed in the following table.

FRCC Projects Listed in NERC 2004 Database

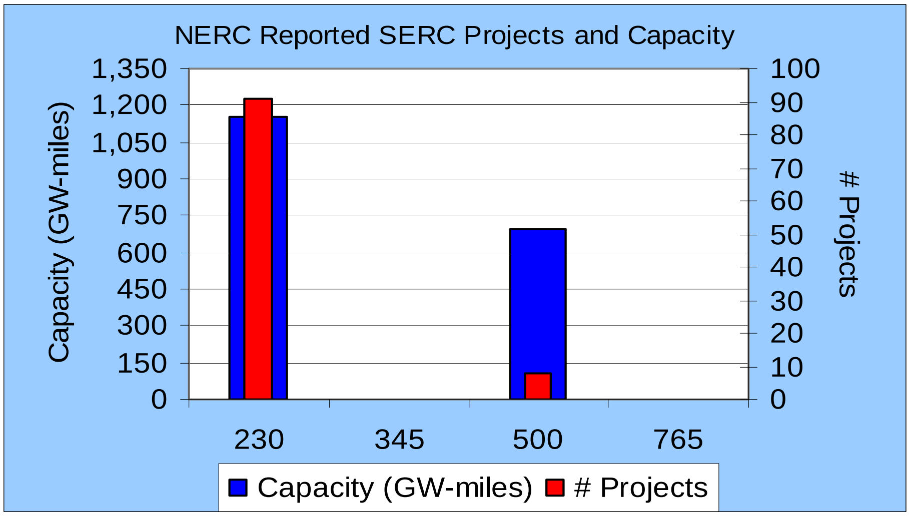
Company Name	Design Voltage	In Service Date	Line Length	Terminal From	Terminal To
Florida Power & Light Co	230	2004-06	2	Andytown	Pennsuco
Florida Power & Light Co	230	2004-06	11	Broward-Corbett	Rainberry-Yamato
Florida Power & Light Co	230	2004-06	11	Dade	Overtown
Florida Power & Light Co	230	2004-06	27	Whidden	Vandola
JEA	230	2004-07	14	Brandy Branch	Normandy
Florida Power Corp	230	2004-10	14	Vandolah	Whidden
Florida Power & Light Co	230	2004-12	10	Bridge	Indiantown
Florida Power & Light Co	230	2004-12	13	Indiantown	Martin #2
JEA	230	2005-05	11	Northside	Center Park
JEA	230	2005-05	6	Westlake	Normandy
JEA	230	2005-05	22	Westlake	St. Johns River Powe
Florida Power & Light Co	230	2005-06	13	Conservation	Oakland Park
Tampa Electric Co	230	2005-06	12	Pebbledale	Twilight

FRCC Projects Listed in NERC 2004 Database					
Company Name	Design Voltage	In Service Date	Line Length	Terminal From	Terminal To
Florida Power & Light Co	230	2005-12	54	Collier	Orange River #3
Seminole Electric Coop Inc	230	2005-12	13	Clay Keystone Height	Clay TP-8
Tampa Electric Co	230	2006-06	8	Twilight	Hampton
Florida Power Corp	230	2006-10	10	Lake Bryan	Windermere #1
Florida Power Corp	230	2006-10	10	Lake Bryan	Windermere #2
Florida Power Corp	230	2007-05	21	Hines Energy Complex	West Lake Wales #1
Tampa Electric Co	230	2007-06	8	Davis	Chapman
Tampa Electric Co	230	2007-06	10	Hampton	Wheeler
Florida Power Corp	230	2008-04	10	Intercession City	Gifford
Florida Power & Light Co	230	2008-06	23	West Palm Coast	St. Johns
Tampa Electric Co	230	2008-06	13	Davis	Wilderness
Tampa Electric Co	230	2008-06	13	Wheeler	Davis
Florida Power Corp	230	2009-05	21	Hines Energy Complex	West Lake Wales #2
Florida Power Corp	230	2010-06	30	Intercession City	West Lake Wales #1
Florida Power Corp	230	2010-06	30	Intercession City	West Lake Wales #2

ESAI referred to the Florida Public Service Commission's report, "A Review of Florida Electric Utility 2003 Ten-year Site Plans," and to websites of individual utilities, including Progress Energy Florida (PEF) (the parent company of Florida Power Corporation), Florida Power & Light Company (FPL), Tampa Electric Company (TECO), JEA, and Seminole Electric Cooperative.

Other than FPL, ESAI found little information on the websites of the utilities located in FRCC by which it could cross-check the information provided in the ES&D database. ESAI was able to identify the five of FPL's eight projects listed in the ES&D database on FPL's website. Two other projects are listed on FPL's website, the Port Sewall to Sandpiper Transmission Line, and the Panacea Substation 230 kV loop project. The size and length of the Port Sewall-Sandpiper Line is not provided, but it does appear to be a project that matches the three remaining FPL projects listed in the ES&D database. It is given an estimated completion date of 2008. The Panacea Substation also does not appear to match any FPL project listed in the ES&D database. It is given an estimated time of completion of summer 2005.

SERC—Southeast Electric Reliability Council



The NERC database reports 99 projects for a total of 1,846 miles that are planned for SERC between 2004 and 2012. Most of the projects (91) have a design voltage of 230 kV, the balance (8) are 500 kV lines. The projects reported in NERC total 1,848 GW-miles of new capacity. The projects are listed in the following table.

SERC Projects Listed in NERC 2004 Database					
Company Name	**Design Voltage**	**In Service Date**	**Line Length**	**Terminal From**	**Terminal To**
South Carolina Electric&Gas Co	230	2004-01	1	Jasper County	Purrysburg
South Carolina Electric&Gas Co	230	2004-01	37	Yemassee	Jasper County
South Carolina Electric&Gas Co	230	2004-01	2	Yemassee	Yemassee
Georgia Power Co	230	2004-03	19	CLERMONT JCT.	Middle Fork
Georgia Transmission Corp	230	2004-04	3	Holcomb Bridge	Martins Landing
Alabama Power Co	230	2004-05	0	Pike County	Pinckard
Alabama Power Co	230	2004-05	0	Pike County	Snowdoun
Georgia Power Co	230	2004-05	2	GLAZE DRIVE	HOLCOMB BRIDGE
Georgia Transmission Corp	230	2004-05	9	Big Shanty	McConnell Road
South Carolina Electric&Gas Co	230	2004-05	1	Hopkins	Hopkins Tap
Duke Energy Corp	230	2004-06	13	Ernest Switching Sta	Sadler Tie
Georgia Transmission Corp	230	2004-06	31	Yellowdirt	Hickory Level
Alabama Power Co	230	2005-04	1	Georgetown DS	Georgetown Tap
Alabama Power Co	230	2005-05	31	Snowdoun	Madison Park
Dominion Virginia Power	230	2005-05	11	Brambleton	Beaumead
Dominion Virginia Power	230	2005-05	14	Chickahamony	Lanexa
Dominion Virginia Power	230	2005-05	8	Landstown	West Landing
Dominion Virginia Power	230 (Underground)	2005-05	2	Navy South	Navy North

SERC Projects Listed in NERC 2004 Database					
Company Name	**Design Voltage**	**In Service Date**	**Line Length**	**Terminal From**	**Terminal To**
Entergy	230	2005-06	63	China	Porter
Entergy	230	2005-06	18	Rankin	South Jackson
Carolina Power & Light Co	230	2005-06	32	Darlington County	Florence
Georgia Power Co	230	2005-06	18	CLERMONT JCT	SOUTH HALL
Georgia Power Co	230	2005-06	12	DAVIS STREET	EAST POINT
Savannah Electric & Power Co	230	2005-06	0	Dean Forest	Little Ogeechee
Dominion Virginia Power	230	2005-06	28	Fentress	Shawboro
Alabama Power Co	230	2005-11	0	Farley N.P.	Cottonwood T.S.
Alabama Power Co	230	2005-11	0	Sinai Cemetery (Scho	Cottonwood T.S.
Entergy	230	2005-12	10	Conway	Panama
South Carolina Pub Serv Auth	230	2006-01	20	Dalzell	Camden
Dominion Virginia Power	230	2006-05	4	Clark	Idylwood
Entergy	230	2006-06	13	Lakeover	Mansdale
Entergy	230	2006-06	9	Ninemile	Waggaman
Entergy	500	2006-06	6	Perryville	Sterlington
Entergy	230	2006-06	23	Waggaman	Waterford
Carolina Power & Light Co	230	2006-06	26	Clinton	Lee
Georgia Transmission Corp	230	2006-06	25	Dresden	South Coweta
Tennessee Valley Authority	500	2006-06	36	Cumberland	Montgomery
Georgia Power Co	230	2006-09	15	CEDARTOWN	ARAGON
South Carolina Pub Serv Auth	230	2006-09	35	Cross	Kingstree No 2
Dominion Virginia Power	230	2006-11	11	Midlothian	Winterpock
Entergy	500	2006-12	12	Bogue Chitto	Bogalusa
Entergy	500	2006-12	12	Bogue Chitto	Franklin
Entergy	230	2006-12	20	Coly	Hammond
Entergy	230	2006-12	18	Hammond	Amite
Entergy	230	2006-12	26	Panama	Dutch Bayou
South Carolina Pub Serv Auth	230	2006-12	43	Hemingway	Red Bluff
Alabama Power Co	230	2007-04	0	Ashland T.S.	Gaston S.P.
Alabama Power Co	230	2007-04	0	Ashland T.S.	Roopville
Alabama Power Co	230	2007-05	1	Prattville CT TS	County Line Road TS
Dominion Virginia Power	500	2007-05	9	Morrisville	Brister
Dominion Virginia Power	230	2007-05	12	Pleasant View	Hamilton
Entergy	230	2007-06	31	Cypress	Jacinto
Entergy	230	2007-06	29	Jacinto	Lewis Creek
Entergy	230	2007-06	4	Yandel	Bozeman
Carolina Power & Light Co	230	2007-06	26	Florence	Marion
Carolina Power & Light Co	230	2007-06	30	Kinston DuPont	Greenville
Carolina Power & Light Co	230	2007-06	43	Marion	Whiteville
Georgia Power Co	230	2007-06	10	CUMMING	SHOAL CREEK
Georgia Power Co	230	2007-06	35	HOPEWELL	MCGRAW FORD
Georgia Power Co	500	2007-06	35	MCGRAU FORD	MOSTELLAR SPRINGS

SERC Projects Listed in NERC 2004 Database					
Company Name	Design Voltage	In Service Date	Line Length	Terminal From	Terminal To
Georgia Transmission Corp	230	2007-06	42	Anthony Shoals	Evans
Georgia Transmission Corp	230	2007-06	19	McGraw Ford	Cumming
Municipal Electric Authority	230	2007-06	8	Fort Valley Tap	Fort Valley #1
South Carolina Pub Serv Auth	230	2007-06	15	Mateeba	Johns Island No 2
Entergy	230	2007-12	11	Mabelvale	Little Rock South
Alabama Power Co	230	2007-12	0	Turf Club T.S.	Boyles T.S.
Alabama Power Co	230	2007-12	0	Turf Club T.S.	Gaston S.P.
Dominion Virginia Power	230	2007-12	24	Fredericksburg	Possum point
Carolina Power & Light Co	230	2008-06	30	Cape Fear	Siler City
Alabama Power Co	230	2008-09	0	Alexander City SS	Danway SS
Alabama Power Co	230	2008-09	0	Alexander City SS	North Opelika TS
Alabama Power Co	230	2008-09	0	Gaston S.P.	Alexander City SS #1
Alabama Power Co	230	2008-09	0	Gaston S.P.	Alexander City SS #2
South Carolina Pub Serv Auth	230	2009-01	88	Cross	Aiken
Georgia Transmission Corp	230	2009-06	36	Bio	Center
Georgia Transmission Corp	230	2009-06	30	Bio	Middlefork
Georgia Transmission Corp	230	2009-06	15	Deshong	Ponce De Leon
South Carolina Pub Serv Auth	230	2009-06	23	Flat Creek	Indian Creek
Georgia Transmission Corp	500	2009-12	45	Augusta	Wadley
South Carolina Pub Serv Auth	230	2009-12	13	Kingstree	Lake City
Entergy	230	2010-06	29	Froscraft	Sterlington
Entergy	230	2010-06	42	Getwell	Batesville
Entergy	230	2010-06	8	Rilla	Froscraft
Entergy	230	2010-06	11	Selman Field	Rilla
Entergy	230	2010-06	16	Sterlington	Selman Field
Entergy	230	2011-06	28	Porter	Lewis Creek
Entergy	230	2011-06	21	Winfield	Danville
Gulf Power Co	230	2011-06	14	Smith	Laguna Beach
Mississippi Power Co	230	2011-06	13	Kiln	Picayune
Municipal Electric Authority	230	2011-06	28	Raccoon Creek	East Moultrie
Dominion Virginia Power	500	2012-05	85	Joshua Falls (AEP)	Lady Smith
Georgia Transmission Corp	230	2012-06	15	Beulah	Hickory Level
Georgia Transmission Corp	230	2012-06	26	Beulah	Portland
Georgia Transmission Corp	230	2012-06	8	East Dallas	McConnell Road
Georgia Transmission Corp	230	2012-06	25	McConnell Road	Portland
Georgia Transmission Corp	230	2012-06	14	Villa Rica	East Dallas
Gulf Power Co	230	2012-06	40	Alligator Swamp	Shoal River
Gulf Power Co	230	2012-06	4	Crist	Alligator Swamp
Gulf Power Co	230	2012-06	35	Laguna Beach	Crystal Beach

ESAI did not review data from all the reporting utilities, but selected a sampling from websites to see if there was consistency between what is reported in the ES&D database and what is reported separately. ESAI reviewed TVA's website, as well as information from Entergy.

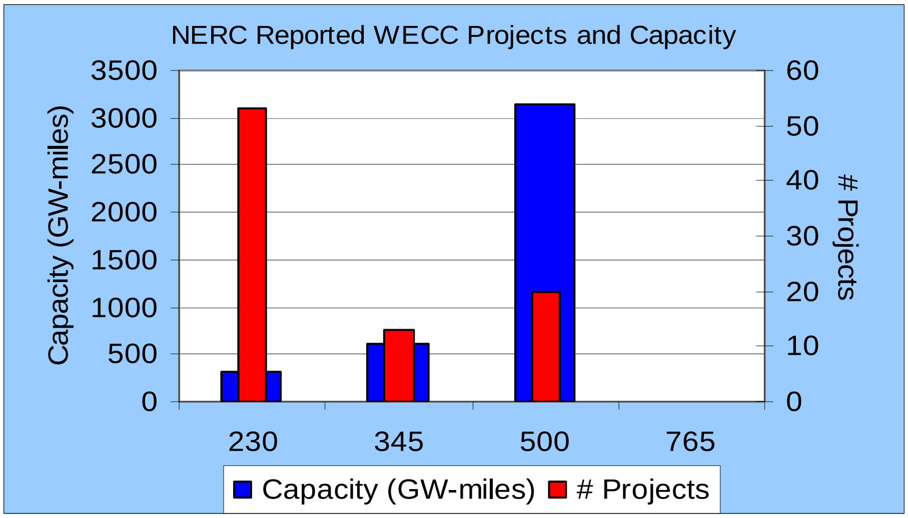
TVA's Cumberland to Montgomery 36-mile 500 kV line is the only firm new transmission project of 230 kV or above. The TVA also provides a description of a planned Paradise-Williams project, new 90-mile 500 kV line with an estimated in-service date of 2009. This project, which would add 180 GW-miles of capacity, is not listed in the ES&D database. In addition, there are six projects for 34 miles of new 161 kV lines. These are below the 230 kV reporting criteria, but they indicate a higher level of new transmission development by the TVA than is reflected in the ES&D database.

ESAI's research into the transmission expansion plans of Entergy revealed the following transmission projects indicated as approved at the Transmission Planning Summit Meeting held on July 8, 2004, and present in the power flow base cases downloaded from the Entergy OASIS. Most of the new projects are upgrades on existing transmission lines. The 230 kV new lines are listed in the NERC ES&D data. The following table lists all the transmission projects included in the power flow model.

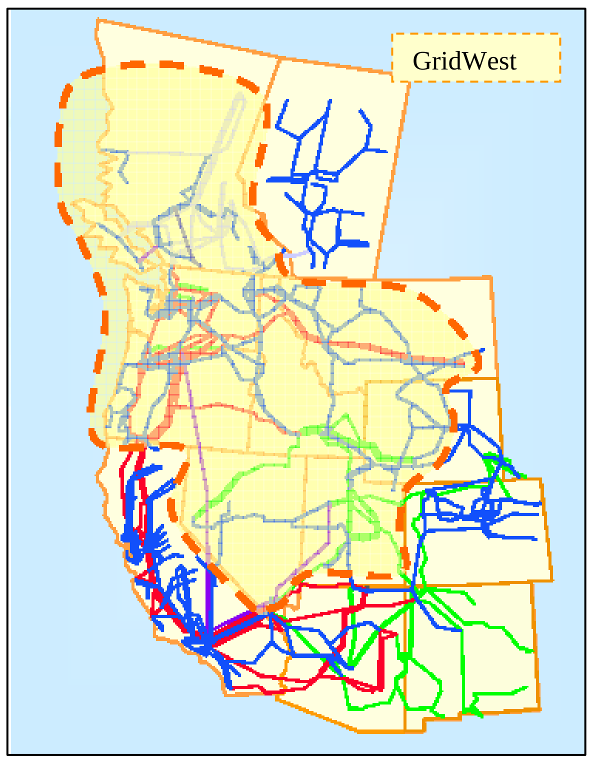
Company Name	Voltage	Upgrade or New	Terminal From	Terminal To
Entergy	115	Upgrade	Couch	MagnoliaDow
Entergy	115	Upgrade	JacksonvilleSouth	JacksonvilleNorth
Entergy	161	Upgrade	Harrisburg Tap	Marked Tree
Entergy	161	Upgrade	Paragould	Paragould South
Entergy	161	Upgrade	Jonesboro	Jonesboro
Entergy	161	Upgrade	ISES	Newport
Entergy	161	Upgrade	Trumann	Harrisburg Tap
Entergy	138	New	Conroe	Goslin
Entergy	230	Upgrade	China	Amelia
Entergy	230	New	Conway	Panama
Entergy	115	Upgrade	Chatawa	Kentwood
Entergy	115	Upgrade	Kentwood	Amite
Entergy	230	Upgrade	Conway	Bagatelle
Entergy	115	Upgrade	Monroe	WalnutGrove
Entergy	230	Upgrade	Rankin	SouthJackson
Entergy	230	Upgrade	Coly	Vignes
Entergy	230	New	Panama	DutchBayou

Western Interconnection

WECC—Western Electricity Coordinating Council



The NERC database reports 86 projects for a total of 3,117 miles that are planned for WECC between 2004 and 2012. The list includes 20 projects that are 500 kV or larger. The projects reported in NERC total 4,042 GW-miles of new capacity in the WECC. There are 39 projects in the Arizona-New Mexico sub-region, nine projects in the California-Nevada sub-region, 28 projects in the Northwest Power Pool sub-region, and 10 projects in the Rocky Mountain Power Pool sub-region.

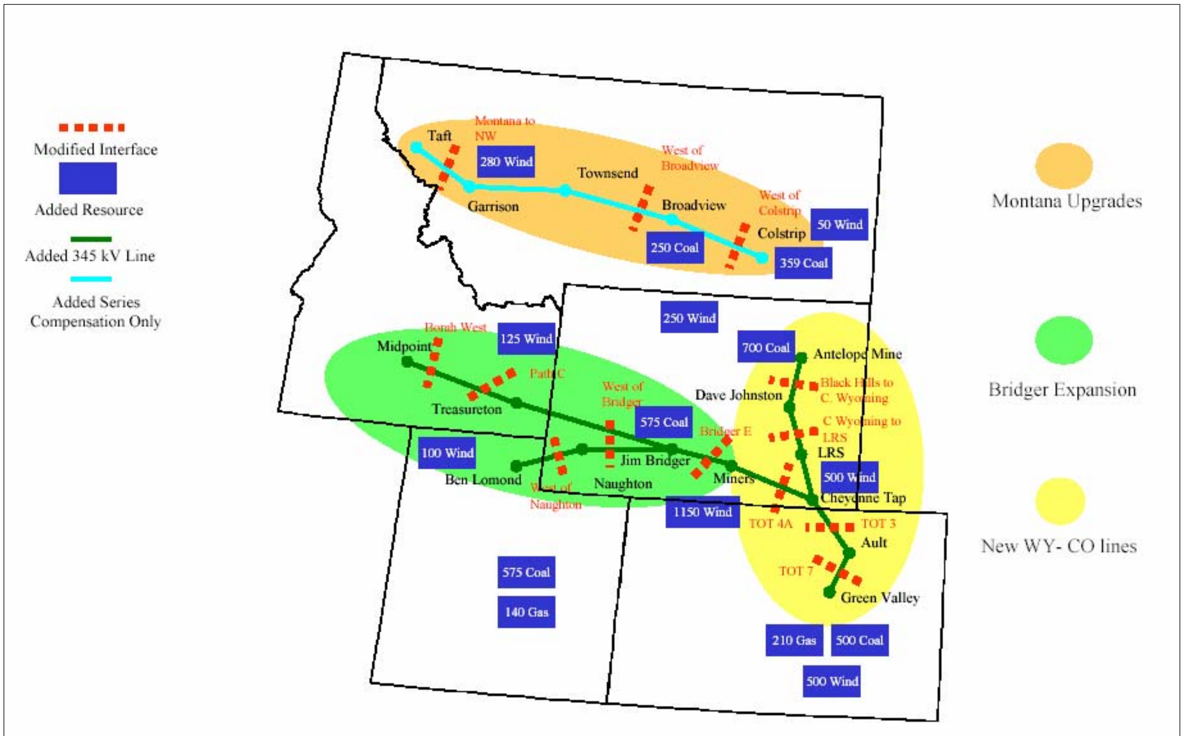


Because of the broad geographic distribution of load and generation in the West, transmission has historically been developed from a regional basis more than in other areas of the country. There is currently no RTO in the West. A group of regional transmission owners including Bonneville Power Administration, Idaho Power Company, Nevada Power Company, NorthWestern Energy, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc., and Sierra Pacific Power Company, agreed last December on bylaws that will govern Grid West. Grid West is the successor to RTO West and includes transmission resources in Washington, Oregon, Idaho, Montana, Nevada, Utah, and Wyoming as shown in the map.

While GridWest is still in the development stage, there has been a keen awareness of the importance of regional transmission planning for both reliability and economic reasons. Five distinct regional transmission planning initiatives have emerged in recent years in response to pressure from state governors and others to develop a planning process in lieu of a true Western RTO. Those initiatives are:

- ***SSG-WI*:** The Seams Steering Group-Western Interconnection process was created as a forum that would address the development of a seamless Western-wide electricity market. The SSG-WI released its first report on transmission needs in the Western Interconnection in 2003. The report presents the results of transmission modeling studies that examine three generation and transmission scenarios for 2008 and 2013. It also created a public database for evaluating the interaction of future transmission and generation development. Several sub-regional efforts within the Western Interconnection, outlined below, have also developed and moved forward.
- ***STEP*:** The Southwest Transmission Expansion Planning Group began work in November 2002 and has met periodically since then. Its focus is on expansion of the transmission system between Arizona, southern California, southern Nevada, and New Mexico. The group consists of utilities, independent power producers, state agency and regulatory entities, and other interested stakeholders.
- ***SWAT*:** The Southwest Area Transmission Group evolved from a smaller area study group, the Central Arizona Transmission System (CATS) Study Group, to cover Arizona, New Mexico, and portions of Nevada and Colorado. Within SWAT there are five smaller study areas.
- ***RMATs:*** Wyoming Governor Dave Freudenthal and Utah Governor Michael Leavitt initiated the Rocky Mountain Area Transmission Study in August 2003. It covers the states of Colorado, Idaho, Montana, Utah, and Wyoming. The study was initiated to stimulate investment in transmission infrastructure in order to serve load growth in the Rocky Mountains and to facilitate the export of coal and wind generated power to other parts of the Western Interconnection. The latest RMAT study, which was released this September, recommends three expanded transmission projects within the five-state Rocky Mountain area and two projects that would export power to California, Arizona, and Nevada.
- The "Frontier Project" was launched by the governors of California, Wyoming, Utah, and Nevada in April 2004. Its purpose is to facilitate the development of HVDC transmission lines sufficient to transfer up to 12,000 MW of power across the Western states into Nevada and California.[14]
- ***NTAC:*** Northwest Transmission Assessment Committee was formed to examine transmission expansion needs in the Pacific Northwest. The Committee is focused on economic projects that will help to reduce price volatility as opposed to reliability issues. The Committee comes under the umbrella of the Northwest PowerPool and has held joint meeting with the California ISO to initiate sub-regional planning similar to that undertaken with the STEP Process.

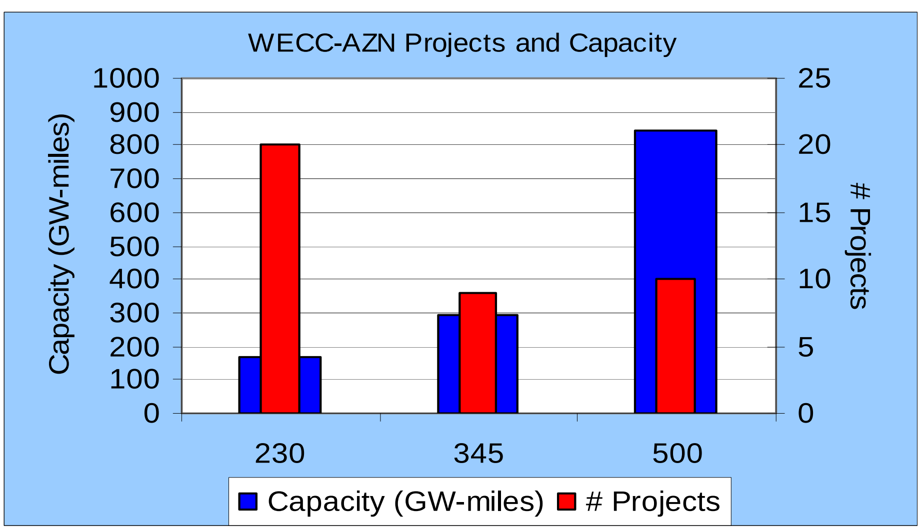
[14] See http://psc.state.wy.us/htdocs/subregional/Frontierline040105.pdf.



Transmission Expansion recommended by the Rocky Mountain Area Transmission Study (2004)

ESAI reviewed the information available from each of these regional plans, as well as information from WECC's "10-Year Coordinated Plan Summary" from September 2004, the California Independent System Operator, and the California Energy Commission, and compared it with NERC's ES&D data for each of the four WECC sub-regions.

Arizona-New Mexico (AZN) Sub-region



Within the AZN sub-region the NERC reports 39 projects, which account for 1,306 GW-miles of new transmission capacity.

WECC-AZN Projects Listed in NERC 2004 Database					
Company Name	**Design Voltage**	**In Service Date**	**Line Length**	**Terminal From**	**Terminal To**
Western Area Power Admin	230	2004-03	-8	Shiprock NM	Four Corners NM
Western Area Power Admin	345	2004-03	8	Shiprock NM	Four Corners NM
Tucson Electric Power Co	345	2004-03	-75	Greenlee AZ	Vail AZ
Tucson Electric Power Co	345	2004-03	45	Greenlee AZ	Winchester AZ
Tucson Electric Power Co	345	2004-03	31	Winchester AZ	Vail AZ
Tucson Electric Power Co	230	2004-04	21	Winchester AZ	Apache AZ
Western Area Power Admin	230	2004-06	5	Hoover AZ	Mead AZ
Tucson Electric Power Co	345	2005-12	60	South AZ #1	Nogales AZ
Tucson Electric Power Co	345	2005-12	60	South AZ #2	Nogales AZ
Tri-State G & T Assn Inc	230	2005-12	113	Gladstone NM	Walsenburg CO
Nevada Power Co	230	2005-12	41	Stirling Mountain NV	Northwest NV
Salt River Proj Ag I & P Dist	500	2006-04	51	Wintersburg AZ	Pinal West AZ
Tucson Electric Power Co	345	2006-06	1	Mobile AZ	Mobile AZ
Nevada Power Co	230	2006-06	44	Diamond NV	Mead NV
Nevada Power Co	230	2006-06	4	Diamond NV	Table Mountain NV
Arizona Public Service Co	230	2006-06	14	Phoenix AZ	Phoenix AZ
Nevada Power Co	230	2006-10	10	Stirling NV	Northwest NV
Salt River Proj Ag I & P Dist	500	2007-04	13	Mobile AZ	Maricopa AZ
Nevada Power Co	525	2007-04	50	Harry Allen Sub NV	Mead Sub NV
Arizona Public Service Co	500	2007-06	45	Palo Verde AZ	West Phoenix AZ
Arizona Public Service Co	230	2007-06	20	West Phoenix AZ	West Phoenix AZ
Arizona Public Service Co	230	2007-06	20	West Phoenix AZ	West Phoenix AZ
Nevada Power Co	525	2008-03	8	Las Vegas NV	Las Vegas NV
Nevada Power Co	525	2008-03	8	Las Vegas NV	Las Vegas NV
Salt River Proj Ag I & P Dist	230	2008-04	12	Mesa AZ	Queen Creek AZ
Imperial Irrigation District	230	2008-05	5	Coachella Tap CA	Indio CA
Arizona Public Service Co	230	2008-06	9	Peoria AZ	Pioneer AZ
Arizona Public Service Co	230	2008-06	15	West Phoenix AZ	West Phoenix AZ
Arizona Public Service Co	230	2009-06	16	Phoenix AZ	Phoenix AZ
Nevada Power Co	230	2009-12	11	Vista NV	Pahrump NV
Arizona Public Service Co	230	2010-06	115	Gila Bend AZ	Yuma AZ
Arizona Public Service Co	500	2010-06	40	Northwest Phoenix AZ	Peoria AZ

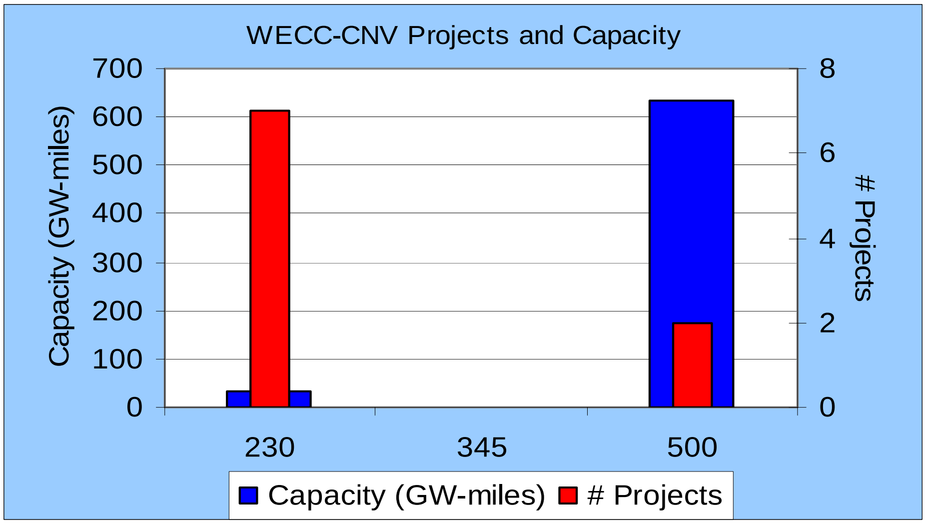
WECC-AZN Projects Listed in NERC 2004 Database					
Arizona Public Service Co	230	2010-06	7	Phoenix AZ	Phoenix AZ
Salt River Proj Ag I & P Dist	500	2011-04	87	Maricopa AZ	Mesa AZ
Nevada Power Co	525	2012-04	61	Las Vegas NV	Las Vegas NV
Tucson Electric Power Co	500	2012-06	60	Mobile AZ	Red Rock AZ
Tucson Electric Power Co	345	2012-12	68	Red Rock AZ	Sahuarta AZ
Public Service Co of NM	345	2013-01	125	San Juan NM	West Mesa NM
Arizona Public Service Co	230	2013-06	11	Phoenix AZ	Phoenix AZ

The Southwest is one of the most active areas of the country for transmission planning. The historic interconnection of generation and transmission between states and the region also means that there is a considerable amount of regional attention to transmission. Transmission in the Southwest is addressed in the SSG-WI report, by the STEP Group, and by the SWAT Group. Other transmission reports covering Arizona that were referred to include the Arizona Corporate Commission’s Third Biennial Transmission Assessment, which was finalized in November and covers the years 2004–2013, and the phase III study of the Central Arizona Transmission System (CATS), which was prepared by Arizona Public Service, Salt River Project, Southwest Transmission Cooperative, Tucson Electric Power, and Western Area Power Administration.

AZN Projects Listed in the WECC 10-Year Coordinated Plan		
Project	**Design Voltage**	**Estimated Completion**
Nogales, AZ to Tucson, AZ	345	2005
Palo Verde to Southeast Valley (Phoenix area) Part 1- Palo Verde to Pinal West	500	2006
Palo Verde to Southeast Valley (Phoenix area) Part 2 - Pinal West to Santa Rosa	500	2007
Palo Verde to Southeast Valley (Phoenix area) Part 3 - Santa Rosa to Browning	500	2011
Northern to central New Mexico	345	2007
Shiprock, NM to Marketplace, NV	500	2008
Palo Verde to West and North Phoenix	500	2008 and 2010
Yuma, AZ to Gila Bend, AZ	230	2012

With the multiple planning initiatives in the Southwest, parsing the data from different reports and comparing it with what is provided in the ES&D database is a substantial task that illustrates some of the issues with data collection. The information provided in the ES&D database for AZN provides from-to locations that are effectively meaningless without some understanding of the project being described. The WECC’s 10-Year Coordinated Plan Summary lists eight projects in AZN; this is a substantially shorter list than the 39 projects listed in the ES&D database and it is assumed that they represent those projects with the highest expectation of completion.

California-Nevada Sub-region



NERC reports nine projects in the California-Nevada Sub-region, which account for 664 GW-miles of transmission capacity. Most of the new capacity (632 GW-miles) comes from two new 500 kV lines. One is the 86-mile Path 15 upgrade, which was activated in December 2004. The other is the 230-mile 500 kV Harquahala-Devers line between California and Arizona. There are seven 230 kV projects reported.

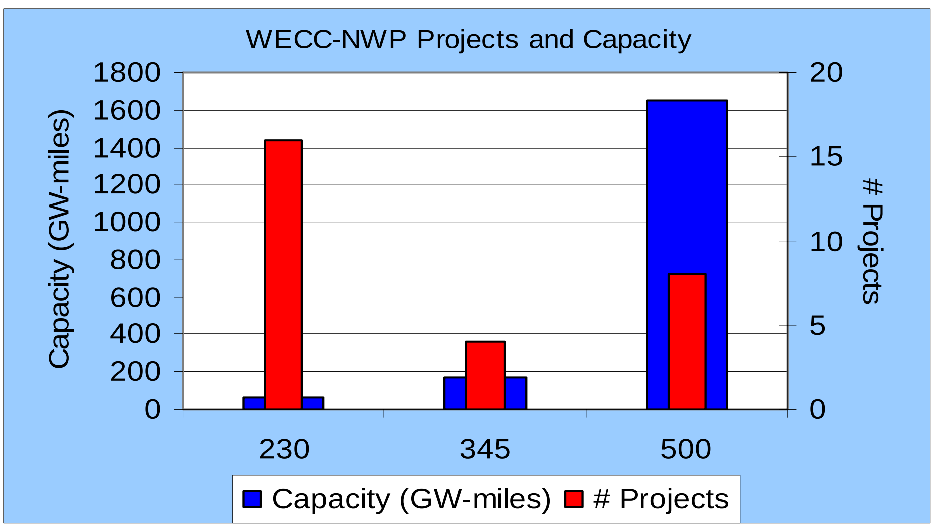
WECC-CNV Projects Listed in NERC 2004 Database

Company Name	Design Voltage	In Service Date	Line Length	Terminal From	Terminal To
Pacific Gas & Electric Co	500	2004-10	86	Gates CA	Los Banos CA
Pacific Gas & Electric Co	230	2005-05	8	Dublin CA	Livermore CA
Pacific Gas & Electric Co	230	2005-09	27	Redwood City CA	Daly City CA
Pacific Gas & Electric Co	230	2006-05	22	Contra Costa CA	Las Positas CA
San Diego Gas & Electric Co	230	2006-06	35	San Diego CA	San Diego CA
Western Area Power Admin	230	2006-12	15	East AltamontCA	Westley CA
Western Area Power Admin	230	2006-12	14	Tracy CA	East Altamont CA
Western Area Power Admin	230	2006-12	-29	Tracy CA	Westley CA
Southern California Edison Co	500	2009-09	230	Harquahala AZ	Devers CA

ESAI reviewed information in reports from the CAISO and the California Energy Commission to create a list of planned and proposed projects for California. This list includes two merchant projects, the Trans Bay Cable which would provide power to the San Francisco peninsula via an underwater cable linked to generators in Pittsburg, and the Lake Elsinore Advanced Pump Storage Project (LEAPS).

ESAI Assembled California Transmission Projects			
Project Name	**Voltage**	**Length (miles)**	**Estimated Completion**
Miguel-Mission #2 230 kV TL	230 kV	35-mile line	Jun-06
Jefferson-Martin 230 kV TL	230 kV	27.1 (14.7 overhead, 12.4 underground)	Dec-05
Otay Mesa Power Purchase Agrement TL Project - (San Diego County)	2- 230 kV	No estimate	Unknown
Tehacahpi Area TL (Kern & LA Counties)	230 or 500 kV	>10	Unknown
Antelope-Pardee Line	230 kV/500 kV	25 miles	Dec-06
Trans Bay Cable Project	350 MW DC	50 miles	Unknown
Palo Verde-Devers #2 500 kV	500 kV	238 miles	2009
Lake Elsinore Advanced Pump Storage Project (LEAPS)	500 kV	30 miles	Unknown
Imperial Valley San Diego Expansion Plan (ISEP)	500 kV	84 to 188 miles depending on route	Unknown
Gates-Gregg 230 kV Double-Circuit Tower Line	230 kV	60 miles	Unknown

Northwest Power Pool Sub-region

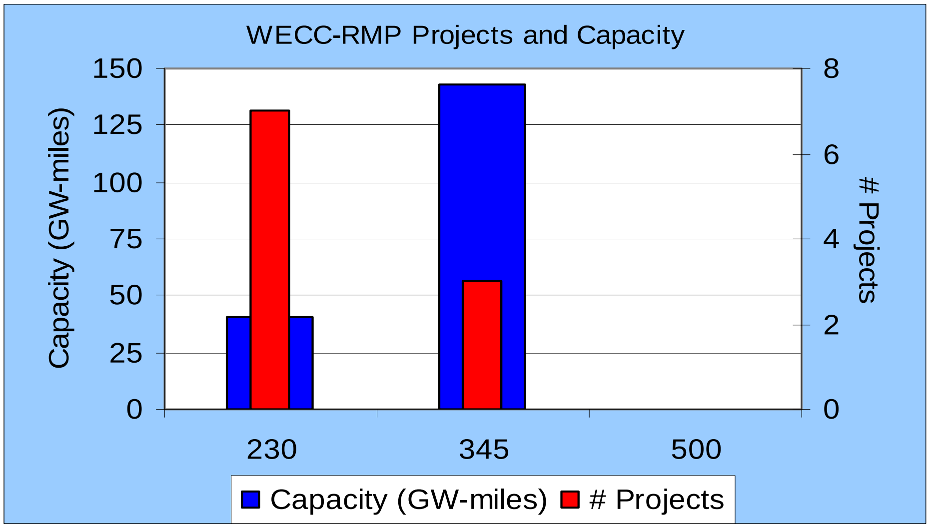


Within the NWP sub-region the NERC reports 28 projects, which account for 1,887 GW-miles of new transmission capacity. Eight 500 kV projects make up nearly 1,700 GW-miles of the new capacity. This includes three 500 kV projects listed by Idaho Power Company with an average length of 173 miles.

WECC-NWP Projects Listed in NERC Database					
Company Name	**Design Voltage**	**In Service Date**	**Line Length**	**Terminal From**	**Terminal To**
PacifiCorp	230	2004-02	26	Point of Rocks WY	Rock Springs WY
PacifiCorp	230	2004-03	18	Monument WY	Craven Creek WY
Idaho Power Co	230	2004-05	5	Caldwell ID	Middleton ID
Sierra Pacific Power Co	345	2004-05	180	Dunphy NV	Ely NV
PacifiCorp	345	2004-06	2	Mona UT	Mona UT
Bonneville Power Admin	500	2004-10	83	Coulee City WA	Spokane WA
Idaho Power Co	230	2004-10	14	Boise ID	Middleton ID
Idaho Power Co	230	2005-04	-105	Boise ID	Midpoint ID
Idaho Power Co	230	2005-04	39	Boise ID	Mountain Home ID
Idaho Power Co	230	2005-04	66	Mountain Home ID	Midpoint ID
Idaho Power Co	230	2005-04	4	Mountain Home ID	Mountain Home ID
Idaho Power Co	230	2005-05	3	Nampa ID	Nampa ID
PacifiCorp	345	2005-06	2	Spanish Fork UT	Spanish Fork UT
Portland General Electric Co	230	2005-11	5	Sherwood OR	Beaverton OR
PacifiCorp	345	2005-12	2	Syracuse UT	Syracuse UT
Avista Corporation	230	2005-12	25	rathdrum ID	Beacon WA
Bonneville Power Admin	525	2006-04	62	Ellensburg WA	Sunnyside WA
Avista Corporation	230	2006-12	60	Benewah ID	Shawnee WA
Puget Sound Energy Inc	230	2007-06	10	Covington WA	Berrydale WA
Bonneville Power Admin	525	2007-10	20	Centralia WA	Shelton WA
Portland General Electric Co	230	2007-11	5	Carver OR	Oregon City OR
Portland General Electric Co	230	2008-11	4	Pearl OR	Sherwood OR
Bonneville Power Admin	525	2009-10	20	Monroe WA	Issiquah WA
Portland General Electric Co	230	2009-11	9	Gresham OR	Troutdale OR
Bonneville Power Admin	525	2011-11	122	Chief Joseph Sub WA	Monroe WA
Idaho Power Co	500	2012-12	240	Ely NV	Las Vegas NV
Idaho Power Co	500	2012-12	130	Shoshone ID	Wells NV
Idaho Power Co	500	2012-12	150	Wells NV	Ely NV

Bonneville Power operates 75 percent of the transmission lines in the Northwest. ESAI found each of the projects reported in NERC's ES&D database on its website.

Rocky Mountain Power Area



Within the Rocky Mountain Power Area (RMP) sub-region NERC reports 10 projects, which account for 184 GW-miles of new transmission capacity. The projects are primarily 230 kV projects, with the exception of one 345 kV project. The projects area listed in the table below.

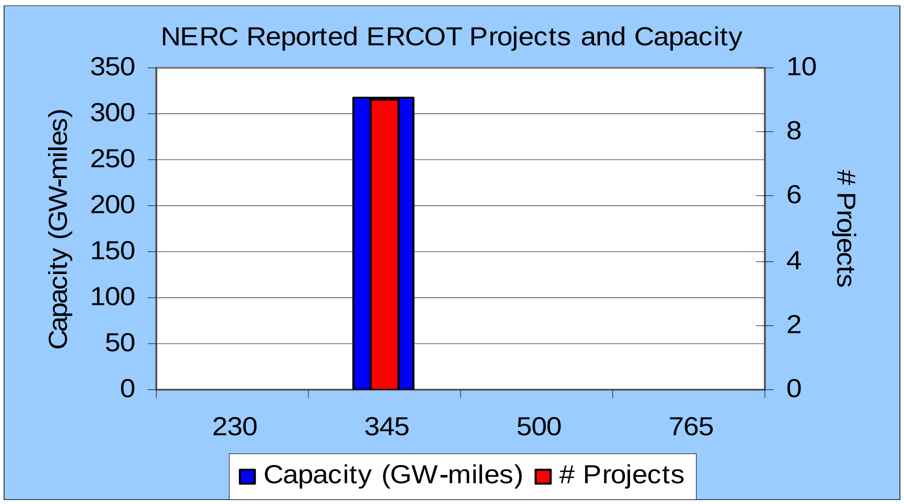
WECC-RMP Projects Listed in NERC Database

Company Name	Design Voltage	In Service Date	Line Length	Terminal From	Terminal To
Public Service Co of Colorado	230	2004-05	19	Green Valley CO	Spruce #2 CO
Public Service Co of Colorado	230	2004-09	16	Wolcott Tap CO	Steamboat #2 CO
Public Service Co of Colorado	230	2005-05	7	Denver Terminal CO	Arapahoe CO
Public Service Co of Colorado	230	2005-05	70	Midway CO	Daniels Park #1 CO
Public Service Co of Colorado	230	2005-05	70	Midway CO	Daniels Park #2 CO
Public Service Co of Colorado	230	2005-05	-70	Midway CO	Daniels Park CO
Basin Electric Power Coop	230	2005-12	43	Car Draw WY	Hartzog WY
Basin Electric Power Coop	230	2005-12	28	Teckla WY	Hartzog WY
Colorado Springs City of	230	2006-06	14	Nixon CO	Kelker CO
Tri-State G & T Assn Inc	230	2009-12	80	Walsenburg CO	San Luis Valley CO

The WECC 10-Year Coordinated Plan Summary lists just four projects in the RMPA that will be completed over the next two years. Longer range projects are conceptualized in the RMAT Study, including three projects that would improve transmission within Colorado, Idaho, Montana, Utah, and Wyoming and two projects that would export power to California, Arizona, and Nevada. These projects are not covered in the ES&D data.

RMPA Projects Listed in the WECC 10-Year Coordinated Plan		
Project	**Design Voltage**	**Estimated Completion**
Green Valley-Spruce	230	2004
Midway-Denver line	345	2005
Carr Draw-Hartzog-Teckla	230	Late 2005
Walsenburg, CO to Gladstone, NM	230	Late 2005

ERCOT Interconnection



The NERC database reports nine projects for a total of 352 miles that are planned for ERCOT between 2006 and 2008. All the projects are new 345 kV lines. The projects reported in NERC total 317 GW-miles of new capacity. The projects are listed in the following table.

ERCOT Projects Listed in NERC 2004 Database					
Company Name	**Design Voltage**	**In Service Date**	**Line Length**	**Terminal From**	**Terminal To**
Oncor	345	2006-05	66	Jacksboro Switch	W. Denton
Oncor	345	2006-05	30	Venus	Liggett
Oncor	345	2006-05	7	Venus	Sherry
Oncor	345	2006-05	7	W. Levee	Norwood
San Antonio Public Service Bd	345	2006-06	63	Kendall	Cagnon
Oncor	345	2006-12	70	Paris Switch	Anna
Oncor	345	2007-05	13	Liggett	Trinity
Lower Colorado River Authority	345	2008-06	64	Zorn	Hutto Switch
Oncor	345	2008-06	32	Hutto Switch	Salado

ESAI reviewed ERCOT's "Report on Existing and Potential Electric System Constraints and Needs within the ERCOT Region," published on October 1, 2004. Appendix A to the report shows ERCOT's Transmission Project Information Tracking (TPIT) database. The database lists 608 transmission projects that include system upgrades as well as new transmission lines. Seventy of the projects listed are for 345 kV lines. All of the projects listed in the NERC database are included, but there are at least six planned projects for 380 miles of 345 kV transmission lines that are not listed in the NERC database. Two of the projects are outside the five year forecast period requested in the EIA-411 form.

In-Service Year	Project Title	TDSP	Primary Planning Region	Location County Start	Location County End	Level kV	Line Length
2006	Clear Springs	LCRA	SOUTH	GUADALUPE		345	100
2007	North McCamey - Odessa 345-kV Line	LCRA	WEST	UPTON	ECTOR	345	50
2010	Highway 59 to San Miguel, build 345-kV line	AEP TCC	SOUTH	WEBB	ATASCOSA	345	110
2012	North McCamey to Twin Buttes 345-kV Line	LCRA AEP	WEST	UPTON	IRION	345	120

The remainder of the 538 projects listed in the TPIT database are for projects involving 69 kV or 138 kV lines. There are 467 projects for 138 kV lines, and another 71 projects for 69 kV lines. These are projects that would not be reported in form EIA-411.

Appendix
SOURCES OF INFORMATION ABOUT TRANSMISSION INVESTMENT

Note: This description of federal transmission data collection procedures is taken in its entirety from US Energy Information Administration, "Electricity Transmission in a Restructured Industry: Data Needs for Public Policy Analysis," Appendix A.

FERC Form 1, “Annual Report of Major Electric Utilities, Licensees and Others,” is filed with the FERC and can provide DOE/EIA with a comprehensive listing of transmission data for investor-owned utilities. Data from this form include line location, voltage rating, structure type, conductor information, number of circuits, and land and construction costs. This form also delineates whether the data are related to either old or new transmission lines. The FERC Form 1 is one of the most useful data sources for investor-owned utilities with critical information related to transmission line identification, ownership, physical/electrical characteristics, and cost.

FERC Form 714, “Annual Electric Control and Planning Area Report,” is filed annually by electric utilities or groups of electric utilities that operate a control area with annual peak demand greater than 200 megawatts. Information related to transmission reported on this form includes adjacent control area names, control area interconnection line/bus names, control area scheduled and actual interchanges, and corresponding line/bus voltage.

FERC Form 715, “Annual Transmission Planning and Evaluation Report,” is filed annually by any transmitting utility that operates network (not radial) transmission facilities at or above 100 kV. In the case of joint ownership, only the operator of the facilities must complete the FERC Form 715. FERC requires each transmitting utility to submit in electronic form its base case power flow data if it does not participate in the development and use of regional power flow data. A respondent that participates in the development and use of regional power flow studies must either submit the regional base case power flow data or designate the regional organization to submit such data. Also included in the submittal are transmission system maps and one-line diagrams, a detailed description of the transmission planning reliability criteria used to evaluate system performance, and a detailed evaluation of the respondent’s anticipated system performance as measured against its stated reliability criteria, using its stated assessment practices.

Form EIA-411, “Coordinated Bulk Power Supply Program Report,” is intended to provide DOE/EIA with an industry-wide source of information regarding regional supply and demand projections for a five-year advance period. The utilities and other electricity suppliers submit their Form EIA-411 information to their respective NERC regional councils by April 1 of each year. NERC collects the data from the regional councils and then provides the data to DOE/EIA. The data reported to DOE/EIA in this form consist of a comprehensive list of supply and demand figures for each NERC regional council. Also included in the Form EIA-411 are transmission line maps, proposed transmission line data (including location, line length, expected service date, Kv rating, and ownership) and load flow studies. Finally, the Form EIA-411 provides information on capacity sales and purchases across regions.

Form EIA-412, “Annual Electric Industry Financial Report,” is filed annually by municipal and Federal utilities and includes information similar to the FERC Form 1. Data from the Form EIA-412 include line location, voltage rating, structure type, conductor information, number of circuits, and land and construction costs. This form also delineates whether the data are related to either old or new transmission lines. The form contains very useful data from municipal utilities with critical information related to transmission line identification, ownership, and physical/electrical characteristics. Additionally, the form initiated collection of transmission data from cooperatives that own generation, beginning with the 2001 annual data.

Form EIA-417, “Emergency Incident and Disturbance Report,” is filed at each occurrence of a loss of transmission ability by those electric utilities that operate a Control Area, and/or Reliability Coordinators, or other electric utility, as appropriate. The type, cause, and extent of the emergency are reported, as well as the response and the eventual resolution of the emergency. Most of the types of emergencies reported on this form occur on local distribution systems rather than on `transmission systems.

Form EIA-860, “Annual Electric Generator Report,” collects data on the status of existing U.S. electric generating plants with a nameplate rating of one megawatt or greater, and those plants scheduled for initial commercial operation within five years of the filing of the form. Data are collected at the generator level, and include fuel source. Respondents include both those in the electricity generation industry and those in other industries (such as manufacturing) that also generate electricity.

Form EIA-861, “Annual Electric Power Industry Report,” reports on the status of electric power industry participants involved in the generation, transmission, and distribution of electric energy in the United States, its territories, and Puerto Rico. Electric power industry participants include electric utilities, wholesale power marketers (registered with the FERC), energy service providers (registered with the States), and electric power producers. Data collected include information on owned or leased transmission lines, purchases (sales) of transmission services on other electrical systems, wholesale power marketing, retail power marketing, and demand-side management (DSM) programs.

Form FE-781R collects electrical import/export data from entities authorized to export electric energy, and those authorized to construct, connect, operate or maintain facilities for the transmission of electric energy at an international boundary as required by 10 CFR 205.308 and 205.325. Actual imports and exports of electricity are reported in detail by month. Export authorization holders primarily report quarterly, while Presidential Permit holders report annually. DOE uses these data to track electricity being imported into the United States.

The Rural Utilities Service (RUS) Form 7, “Financial and Statistical Report for Electrical Distribution Borrowers,” is filed annually by current RUS borrowers that do not own generation. Data from this form includes miles of transmission lines and transmission operating and maintenance expenses. The information included in the RUS Form 7 is somewhat limited in detail and scope and does not provide as much critical data as the preceding non-RUS forms.

RUS Form 12, “Financial and Statistical Report for Power Supply Borrowers and Electric Distribution Borrowers with Generating Facilities,” is filed annually by current RUS borrowers that own generation. Data from this form includes miles of transmission lines by voltage, limited substation information, and transmission operating and maintenance expenses. The information included in the RUS Form 12 is also somewhat limited in detail and scope and does not provide as much critical data as the preceding non-RUS forms.

Form EIA-411 Schedule 6

Schedule 6. Projected Transmission Line Additions

1. This Schedule shall be completed for all transmission line additions at 230 kV and above projected for the five-year period beginning with the year following the reporting year.
2. For line 1, **Terminal Location (From)**, enter the name of the beginning terminal point of the line.
3. For line 2, **Terminal Location (To)**, enter the name of the ending terminal point of the line.
4. For line 3, **Company Name**, enter the company name.
5. For line 4, **EIA Company Code**, identify each organization by the six-character code assigned by EIA.
6. For line 5, **Type of Organization**, identify the type of organization that best represents the line owner including the following types of utilities – Investor-owned (I), Municipality (M), Cooperative (C), State-owned (S), Federally-owned (F), or other (O).
7. For line 6, **Percent Ownership**, if the transmission line will be jointly-owned, enter the percentages owned by each individual respondent.
8. For line 7, **Line Length**, enter miles between beginning and ending terminal points of the line, regardless of the number of conductors or circuits carried.
9. For line 8, **Line Type**, select physical location of the line conductor – overhead (OH), underground (UG), or submarine (SM).
10. For line 9, **Voltage Type**, select voltage as alternating current (AC) or direct current (DC).
11. For line 10, **Voltage Operating**, enter the voltage at which the line is normally operated in kilovolts (kV).

U.S. Department of Energy Energy Information Administration Form EIA-411 (2004)	*COORDINATED BULK POWER SUPPLY PROGRAM REPORT*	Form Approved OMB No. 1905-0129 Approval Expires 11/30/04

INSTRUCTIONS

Specific Instructions
Schedule 6. Projected Transmission Line Additions (Continued)

12. For line 2, **Terminal Location (To)**, enter the name of the ending terminal point of the line.
13. For line 3, **Company Name**, enter the company name.
14. For line 4, **EIA Company Code**, identify each organization by the six-character code assigned by EIA.
15. For line 5, **Type of Organization**, identify the type of organization that best represents the line owner including the following types of utilities – Investor-owned (I), Municipality (M), Cooperative (C), State-owned (S), Federally-owned (F), or other (O).
16. For line 6, **Percent Ownership**, if the transmission line will be jointly-owned, enter the percentages owned by each individual respondent.
17. For line 7, **Line Length**, enter miles between beginning and ending terminal points of the line, regardless of the number of conductors or circuits carried.
18. For line 8, **Line Type**, select physical location of the line conductor – overhead (OH), underground (UG), or submarine (SM).
19. For line 9, **Voltage Type**, select voltage as alternating current (AC) or direct current (DC).
20. For line 10, **Voltage Operating**, enter the voltage at which the line is normally operated in kilovolts (kV).

12\. For line 11, **Voltage Design**, enter the voltage at which the line was designed to operate in kilovolts (kV).

13\. For line 12, **Conductor Size**, enter the size of the line conductor in thousands of circular mils (MCM).

14\. For line 13, **Conductor Material Type**, enter the line conductor material type – aluminum, ACSR, copper, or other.

15\. For line 14, **Bundling Arrangement**, enter the bundling arrangement/configuration of the line conductors – single, double, triple, quadruple, or other.

16\. For line 15, **Circuits per Structure Present**, enter the current number of three-phase circuits on the structures of the line.

17\. For line 16, **Circuits per Structure Ultimate**, enter the ultimate number of three-phase circuits that the structures of the line are designed to accommodate.

18\. For line 17, **Pole/Tower Type**, identify the predominant pole/tower material for the line – wood, concrete, steel, combination, composite material, or other. Also include the type of structure – single pole, H-frame structure, tower, underground, or other.

19\. For line 18, **Capacity Rating**, enter the normal load-carrying capacity of the line in millions of volt-amperes (MVA).

20\. For line 19, **Projected In-Service Date**, enter the projected date the line will be energized under the control of the system operator. Please provide a month and year (e.g. **12-2004**).

U.S. Department of Energy Energy Information Administration Form EIA-411 (2004)	***COORDINATED BULK POWER SUPPLY PROGRAM REPORT***	Form Approved OMB No. 1905-0129 Approval Expires 11/30/04

REPORT FOR: <respondent name> <respondent id>
REPORTING PERIOD: As of January 1, 2004

Council		
Reporting Party		

SCHEDULE 6. PROPOSED TRANSMISSION LINES
(If Necessary or Multiple Owners, Copy and Attach Additional Sheets)

LINE NO.		TRANSMISSION LINE (a)	TRANSMISSION LINE (b)	TRANSMISSION LINE (c)
TRANSMISSION LINE IDENTIFICATION				
1	Terminal Location (From)			
2	Terminal Location (To)			
TRANSMISSION LINE OWNERSHIP				
3	Company Name			
4	EIA Company Code			
5	Type of Organization			
6	Percent Ownership			
TRANSMISSION LINE DATA				
7	Line Length (miles)			
8	Line Type	[ ] OH [ ] UG [ ] SM	[ ] OH [ ] UG [ ] SM	[ ] OH [ ] UG [ ] SM
9	Voltage Type	[ ] AC [ ] DC	[ ] AC [ ] DC	[ ] AC [ ] DC
10	Voltage Operating (Kilovolts)			
11	Voltage Design (Kilovolts)			
12	Conductor Size (MCM)			
13	Conductor Material Type (Select codes from legend below)			
14	Bundling Arrangement (Select codes from legend below)			
15	Circuits per Structure Present			
16	Circuits per Structure Ultimate			
17	Pole/Tower Type (Select codes from legend below)	Pole Material: [ ] Pole Type: [ ]	Pole Material: [ ] Pole Type: [ ]	Pole Material: [ ] Pole Type: [ ]
18	Capacity Rating (Megavoltamperes)			
19	Projected In-Service Date (e.g., 12-2004)			

LEGEND

Line Type	Voltage Type	Conductor Material Type	Bundling Arrangement	Pole/Power Type: Pole Material	Pole/Power Type: Pole Type
OH=Overhead UG=Underground SM=Submarine	AC=Alternating Current DC=Direct Current	AL = Aluminum ASCR = ASCR CU = Copper OT = Other	1 = Single 2 = Double 3 = Triple 4 = Quadruple OT = Other	W = Wood C = Concrete S = Steel B = Combination P = Composite O = Other	P = Single pole H = H-frame T = Tower U = Underground O = Other

Page ____ of ____

Edison Electric Institute (EEI) is the association of United States shareholder-owned electric companies, international affiliates, and industry associates worldwide. Our U.S. members serve 97 percent of the ultimate customers in the shareholder-owned segment of the industry, and 71 percent of all electric utility ultimate customers in the nation. They generate almost 60 percent of the electricity produced by U.S. electric generators.

Organized in 1933, EEI works closely with its members, representing their interests and advocating equitable policies in legislative and regulatory arenas. In its leadership role, the Institute provides authoritative analysis and critical industry data to its members, Congress, government agencies, the financial community and other influential audiences. EEI provides forums for member company representatives to discuss issues and strategies to advance the industry and to ensure a competitive position in a changing marketplace.

EEI's mission is to ensure members' success in a new competitive environment by:

- Advocating Public Policy
- Expanding Market Opportunities
- Providing Strategic Business Information

For more information on EEI programs and activities, products and services, or membership, visit our Web site at www.eei.org.

EDISON ELECTRIC INSTITUTE

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
202-508-5000
www.eei.org