National Transmission Grid Study

The Honorable Spencer Abraham
Secretary of Energy

U.S. Department
of Energy

May 2002

The Secretary of Energy
Washington, DC 20585

May 2002

The Honorable George W. Bush
President of the United States
The White House
Washington, DC 20500

Dear Mr. President:

On behalf of the United States Department of Energy, I am pleased to submit our study of the nation's electricity transmission system. As directed in your National Energy Policy, we have prepared a detailed assessment of the major bottlenecks in our nation's transmission system and recommended ways to eliminate them.

This report makes clear that our nation's transmission system over the next decade will fall short of the reliability standards our economy requires and will result in additional bottlenecks and higher costs to consumers. It is essential that we begin immediately to implement the improvements that are needed to ensure continued growth and prosperity.

To achieve these goals, we will continue to identify bottlenecks that affect national interests and facilitate regional solutions to address them. And we will work to unleash innovation and strengthen our markets to allow entrepreneurs to develop a more advanced and robust transmission system.

As you have directed, we will continue to work with Congress, Governors, and other stakeholders to develop a transmission grid that serves all Americans, safeguards the environment, and ensures America's energy and national security.

Sincerely,

Spencer Abraham

Enclosure

How This Study Was Conducted

The National Energy Policy Plan directed the U.S. Department of Energy (DOE) to conduct a study to examine the benefits of establishing a national electricity transmission grid and to identify transmission bottlenecks and measures to address them.

DOE began by conducting an independent analysis of U.S. electricity markets and identifying transmission system bottlenecks using DOE's Policy Office Electricity Modeling System (POEMS). DOE's analysis, presented in Section 2, confirms the central role of the nation's transmission system in lowering costs to consumers through increased trade. More importantly, DOE's analysis also confirms the results of previous studies, which show that transmission bottlenecks and related transmission system market practices are adding hundreds of millions of dollars to consumers' electricity bills each year. A more detailed technical overview of the use of POEMS is provided in Appendix A.

DOE led an extensive, open, public input process and heard a wide range of comments and recommendations that have all been considered.[1] More than 150 participants registered for three public workshops held in Detroit, MI (September 24, 2001); Atlanta, GA (September 26, 2001); and Phoenix, AZ (September 28, 2001). In addition, more than 40 public comments were received

The National Energy Policy Development (NEPD) Group recommends that the President direct the appropriate federal agencies to take action that will remove constraints on the interstate transmission grid so that our nation's electricity supply will meet the growing needs of our economy.

NEPD directs the Secretary of Energy to examine the benefits of establishing a national grid and to identify transmission bottlenecks and measures to address them.

Source: Office of the President. 2001. National Energy Policy Plan.
Download from http://www.pi.energy.gov/pilibrary.html

[1]Federal Register Notice for the study and public input process was published September 12, 2001.

by mail or through a DOE website created for the study (http://www.ntgs.doe.gov/). Appendix B lists the organizations that offered public comment at one or more of the workshops or through the website.

As further input to this study, DOE commissioned a series of six issue papers from teams of nationally recognized experts. Each team of experts was asked to provide a comprehensive survey of a topic, including review of the comments from DOE's public hearings, and to identify and assess options for DOE's consideration. The six topics reviewed in the issue papers are:

- Transmission System Operation and Interconnection
- Reliability Management and Oversight
- Alternative Business Models for Transmission Ownership and Operation
- Transmission Planning and the Need for New Capacity
- Transmission Siting and Permitting
- Advanced Transmission Technologies

The issue papers are published under a separate cover. Readers are cautioned that the views expressed by the authors in the issue papers are not necessarily those of DOE.

In preparing its recommendations, DOE considered the analysis and options presented by the public comments received, DOE's own analysis, and the issue papers. As one would expect on such a complex subject, there were many divergent opinions on the recommendations that DOE should include. It is not possible, or desirable, to discuss each and every position. Instead, this study presents the results of DOE's comprehensive review and analysis.

Acknowledgments

This report was prepared by the Secretary of Energy under the direction of Jimmy Glotfelty and Logan Walters, Office of the Secretary, and Paul Carrier, Office of Policy and International Affairs.

The study was supported by an interagency working group that included: Tracy Terry, Office of Policy and International Affairs; Larry Mansueti and Philip Overholt, Office of Energy Efficiency and Renewable Energy; Anthony Como, Office of Fossil Energy; Alison Silverstein, Federal Energy Regulatory Commission; and Douglas Hale, Energy Information Administration.

POEMS analysis was led by Tracy Terry, Office of Policy and International Affairs. Frances Wood and Lessly Goudarzi, OnLocation, Inc. provided modeling support.

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Technical support was coordinated by the Consortium for Electric Reliability Technology Solutions under the direction of Joseph Eto, Lawrence Berkeley National Laboratory. The technical team consisted of Fernando Alvarado, University of Wisconsin, Madison; Jeff Dagle, John Hauer, and Steve Widergren, Pacific Northwest National Laboratory; George Gross and Tom Overbye, University of Illinois, Urbana-Champaign; Eric Hirst, Consultant; Brendan Kirby, Oak Ridge National Laboratory; David Meyer, Consultant; Shmuel Oren, University of California, Berkeley; and Richard Sedano, Regulatory Assistance Project. Anthony Ma, Nan Wishner, and Ted Gartner, Lawrence Berkeley National Laboratory, provided editorial and production support.

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Acronyms

AC	Alternating current
AEP	American Electric Power
ATC	Available Transfer Capability
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CREPC	Committee for Regional Electric Power Cooperation
DC	Direct current
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FACTS	Flexible AC transmission system
FERC	Federal Energy Regulatory Commission
HTS	High-temperature superconductivity
HVDC	High-voltage direct current
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
kV	Kilovolt
MWh	Megawatt hour
NARUC	National Association of Regulatory Utility Commissioners
NASEO	National Association of State Energy Officials
NEPD	National Energy Policy Development
NERC	North American Electric Reliability Council
NGC	National Grid Company
NYISO	New York Independent System Operator
OASIS	Open Access Same Time Information System
PBR	Performance-based regulation
PCR	Price-cap regulation
PJM	Pennsylvania, New Jersey, Maryland Interconnection
PMA	Power Marketing Administration
POEMS	Policy Office Electricity Modeling System
PUC	Public utility commission
R&D	Research and development
RTO	Regional Transmission Organization
SWPA	Southwestern Power Administration
TLR	Transmission Loading Relief
TTC	Total Transfer Capability
TVA	Tennessee Valley Authority
WAPA	Western Area Power Administration
WGA	Western Governors' Association
WSCC	Western Systems Coordinating Council

Executive Summary

The U.S. electricity transmission system is an extensive, interconnected network of high-voltage power lines that transport electricity from generators to consumers. The transmission system must be flexible enough, every second of every day, to accommodate the nation's growing demand for reliable and affordable electricity.

The transmission system was built over the past 100 years by vertically integrated utilities that produced and transmitted electricity locally. Small interconnections between neighboring utilities existed, but they were created to increase reliability and share excess generation. Over the past 10 years, we have introduced competition into wholesale electricity markets to lower costs to consumers by spurring needed investments in generation and increasing the efficiency of operations. Today, our transmission system acts as an interstate highway system for wholesale electricity commerce.

There is growing evidence that the U.S. transmission system is in urgent need of modernization. The system has become congested because growth in electricity demand and investment in new generation facilities have not been matched by investment in new transmission facilities. Transmission problems have been compounded by the incomplete transition to fair and efficient competitive wholesale electricity markets. Because the existing transmission system was not designed to meet present demand, daily transmission constraints or "bottlenecks" increase electricity costs to consumers and increase the risk of blackouts.

Eliminating transmission constraints or bottlenecks is essential to ensuring reliable and affordable electricity now and in the future. The Department of Energy (DOE) conducted an independent assessment of the U.S. electricity transmission system and found that:

- Our U.S. transmission system facilitates wholesale electricity markets that lower consumers' electricity bills by nearly $13 billion annually.
- Despite these overall savings, interregional transmission congestion costs consumers hundreds of millions of dollars annually. Relieving bottlenecks in four U.S. regions (California,

PJM, New York, and New England) alone could save consumers about $500 million annually. Savings could be even greater because DOE's analysis does not capture all of the factors, such as impacts on reliability, that result from bottlenecks.

- Introducing advanced transmission technologies and improved operating practices, siting generation closer to areas where electricity is needed, and reducing electricity use through targeted energy efficiency and distributed generation could all help reduce transmission congestion.

- Better utilizing existing facilities can help delay the need for new transmission facilities, but it cannot avoid construction of new transmission facilities entirely.

Much work is needed to address transmission bottlenecks and modernize our nation's transmission systems. As a percentage of total energy use, electricity use is growing.[2] This reflects the transformation of our economy to an increasingly sophisticated, information-based economy, one that relies on electricity. Electricity, though, is not a commodity that can be stored easily. Our transmission infrastructure is at the heart of our economic well-being. Imagine an interstate highway system without storage depots or warehouses, where traffic congestion would mean not just a loss of time in delivering a commodity, but a loss of the commodity itself. This is the nature of the transmission infrastructure. That is why bottlenecks are so important to remove and why an efficient transmission infrastructure is so important to maintain and develop.

This report outlines 51 recommendations that will help ensure a robust and reliable transmission grid for the 21st century. The following are six general recommendations:

- First, we must increase regulatory certainty by completing the transition to competitive regional wholesale markets.

- Second, we need to develop a process for identifying and addressing national-interest transmission bottlenecks.

[2]In 1970, electricity accounted for 8 percent of total U.S. energy use. In 2000, electricity accounted for 16 percent of total U.S. energy use. Source: Energy Information Administration. *Annual Energy Outlook 2002*. Download from http://www.eia.doe.gov

- Third, we can avoid or delay the need for new transmission facilities by improving transmission system operations and fully utilizing our existing facilities. Regional planning processes must consider transmission and non-transmission alternatives when trying to eliminate bottlenecks.
- Fourth, opportunities for customers to reduce their electricity demands voluntarily, and targeted energy-efficiency and distributed generation, should be coordinated within regional markets.
- Fifth, ensuring mandatory compliance with reliability rules must include enforceable penalties for non-compliance that are commensurate with the risks that the violations create.
- Sixth, DOE will take an increased leadership role in transmission R&D and policy by creating a new Office of Electricity Transmission and Distribution.

Action is needed now to put this study's recommendations in place. Private industry and federal, state, and local governments must work together to ensure that our electricity transmission system will meet the nation's needs for reliable and affordable electricity in the 21st century.

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Electricity is a cornerstone on which the economy and the daily lives of our nation's citizens depend. This essential commodity has no substitute. Unlike most commodities, electricity cannot easily be stored, so it must be produced at the same instant it is consumed. The electricity delivery system must be flexible enough, every second of the day and every day of the year, to accommodate the nation's ever changing demand for electricity. There is growing evidence that both private and public action are urgently needed to ensure our transmission system will continue to meet the nation's needs for reliable and affordable electricity in the 21st century.

Our National Transmission System Today and Tomorrow

The electricity transmission system is one of the greatest engineering achievements of the 20th century. It is an extensive system of interconnected networks in which high-voltage power lines transport electricity from generators to customers. A critical early decision to rely on alternating current (AC) technologies for high-voltage transmission has led to the construction of three major interconnected power systems: the Eastern and Western Interconnections, and the Electric Reliability Council of Texas (ERCOT). Within each system, disturbances or reliability events are felt nearly instantaneously throughout the system. This interdependence leads to reliance on well-coordinated actions among its users to ensure

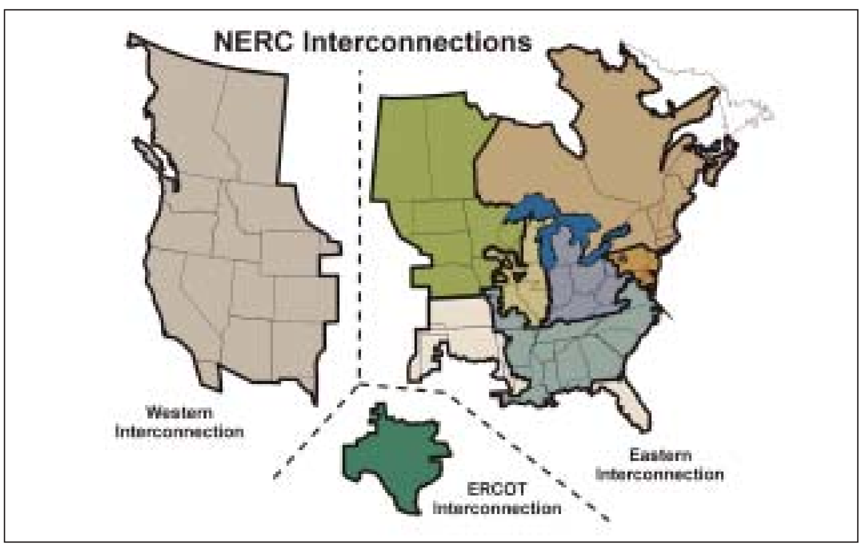


Fig. 1.1
North American Electricity Transmission Systems

The North American electricity transmission system consists of three interconnected systems: the Eastern Interconnection, the Western Interconnection, and most of the state of Texas. Within these interconnections, more than 140 control areas manage electricity operations for local areas and coordinate reliability through 10 regional councils.

Source: NERC 2001.

reliability. The continued need to coordinate actions to ensure reliability is a key institutional challenge as the system transitions to support competitive wholesale markets (see Section 4). There is also renewed interest in revisiting the decision to rely on AC transmission technologies and increasing reliance on direct current (DC) transmission technologies, which makes some coordination actions simpler in principle (see Sections 3 and 5).

The transmission system was built, over the past 100 years, by vertically integrated utilities that produced electricity at large generation stations located close to fuel supplies or needed infrastructure and then relied on transmission facilities to transport their electricity to customers. Interconnections among neighboring utility systems were constructed to exchange power to increase reliability and share excess generation during certain times of the year. Today, over 150,000 miles of high-voltage transmission lines link generators to load centers through interconnected transmission systems that span utility service territories, states, regions, and the borders of Mexico and Canada (Table 1.1).[3]

Ensuring the reliability of the transmission system has always been paramount. For years, utilities were the system's only users, and reliability was managed successfully through voluntary compliance with planning and operating standards established by the North American Electric Reliability Council (NERC). System operations depended on local utility expertise to complement these standards in recognition of the unique design of each utility's system and the technical complexity of coordinating operations.

Table 1.1

U.S. High-Voltage Transmission System

Voltage	Miles of Transmission Line
AC	
230 kV	76,762
345 kV	49,250
500 kV	26,038
765 kV	2,453
Total AC	154,503
DC	
250-300 kV	930
400 kV	852
450 kV	192
500 kV	1,333
Total DC	3,307
Total AC & DC	**157,810**

The U.S. electricity transmission system consists of over 150,000 miles of high-voltage transmission lines.

Source: NERC.

In 1996, the Federal Energy Regulatory Commission (FERC) issued its landmark Orders 888 and 889, which required utilities to allow non-utilities, or independent power producers, access to, and use of, utility transmission systems. Prior to these Orders, electricity production decisions were made centrally by vertically integrated utilities relying on generators they owned or exchanges with neighboring utilities. Investment in new generation by utilities had slowed and production of electricity by non-utilities was modest. FERC's orders were fundamental shifts in electricity policy and dramatically changed the ways that electricity production decisions were made and, consequently, in how the transmission system is used and operated.

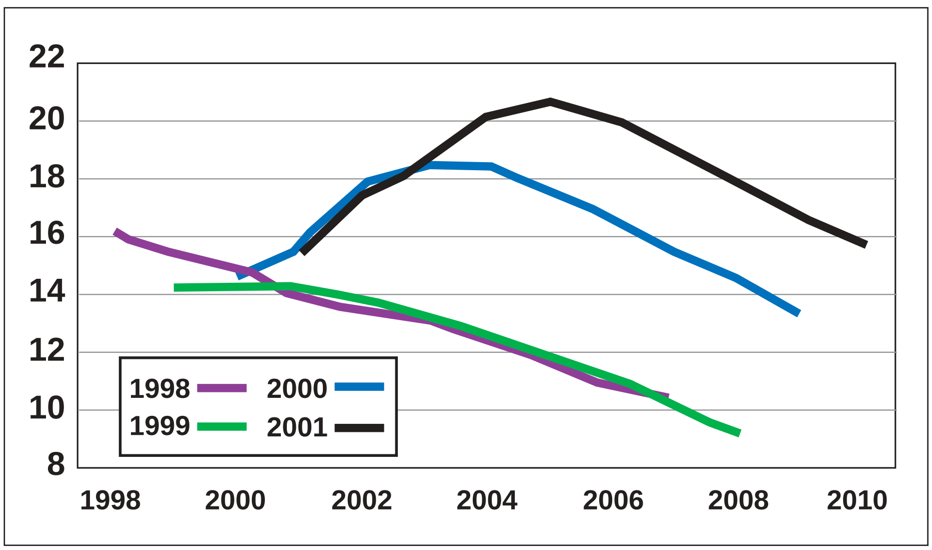
[3]Electricity is delivered from the high-voltage transmission system to customers through progressively lower voltage (<100 kV) distribution systems.

Centralized decision making by vertically integrated utilities, alone, now no longer determines electricity production. Instead, competitive market forces, involving a number of new market participants, increasingly determine who produces electricity and where it will be consumed. Since 1996, the transmission system has been slowly transformed into an interstate highway of commerce upon which emerging wholesale electricity markets depend.

During the past few years, wholesale power markets have flourished, as new market participants have undertaken the risks and rewards of developing merchant power plants. From 1996 to 1999, wholesale power marketers increased sales by more than six-fold. This, in addition to both continued load growth and increased wholesale power sales by traditional utilities, has resulted in the need for an expanded transmission system. More than half of all electricity generated is now exchanged on the wholesale market before being sold to ultimate consumers.[4]

The creation of wholesale electricity markets has enabled new market participants to address the nation's needs for new generating capacity. After years of decline, NERC forecasts now indicate that generation capacity margins will increase.[5,6] Summer peak electricity demand and generation capacity are projected to increase by almost 20 percent each during the next 10 years. Much of this new generation will be developed by independent power producers and unregulated affiliates of utilities.[7] (Figure 1.2)

Fig. 1.2
Capacity Margins over Time



After many years of decline, the ratio of generating capacity to electricity demand has begun and, according to NERC forecasts, will continue to increase. This increase means that there will be adequate generation capacity to meet expected electricity demand.

Source: NERC. 2001. *Reliability Assessment, 2001-2010.* Download from http://www.nerc.com

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[4]U.S. Energy Information Administration. 2000. *The Restructuring of the Electric Power Industry: A Capsule of Issues and Events.* Download from http://www.eia.doe.gov

[5]Capacity margin is the ratio of generating capacity to electricity demand. Excess generating capacity is needed to ensure reliability because demand can shift rapidly (e.g., in response to weather) and total generation capacity is not available at all times (e.g., because of planned maintenance or unexpected equipment failure).

[6]North American Electric Reliability Council. 2001. *Reliability Assessment, 2001-2010.* Download from http://www.nerc.com

[7]However, the recent contraction of our capital markets, and the announced delay in the construction of many new power plants, will affect this trend.

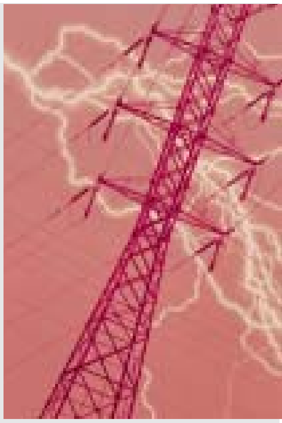
1

The U.S. Electricity Transmission System Is Under Stress

Despite the success of the wholesale electricity markets and the ability of new participants to address the nation's needs for new generation capacity, there is growing evidence that the U.S. transmission system is under stress. Growth in electricity demand and new generation, lack of investment in new transmission facilities, and the incomplete transition to fully efficient and competitive wholesale markets have allowed transmission bottlenecks to emerge. These bottlenecks increase electricity costs to consumers and increase the risks of blackouts.

The growth of electricity demand during the 1990s, coupled with new generation resulting from the emergence of competitive wholesale electricity markets, has led to electricity flows that are greater in size and in different directions than those that were

The California Electricity Crisis



At its root, the California power crisis was caused by an imbalance in the supply and demand for electricity. Very little new generating capacity had been built or proposed in California and the western states during the early 1990s. Once electricity restructuring rules were put in place, independent power producers responded quickly, beginning in 1997, to file applications to build more than 14,000 megawatts of new capacity. Yet, almost none of this proposed new capacity was available by summer 2000. Despite electricity demand growth rates that were lower than the national average during the 1990s, California was short of generation capacity. The absence of new generation capacity, along with high natural gas prices, lack of water available for hydroelectric generation, market design flaws, and little demand-side participation in the energy market all combined to drive wholesale power prices up to unprecedented levels.

The lack of adequate transmission played an important role in exacerbating the problems created by the imbalance between California's supply and demand for electricity. Because transmission is constrained between the northern and southern portions of the state, the number of competitors able to provide electricity in each of these markets is effectively reduced thereby leading to higher prices.

The situation in California stabilized during the past year when wholesale power prices fell dramatically as a result of lower natural gas prices, new generation finally coming on line, extraordinary load reduction efforts by households and businesses, improved hydro conditions, and Federal Energy Regulatory Commission actions. Nevertheless, transmission system upgrades remain an important element of a comprehensive, long-term solution to California's electricity system.

Source: U.S. Department of Energy. 2000. *Horizontal Market Power in Restructured Electricity Markets*. DOE/PO-0060. Download from http://www.policy.energy.gov/HMPReport.pdf anticipated when the transmission system was first designed. NERC reports that there is minimal operating experience for handling these conditions. The increased use of the system has led to transmission congestion and less operating flexibility to respond to system problems or component failures. This lack of flexibility has increased the risk of blackouts. Today, power failures, close calls, and near misses are much more common than in the past.

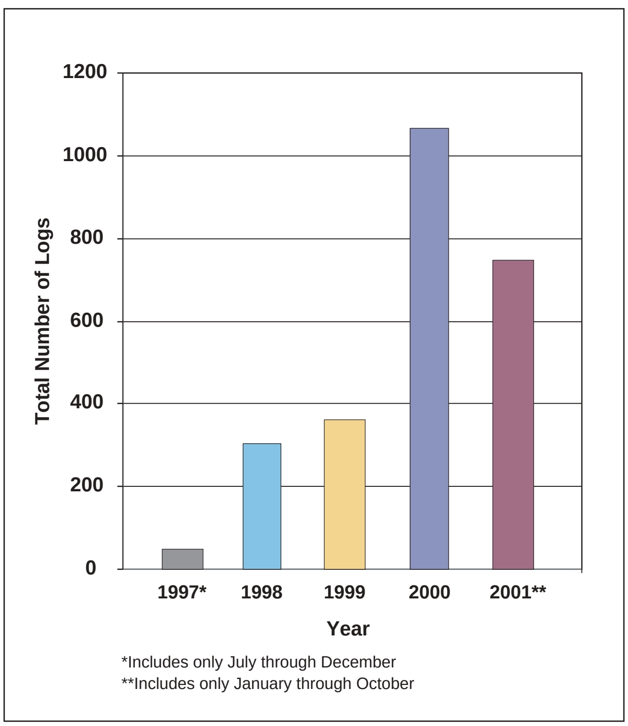
Transmission congestion or bottlenecks result when there is not enough transmission capability to accommodate all requests to ship power over existing lines and maintain adequate safety margins for reliability. Because electricity cannot yet be stored economically, transmission system operators must deny requests for transmission service when they receive too many of them in order to prevent lines from becoming overloaded. In other words, transmission congestion does not refer to deliveries that are merely held up or delayed (as in traffic congestion); it refers to transactions that cannot be executed.

Transmission operators manage transmission congestion through a set of NERC-approved procedures called Available Transfer Capability (ATC) and Transmission Loading Relief (TLR). ATC calculations establish the maximum ability of a system to support expected wholesale transactions reliably. When the system is in danger of exceeding these limits, TLR procedures (known as TLR “calls”) determine which requests for transmission will be denied in order to prevent lines from becoming overloaded.

In the last two years, the frequency of TLR “calls” has increased dramatically. The frequent use of TLRs indicates that the system is under greater stress because it is being operated closer to its limits. (Figure 1.3)

Today, the ATC and TLR procedures play a key role in ensuring transmission reliability. Unfortunately, the use of these procedures also interferes with market efficiency. Transmission congestion and the use of TLR calls increases consumer costs by frequently denying low-cost transactions in favor of high-cost transactions. As customer demand in an area surpasses the import capability of the transmission lines serving that area, operators are forced to meet the

Fig. 1.3
Transmission Loading Relief Events



Actions by operators to curtail proposed transactions in order to ensure reliability according to procedures developed by the North American Electric Reliability Council have increased dramatically since the time they were first adopted in 1997.

Source: NERC.

area's energy demand with more expensive local generation rather than less expensive generation from elsewhere in the region.[8]

Construction of new transmission facilities would alleviate these stresses. However, NERC also reports that investment in new transmission facilities is lagging far behind investment in new generation and growth in electricity demand. Construction of high-voltage transmission facilities is expected to increase by only 6 percent (in line-miles) during the next 10 years, in contrast to the expected 20 percent increase in electricity demand and generation capacity (in MW). Although we would not expect transmission to grow as quickly as new generation capacity or demand, this projected growth is not adequate to ensure reliability and sustain continued growth of competitive regional wholesale electricity markets. (Figure 1.4)

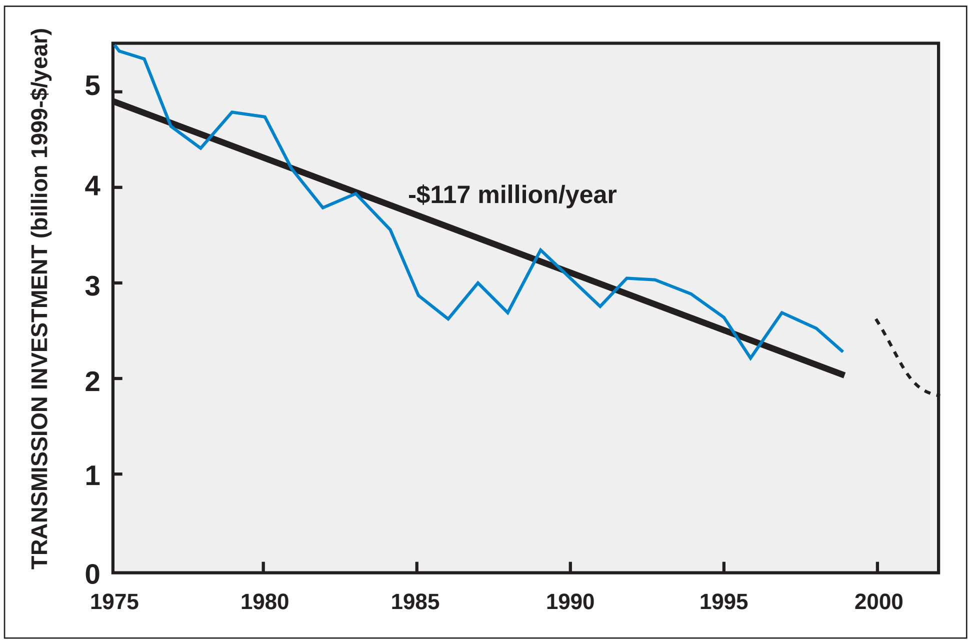


Fig. 1.4 **Transmission System Investment over Time**

Investment in new transmission facilities has declined steadily for the last 25 years.

Source: E. Hirst and B. Kirby. 2001. *Transmission Planning for a Restructured U.S. Electricity Industry.* Edison Electric Institute.

1

Toward the Transmission System of Tomorrow

During the late 1970s, there was debate about whether the U.S. should "nationalize" the electricity grid. Some felt the electricity system was of such great importance that it had to be managed by the federal government; others were wary of centralized federal decision making and advocated industry-led solutions. During the 1990s, the nation chose to introduce competi-

[8]For additional background, see the Issue Paper, *Transmission System Operation and Interconnection,* by F. Alvarado and S. Oren.

tion to the electricity market and has since begun to reap the benefits of private developers' investment in merchant generation capacity. A key benefit to consumers is that the financial risks of power plant construction and operation have been shifted from consumers to private developers whose earnings depend on their ability to generate power competitively.

Robust and reliable regional electricity transmission systems are the key to sustaining fair and efficient competition in wholesale markets that lowers costs to consumers. The national transmission grid DOE envisions is based on the principles of free markets with clear rules, equal access, consumer safeguards, economic incentives, and investment opportunities rather than federal ownership and operation.

Building new transmission facilities or undertaking other strategies to address transmission bottlenecks should depend first and foremost on market participants responding to business opportunities. Similarly, greater electrical interconnections among existing transmissions systems should be the result of regional initiatives, not federal directives. When the private sector and markets can do the job, the federal role is to let regional markets work.

Discussions of regional transmission systems heighten state concerns over their regulatory responsibility to protect reliability and ensure affordable electricity to retail consumers. Movement toward regional transmission systems and competitive wholesale electricity markets must balance state, regional, and federal responsibilities. In the end, consumers must be assured reliable and affordable electricity.

The future provision of reliable and affordable electricity requires modernizing the structure and operation of the nation's transmission systems to serve the regional needs of competitive wholesale electricity markets. The transmission systems of tomorrow must be operated in ways that take full advantage of market forces to ensure reliability in an economically efficient manner, allow customers to adjust their demands in response to system needs and be compensated for these actions, incorporate advanced hardware and software technologies to increase utilization of existing facilities safely, and follow strict rules for reliability with appropriate penalties for non-compliance. The transmission systems of tomorrow must be built by relying on open regional planning processes that consider a wide range of alternatives, accelerating the siting and permitting of needed facilities, taking full advantage of advanced transmission technologies, and incorporating appropriate safeguards to ensure the physical and cyber security of the system.

The cost of transmission accounts for less than 10 percent of the final delivered cost of electricity in what is today a $224 billion electricity industry.[9] We cannot afford to allow the relatively small cost of transmission to prevent consumers from enjoying the reliable and affordable electricity service that properly managed competitive forces will deliver to our nation.

[9]Source: Energy Information Administration. *Electric Sales and Revenue 2000.* Download from http://www.eia.doe.gov

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Transmission bottlenecks affect national interests by increasing the cost of electricity to consumers and the risk of transmission system reliability problems in various regions throughout the United States. Relieving transmission bottlenecks is a regional issue. DOE will work in partnership with FERC, states, regions, and local communities to designate significant bottlenecks as national-interest transmission bottlenecks and take actions to ensure that they are addressed.

The National Interest in Relieving Transmission Bottlenecks

DOE believes that identifying and eliminating major transmission bottlenecks is vital to our national interest. National-interest transmission bottlenecks create congestion that significantly decreases reliability, restricts competition, enhances opportunities for suppliers to exploit market power, increases prices to consumers, and increases infrastructure vulnerabilities.

Transmission bottlenecks and the options to address them are regional in nature. When the consequences of bottlenecks become large, it is in the national interest to ensure that they are addressed in a timely fashion. Since no state has control or authority over regional transmission systems, the federal government has a role to play in identifying major bottlenecks and ensuring that they are addressed. The national interest is best served if DOE and FERC together work with states and regions to identify and address the most significant bottlenecks.

To begin the process of analyzing the effects of transmission bottlenecks on national interests, DOE conducted an independent analysis focusing on the impacts of transmission on regional electricity markets. Through the use of the POEMS model (see text box), DOE determined the location of major bottlenecks in both the Eastern and Western Interconnections and estimated the costs of these constraints to consumers.[10] DOE also estimated the benefits consumers currently receive from regional electricity markets.

Over the past year, there have been several national and regional studies that have highlighted congested transmission paths. DOE has also developed a list of congested paths and has compared it to those recently identified by FERC. Even though the studies were conducted using different methods, the patterns of congestion found in both studies are very similar.

DOE's current tools have identified a number of bottlenecks that may have significant impacts on national interests. More work and additional public input are required to develop a comprehensive set of tools and data needed to capture the full range of impacts of transmission bottlenecks on national interests, including the impacts on reliability and on the competitiveness of wholesale electricity markets.

[10] DOE's model does not consider congestion within single control areas such as ERCOT.

Policy Office Electricity Modeling System (POEMS)

DOE estimated the benefits of interregional wholesale power markets using the Policy Office Electricity Modeling System (POEMS). POEMS is a full-scale national energy model designed specifically to examine the impacts of electricity industry restructuring. The model includes significant economic, regional, and temporal detail that is needed to analyze the economics of interregional trade.

POEMS aggregates individual transmission lines to create a network of transmission paths that connect 69 subregions. The model represents the transmission system as a highway system—a series of paths between regions with a fixed amount of transmission capacity along each path. Trades are executed among the model's subregions based on the relative costs of generation in each subregion as well as the costs of executing each trade. A more detailed description of the model and its use in this study is provided in Appendix A.

POEMS is an important tool for assessing the economic consequences of electricity trade and identifying major transmission bottlenecks. However, it does not explicitly represent the physical flows of electricity over paths in response to the combined effects of all other flows on the system. Also, because it is national in scope, the model does not consider trade within subregions.

For the National Transmission Grid Study, POEMS was used to study:

- **Transmission bottlenecks as evidenced by the costs of transmission congestion among subregions**
- **The benefits of regional electricity markets today**
- **The benefits of regional electricity markets that would be enabled by eliminating rate pancaking.***

Results from the first two analyses are presented in this section; results from the third analysis are presented in Section 3, "Relieving Transmission Bottlenecks by Completing the Transition to Competitive Regional Wholesale Electricity Markets."

*In many regions, when electricity must be transmitted over multiple transmission systems, users must pay each owner/operator a separate fee for use of its transmission system. This is generally referred to as rate pancaking.

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Major Eastern Transmission Bottlenecks

DOE's analysis confirms the tendency for transmission congestion to develop at many locations within the Eastern Interconnection. Out of a total of 186 transmission paths modeled in the East, 50 are used to their maximum capacity at some point during the year, and 21 paths are congested during more than 10 percent of the hours of the year.[11] The highest levels of congestion are found along transmission corridors from Minnesota to Wisconsin, the Midwest into

[11]As noted previously, POEMS generally does not represent individual transmission lines. Thus, the results presented in this study do not suggest that there is congestion on any particular transmission line but rather that there is congestion along transmission paths or corridors between subregions.

the Mid-Atlantic, from the Mid-Atlantic to New York, and from the Southeast into Florida.

In general, DOE's findings are very similar to historical data on transmission congestion, which also indicate that there is substantial congestion in the Midwest and upper Midwest, and from the Mid-Atlantic to the Northeast.[12]

DOE also found congestion in some areas where there have been few TLR events called, such as in the Southeast. DOE's analysis suggests that substantial congestion would result in these areas if there were greater volumes of economic wholesale electricity transactions. In particular, all of the transmission paths out of the Tennessee Valley Authority (TVA) would be congested at some point, and some would be congested roughly 15 percent of the time. Even more striking are the electricity flows that would take place from the Southeast into Florida; these lines would be congested during 40 to 80 percent of the hours of the year. (Figure 2.1)

DOE's findings are consistent with the comments of market participants who offered input to a recent FERC staff report on bulk-power markets in the Southeast.[13]

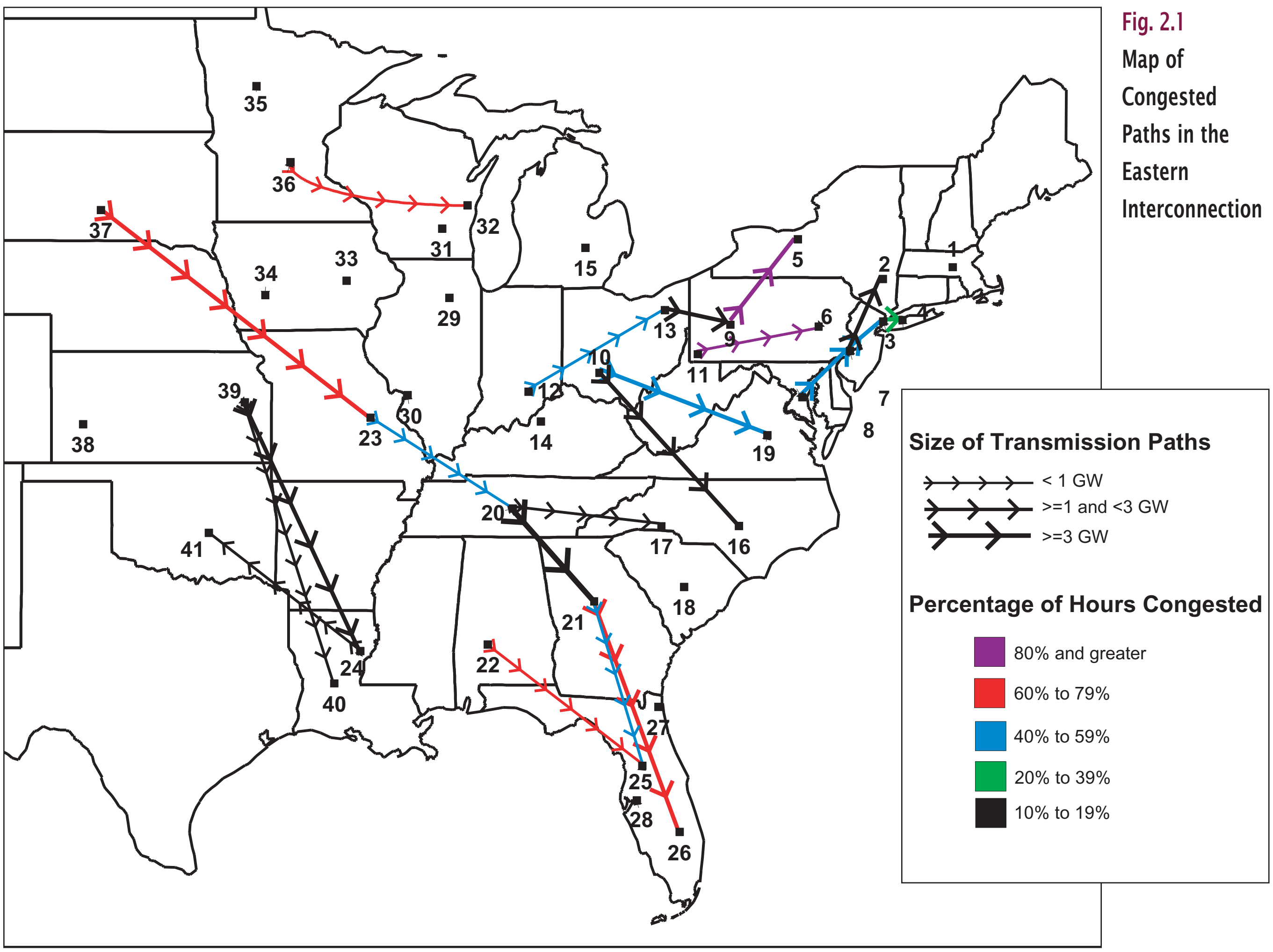


Fig. 2.1
Map of Congested Paths in the Eastern Interconnection

[12]This finding is based on a comparison of POEMS results and information on transmission loading relief (TLR) incidents that is routinely reported to NERC.

[13]FERC. 2000. *Investigation of Bulk Power Markets: Southeast Region*. Staff Report. Download from http://www.ferc.gov

Table 2.1

Hours of Congestion for Twenty Most Congested Paths				
EAST	Exporter*	Importer*	%Hrs Congestion per year	Path Size (GW)
1	ECAR	MAAC	89%	0.176
2	MAAC	NYPP	85%	2.605
3	SERC	FRCC	78%	0.536
4	MAPP	MAIN	73%	0.202
5	SERC	FRCC	71%	2.837
6	MAPP	SERC	65%	1.178
7	ECAR	SERC	58%	2.175
8	MAAC	NYPP	50%	2.797
9	ECAR	ECAR	48%	0.765
10	MAAC	MAAC	48%	2.866
11	SERC	FRCC	44%	0.581
12	SERC	SERC	43%	0.408
13	NYPP	NYPP	22%	1.143
14	SERC	SPP	19%	0.866
15	SPP	SPP	19%	0.398
16	ECAR	MAAC	16%	1.643
17	MAAC	NYPP	16%	1.191
18	ECAR	SERC	14%	1.500
19	SERC	SERC	14%	0.552
20	SERC	SERC	14%	3.468
WEST				
1	NWP	NWP	59%	0.044
2	NWP	NWP	51%	0.337
3	NWP	CNV	41%	1.200
4	NWP	CNV	39%	3.100
5	NWP	CNV	38%	0.300
6	CNV	NWP	36%	0.083
7	NWP	NWP	35%	0.300
8	NWP	NWP	32%	1.250
9	NWP	NWP	26%	0.044
10	NWP	RA	22%	0.390
11	CNV	NWP	19%	3.100
12	RA	RA	19%	0.485
13	CNV	CNV	17%	0.637
14	CNV	CNV	16%	3.000
15	NWP	NWP	14%	0.359
16	CNV	CNV	8%	3.000
17	RA	RA	6%	0.690
18	CNV	RA	5%	1.300
19	NWP	NWP	4%	1.560
20	RA	NWP	3%	0.900

*See Appendix A for acronyms.

The Southeast includes more generation owned by vertically integrated, investor-owned utilities than any other region of the country, and many independent power producers and marketers believe these utilities are preventing equal and open access to the transmission systems in this region.

In its report, FERC identified a number of barriers to wholesale electricity trade in this region, including: uncertainty in transmission access, inconsistent posting and withholding of available transfer capability, and the lack of consistency when implementing transmission loading relief protocols. Utilities in the Southeast report that the absence of coordinated generation and transmission planning has led to new generation that has been built in areas that contribute to congestion. Hence, although FERC could not verify the basis for all of the concerns expressed, market participants perceive that these problems exist and discourage investment and wholesale trade in the region.

In addition, trading into the Southeast power market is difficult. Due to its location, the Tennessee Valley Authority (TVA) controls the majority of transmission access into and out of the region. Although TVA is largely exempt from FERC regulation, it voluntarily provides open access to its transmission system. However, TVA and various suppliers in the market continue to disagree over access to the transmission system.

Strengthening the Interconnection between ERCOT and the Eastern Interconnection

In 1999, the Texas Public Utility Commission completed a study evaluating the most economical, reliable, and efficient means to interconnect the transmission facilities in the Electric Reliability Council of Texas (ERCOT) with those in the Southwest Power Pool within the Eastern Interconnection. The study determined the costs and reliability concerns associated with a hypothetical scenario of six inter-ties. It also discussed the state and federal jurisdictional issues that would need to be addressed. The final report, while very detailed, was not able to draw a firm conclusion regarding the desirability of greater interconnection.

The study found that total costs for the interconnection facilities alone would be between $300 and $350 million in 1997 dollars. It also identified additional costs, which are difficult to quantify, that would be imposed upon utilities and generators based on operating characteristics of the combined grid.

Since the study was completed, between 10,000 and 20,000 megawatts of new generation have been brought on line in Texas, new transmission lines have been completed, and the retail market has opened.

With reserve margins as high as 31 percent in ERCOT, generators may begin a renewed push for the opening of additional markets for their power. It may be time to conduct a new study that evaluates alternatives, including additional AC interconnections, new DC interconnections, as well as expansion of existing ties.

Source: Synchronous Interconnection Committee. 1999. *Feasibility Investigation for AC Interconnection between ERCOT and SPP/SERC.* Report to the 76th Texas Legislature.

2

Major Western Transmission Bottlenecks

Electricity trading patterns and transmission congestion are somewhat different in the West than in the East for several reasons. First, the transmission system in the West, unlike the one in the East, was built primarily to carry power over long distances. Several large power plants in the West were intentionally built in remote locations; along with these plants, owners constructed high-voltage transmission lines to ship power to densely populated load centers.[14]

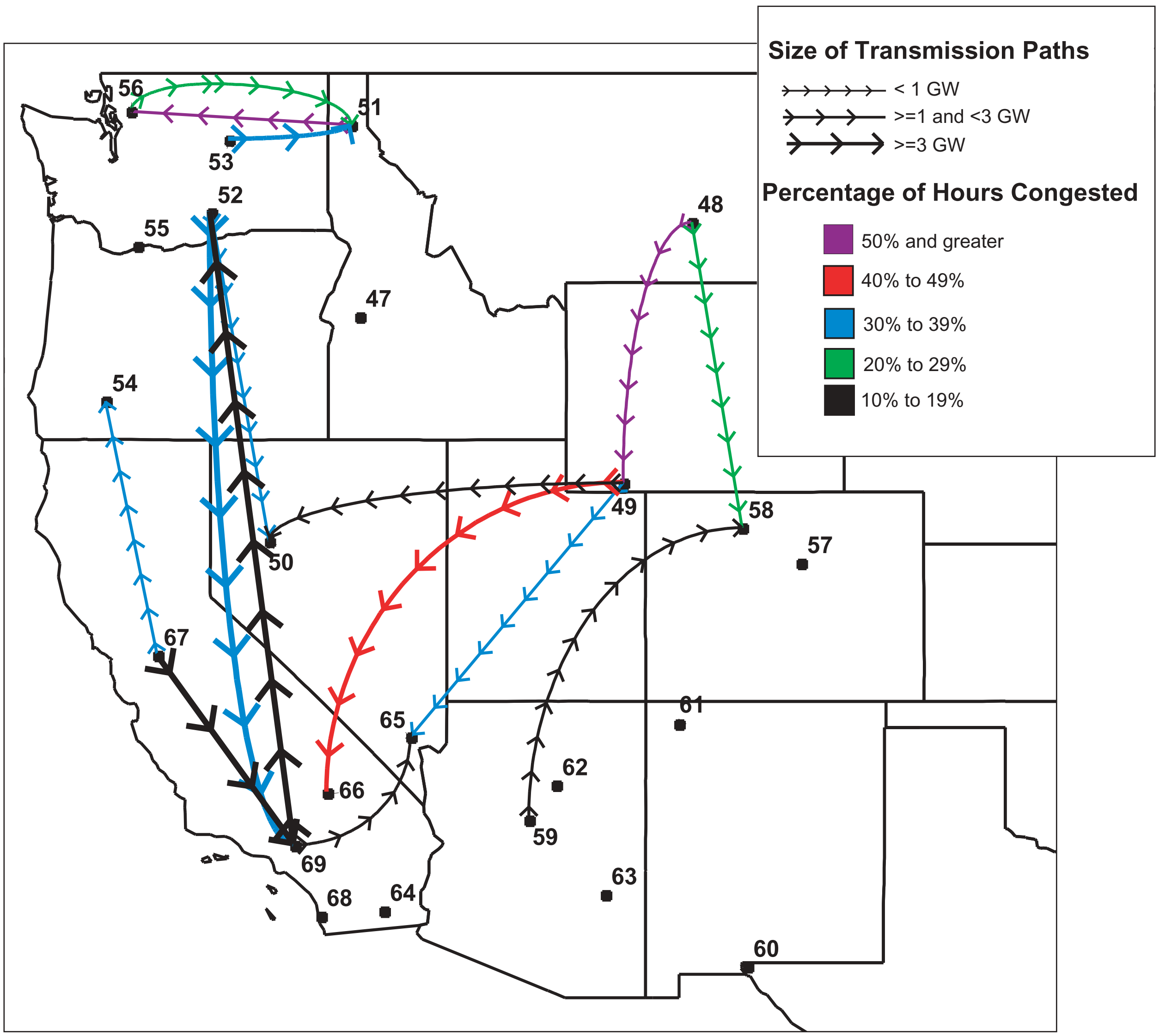


Fig. 2.2 Map of Congested Paths in the Western Interconnection

[14]For example, the Palo Verde nuclear plant was built in southern Arizona in part to serve load in southern California. Similarly, the Intermountain Power Project, a 1,640-megawatt coal plant in Utah, was built to serve a number of municipalities in Utah and in California, including Los Angeles. A 490-mile transmission line connects the plant to southern California.

In addition, the Pacific Northwest is dominated by hydroelectric power. The amount of water available for hydropower generation in this area is greatest during the spring and summer when runoff from snow pack is highest; however, electricity demand in the region is greatest during winter. During spring and summer, the Pacific Northwest sells its excess electricity to California and other western states. During the winter, the Pacific Northwest purchases excess power from these areas. For the purpose of these transactions, a large direct current (DC) transmission line links southern California and the Bonneville Power Administration (BPA) in Oregon.

As a result of these patterns of supply and demand, utilities in the West rely substantially more on transporting electricity over long distances to meet local demand than is commonly the case in the East. Electricity trade as a percentage of demand in the West reaches nearly 30 percent during some periods, compared to only 15 percent in the East. Because the transmission system in the West was specifically designed to support these imports and exports, there is less interregional congestion overall in the West. Of the 106 western transmission paths represented in POEMS, 37 are congested at some point during the year, half of these are congested less than 10 percent of the time, and no path is congested more than 60 percent of the hours during the year.[15] (Figure 2.2)

2

The Costs of Transmission Congestion

DOE estimated in two steps the costs of congestion in four U.S. regions where independent system operators manage wholesale electricity markets: California, PJM, New York, and New England.[16] In the first step, DOE used POEMS to examine the cost reductions that would occur if increased electricity transfers across congested paths were allowed in these four regions, under the assumption that all generators bid their marginal operating cost. Under this assumption, consumer costs for electricity decline by $157 million per year.

In the second step, DOE calculated the increase in congestion costs (costs to consumers) under the assumption that generators bid above their marginal operating costs when supplies are tight and additional electricity cannot be imported, leading to price spikes. For this calculation, price spikes were assumed to occur during the hours when at least one transmission link

[15]POEMS does not consider congestion within the subregions in the West. Consequently, congestion on California's Path 15, which is within a subregion, is not assessed by POEMS.

[16]Since ISO New England is represented in POEMS as a single subregion, increased costs resulting from congestion within New England are not reflected in the analysis. Instead, the estimates reported here include only the increased costs due to congestion into New England. For the other three regions, the estimates reflect costs arising from congestion into and within the region. See Appendix A for additional discussion of DOE's analysis using POEMS.

into a subregion was congested and demand was greater than 90 percent of peak demand. When prices spike an additional $50 per MWh (above the price predicted when generators bid their marginal operating cost) during these periods, congestion costs nearly double to $300 million. When prices spike an additional $100 per MWh during these periods, congestion costs nearly triple to $447 million. This calculation is a conservative estimate of congestion costs. Recently, FERC estimated costs for 16 individual constraints that ranged up to more than $700 million for a handful of recent summer months (see text box).[17, 18]

It is important to note that DOE's findings do not address transmission bottlenecks that may exist within subregions. For example, all of New England is represented as a single subregion within the model, so benefits from trade within New England are not reflected in the analysis. ISO New England estimates the costs of congestion in New England are $125–600 million per year.[19] California's Path 15, which is often congested, is also not specifically represented in POEMS. The California ISO (CAISO) estimates that the cost of congestion created by a single transmission corridor, Path 15, was $222 million over the 16 months prior to December 2000.[20]

FERC Electric Transmission Constraint Study

On December 19, 2001, FERC presented findings from an analysis of transmission constraints in the U.S. FERC staff identified 16 constraints (see map) across the nation characterized by either:

- **A large number of Transmission Load Relief (TLR) events (instances when market sales cannot be executed because of transmission constraints, which forces operators to use more expensive local energy rather than less expensive imported energy), or**
- **High price differentials across an interface (where the delivered energy price inside an area is higher than the price of energy at the same moment outside that area).**

FERC estimated the economic cost of transmission congestion during the months of June through August 2000 and 2001 using actual data on the number of hours during which a specific transmission interface was constrained, the amount of energy that was redispatched in each congestion event, and the costs of imported and replacement energy in each of these hours.

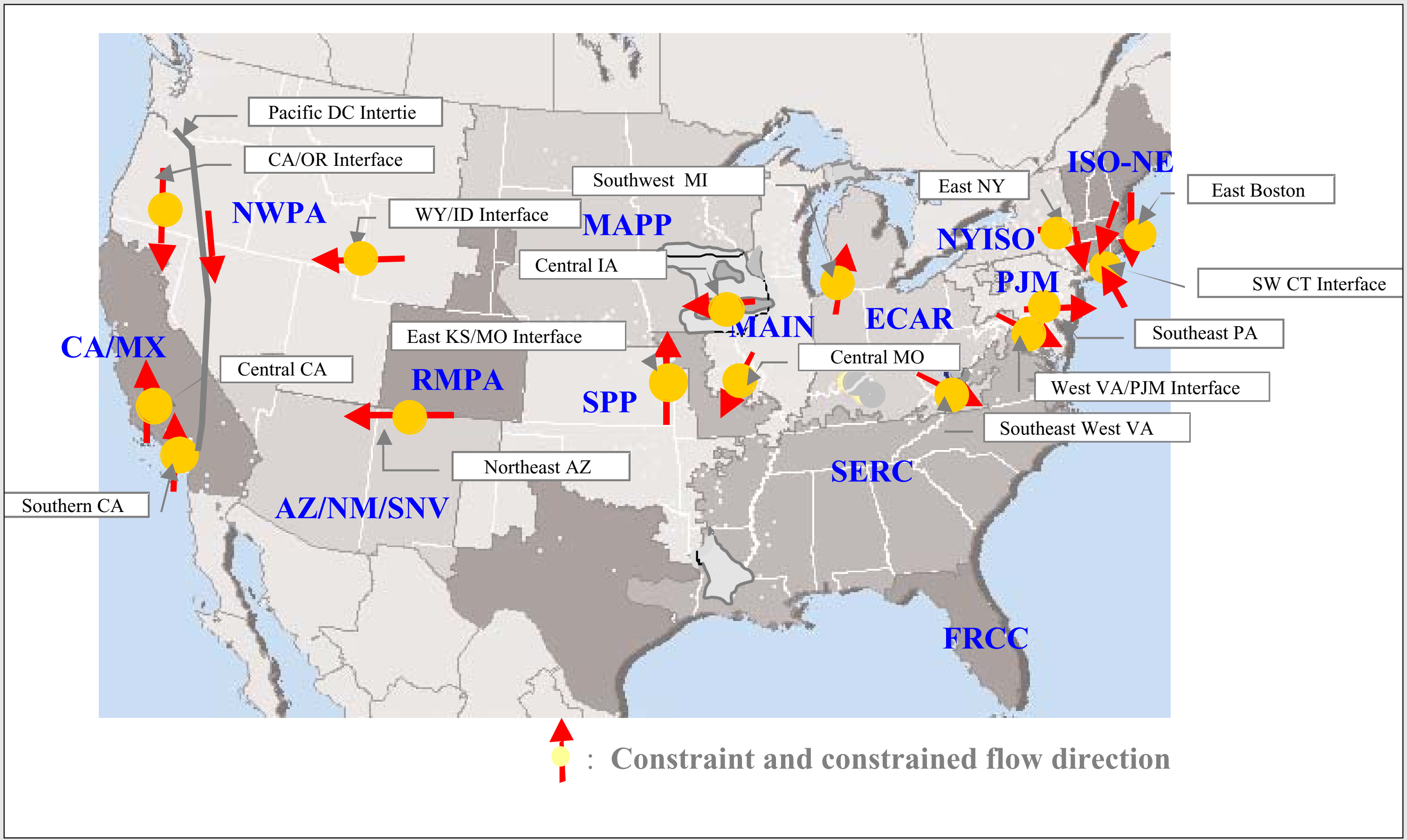
[17]Federal Energy Regulatory Commission. 2001. *Electric Transmission Constraint Study*. Division of Market Development. Download from http://www.ferc.gov

[18]Although DOE's analysis and FERC's analysis are not strictly comparable because of differences in the methods used, their findings are generally consistent. FERC's analysis is based on actual market prices and does not reflect price changes that would occur on both sides of a constrained transmission link if additional electricity could be traded. As a result, FERC's estimates are likely to be somewhat higher than DOE's.

[19]ISO New England. 2001. *2001 Regional Transmission Expansion Plan*. Download from http://www.iso-ne.com

[20]California Independent System Operator. 2001. *Testimony of Armando J. Perez, Stephen Thomas Greenleaf, and Keith Casey. Conditional Application of Pacific Gas and Electric Company for a Certificate of Public Convenience and Necessity Authorizing the Construction of the Los Banõs-Gates 500 kV Transmission Project. Application 01-04-012*. California Public Utilities Commission. Download from http://www.caiso.com.

Transmission Constraints in Contiguous U.S.



FERC found that the costs of individual constraints for these months generally ranged from less than $5 million to more than $50 million. However, for one particular set of conditions in the eastern portion of New York during the summer of 2000, FERC estimated a cost of more than $700 million.

Source: FERC. 2001. *Electric Transmission Constraint Study*. Division of Market Development. Download from http://www.ferc.gov

Finally, POEMS does not analyze reliability benefits. Increased transmission capacity will generally improve the overall reliability of the grid and allows regions to share capacity reserves. Although the risk of blackouts is generally small, blackouts usually entail very high economic costs. As such, even a small reduction in the risk of a blackout will have substantial benefits.

The POEMS analysis offers minimum estimates of the benefits of vibrant wholesale markets to the consumer. However, the trend is clear: transmission bottlenecks today compromise important national interests in efficient regional wholesale electricity markets and reliable transmission systems.

The Benefits of Wholesale Electricity Markets Today

In addition to the costs of specific bottlenecks, DOE found that today's wholesale electricity markets save consumers nearly $13 billion per year in electricity costs. In other words, the nation's current $224 billion annual electricity bill would be $13 billion higher without these wholesale shipments of electricity. On average, wholesale power transactions reduce generation costs by approximately $370,000 per hour in the East and by more than $1,000,000 per hour in the West. These savings translate directly to lower prices for consumers. Average wholesale electricity prices are roughly 12 percent lower as a result of interregional trading.[21] (Figure 2.3)

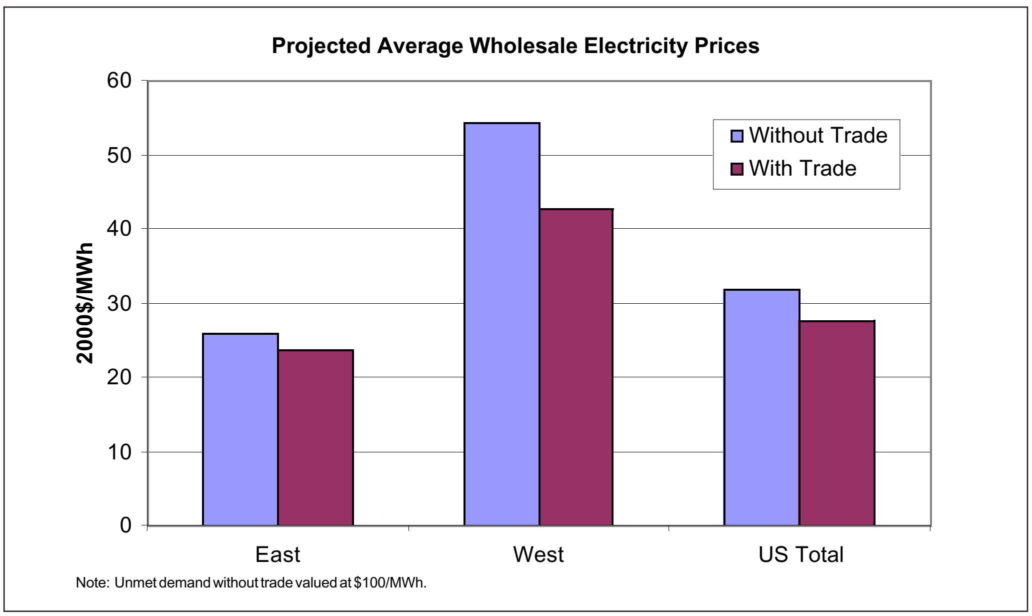


Fig. 2.3
Electricity Prices (by Interconnection) With and Without Interregional Electricity Trading

Next Steps Toward Relieving Transmission Bottlenecks

DOE's analysis has confirmed the tendency for transmission lines to become congested in many locations across the U.S. The consequences of this congestion warrant additional scrutiny to determine the extent to which national interests are jeopardized. In particular,

[21]This estimate includes the savings due to all electricity trade among the 69 subregions in the model. It does not distinguish increased trade due to wholesale competition from economy trades that routinely occurred among neighboring utilities prior to FERC Orders 888 and 889.

DOE has not assessed the impacts of congestion on market power and reliability.

Successfully addressing transmission bottlenecks requires careful analysis and consideration of their impacts on both market operations and system reliability, as well as analysis of the costs of transmission and non-transmission alternatives. In other words, removing bottlenecks is not simply a matter of finding "congested" transmission paths and then reinforcing existing transmission facilities along those paths or constructing new facilities. Because the system is a network, reducing congestion in one part of the system may shift it to another (the next-most-vulnerable) part. Congestion also tends to move around the system from year to year and in response to weather and other seasonal factors.

In addition, solving the problem of transmission constraints within the United States will also require cooperation with Canada. Many scheduled power transactions within the U.S., particularly east-to-west transactions within the Eastern Interconnection, flow over transmission lines located in Canada before reaching loads in the U.S. This is a particular problem at points in the upper Midwest where the transmission systems of the two countries interconnect. These unintended flows (or "loop flows") often require transmission service curtailments in the U.S.

The benefit of increasing transmission capability to increase economic trade depends on relative electricity prices in the regions linked by the additional capacity and on the additional amount of electricity that

The Cost of Reliability—August 10, 1996, Power Outages in the Western States

The blackout in the western states on August 10, 1996, was a complex and dramatic reminder of the importance our modern society places on reliable electricity service. Ultimately, power was interrupted to approximately 7.5 million customers, for periods ranging from a few minutes to about nine hours. Immediate costs to the region's economy were estimated at $2 billion.

The August 10 outages were caused by multiple transmission line failures over a period of several hours. A single transmission line failure is a contingency that is routinely considered in reliability planning. However, the failure of several lines, combined with the day's pattern of operation, caused the system to become unstable (which had not been anticipated by reliability planners), causing automatic controls to open the California-Oregon Intertie, a major link between the northern (Pacific Northwest) and southern (California) portions of the western system. Opening the Intertie produced a power surge from the Pacific Northwest through the eastern portion of the grid toward Arizona and southern California, causing many lines to disconnect automatically and eventually fracturing the western grid into four separate electrical "islands." Within each island, large blocks of customers lost power when their electricity demands suddenly exceeded available local generation. The situation was worst in the southern island where automatic controls disconnected over 90 generators to prevent them from being further damaged. Some of the larger units were out of service for several days.

Source: J. Hauer and J. Dagle, 1999. *Review of Recent Reliability Issues and System Events*. Report PNNL-13150.
Download from http://www.eren.doe.gov/der/transmission

would be traded on the new lines. If price differences are small and the added transmission capacity would be used during only a small percentage of the hours during the year, then the cost of a new transmission line may not be justified.[22]

However, the benefits of increasing transmission capability to ensure reliability, even if this insurance is used only once to prevent a system-wide blackout, would be enormous and could far outweigh any potential gains from increased trade. Similarly, increasing transmission capability to reduce the ability of a competitor to exert market power could lead to benefits far in excess of those gained from increased trade.

Because assessing these issues will involve tradeoffs, for example, commerce versus reliability, and local versus regional benefits, it is critical that DOE develops an open public process to weigh the various interests. Once it is determined that the benefits of addressing bottlenecks outweigh the costs, DOE must work with regions, states, and localities to ensure that these bottlenecks are remedied appropriately.

Path 15—Example of Federal Leadership

Path 15 is an 84-mile stretch of electrical transmission lines in the central valley of California connecting the northern and southern portions of the state. The federal government's recent efforts to increase transfer capacity on this path illustrate both the role for responsible federal leadership to address bottlenecks affecting national interests and how these bottlenecks might be addressed through private investment.

Capacity on Path 15 is sometimes insufficient and has contributed to rolling blackouts in the state. The California ISO has estimated that congestion on Path 15 resulted in up to $222 million in increased electricity costs to customers in California during the 16-month period ending December 31, 2000.

In May 2001, U. S. Energy Secretary Spencer Abraham directed the Western Area Power Administration (WAPA) to complete planning for upgrading Path 15 and to determine whether outside parties would be interested in helping finance and co-own the new transmission line.

In June, WAPA requested Statements of Interest and 13 entities responded. In October 2001, Secretary Abraham announced a $300 million agreement to upgrade Path 15 with WAPA and other participants from the public and private sectors.

The proposed upgrade will add a third 500-kilovolt transmission line to the existing two lines and make other improvements. The upgrade will increase the capacity of Path 15 by an estimated 1,500 MW, enough power for two million households, and could come on line as early as summer 2004.

[22] Building new transmission lines is not the only strategy to reduce congestion; as subsequent sections in this report discuss, many steps can be taken to relieve transmission bottlenecks that may avoid or delay the need to construct new transmission facilities.

DOE believes that the federal government should facilitate the process of energy-market participants seeking appropriate solutions to transmission bottlenecks. The recommendations in the following sections of this report identify actions that are needed to address transmission bottlenecks, based on this perspective.

DOE expects that these actions alone will go a long way toward addressing the most important of transmission bottlenecks—those affecting significant national interests. In view of the national interests at stake, the federal government must stand ready to take additional action if the efforts of others prove inadequate. Toward this end, DOE has an ongoing responsibility to assess how transmission bottlenecks affect the national interests as well as to monitor progress in addressing bottlenecks.

RECOMMENDATIONS

- DOE, through a rulemaking, will determine how to identify and designate transmission bottlenecks that significantly impact national interests.
- DOE will further develop the analytic tools and methods needed for comprehensive analysis to determine national-interest transmission bottlenecks.
- In an open public process, DOE will assess the nation's electricity system every two years to identify national-interest transmission bottlenecks.

3

Our nation's transmission systems must be modernized to ensure their continued reliability and facilitate fair and efficient regional wholesale electricity markets that lower costs to consumers. To achieve these goals, we must complete the transition to a restructured industry.

Relieving Transmission Bottlenecks by Completing the Transition to Competitive Regional Wholesale Electricity Markets

The current upheavals and challenges facing our nation's electricity transmission system result, in part, from the incomplete transition to fair and efficient competitive regional wholesale electricity markets. In the view of many, the incomplete transition to a restructured industry poses the greatest challenge facing the electricity system today. Lack of clarity in the regulatory structure inhibits effective planning and needed investment. The transmission system is too important to leave in an extended state of uncertainty. We must complete the transition soon.

Core elements of the transition include establishing regional transmission organizations (RTOs) and increasing regulatory certainty and focus to stimulate investment in innovative solutions to address transmission bottlenecks. Completion of the transition will result in a stable business environment that rewards those who take action to improve the transmission system. The economic rewards from improving the transmission system must be greater than the rewards from maintaining the status quo or decreasing the system's ability to reliably support fair and efficient competitive wholesale markets.

3

Establishing Regional Transmission Organizations

FERC Order 2000 was a major milestone in the movement toward fair and efficient competitive regional wholesale electricity markets. Order 2000 calls for the formation of large RTOs to coordinate markets and ensure the reliability of the nation's transmission system.

FERC outlined four characteristics that RTOs must, at a minimum, demonstrate:

- Independence. RTOs must be independent of market participants;
- Scope and Regional Configuration. RTOs must serve a region of sufficient scope and configuration to permit each RTO to effectively perform its functions;
- Operational Authority. The RTO must coordinate security for its region; and
- Short-term Reliability Authority. The RTO must have exclusive authority for maintaining short-term reliability of the grid it operates.

FERC also identified eight functions that RTOs must perform:

- Tariff Administration and Design. Each RTO must be the sole provider of transmission service in its region and the sole administrator of its own open-access tariff;
- Congestion Management. Each RTO must ensure the development and operation of market mechanisms to manage congestion;
- Parallel Path Flow. Each RTO must implement procedures to address parallel path flow issues within its region and with other regions;
- Ancillary Services. Each RTO must be the provider of last resort of all ancillary services required by FERC Order No. 888 and subsequent orders;
- Open Access Same Time Information System (OASIS) Administration. The RTO must be the single OASIS site administrator for all transmission facilities under its control, with responsibility for independently calculating Total Transfer Capability and Available Transfer Capability;
- Market Monitoring. Each RTO must provide for objective monitoring of the markets it operates to identify design flaws, market power abuses, and opportunities for efficiency improvements and must propose appropriate actions;
- Planning and Expansion. Each RTO must plan and direct necessary transmission expansions and upgrades to enable it to provide efficient, reliable, nondiscriminatory service and must coordinate such efforts with the appropriate state authorities; and
- Interregional Coordination. RTOs must develop mechanisms to coordinate their activities with other regions.

In the summer of 2001, FERC adopted a more directive posture toward RTO formation and began to use existing regulatory authorities to accelerate the process. More recently, FERC has completed a benefit-cost analysis of RTOs and concluded that savings from RTO operation will save between $1–10 billion annually.[23]

RTOs are a means to an end. DOE supports the establishment of well-designed RTOs as an effective way to address many of the market and reliability coordination problems currently facing the nation's transmission systems. Whether RTOs represent the appropriate end-state for the evolution of the U.S. electricity transmission system will depend on their ability to ensure reliability and secure the benefits of fair and efficient competitive regional wholesale electricity markets.

[23]FERC. 2002. *Economic Assessment of RTO Policy.* Download from http://www.ferc.gov

Much work remains to realize this vision. The rules for RTO formation and operation must be clear and rapidly adopted. They must include stable market rules that stimulate the supply and demand sides of markets, interconnection and reliability standards, and transmission pricing mechanisms that reward efficient operation and investment.[24] RTOs must be able to address transmission bottlenecks in their regions.[25]

The Impacts of Transmission Fees on Trade and Congestion

Transmission fees have a substantial impact on electricity trade and congestion. In many regions, users must pay each utility a separate fee for use of its transmission system. This is generally referred to as "rate pancaking." Pancaked transmission rates create economic distortions in bulk-power markets by preventing some trades that would be profitable if not for the multiple transmission fees involved. One of the benefits of large RTOs would be the elimination of pancaked transmission rates.

DOE used POEMS to analyze a scenario that eliminates rate pancaking and instead uses a single access charge to ship power anywhere within an RTO. Five RTOs were assumed for this scenario:

- **Northeast (composed of PJM Interconnection, New York ISO, and ISO New England);**
- **Southeast and Florida;**
- **Midwest;**
- **Texas (ERCOT); and**
- **West (Western Systems Coordinating Council or WSCC).**

Not surprisingly, both electricity trade and transmission congestion between regions increase dramatically when transmission fees are structured as a single access charge. This is a reflection of the increased business activity that would lead to more efficient markets but also to increased loading of interregional transmission facilities. The total volume of electricity traded across regions increases by nearly 20 percent annually, and the average number of congested paths doubles.

The economic impacts of eliminating rate pancaking are even more dramatic. The benefits to consumers from more efficient trade are more than $1 billion per year.*

*This analysis is not an estimate of the benefits of RTOs, nor does it represent DOE's position on appropriate geographic boundaries for RTOs. This analysis only illustrates the importance of transmission fees in shaping trade and congestion patterns. Eliminating pancaked rates is only one of the expected benefits of RTOs.

[24] See Section 4, "Relieving Transmission Bottlenecks Through Better Operations," for specific recommendations to improve transmission system operations.

[25] See Section 5, "Relieving Transmission Bottlenecks Through Effective Investments," for specific recommendations on how RTOs should address transmission bottlenecks.

Effective operation of RTOs will be technically challenging. The tools and technologies originally developed to support centrally planned, vertically integrated operations are inadequate to manage reliability in competitive, region-wide electricity markets where power flows are driven by market participants whose behavior cannot be predicted using only traditional monitoring and dispatch concepts. DOE will work with industry to facilitate the development of transmission enhancement and control technologies that can help ensure reliable operations on a regional scale.[26]

So far, there have been several proposals for the organization and operation of RTOs (see Table 3.1). As expected, there are substantial differences in these proposals, in part because of regional differences in the electricity industry. It will be some time before the various RTO business models can be fully evaluated and fine-tuned. DOE can contribute to this process by helping FERC, the states, industry, and other stakeholders acquire appropriate tools to evaluate the performance of RTOs in meeting functional requirements. DOE can also help by sponsoring forums to determine what economic and reliability data must be collected to conduct these evaluations, who should collect them, and under what circumstances the information should be made publicly available.

The movement toward RTO formation has been slow because today's transmission facilities are owned by many different companies and agencies. Aligning and harmonizing the incentives of these owners to form RTOs that support regional markets involves many different decision and policy makers. Each transmission owner has its own perspective and responds to the incentives (or mandates) created by the economic and legal environment in which it operates. In addition, many states and the federal government have laws that hinder transfer of the assets or operational control of transmission systems to RTOs. These barriers will need to be identified and addressed.

Table 3.1

Current Status of RTO Applications

Name	Status
Alliance RTO	Denied
California ISO	ISO operational
Crescent Moon RTO	Under discussion
West Connect RTO	RTO proposed
ERCOT	Operational (not under FERC jurisdiction)
GridFlorida Transco	Provisionally approved
GridSouth Transco	Provisionally approved
Midwest ISO/ITC	RTO approved
New England RTO	ISO operational. RTO denied
New York RTO	ISO operational. RTO denied
PJM / PJM West	ISO operational
RTO West/ TransConnect	Stage 1 approved
SeTrans Grid	Under discussion
Southwest Power Pool	RTO proposed, now merging with Midwest ISO
American Transmission Company	Operational ITC. Approved under Midwest RTO
TRANSLink Transmission	Proposed ITC under Midwest RTO

Source: Federal Energy Regulatory Commission, as of January 30, 2002.

[26]See Section 5, "Relieving Transmission Bottlenecks Through Effective Investments," for additional discussion of advanced transmission technologies and specific recommendations.

In some cases, tax laws may be a barrier to the formation of RTOs both in transferring operational control of certain transmission assets to an RTO and in transferring ownership of the assets.[27] Federal tax law restricts the use by private firms of transmission facilities that are financed with tax-exempt bonds, or that are owned by certain cooperatives. Under existing statutes and regulations, municipal utilities could lose some or all of their ability to use tax-exempt financing, and certain cooperatives could suffer adverse tax consequences, if they turn operation of their transmission facilities over to an RTO. Temporary Treasury regulations, which are scheduled to expire in 2004, address some of the private use issues arising from participation by municipal utilities in open access. For example, the temporary regulations specify certain open access transactions that do not result in private use, or otherwise do not adversely affect the tax exemption of outstanding bonds. Finalization of the temporary regulations by the Treasury Department, in a manner that enables municipal utilities to transfer operational control of their transmission assets to an RTO in appropriate circumstances, will provide needed certainty in this area. In addition, proposals to remedy this and other tax obstacles are currently pending before Congress.

DOE and the Administration can play a significant role in advancing the formation of effective RTOs. DOE's Power Marketing Administrations (PMAs) have been supportive of RTO formation and have been key participants in RTO discussions. Bonneville Power Administration (BPA), Western Area Power Administration (WAPA), and the Southwestern Power Administration (SWPA) all operate extensive federal transmission systems. However, some legal barriers may prevent PMAs from shifting complete operational control over federal transmission lines to a non-federal entity such as an RTO. PMAs also have a unique relationship with their public power utility customers. These issues need to be evaluated carefully and appropriate measures must be taken to allow PMAs to become full participants in RTOs.

The Tennessee Valley Authority (TVA) is a large federal utility that operates federal transmission as well as significant generation facilities. TVA was originally formed to facilitate unified resource development in the Tennessee Valley. Today, among other things, it manages the Tennessee River system and provides electricity to eight million customers in the southern U.S. The unique circumstances of its creation and its special relationship to customers must be considered as part of any plans for TVA to participate in wholesale competitive markets, but should not inhibit its full participation in an RTO.

[27]Greater horizontal consolidation of transmission assets through the creation of independent transmission companies is described in the next subsection.

RECOMMENDATIONS

- RTOs should be responsible for maintaining the reliability of the grid and ensuring that transmission bottlenecks are addressed.
- DOE, with industry, will assess current system monitoring and control technologies that support efficient, reliable, and secure operation of RTOs and coordinate development of a plan for future research and development.
- DOE will work with FERC and stakeholders to develop objective standards for evaluating the performance of RTOs and will collect the information necessary for this assessment.
- DOE will work with the Energy Information Administration (EIA), FERC, National Governors' Association (NGA), the National Association of Regulatory Utility Commissioners (NARUC), the National Association of State Energy Officials (NASEO), industry, and consumer representatives to determine what economic and reliability data related to the transmission and the electricity system should be collected at the federal level and under what circumstances these data should be made publicly available.
- NGA and NARUC should identify state laws that could hinder RTO development.
- DOE will review federal laws that may prevent PMAs from full participation in RTOs, direct them to participate in the creation of RTOs, and take actions to facilitate their joining RTOs.
- DOE will work with TVA to help it address any issues that inhibit its participation in wholesale competitive markets, including full participation in an RTO.

3

Increasing Regulatory Certainty and Focus

Establishment of RTOs is an important step toward a more stable business environment for transmission system operations and investment. In order to complete the transition to a more stable business environment, additional efforts are necessary to increase regulatory certainty and focus to ensure investment in innovative solutions that will address transmission bottlenecks.[28] These efforts require solving the problems that emerge from:

- The current ways in which owners profit from existing and new transmission investments;

[28]For additional background on this discussion, see the Issue Paper, "Alternative Business Models for Transmission System Investment and Operations," by S. Oren, G. Gross, and F. Alvarado.

- Coordination of the tradeoffs between transmission investments and operation when the organizations that own the transmission system are not the same as those that operate it; and, finally,
- The interconnectedness of the AC transmission system itself, which means that investors in new transmission facilities cannot always charge "rent" for unauthorized use of their facilities because electricity flows over all available paths.[29]

Ensuring Beneficial Transmission Investments Are Profitable

New generation facilities are being built in significant numbers in almost every region of the country while new transmission facilities generally are not. From a business perspective, the explanation is simple: new generation developers have figured out how to produce power more efficiently and to make an attractive return on investments in the current market, while would-be new transmission developers have been frustrated in their efforts to achieve similar goals because their returns depend on regulatory policies and tariffs.

DOE believes that uncertainty about recovery of transmission system investments is a major barrier to new investments in needed transmission facilities. For investor-owned utilities, the costs of transmission are recovered in rates authorized by federal and state regulators. FERC authorizes rates for transmission service that are based on a target rate of return on transmission investments. State regulators authorize rates for retail service, also based primarily on a target rate of return that takes the costs of transmission into account along with all the remaining costs of providing electricity service, including generation, wholesale power purchases, and distribution costs. Recovering the cost of transmission becomes a local responsibility while the benefits of increased market efficiency and reliability are regional. The key to spurring new transmission investments lies in ensuring that the rewards offered by

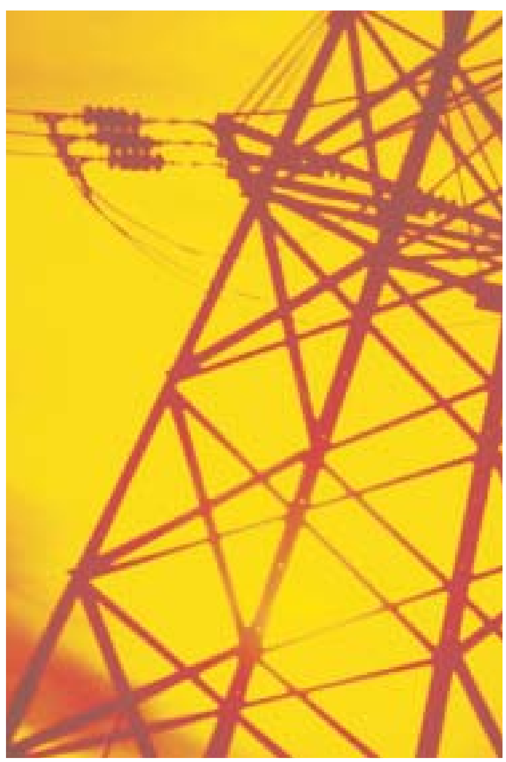
[29]This phenomenon, called loop flow, is described in more detail in the subsection *Loop Flow and the Emergence of Merchant Transmission*, below.

this system of regulation are commensurate with the risks of undertaking these investments and finding innovative approaches to align costs and benefits.

Industry participants have asserted that current rates of return for transmission system investments are not high enough. Authorizing higher rates of return is not the only approach to stimulating needed investments in transmission facilities over the long term. Reducing regulatory uncertainty should also be a focus of efforts to stimulate needed investments. Because transmission assets are long lived, regulatory uncertainty increases the risks to investors and, therefore, increases the returns they need to justify transmission system investments. Increasing regulatory certainty, therefore, should lower the returns needed to justify these investments.

Reconciling conflicting regulatory signals should be a core strategy for reducing regulatory uncertainty. In some states, rate freezes may undermine the benefits that could be realized by new transmission investment because the costs of these investments might not be fully recovered. In fact, rate freezes can create strong incentives not to build transmission. That is, utilities can increase profits under a rate freeze (as the rate base depreciates, costs decline, and load/revenue grows) by not making significant new rate-based investments, which would increase their net cost structure relative to frozen assets. Hence, the utilities' financial interest in avoiding new investment may conflict with the benefits that new investment might provide to the region as a whole. In these cases, state regulators should balance the reasons for the rate freeze against the need to stimulate adequate transmission investment.

More closely aligning the incentives of transmission owners with those of the public and consumers should be another element of eliminating regulatory uncertainty and sharpening the focus of regulatory decisions. For example, one approach that needs to be considered is shifting some responsibility for congestion (both its costs and the benefits from investment to reduce these costs) to transmission owners so that they have an incentive to address transmission bottlenecks. The current form of rate-of-return regulation is based on investment costs. Simply passing costs of congestion through to consumers disconnects the decision to invest from the benefit to the consumer of the investment and thus provides no



incentive to transmission owners to address bottlenecks.

Rate-of-return regulation, therefore, may be inconsistent with newer forms of regulation that seek to emulate the role of competitive market forces in eliciting efficient behavior from regulated firms. A basic tenet of competitive markets is that investors are rewarded based on the value and innovativeness of their actions (not on the cost of their investments, which is the basis for rewards under rate-of-return regulation). A new class of regulatory approaches, called performance-based regulation (PBR), offers greater promise in offering incentives toward this end. Examples of PBR can be found in the telecommunications industry in the U.S. and in regulated utility industries around the world, most notably in the UK.

PBR is attractive because it provides targeted incentives to regulated firms to achieve specific objectives (e.g., to increase market efficiency, ensure reliability, and make timely investments). In order to ensure that these objectives are met, it is necessary to define performance measures that directly relate to the objectives and to ensure that firms have adequate control over the means of meeting the objectives. If the goal is to minimize the cost of transmission service, a firm must be able to balance improvements in operations with investments in new transmission facilities, including the deployment of advanced technologies. Similarly, if the transmission owner bears no responsibility for costs of congestion, there is no incentive to reduce it.[30] PBR in the UK has led to a substantial reduction in congestion costs (see text box).

The Role of Performance-Based Regulation in Promoting Efficient Transmission

One of the best-known PBR mechanisms for electricity markets is found in the UK, for transmission services provided by the National Grid Company (NGC). Though it could not be transferred directly to the U.S., this approach also illustrates the role that incentives for enhanced transmission system operations can play in stimulating efficient transmission operation, including investment in innovative transmission technologies.

NGC's PBR mechanism employs a profit-sharing approach to reward NGC for reducing the charges that are passed on to consumers for recovery of congestion relief costs incurred by NGC. The profit-sharing scheme is based on NGC's performance relative to a predetermined "yardstick" set by the regulator in view of historical performance and expected efficiency improvements. NGC has reduced the costs of congestion through a combination of operational efficiency improvements, improved forecasting, investment in transmission expansion, and adoption of technologies that improve transmission grid utilization. NGC has pioneered an innovative approach in which some of these technologies, in contrast to conventional approaches, are mobile. NGC moves them around the system in order to target areas in need of relief, which vary from year to year in response to changing market trading patterns.

Source: S. Oren, G. Gross, and F. Alvarado. 2002. *Alternative Business Models for Transmission System Investment and Operations*, Issue Papers.

[30]For example, one way owners might, in turn, address increased responsibility for managing congestion costs is by pricing it explicitly, thus providing an incentive to market participants to reduce these costs through adjustments to their own actions to use the transmission system. This concept is discussed further in Section 4, "Relieving Transmission Bottlenecks Through Better Operations."

Finally, it may be appropriate to consider other methods for increasing the profitability of transmission investments, especially when investments address important regional or national interests.

Coordinating Transmission Investment and Operation

During the 1990s, many states passed electricity industry restructuring legislation to introduce wholesale and sometimes retail competition. In addressing wholesale competition, state legislation typically reinforced FERC Orders 888 and 889 by directing utilities to accelerate the process of separating transmission and generation functions, including divesting generation assets, or by providing strong incentives for divestiture. States directed utilities to ensure that operation of the transmission system would support the emergence of competitive wholesale markets for generation. Insulating transmission and generation operations from each other typically entailed allowing transmission owners to retain possession of their transmission assets but transfering operational control of them to an independent entity.

Independent System Operators (ISOs), the new institutional structures authorized by FERC in recent years to operate transmission assets, have led to a disconnection between transmission investment and operational needs. A major challenge to investment and innovation when control and ownership of transmission are separated is the creation of a financial linkage between those who benefit from the investment (the public) and those who finance it (the owners). Today in the U.S., there are five ISOs operating transmission systems: California, New England, PJM, New York, and Texas. Although these entities operate the systems, they cannot ensure that needed transmission is built.[31] Unless managed carefully, disconnections could lead to underinvestment and poor operations, which would raise electricity costs and reduce reliability. As recommended earlier, if we are to succeed in completing the industry's transition to a fair, efficient, and competitive market, RTOs must be able to address transmission bottlenecks.

Independent transmission companies that own and operate transmission assets are a new development and offer perhaps the greatest potential for improving the coordination of transmission operation and investment. These companies achieve a complete corporate sepa-

[31]Texas is building transmission in part because the state's utility commission regulates both the ISO and the transmission-owning utilities and supports the ISO's transmission planning efforts with expeditious regulatory review of proposed transmission expansion.

ration between generation and transmission. They are formed by divesting the transmission assets from vertically integrated firms to wholly independent firms that have no generation assets. Creation of these independent companies is a reflection of private investors' desire to separate and consolidate the very different risks and rewards offered by generation and transmission businesses today.

It is imperative that private-sector initiatives such as independent transmission companies be allowed to flourish. Tax laws that may encumber the economic transfer of transmission assets must be reviewed.

Loop Flow and the Emergence of Merchant Transmission

A unique feature of transmission facilities is the existence of "externalities" associated with interconnected AC networks. Loop flow, in particular, in which electricity passes over systems that are not parties to its sale and transmission, is an unavoidable feature of bulk-power AC transmission because electricity takes the path of least resistance and does not follow prescribed routes.[32] For developers of new transmission lines, the situation is akin to building a new road but then having no means to effectively control (or charge for) the flow of traffic over it.

RTOs are expected to better address loop flow by internalizing it within the large geographic boundaries of each RTO. Greater horizontal consolidation of transmission assets, as reflected in the formation of independent transmission companies that combine the assets of many individual transmission-owning utilities (also leading to larger geographic boundaries), is yet another approach for internalizing loop flow, in this case within the boundaries of a single firm.

Merchant transmission, a new entrant in the transmission market, has relied on a technological solution to the problem of loop flow. To date, all merchant transmission projects have relied on DC transmission technologies

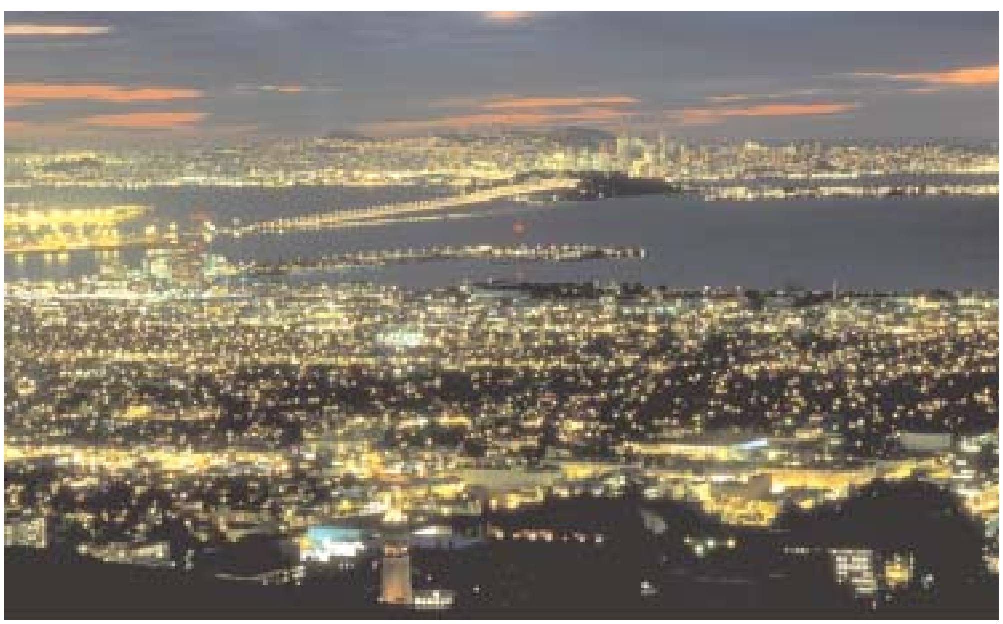
[32]Flexible AC transmission system (FACTS) devices can control flows over transmission lines; however, these devices are expensive and have seen limited application to date. See Section 5, "Ensuring the Timely Introduction of Advanced Technologies," and the Issue Paper, "Advanced Transmission Technologies" by J. Hauer, T. Overbye, J. Dagle, and S. Widergren.

(e.g., Transenergie's recently approved link between Connecticut and Long Island, and Neptune's proposed Regional Electric Transmission System in the Northeast), which permit facility owners to directly control flows over their investments and avoid the problem of loop flow.

A merchant transmission project is one that is financed by private investors with no regulatory support (i.e., no regulator ensures that the investor has the opportunity to earn a reasonable return on that investment). In return for lack of regulatory protection, the owner of a merchant transmission facility can, in principle, charge market-based rates. Although merchant transmission is a potentially powerful approach to resolving many of the difficulties (including those related to planning, expansion, and pricing) facing traditional transmission systems, we do not know to what extent projects financed in this manner can meet current and future needs for new transmission. Nevertheless, merchant transmission projects could introduce competition directly into an aspect of the industry that has long been regarded as a natural monopoly. And it seems clear that when private investment in transmission can be undertaken in ways that avoid the problems of loop flow, this investment may be in the national interest.

RECOMMENDATIONS

- DOE will work with NGA, regional governors' associations, NARUC, and other appropriate state-based organizations to promote innovative methods for recovering the costs of new transmission-related investments. These methods should consider situations where rate freezes are in effect and also examine incentive regulation approaches that reward transmission investments in proportion to the improvements they provide to the system.
- DOE will research and identify performance metrics and evaluate designs for performance-based regulation.
- The Department of Treasury should evaluate tax law changes related to electricity modernization. Treasury should review its current regulations regarding the application of private use limitations to facilities financed with tax exempt bonds in light of dynamics in the industry and proceed to update and finalize its regulations. This will give greater certainty to public power authorities providing open access to their transmission and distribution facilities.
- Entrepreneurial efforts to build merchant transmission lines that pose no financial risk to ratepayers and that provide overall system benefits should be encouraged.
- DOE and the Department of Treasury will evaluate whether tax law changes may be necessary to provide appropriate treatment for the transfer of transmission assets to independent transmission companies.



4

Improving transmission system operations should be the first element of a coordinated strategy to address transmission bottlenecks. Operational improvements can be implemented more quickly and at lower cost than construction of new transmission facilities. Needed improvements include: using market forces to manage transmission congestion through better price signals; voluntary load-reduction programs and targeted energy efficiency and distributed generation; relying on better real-time information to determine safe operating limits; and ensuring mandatory compliance with reliability rules.

Relieving Transmission Bottlenecks Through Better Operations

Ensuring the reliability of the transmission system has always been paramount. The primary objective of reliable transmission system operation has been to minimize the risk of large-scale blackouts. In extreme situations, temporary "rolling blackouts" have been imposed in parts of the system in order to maintain the integrity of the remainder of the system.

Current rules and operational procedures for addressing transmission bottlenecks reflect traditional operating practices based on experiences developed when electricity transactions were smaller in volume, involved fewer participants, and did not routinely span multiple regions. These rules and procedures embody a central-planning approach that gives little consideration either to the commercial value of electricity trade and the cost to consumers of lost trading opportunities, or to customers' willingness to accept compensation voluntarily for interruptions of electricity service.

Consistent with DOE's vision, market forces, not central planning, should be relied upon to the extent feasible to ensure reliability and to efficiently allocate transmission services when they become scarce. Increasing reliance on market forces to improve transmission system operations is a needed next step in the transition to a reliable transmission system that supports fair and efficient competitive regional wholesale markets that lower the cost of electricity to consumers.

This is not to suggest that market forces, alone, will be adequate to ensure reliability. In competitive wholesale markets, there is an even greater need than in the past for agreed-upon mandatory approaches to reliability management and real time operations. However, market forces should serve as a first line of defense before turning to these approaches.[33]

[33]For additional background on this discussion, see the Issue Paper, "Transmission System Operation and Interconnection," by F. Alvarado and S. Oren.

4

Pricing Transmission Services to Reflect True Costs

The first step toward increasing the role of market forces in managing transmission system operations efficiently and fairly is increasing the role of price signals to direct the actions of market participants toward outcomes that improve operations. Improving operations by relying on accurate price signals may, by itself, alleviate the need for some construction of new transmission facilities. Moreover, when new construction is needed, price signals will help market participants identify opportunities and assess options to address bottlenecks.

Several aspects of transmission operations, including congestion and losses, could be effectively addressed by pricing based on the principle that if market participants see the true costs of transmission services reflected in prices, they will use or procure these services efficiently. For example, pricing principles should encourage location of new generation in congested areas as opposed to location in areas with no congestion. Thus, reliance on uplift charges, in which costs are recovered from all transmission users on an equivalent basis, should be minimized.[34] Here, we focus on examples where application of these principles may be especially important for addressing transmission bottlenecks.[35]

Although curtailing some transactions is essential to ensure reliability when transmission lines are in danger of being overloaded, the economic losses associated with these curtailments can be reduced by sending price signals that will allow market participants to choose which transactions to curtail in response to the relative value of the transactions. Congestion pricing, in which the party that creates congestion pays for the costs of relieving it, is a powerful example of using

[34]Uplift charges are charges paid by all users; these charges represent costs that are difficult to apportion to particular market participants or that regulators allocate evenly among all users in order to achieve other policy objectives. In cases where uplift charges must be used to recover costs, however, performance-based regulations (discussed in Section 3) that provide incentives to minimize these charges and improve operational efficiency should be considered.

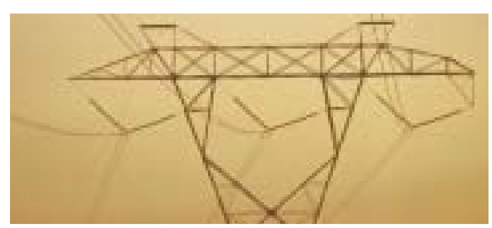
[35]For additional background on this discussion, see the Issue Paper, "Transmission System Operation and Interconnection," by F. Alvarado and S. Oren.

economic signals to relieve congestion efficiently. FERC's Order 2000 identifies reliance on market-based mechanisms to manage congestion as one of the eight functions of RTOs.

Transmission of electricity is not 100 percent efficient; losses, which result from the heating of lines and transformers, are inevitable, so delivering 100 MWs of electricity to an end point requires that more than 100 MWs be put into the transmission system. Losses depend on a variety of factors, including the physical properties of transmission facilities, the distance the electricity must travel, and the current use of transmission facilities by others. The costs of system losses are sometimes included in uplift charges borne equally by all transmission system users, which leads to inefficient use of the system. More accurate pricing and allocation of transmission losses will lead to more efficient markets because participants can see and respond to the true costs of using the transmission system.

Transmission pricing should recognize the inherent differences between intermittent, low-capacity-factor renewable energy sources that are often located far from loads (such as wind energy) and conventional generation, which is not intermittent. Pricing should not unduly disadvantage renewable power plants. For example, wind plants must pay for their own ancillary services. However, because of the inherent difficulty of precisely scheduling transmission needs for wind plants on a day-ahead basis, these plants should be allowed access to a real-time clearing market for differences, subject to non-punitive penalties based on cost, and/or allowed a wider clearing band for scheduling, as has been proposed by several states.

When we propose greater reliance on competitive economic forces to procure and apportion the costs of transmission services, we must recognize that markets for electricity and electricity services are still maturing. Approaches for organizing markets must minimize the risks of unintended design flaws that can be exploited by market participants. There is a need to develop methods for "testing" market rules in controlled laboratory-like settings to identify and correct design flaws prior to implementation. While we are gaining experience with markets, there must be safeguards—i.e., close oversight and rapid, deliberate response by FERC, including stringent penalties—to prevent market abuses. FERC has already initiated activities to increase its capability to monitor electricity markets more aggressively.



RECOMMENDATION

- DOE, working with FERC, will continue to research and test market-based approaches for transmission operations, including congestion management and pricing of transmission losses and other transmission services.

4

Increasing the Role of Voluntary Customer Load Reduction, and Targeted Energy Efficiency and Distributed Generation

Enabling customers to reduce load on the transmission system through voluntary load reduction or through targeted energy efficiency and reliance on distributed generation are important but currently underutilized approaches that could do much to address transmission bottlenecks today and delay the need for new transmission facilities.

Voluntary Customer Load Reduction

Allowing the "demand side" of regional wholesale electricity markets to interact with the "supply side" is a critical missing element in the transition to fully competitive, fair, and efficient markets. Without meaningful participation by the demand side, today's market is, at best, half a market. Relaxing the current electric system operating principle that all customer demand must be served at any cost is the key to rational provision of reliable and affordable electricity services. We can keep most of the lights on at a lower total cost to all customers if we allow those who are willing to turn their lights off voluntarily (e.g., in response to economic incentives and price signals) to do so.

Voluntary load-reduction programs encompass a variety of strategies that enable customers to curtail or displace load from their local utility in response to system conditions. Providing opportunities for customers to respond to the true costs of electricity is not the same as enabling retail choice; voluntary load-reduction programs can be operated in states where there is retail choice as well as in states where incumbent utilities continue to provide retail electricity service.

A full-scale effort is needed to understand how customers would voluntarily reduce electricity loads, conduct pilot programs, assess the impacts of these programs on wholesale markets and system reliability, and develop new technologies for price transparency and customer participation in the market.

Eliciting load response from customers will not be easy. Flexible programs will be required in view of these key considerations:

New York ISO Demand-Response Programs

The New York Independent System Operator (NYISO) operated two demand-response programs in 2001: the Emergency Demand Reduction Program and the Day-Ahead Demand Reduction Program. Both are examples of the types of programs needed to enable voluntary customer load reduction in wholesale markets for the purposes of enhancing system reliability and increasing market efficiency.

The Emergency Demand Reduction Program is a "call"-type program (i.e., customers agree in advance to curtail load when called to do so by NYISO) but is voluntary in that there are no penalties for choosing not to curtail when called, so payment is based on a participant's performance in each hour of a curtailment event. In summer 2001, the program was operated four times because of shortages in operating reserves. On average, the program delivered 450 MW, which is a significant share of the 1,800 MW operating reserve that NYISO maintains.

The Day-Ahead Demand Reduction Program is a "quote"-type program (i.e.. customers are given an opportunity to offer load reductions to the wholesale market). In summer 2001, the program operated during July and August and achieved modest load reductions. Efforts are under way to improve the design and operation of the program for summer 2002.

Source: New York ISO. http://www.nyiso.com/services/documents/groups/bic_price_responsive_wg/demand_response_prog.html

- Some customers may be quite willing to view reduction of their load for economic purposes as a new source of profit/savings, but others may only be willing to reduce their loads in response to circumstances such as true system reliability emergencies.
- Many customers will require substantial advance notification to reduce load and will want to limit the duration and frequency of interruptions in service; others will be more flexible.
- Real-time pricing is essential for allowing customers to determine how much power they wish to use based on the actual price of electricity at any point in time. However, other programs, such as priority service and demand bidding, should also be explored to accommodate customers who do not wish to respond to real-time prices.

DOE, the states, and private industry can help enable widespread customer participation in voluntary load-reduction programs by educating consumers about successful programs. DOE can also stimulate the development and dissemination of successful approaches and technologies. Advanced meters must be deployed that allow customers to receive signals in real time (e.g., hourly prices for electricity) and new system integration techniques must be developed and demonstrated to automate responses to these signals.

Modifying transmission operation control systems to accommodate load reduction on an equivalent basis with electricity generation poses a series of challenges. First and most important, the system reliability rules and practices underlying current telemetry requirements and control procedures must be reviewed and redefined from a technology-neutral point of view, without compromising system reliability. Second, new communication and control technologies consistent with these redefinitions must be developed and implemented. DOE can help industry accelerate these needed changes.

Targeted Energy Efficiency and Distributed Generation

Targeted energy efficiency and distributed generation are approaches through which customers can reduce electricity loads on the transmission system, alleviate bottlenecks, and delay the need for construction of new facilities. They are complementary strategies to voluntary customer load-reduction programs.

Utilities and government have spent more than 25 years developing and implementing proven energy-efficiency programs and standards that save consumers money. Today, funding for utility-led energy-efficiency programs is significantly lower than before industry restructuring because recovering the costs of these programs conflicted with rate reductions and freezes and the need to recover the much larger costs of utilities' stranded assets.

Regulators should re-evaluate and consider expanding utility support for energy efficiency programs in view of their potential benefits to the electricity system as well as their direct benefits to customers in the form of lower electricity bills. State regulators need to eliminate

Summer 2001 Demand Reductions in California

California's experiences during the electricity crisis in summer 2001 offer important lessons about peak demand reduction. According to the California Energy Commission, Californians used 8.9% less electricity during peak hours in 2001 compared to 2000 when adjusted for growth and weather (see http://www.energy.ca.gov/).

These are very large savings compared with what almost all observers at the time expected and historical behavior patterns. In other words, demand-reducing programs performed very well, and these reductions were of great importance during the crisis. However, although an estimated 30 percent of these savings related to investment in more efficient end-use devices and on-site generation will likely persist, the remaining reductions are the result of changes in behavior and operations that may not continue now that the crisis appears to have passed. California spent a large sum of (one-time) funds strongly encouraging consumers to reduce energy use. Many consumers did so for reasons including: the desire to be good citizens, concerns about high electricity bills, and the prospect of receiving a 20 percent electricity bill rebate if they achieved 20 percent savings.

Thus, although demand reduction can play an important role in relieving transmission bottlenecks, the crisis situation to which Californians responded in summer of 2001 is not a desirable model for future efforts. The crisis in California was very expensive. The goal should be to avoid such crises, in California and elsewhere. Long-term demand reduction programs, enhancement of the transmission system, and the new supplies are all essential to achieving this goal.

disincentives facing utilities and third-party energy service providers who wish to lower customer energy bills and help mitigate transmission bottlenecks though energy efficiency programs.

Distributed generation and storage allows customers to reduce reliance on the transmission system by "distributing" or placing generation sources (such as photovoltaics; combined heat and power systems; and small, clean generators, including microturbines and fuel cells) and energy storage closer to the locations at which electricity is used, e.g., at customers' homes or businesses. For distributed generation that also incorporates combined heat and power technologies, the economics are enhanced by opportunities to use the heat produced in the conversion of fuel to electricity. Other applications benefit from the increase in power quality offered by certain distributed technologies (e.g., energy storage).

There is some local utility resistance to increasing customers' reliance on distributed generation. This resistance is based on technical concerns (e.g., safety of utility crews working in the field who do not know that current is flowing from distributed resources) and a combination of regulatory (e.g., loss of sales revenues) and competitive considerations (e.g., high charges for back-up power from the utility).

Current utility procedures for interconnecting distributed generation to the electricity grid are generally expensive and non-transparent. The Institute of Electrical and Electronics Engineers (IEEE) is working to establish technical interconnection standards in its draft standard IEEE P 1547. This effort must be completed soon to help promote distributed generation solutions. Standardized interconnection procedures (agreements, rules, and business procedures) are also needed to reduce costs and clarify requirements.

Current rate-making practices create disincentives for utilities to "lose" load to distributed generation (as well as to energy efficiency) despite the benefits to the system and the potential cost savings to customers from these two strategies. State regulators should examine the current regulatory disincentives to energy efficiency and distributed generation and address them consistent with the public interest in ensuring cost-effective consumer investments in distributed generation and energy efficiency.

RECOMMENDATIONS

- DOE will work with FERC, the states, and industry, and conduct research on programs and technologies to enhance voluntary customer load reduction in response to transmission system emergencies and market price signals.
- DOE will work with states and industry to educate consumers on successful voluntary load-reduction programs. DOE will disseminate information on successful approaches and technologies.
- DOE will continue to work with NGA, regional governors' associations, and NARUC to remove regulatory barriers to voluntary customer load-reduction programs, and targeted energy efficiency and distributed generation programs that address transmission bottlenecks and lower costs to consumers.
- IEEE should expeditiously complete its technical interconnection standards for distributed generation.
- DOE will work with NGA and NARUC to develop and promote the adoption of standard interconnection agreements, rules, and business procedures for distributed generation.

4

Using Improved Real-Time Data and Analysis of Transmission System Conditions

The maximum electrical loads allowed on the transmission system today are estimated conservatively. Total Transfer Capability (TTC), which is the basis for establishing Available Transfer Capability (ATC), has traditionally been determined by a static analysis of acceptable system conditions—that is, system operators assumed conservative values for ambient conditions, such as air temperature and wind speed, that affect the safe and reliable operation of transmission lines and other transmission facilities. This practice was acceptable in the past because of the lack of measurement, communication, and analysis tools to determine the real-time status of the electric system. In addition, it was easier to conduct a static analysis and overbuild the transmission system than to conduct a dynamic analysis so that the system could be operated more efficiently, i.e. closer to its actual safety limits, which vary over time.

The increased demand for transmission services and the increasing difficulty in getting new transmission lines built compel us to better understand the limits of safe and reliable transmission system operation. As ambient conditions change, so will TTC. A dynamic system analysis that uses real-time data instead of the conservative proxies used in a static analysis provides a better estimate of TTC and would allow operators to safely move more power across existing lines.

In addition to the corresponding increase in ATC that would result from a more precise assessment of TTC, dynamic analysis can further increase ATC by identifying unused transmission rights that can be made available to the market on a nonfirm basis. The overall result of using dynamic transmission system analysis could be a substantial increase in ATC, a reduction in transmission congestion, and more efficient use of the transmission system.

Recent advancements in measurement, communication, and analysis tools now make dynamic analysis a possibility.[36] In some cases, a change from a static transmission system analysis to a dynamic analysis may be the most cost-effective way to reduce a transmission bottleneck.

RECOMMENDATION

- DOE will work with industry to demonstrate and document cost-effective uses of dynamic transmission system analysis.

4

Ensuring Mandatory Compliance with Reliability Rules

Ensuring reliability has and will remain a fundamental priority for the nation's electricity transmission systems. The procedures that have in the past been used to set and enforce rules to ensure reliability must change to be consistent with and supportive of competitive wholesale electricity markets.[37]

The 1990s witnessed an increase in the number of large-scale blackouts and near misses. Some have expressed concern that this increase is evidence of the losing battle firms now face in trying to manage reliability while operating in competitive business environments that provide few if any economic

[36]A description of tools, such as the Wide Area Measurement System (WAMS), that would support more precise determinations of the dynamic state of the transmission system can be found in Section 5, "Relieving Transmission Bottlenecks Through Effective Investments." See also the Issue Paper, "Advanced Transmission Technologies," by J. Hauer, T. Overbye, J. Dagle, and S. Widergren.

[37]For additional background on this discussion, see the Issue Paper, "Reliability Management and Oversight," by B. Kirby and E. Hirst.

rewards for continued stewardship of the public interest in electricity system reliability.

Industry has stated clearly that it can no longer rely on the historic system of voluntary compliance with rules to ensure the reliability of the nation's interconnected transmission systems because of the competition among firms in today's marketplace.[38] There is widespread agreement that mandatory rules are now required to ensure transmission system reliability. In the West, the WSCC is creating a mandatory system based on contractual agreements with its members. This is a significant improvement over the historic voluntary system, however, federal legislation to create a mandatory system remains essential.

Foremost among the issues that must be considered in reviewing reliability rules is the recognition that these rules directly impact market operations (for example, TLRs curtail certain commercial transactions, as explained in Section 1). An open, inclusive process for reviewing and establishing reliability rules is required in view of their economic implications.

New reliability rules must accommodate variations in transmission system designs and build upon the knowledge of local transmission system operators in open rule-setting processes. However, it is essential that local variations do not hinder the operation of competitive regional electricity markets and are not used unfairly to give a competitive advantage to one group of market participants at the expense of others.

Although reliability has never been ensured "at any cost," the costs of reliability to consumers should be explicitly accounted for when reviewing reliability rules. At a minimum, the penalties for violating reliability rules should reflect the costs imposed on society by these violations, e.g., the cost of replacing the reliability services that are not provided by the violator.

Similarly, as a cornerstone of restructuring, we should allow consumers to pay for a higher level of reliability than that provided by the current electricity system. A critical barrier to informed consumer choice about reliability, which includes power quality, has been the lack of public data on the subject. Although records are kept by utilities, their interpretations of reliability and power quality events vary

Table 4.1

Summary of Major Electricity Reliability Events in North America
Northeast blackout: November 9-10, 1965
New York City blackout: July 13-14, 1977
Los Angeles earthquake: January 17, 1994
Western States cascading outage: December 14, 1994
Western States events in Summer 1996 - July 2, 1996—cascading outage - July 3, 1996—cascading outage avoided - August 10, 1996—cascading outage
Minnesota-Wisconsin "near miss": June 11-12, 1997
Northeast ice storm: January 5-10, 1998
Upper Midwest cascading outage: June 25, 1998
San Francisco blackout: December 8, 1998

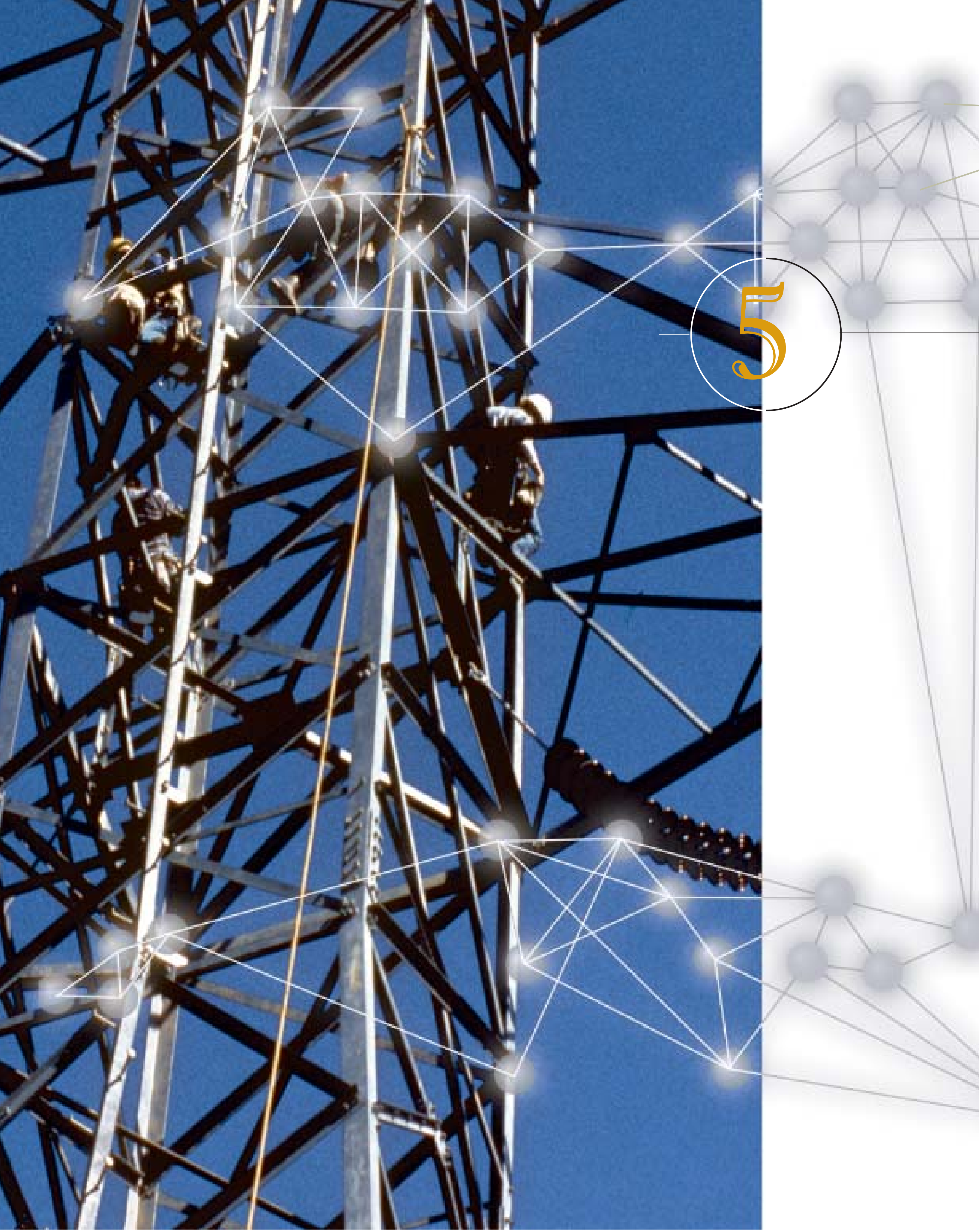
Source: J. Hauer and J. Dagle. 1999. *Review of Recent Reliability Issues and System Events*. Download from http://www.eren.doe.gov/der/transmission

[38] North American Electric Reliability Council. 2001. *Reliability Assessment, 2001-2010*. Download from http://www.nerc.com

considerably, so data from different utilities are often not comparable. Of greater concern is that consumers do not routinely have access to these data. For example, when businesses experience interruptions that disrupt their processes, it starts a long and expensive process of data collection and analysis to diagnose the problem before a solution can be prescribed. Without these data, consumers cannot make informed decisions and cannot fully assess the significance of electricity reliability and power quality and thus the value of options available to address them.

RECOMMENDATIONS

- Federal legislation should make compliance with reliability standards mandatory.
- Current reliability standards should be reviewed in an open forum to ensure that they are technically sound, nondiscriminatory, resource neutral, and can be enforced with federal oversight.
- Penalties for noncompliance with reliability rules should be commensurate with the costs and risks imposed on the transmission system, generators, and end users by noncompliance. Penalties collected should be used to reduce rates for consumers.
- DOE will work with industry and NARUC to promote development and sharing of best transmission and distribution system operations and management practices.
- DOE will work with FERC, state PUCs, and industry to ensure the routine collection of consistent data on the frequency, duration, extent (number of customers and amount of load affected), and costs of reliability and power quality events, to better assess the value of reliability to the nation's consumers.



5

Ultimately, construction of new transmission facilities will be needed to ease transmission bottlenecks. We must implement open, regional transmission planning processes that consider a broad range of transmission and non-transmission alternatives, accelerate and coordinate siting and permitting processes for needed facilities, ensure that the transmission system can take advantage of the latest technologies, and address physical and cyber security issues.

Relieving Transmission Bottlenecks Through Effective Investments

Improving transmission system operations will go a long way toward easing transmission bottlenecks by delaying or alleviating the need for construction of new transmission facilities. However, construction of new facilities cannot be avoided entirely. We must ensure that needed facilities are identified in a timely fashion through open processes and that, once identified, they are constructed expeditiously.

In view of its ongoing responsibilities for public-interest energy R&D, DOE must work closely with industry to ensure the continued development and deployment of needed new, transmission-enhancing technologies. This need is especially great today to address gaps that have emerged during the transition to competitive regional wholesale markets. Finally, we must also re-double efforts to ensure the security of new and existing facilities in the nation's transmission infrastructure.

5

Implementing Regional Transmission Planning

Effective regional transmission planning requires:

- An open, inclusive process;
- Clear planning objectives; and
- A planning entity with authority to conduct the process and implement the results.[39]

FERC Order 2000 assigns responsibility for transmission planning to RTOs. Vesting this responsibility in RTOs is an acknowledgment of the regional implications of transmission in facilitating the development of regional wholesale electricity markets. RTOs are the key institutions with a regional perspective central to

[39]For additional background on this discussion, see the Issue Paper, "Transmission Planning and the Need for New Capacity," by E. Hirst and B. Kirby.

their charter. As noted in Section 3, DOE believes that a key element of RTOs' role in transmission planning should be to identify and address transmission bottlenecks

It is critical that the RTOs formed in response to FERC Order 2000 adopt planning principles and practices that facilitate private investment in new transmission facilities and non-transmission alternatives. These principles and practices should advance local, state, regional, and national interests. The goal of RTO planning should be to identify transmission needs and the criteria for evaluating proposed solutions, and then to empower the market to respond to these needs, including, if necessary, support for market solutions in state regulatory proceedings.

A critical challenge is to reintegrate the generation and transmission system planning perspectives that were once a routine element of planning by vertically integrated utilities. Today, generators are building power plants where permits can be obtained with ease and there is access to fuel, water, and other necessary infrastructure. Transmission issues are an afterthought in this process because transmission is viewed as the utilities' obligation. For example, in the Southeast, a large number of power plants have been proposed in areas where there is inadequate transmission. Building new generation in these areas will increase congestion on the transmission system.

Expansion of the transmission system must be viewed as one strategy in a portfolio to address transmission bottlenecks; this portfolio also includes locating generation closer to loads, relying on voluntary customer load reductions, and targeting energy efficiency and distributed generation. Planned natural gas infrastructure investments, which affect where new generation will be built (both large, remote stations as well as small, distributed generation), must also be considered.

Once transmission bottlenecks are identified, market-based approaches should be relied upon to address them in the most efficient way. As mentioned in the previous section, one way to empower market solutions is better pricing of transmission congestion to signal needs to private developers so that they can capture the benefits of relieving transmission bottlenecks. Better pricing allows generators to incorporate transmission considerations into their business decisions for locating new power plants.

When possible, solutions to bottlenecks should be solicited through open, competitive processes that allow private developers to offer proposals that might encompass new transmission facilities, non-transmission alternatives, or both. Access to operational data is essential to allow market participants to formulate and evaluate viable proposals.

Transmission plans must balance traditional reliability considerations with economic efficiency. Taking the economic efficiency attributes of electricity markets into account requires adopting a regional perspective because these markets span across regions. This is in sharp contrast to most current transmission plans, which, because of the limited geographic scope and mandate of today's transmission owners, focus primarily or solely on local considerations.

In contrast to the majority of today's transmission planning processes, open planning processes will be essential to ensure meaningful public input throughout. This input is especially needed to support the identification and assessment of tradeoffs among planning criteria (e.g., reliability versus economic efficiency, local impacts versus regional benefits) as well as to better understand how parties might be affected by different planning outcomes. Too often, clear planning criteria and public input are delayed until state and federal siting processes are under way. Delaying public input until the siting process can cause substantial delays because it often introduces new alternatives that had not previously been evaluated. The siting process must then be stopped while these new possibilities are assessed. These delays can be avoided if planning criteria and public input are incorporated early in the planning process. Greater public access to planning data and resources is needed to effectively inform public input.

Meaningful public input and assessment of reasonable alternatives in the early stages of planning will increase public acceptance of plans once they are final and will facilitate any required siting and permitting processes.

RECOMMENDATION

- DOE will work with the electricity industry and state and federal regulators to identify the type of electricity system data that should be made available in the planning process to facilitate the development of market-based transmission solutions and devise a process for making that information available.

5

Accelerating the Siting and Permitting of Needed Transmission Facilities

There have been significant delays during the siting and permitting process for many large, interstate or regional transmission projects.[40] These processes have emerged as significant deterrents to building new regional transmission facilities. It is important that we eliminate unnecessary delays once the need for these facilities has been established.

State and federal regulators must work with states and regions to ensure that transmission siting and permitting processes work —and work together. States should retain their present authority and play a more active role in managing review processes for energy infrastructure siting and permitting. As part of their reviews, states should ensure that regional considerations are taken into account in assessing the costs and benefits of new transmission. They should also coordinate their reviews with other regional and state planning, siting, and permitting processes. As part of these processes, the federal government has a special responsibility to ensure that siting and permitting on federal lands is not needlessly delayed.

Federal regulators should actively support and defer to these state and regional siting and permitting processes. However, since new regional transmission facilities will typically span or impact multi-state areas that seldom align with the political boundaries of states, FERC must have appropriate backstop authority to ensure that the public interest is served and that national interest transmission bottlenecks designated by DOE are addressed. When state and regional processes determine that construction of transmission facilities is needed to address national interest transmission bottlenecks, yet are unable to site or permit them in a timely fashion, FERC must be able to grant designated entities the right of eminent domain to acquire property for rights-of-way.

[40]For additional background on this discussion, see the Issue Paper, "Transmission Siting and Permitting," by D. Meyer and R. Sedano.

American Electric Power's 765-kV Project between West Virginia and Virginia

Ten years after it was first proposed, a major transmission project by American Electric Power (AEP) in West Virginia and Virginia is still about a year from final approval. The following chronology documents the delays resulting from state regulators' efforts to take account of local and other concerns, and from lack of coordination among the principal parties.

1991—AEP submits a proposal for a 765-kV transmission line to Virginia, West Virginia, the U.S. Forest Service, the National Park Service, and the U.S. Army Corps of Engineers with the goals of maintaining reliability in southern West Virginia and southwestern Virginia and reducing the risks of a cascading outage that could affect many states in the eastern U.S.

1992–1994—Extensive hearings are held in Virginia and West Virginia, many in potentially affected localities.

1996—The Forest Service issues a draft environmental impact statement which recommends that the line not be constructed as proposed because it will cross sensitive public lands.

1997—AEP proposes, to the regulatory commissions in the two states, a longer alternate route that would cross less sensitive areas than the initial route.

1998—The West Virginia Public Service Commission approves its portion of the alternate route.

Later in 1998—AEP agrees to a request from the Virginia Corporation Commission that the utility conduct a detailed study of a second alternate route. After AEP completes its review, it agrees that the second route is acceptable although this route would not allow as much margin for future load growth as had been available with the first alternate route.

2001—The Virginia Corporation Commission approves the second route, chiefly because this route would have fewer adverse environmental and social impacts than the previous routes.

Late 2001—The West Virginia Public Service Commission must review and approve the newest route even though the West Virginia portion of that route differs very little from the one the commission approved in June 1998. In addition, because the newest route would also cross about 11 miles of national forest in an area not studied in the Forest Service's 1996 draft environmental impact statement, the Forest Service must conduct a supplementary analysis before deciding whether to grant a permit for construction.

Source: D. Meyer and R. Sedano. 2002. *Transmission Siting and Permitting*. Issue Papers.

The Alturas Line

Sierra Pacific's experience in building a 163-mile transmission line is an example of the costs and delays that can arise when transmission projects involve multiple federal agencies with land management responsibilities.

Sierra Pacific prepared detailed plans for the Alturas project in 1992. The Nevada Public Service Commission approved the project in November 1993. After obtaining Nevada's approval, Sierra Pacific turned to the other affected agencies—the California Public Utilities Commission (CPUC) and several Federal agencies: the U.S. Bureau of Land Management (BLM), the U.S. Forest Service, BPA, and the U.S. Fish and Wildlife Service. BLM had the most acreage affected by the proposal and became the lead agency for the Federal review of the project. CPUC became the lead agency for state environmental purposes. In spring 1994, BLM and CPUC collaborated to begin a draft environmental impact report (EIR) for the state and a draft environmental impact statement (EIS) for the Federal agencies. Sierra Pacific paid the cost of the studies. BLM issued the final EIS in November 1995 and approved its portion of the project in February 1996. The CPUC approved its portion of the line in January of 1996.

In February 1996, the manager of the Toiyabe National Forest issued a "no action" decision, arguing that the EIS was flawed because it had not addressed a sufficiently wide range of alternatives. Eventually, Sierra Pacific decided to pursue an alternative route and withdrew the application to cross the Toiyabe area. In April 1997, the Modoc National Forest manager denied the project a permit to cross a three-mile portion of the Modoc National Forest. The applicant appealed this decision to the chief of the Forest Service in May 1997; a permit was issued October 1997. However, several other parties to the proceeding appealed this permit. After review, the decision to issue the permit was upheld in January 1998.

Construction was begun in February 1998 and completed in December 1998. Sierra Pacific estimates that the project was delayed by at least two years and that these delays led to additional costs of more than $20 million.

A Coordinated Regional Approach

One way to reduce delays in siting and permitting is to foster coordinated review when several state or federal agencies are affected by a proposed facility. When proposed facilities cross boundaries between states or cross lands managed by one or more federal land management agencies—which is frequently the case for facilities whose impacts are regional in nature—the potential for miscommunication, poor coordination, and delay is increased significantly. As demonstrated by the AEP example (see text box), failure by state and federal agencies to coordinate their reviews can lead to the issuance of permits that are inconsistent with one another. This can necessitate multiple additional rounds of review to resolve differences and further delay an already lengthy process. A common timetable and coordinated process for affected agencies is needed to reduce these delays.

Transmission systems are regional in scope, and their benefits are generally regional in nature, yet frequently their impacts are local. Siting processes need to take a regional perspective, incorporating local input to fairly and equitably assess a wide range of proposals for transmission enhancements. Regional coordination for siting and permitting should be organized according to RTO boundaries.

State and federal siting agencies can improve regional siting and permitting by working together in a cooperative fashion to:

- Agree on the information that is necessary to evaluate a transmission proposal;
- Develop common documents (e.g., environmental impact statements) for reviewing proposals;
- Set a reasonable time frame for completing review and issuing required permits; and
- Ensure that the completed permits are consistent.

A coordinated regional approach is being developed by the Western Governors' Association, which has formed the Committee for Regional Electric Power Cooperation (CREPC) to address regional transmission planning and siting issues in the Western Interconnection. Similar efforts for regional coordination in planning and siting transmission should be undertaken within the Eastern Interconnection.

DOE encourages development of regional protocols to govern the siting of transmission facilities. These protocols should ensure that states within a region follow the same rules and that the rules are enforced. Regional transmission siting protocols should include:

- Agreements that states concurrently review proposals;
- Ground rules for addressing reliability issues;
- A provision for common assessment of market power in the region;

Regional Transmission Planning and Development of Cooperative Regional Institutions

A promising example of a regional institution that could be used to address regional transmission siting issues on a cooperative basis is the Western States' Committee for Regional Electric Power Cooperation (CREPC). CREPC was created jointly in 1984 by the Western Interstate Energy Board, which acts as the energy arm of the Western Governors' Association, and the Western Conference of Public Service Commissioners. CREPC has representatives from the regulatory commissions and energy and facility-siting agencies in the 11 states and two Canadian provinces in the Western Interconnection. Through CREPC, the western states have begun negotiations to develop a common interstate transmission siting protocol; June 2002 is the target date for publication of their draft.

Source: Western Interstate Energy Board. http://www.westgov.org/wieb/crepnew2.htm

- A provision for consideration of the ways that a proposed transmission facility might increase regional fuel diversity;
- Criteria for evaluating both transmission and non-transmission alternatives; and
- Requirements for disclosure of existing rights of way and opportunities to increase the transmission capacity of existing facilities.

Responsibilities of Federal Agencies

The record for siting transmission lines across federal lands is spotty. Some efforts to build lines across federal lands, especially in the Western U.S., have been delayed or stopped by an inconsistent and time-consuming process. DOE believes that federal agencies that manage federal lands and natural resources should support regional transmission siting agreements. These agreements should provide for cooperation, timely participation, dedication of sufficient resources to carry out required

Distribution of Federal Lands in the United States

Although almost 29 percent of the land area of the United States is federally owned, 54 percent of federally owned land is concentrated in the 11 states of the contiguous U.S. located wholly or partially west of the Continental Divide.

State	Total Area in Acres	% Federal Land
Arizona	72,688	45.6
California	100,207	44.9
Colorado	66,486	36.4
Idaho	52,933	62.5
Montana	93,271	28.0
New Mexico	77,766	34.2
Nevada	70,264	83.1
Oregon	61,599	52.6
Utah	52,697	64.5
Washington	42,694	28.5
Wyoming	62,343	49.9

Source: *Statistical Abstract of the United States, 2000* (U.S. Dept. of Commerce, December, 2000), Table No. 381 (1997 data).

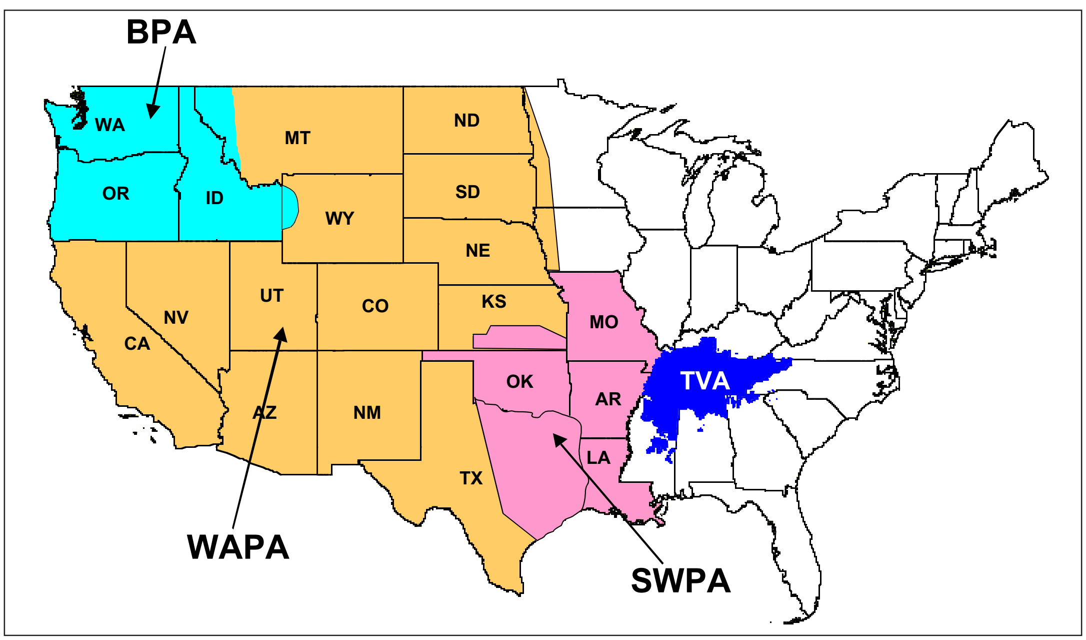


Fig. 5.1
WAPA, BPA, SWPA, and TVA Power Marketing Areas

environmental reviews, and integration of review requirements by all parties for proposed transmission lines. These agreements should ensure that National Environmental Policy Act and other reviews are conducted in a coordinated and timely manner. As shown in the chart on the previous page, the federal government still manages large sections of land in the United States.

The present administration has worked to improve coordination among federal agencies. To help address transmission bottlenecks, the federal government should continue to improve coordination amongfederal agencies. A key first step should be a jointly developed process for expedited evaluation of permits for construction or modification of transmission on federal lands.

Federal agencies should support regional planning efforts by identifying and evaluating potential transmission corridors across federal lands. In addition, federal agencies should reexamine existing transmission paths across federal lands to determine the potential to increase transmission capacity along these paths.

Establishing a FERC Role in Transmission Siting

Electricity transmission is a vested public interest. As the U.S.'s demand for electricity grows and new generation capacity is built to meet this demand, the need for more transmission capacity will follow. Increasing transmission capacity will include the construction of longer, higher voltage lines. These lines will allow delivery of the least expensive electricity that is being produced at the time, possibly several states away, to consumers.

Construction of transmission facilities that are needed to significantly advance national interests must not be delayed. Rules and regulations that will improve

procedures for the siting and permitting of transmission lines should be implemented immediately. The FERC should play a limited role focused on supporting state and regional efforts, but should also possess backstop authority to ensure that transmission facilities that eliminate national interest transmission bottlenecks are sited and constructed. The FERC should act if state and regional bodies are unsuccessful in siting and permitting national interest transmission lines. In order to serve the public interest, the FERC should enable an applicant to exercise the right of eminent domain to acquire property to site and permit transmission facilities in these instances. Eminent domain is used by many different branches of the federal government to acquire property to serve the public interest.

- The Federal Aviation Administration uses eminent domain to acquire land for radar installations.
- The General Services Administration has used eminent domain to acquire property rights to provide security and has used eminent domain to acquire office space when other negotiations have failed.
- The four Department of Energy strategic petroleum reserve sites in Louisiana and Texas were established by eminent domain.
- The FERC may grant a certificate of public convenience and necessity to a natural-gas company which gives the recipient the right to exercise eminent domain to acquire property for rights-of-way in the siting and construction of natural gas pipeline facilities.
- Power Marketing Administrations use

eminent domain to site transmission facilities in much of Midwest and Western United States

DOE believes that Congress should grant limited federal siting authority to FERC to be conveyed only when a transmission facility that would significantly advance national interests is in jeopardy of not being built and only after regional bodies have determined that this facility is preferred among all possible alternatives.

RECOMMENDATIONS

- FERC and DOE should work with states, pertinent federal agencies, and Native American tribes to form cooperative regional transmission siting forums to develop regional siting protocols.
- Utilities and state utility commissions should develop an inventory of underutilized rights of way and space on existing transmission towers. DOE will work with PMAs and TVA to conduct a comparable evaluation.
- DOE will work with NGA, regional governors' associations, NARUC, and other appropriate state-based organizations to develop a list of "best practices" for transmission siting.
- DOE will undertake demonstration programs to support the use of innovative approaches to transmission planning and siting (e.g., reliance on open planning processes, consideration of a wide range of alternatives, incorporation of innovative or uncommonly employed technologies, use of alternative mitigation measures, etc.).
- Federal agencies should be required to participate in regional siting forums and meet these forums' deadlines for reviews or complete reviews within 18 months, whichever occurs first.
- All federal agencies with land management responsibilities or responsibilities for oversight of non-federal lands should assist FERC-approved RTOs in the development of transmission plans.
- Congress should grant FERC limited federal siting authority that could only be used when national-interest transmission bottlenecks are in jeopardy of not being addressed and where regional bodies have determined that a transmission facility is preferred among all possible alternatives.
- The Council on Environmental Quality should continue to coordinate efforts with the Secretary of the Interior, Secretary of Energy, Secretary of Agriculture, Secretary of Defense, and Administrator of the EPA to ensure that federal permits to construct or modify facilities on federal lands are acted upon according to timelines agreed to in any FERC-approved regional protocol. The agencies should work together to re-evaluate the development of transmission corridors across federal lands and identify the current and potential future use of existing transmission corridors on federal lands.

5

Ensuring the Timely Introduction of Advanced Technologies

The electricity system is one of the greatest engineering achievements of the 20th century. The system has benefited from countless technological innovations that have lowered costs and increased reliability. Today, many more innovations are not being utilized because their pathway to the market is blocked by the business uncertainties resulting from the incomplete transition to a fully restructured electricity industry. A large number of advanced transmission technologies are available that could enhance reliability and dramatically increase electricity flows through existing transmission corridors (Table 5.1).[41]

Table 5.1

Advanced Transmission Technologies

Technology	Overview	Commercial Status
High-Temperature Superconducting Cables	Superconducting ceramic cables can carry much more current than standard wires of the same size, with extremely low resistance, allowing more power to flow in existing right-of-ways. But the required refrigeration results in higher initial and ongoing costs.	Demonstration project underway with cables up to 400 ft. Self-contained current limiters are close to commercial availability.
Underground Cables	Underground cables transmit power with very low electromagnetic fields in areas where overhead lines are impractical or unpopular. Costs are 5 to 10 times that of overhead lines, and electrical characteristics limit AC lines to about 25 miles.	Widely used when overhead is not practical, mostly in urban areas and underwater. Research is ongoing to reduce costs.
Advanced Composite Conductors	New transmission conductors with composite cores, as opposed to steel cores, are both lighter and have greater current carrying capacity, allowing more power to flow in existing right-of-ways.	Just entering commercial testing. More experience is needed to lower total life cycle costs.
More Compact Transmission Line Configurations	New computer-optimized transmission line tower designs allow for more power to flow in existing right-of-ways.	Commercially available, with increasing use.
Six or Twelve Phase Transmission Line Configurations	Practically all AC high voltage power transmission is performed using three phases. The use of six or even twelve phases allows for greater power transfer in a particular right-of-way with reduced electromagnetic fields due to greater phase cancellation.	Demonstration lines have been built. Key challenge is cost and complexity of integrating with existing three phase systems.
Modular Equipment	Modular equipment designs provide greater transmission system flexibility, allowing the grid to quickly adapt to changing usage. They could also facilitate emergency deployment from a "strategic reserve" of critical devices, such as transformers.	Many standards already exist, but further work is needed.
Wireless Power Transmission	High power, wireless transmission using either microwave or laser radiation is being explored. Application includes power transmission from earth to orbiting satellites.	Not expected to be competitive for at least 20 years except in very specialized niche markets such as space power.

Continued on next page

[41]For additional background on this discussion, see the Issue Paper, "Advanced Transmission Technologies," by J. Hauer, T. Overbye, J. Dagle, and S. Widergren.

Advanced Transmission Technologies (continued)		
Technology	**Overview**	**Commercial Status**
Ultra High Voltage Lines	Higher voltage lines can carry more power than lower voltage lines. The highest transmission voltage line in North America is 765 kV. Higher voltages are possible, but require much larger right-of-ways, increase need for reactive power reserves, and generate stronger electromagnetic fields.	Voltage levels of 1000 kV are currently used in Japan. Electro-magnetic fields, right-of-way, and technical concerns limit use in the U.S.
High-Voltage DC (HVDC)	HVDC provides an economic and controllable alternative to AC for long distance power transmission. DC can also be used to link asynchronous systems and for long distance transmission under ground/water. Conversion costs from AC to DC and then back to AC have limited usage. Currently there are several thousand miles of HVDC in North America.	Converter costs are decreasing making DC an increasingly attractive alternative. Most merchant transmission lines propose utilizing HVDC.
Flexible AC Transmission System (FACTS) devices	FACTS devices use power electronics to improve power system control, helping to increase power transfer levels without new transmission lines. But currently they are expensive, making FACTS uneconomic for most transmission owners.	Several large demonstrations projects are operating. New power electronics advances may result in costs reductions.
Energy Storage Devices	Energy storage devices permit use of lower cost, off-peak energy during higher-cost peak-consumption periods. Some specialized energy storage devices can be used to improve power system control. Technologies include pumped hydro, compressed air, superconducting magnetic energy storage (SMES), flywheels, and batteries.	Demonstrations are underway for many advanced storage technologies. The economics of the others is still elusive except in small markets.
Controllable Load	Fast-acting load control has the potential to become an important part of transmission system control. Flexible load allows higher normal-power transfer levels since during system emergencies the load can be rapidly curtailed.	Commercially available with increasing use.
Distributed Generation	Small, distributed generators, including conventional (e.g., diesel generators) and newer (e.g., PV, fuel cells and micro-turbines) technologies, allow generation to be located close to the load, decreasing the need for reliance on the transmission system.	Commercially available with the economics dependent upon the price of natural gas and utility interconnection policies. Ongoing maintenance costs are also an issue.
Enhanced Power Device Monitoring	The operation of many power system devices, such as transmission lines, cables, and transformers is limited by the device's thermal characteristics. The high operating voltages of these devices make direct temperature measurement difficult. Lack of direct measurements required conservative operation, resulting in less power transmission capacity. Newer dynamic sensors have the potential to increase transmission system capacity.	Commercial units are available to measure conductor sag allowing for dynamic transmission line limits. Dynamic transformer and cable measurement units are also commercially available.
Direct System State Sensors	In some situations the capability of the transmission system is limited by region-wide dynamic constraints. Direct system voltage and flow sensors can be used to rapidly measure the system operating conditions, allowing for enhanced system control.	High speed power system measurement units are commercially available and are being used by several utilities. Research has only begun to examine use of these measurements for real time control of the power system.

Source: J. Hauer, T. Overbye, J. Dagle, and S. Widergren. 2002. *Advanced Transmission Technologies.* Issue Papers.

One class of technologies that could be used seeks to improve throughput of electricity over existing transmission corridors by using advanced composite materials for new overhead conductors and high-temperature superconducting (HTS) cables that can carry five times as much electricity as copper wires of the same size. DOE has been a leader in developing HTS (see text box). Another approach to better utilization of existing corridors is improvement in the configuration of transmission lines or placement of conductors underground, which also minimizes some environmental impacts of electricity transmission.

High-Temperature Superconductivity

At the beginning of 2002, the Southwire Company, in a 50/50 cost share with DOE, completed two years of the first operational test of superconducting cables in an industrial application.

During the past decade, DOE and industry have pursued research on a promising technology called high-temperature superconductivity. Superconductivity refers to a physical state of materials at which electricity can pass with no loss of energy. Formerly thought to occur only at very low temperatures, which would not be practical in commercial applications, superconductivity has been de-monstrated with newer materials at higher temperatures. Commercial applications of superconductivity that are now being explored include more efficient motors, generators, transformers, and other electric equipment.

For electricity transmission, superconductivity offers the promise of dramatically lowering the losses associated with long distance transmission of electricity. Electricity losses in transmission and distribution systems exceed 10 percent of total electricity generated. Reducing these losses would represent hundred of millions of dollars in annual savings to the nation's electricity bill.

DOE supports industry efforts to commercialize superconducting technologies through basic research and testing that will speed its acceptance and use. In partnership with industry, DOE expects to assist industry in rapidly moving these technologies into the marketplace.

Several states, including Michigan, New York, and Ohio, will soon see first-of-a-kind operational testing of superconducting generators, power lines, and transformers. These real-world experiences will lay the foundation for widespread use across the grid of this next-generation technology that provides higher capacity, greater reliability, and improved efficiency.

Source: U.S. Department of Energy. http://www.eren.doe.gov/superconductivity/

Another class of technologies enables better control of the flow of electricity over existing lines. Flexible AC transmission system (FACTS) devices are high-voltage power electronics devices that allow precise and rapid control of power. They can help eliminate loop flow in AC networks. High-voltage direct current (HVDC) lines and more recently HVDC "light" can completely avoid the problems of loop flow. Superconducting magnetic energy storage can be located strategically throughout the grid to damp out disturbances.[42]

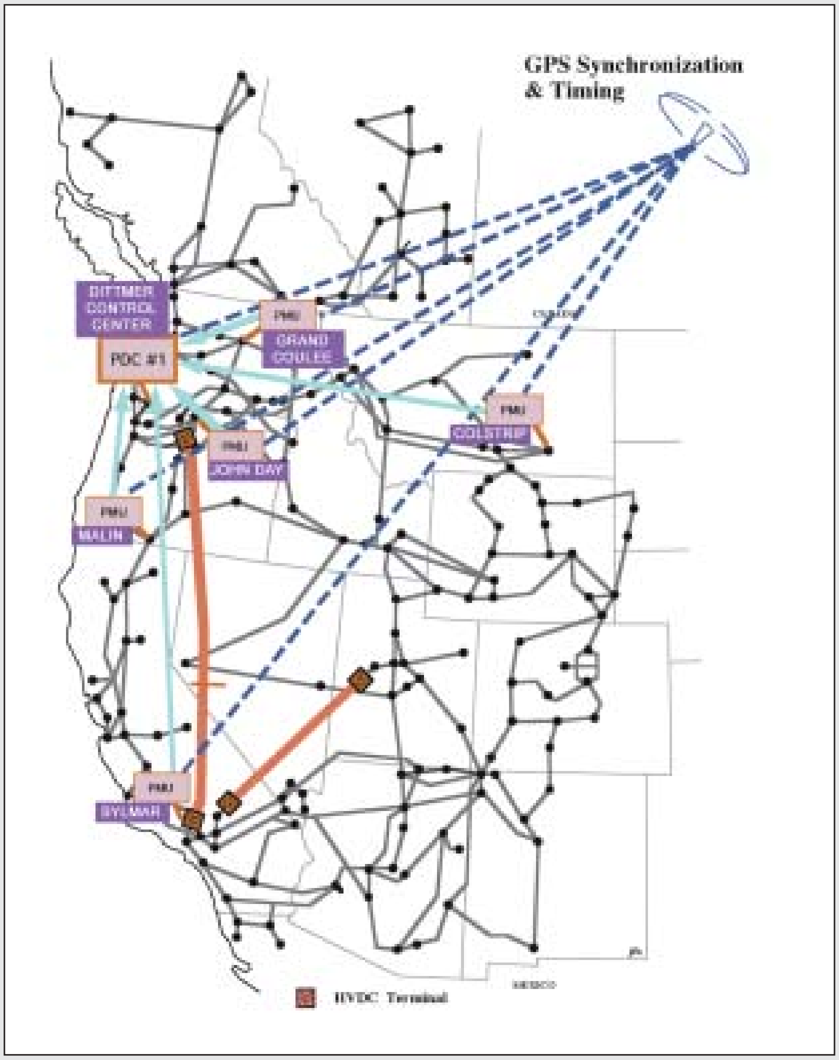
Another class of technologies would increase the accuracy with which the limits of safe operation could be determined. These technologies take precise measurements of the system in real time. Real-time monitoring of the actual status of the power system would permit the introduction of sophisticated automatic controls to prevent blackouts. The Wide Area Measurement System was an early DOE-supported demonstration of the improvements in reliability management made possible by advanced measurements (see text box). Real-time monitoring of conductor temperatures would replace reliance on conservative, predetermined ratings for conductors, safely permitting increased flows over transmission lines.

These hardware technologies can provide the muscle for improved transmission system capabilities, but software technologies are also needed to provide the intelligence to use these hardware technologies effectively. Advanced visualization techniques can dramatically enhance the ability of system operators to identify emerging grid problems in real time, assess options to address them, and take rapid corrective actions. New models and modeling techniques have improved our understanding of how the system behaves in response to region-wide transfers of electricity.

Encouraging the use of these new technologies is essential to make better use of existing transmission facilities and reduce the number of new facilities that are needed.

[42]It is also appropriate to consider non-transmission alternatives, such as controllable load and distributed generation, as technologies that enable greater control of electricity flows. See Section 4, "Relieving Transmission Bottlenecks Through Better Operations."

Wide Area Measurement Systems



Wide Area Measurement Systems (WAMS) technology is based on obtaining high-resolution power-system measurements (e.g., voltage) from sensors that are dispersed over wide areas of the grid, and synchronizing the data with timing signals from Global Positioning System (GPS) satellites. System operators currently retrieve archived data to analyze grid disturbances and improve system models; in the future, they will be able to use these data in real time to assess the health of the grid.

In 1995, DOE launched the WAMS project, in cooperation with Federal utilities and the private sector, to determine the information needs of the emerging power system and to develop technologies to meet these needs. A prototype WAMS network was installed, and software was developed to record, archive, and retrieve data.

The real-time information available from WAMS may allow operators to detect and mitigate a disturbance before it can spread and enable greater utilization of the grid by operating it closer to its limits while maintaining reliability. The capacity that is freed up is available to move larger amounts of power over the grid in response to competitive market transactions.

WAMS demonstrated its value following the massive Western system blackouts on August 10, 1996. Engineers began analyzing WAMS data within minutes of the blackout to reconstruct the sequence of events that led to it and to initiate corrective actions to restore service. DOE is working with Federal and private utilities to transfer this technology to system operators nationwide. Additional hardware and software enhancements using state-of-the-art technologies are needed to allow WAMS to realize its full potential.

Source: U.S. Department of Energy. http://www.eren.doe.gov/der/transmission

Continued development of these technologies is also expected to lead to a smart, switchable grid that can anticipate impending emergencies and automatically take preventive actions. Technologies such as these can protect the grid not only against traditional threats to reliability (such as storms and other natural events) but also against deliberate disruptions. (Transmission system security is discussed in more detail in the next subsection.)

Despite the obvious advantages of advanced transmission technologies, their development and deployment has been waning during the past 10 years. The uncertainties created by the anticipation of and the incomplete transition to a restructured electricity industry has led to a decline in traditional utility support for advanced technologies.

Before restructuring, funding for utility R&D was recovered in rates paid by all electricity consumers. In the vertically integrated industry of the past, collaborative, public-interest transmission-system R&D supported by all utilities (which did not compete with each other) was a logical complement to longer-range, higher-risk R&D, which was supported by the federal government.

Today, new institutions in the restructured industry, such as RTOs and ISOs, should be responsible for ensuring that adequate research and development is undertaken to support a reliable and efficient transmission system. However, these institutions have either not yet formed or have not been given an explicit charter to ensure adequate support for these activities. Once the transition to a restructured industry is complete, the private sector should once again be able to ensure adequate R&D investments. However, there is a critical need for the federal government to increase efforts to monitor and address emerging gaps in public-interest R&D for transmission technologies.

The areas appropriate for increased federal scrutiny and focus are defined by the technology requirements of reliable electric transmission systems that support regional competitive wholesale electricity markets. As noted in Section 3, there is a need for technologies to help manage the operations of large regional transmission systems reliably. As noted in Section 4, expanded efforts are also needed in the areas of improved real-time measurements, analysis of competitive market rules and their impacts on (and the opportunities they offer for enhancing) reliability, programs and technologies to enhance voluntary customer load reduction, and interconnection and integration of distributed generation.

Federal PMAs, such as BPA and WAPA, remain important, unique elements of the U.S. R&D infrastructure. TVA has been a leader in development and demonstration of advanced transmission technologies. These entities have a long tradition of multi-institutional R&D conducted in the public interest. Today, they are functioning, proven, and immediately available resources for joint public-private technology development efforts.

One of the gaps on the pathway to market is demonstration of advanced technologies in utility systems using utility procedures and independent evaluation of the performance of these technologies. One way to fill this gap would be to combine the expertise of DOE's national laboratories, TVA, and the PMAs to develop flexible field test facilities that can create realistic demonstrations of advanced technologies under a wide range of electrical conditions without jeopardizing normal operations. Overhead and underground transmission, composite conductors, high-temperature superconducting equipment, high-voltage power electronics, energy storage systems, and combinations of these technologies and other equipment would benefit from this type of test facility. Public-private partnerships should guide the evaluation of these technologies.

It is worth nothing that a crisis may be brewing upstream in power system engineering education as talented young engineers seek out careers in other, more lucrative professions. Some argue that the dearth of talented engineers is simply a reflection of a supply and demand system that has not valued power engineers sufficiently to attract young new recruits to the profession. The solution to the problem, these observers argue, is not to artificially increase the numbers of poorly paid engineers but instead to create a reward structure to attract the necessary talent. Regardless of the reason or the best solution, there is no question that there is at the moment an apparent shortage of qualified operating staff for the electricity power systems just at the time when many senior engineers—the collective engineering institutional memory of the industry—are about to retire.

RECOMMENDATIONS

- DOE will work with NARUC to develop guidance for state regulators and utilities on evaluating the risks of investment in innovative new technologies that advance public interests. These guidelines will help determine when a technology is a reasonable performance risk and how to weigh the costs and benefits of using a new versus an established technology.
- The PMAs and TVA should maintain their leadership of demonstration efforts to evaluate advanced transmission-related technologies that enhance reliability and lower costs to consumers.
- DOE will develop national transmission-technology testing facilities that encourage partnering with industry to demonstrate advanced technologies in controlled environments. Working with TVA, DOE will create an industry cost-shared transmission line testing center at DOE's Oak Ridge National Laboratory (with at least a 50 percent industry cost share).
- DOE will accelerate development and demonstration of its technologies, including high-temperature superconductivity, advanced conductors, energy storage, real-time system monitoring and control, voluntary load-reduction technologies and programs, and interconnection and integration of distributed energy resources.
- DOE will work with industry to develop innovative programs that fund transmission-related R&D, with special attention to technologies that are critical to addressing transmission bottlenecks.

5

Enhancing the Physical and Cyber Security of the Transmission System

Recent concern about national security issues has focused attention on the basic design of the interconnected transmission system and the reliability management philosophies that guide its operation. While DOE has included a limited discussion of transmission-related energy security issues in this subsection, this study is not intended as a comprehensive discussion of electricity infrastructure security issues.

Reliability has always taken into account the impacts of weather and random equipment failure. Extensions of existing practices, as well as new technologies and operating practices are now needed to protect the transmission system against deliberate, coordinated attacks. For example, increased reliance on distributed generation—electricity generation closer to the point of use (which would result in less reliance on the transmission system)—leads to a more robust electricity system.

As the U.S. moves forward with the modernization of its transmission systems, it is critical that infrastructure protection be built into these decisionmaking processes. Hardware and software technologies that are available in the market today can protect facilities, improve recovery and restoration speed, and reduce the effectiveness of deliberate attacks. The smart, switchable grid discussed in the previous subsection should be an important element in this portfolio; R&D on this concept must extend its capabilities to address multiple contingencies in the case of deliberate attack.

The Northeast Ice Storm of 1998—Lessons for Power System Recovery

No reasonable set of precautions can entirely prevent widespread disruptions of electrical services. However, when such disruptions do occur, their impact can be greatly reduced if advance preparations have been made.

Between January 5 and 10, 1998, a series of exceptionally severe ice storms struck large areas within New York, New England, Ontario, Quebec, and the Maritime Provinces. The worst freezing rains ever recorded in the region deposited ice up to three inches thick. Damage to transmission and distribution facilities was severe—more than 770 transmission towers collapsed.

The Northeast ice storm showed that the following types of resources should be part of advance preparation for emergencies:

- **Comprehensive procedures for emergency management;**
- **Stockpiles of reserve equipment for emergency management and repair of facilities; and**
- **Procedures to ensure that adequate numbers of trained personnel can be mobilized.**

Source: Northeast Power Coordinating Council. 1998. *January 1998 Ice Storm—Final Report.* http://www.npcc.org

It should be designed to prevent, detect, and mitigate threats to reliability.

Unlike operational failures of the grid, which can usually be corrected within several hours, attacks on the grid are likely to result in the type of physical damage to equipment that is experienced in severe storms. The costs of service disruption to individual customers and to society rise sharply the longer an outage lasts. Emergency preparedness can greatly mitigate the impact of widespread disruptions whether they are natural events or the result of malicious attack. Recent experiences with natural disasters may be used as a roadmap for advance planning to minimize disruptions.

There is great diversity of electricity system and equipment designs and parts. Our electricity systems were designed by hundreds of local utilities with little consideration for standardization. Discussions within the industry should identify key hardware and software items that link our transmission system and evaluate the costs and benefits associated with standardizing equipment, where possible, and maintaining a reserve supply of transmission equipment. Reserve equipment is shared among utilities today; now is the time to ensure that adequate reserves of equipment are also available in a restructured market tomorrow.

We have an unprecedented opportunity to address these issues. As RTOs begin the process of building the software and hardware needed to operate our regional transmission systems, energy security issues should be factored into decisions on how we can best protect the reliability of our transmission system.

Critical Infrastructure Protection

DOE works closely in partnership with industry to address critical infrastructure protection challenges. DOE has led assessments to help industry understand the vulnerability of its systems to cyber or physical disruptions and identify ways to mitigate these vulnerabilities. DOE also works with industry to provide security alerts, contain and divert attacks, plan a system that can respond effectively to energy-sector attacks, and identify ways to facilitate rapid restoration of the system.

http://www.energy.gov/

RECOMMENDATIONS

- DOE will work with industry to evaluate the feasibility of adopting modular designs and standards for substation and other transmission equipment to facilitate rapid replacement.
- DOE and the national laboratories will continue to develop cost-effective technologies that improve the security of, protect against, mitigate the impacts of, and improve the ability to recover from disruptive incidents within the energy infrastructure.
- DOE will continue to develop energy infrastructure assurance best practices through vulnerability and risk assessments.
- DOE will work with industry to evaluate the costs and benefits associated with maintaining a reserve supply of transmission equipment that is funded by transmission rates. This reserve would be a resource in case of major outages resulting from terrorism or natural disasters.
- DOE will continue to work with industry to promote education and awareness in the industry about critical transmission infrastructure issues.
- DOE will continue to work closely with industry and state and local officials on implementation plans that respond to attacks on our transmission infrastructure.
- DOE will continue to provide training in critical infrastructure protection matters and energy emergency operations to state government agencies and to private industry.
- DOE will study the Eastern and Western AC Interconnections to assess the costs and benefits, including impacts on national security, of a series of smaller interconnections that are electrically independent of one another with DC links between them.
- DOE will work with industry and the states to develop standardized security guidelines to help reduce the cost of facility protection and facilitate consequence management.

6

The importance of the interstate commerce that is conducted through our electricity transmission system dictates that there will be a federal role in ensuring reliable transmission systems that support fair and efficient competitive regional wholesale electricity markets. DOE is committed to taking a leadership role in addressing emerging transmission bottlenecks that threaten our national interests. Furthermore, DOE will develop the state-of-the-art tools needed to evaluate the system's operation and efficiency, and will continue to work with industry and Congress to ensure that basic transmission research and development continues.

DOE's Commitment and Leadership

DOE is the lead federal agency responsible for developing sound and secure national energy policy. DOE funds and promotes new transmission technologies, oversees the federal Power Marketing Administrations, issues permits for cross-border transmission lines, and addresses national energy security.

DOE must also take responsibility for identifying and helping eliminate transmission bottlenecks of national importance, and for developing the tools needed to ensure efficient regional markets.

DOE's objective is simple: to provide our citizens with a reliable supply of electricity at the lowest possible cost. During the early 1990s, the department worked closely with the Administration and Congress to support this objective through the Energy Policy Act of 1992, which moved the nation toward competitive electricity markets.

Opening the electricity industry to competitive wholesale markets has resulted in newer, cleaner power plants that cost less and are more efficient than older power plants. Where less than 200 heavily-regulated, vertically-integrated electric utilities used to control more than 80 percent of the industry, non-regulated power producers now account for the majority of new power plant additions. Consumers have benefited from lower electricity bills. But, we cannot stop here; there are many more economies to be gained by completing the transition to competitive electricity markets.

Differences in electricity prices prompted the push for competition. Under monopoly regulation, some consumers used to pay many times more than others for wholesale electricity. Competitive markets give firms incentives to lower costs, improve efficiency, innovate, and provide new services to consumers. The electricity industry is still undergoing substantial change. Although industry participants do not agree on how best to achieve the ultimate objective of reliable supplies at the lowest cost, they do agree that, in order to obtain the full benefits of competitive electricity markets, we need to dramatically improve our electricity delivery system.

Developing and implementing policies that will lead to needed beneficial investments in the nation's electricity transmission system and support fair and efficient regional wholesale electricity markets will be challenging. The public interest is foremost and the views of consumers, states and industry must be heard and considered. Accommodating diverse interests is imperative because federal transmission policies will only work if they can be supported politically and implemented; the recommendations contained in this study will help guide us.

Some of the recommendations included in this report are not new. Similar recommendations have been made in other DOE reports in recent years.

For example, the Secretary of Energy Advisory Board's 1998 report "Maintaining Reliability in a Competitive U.S. Electricity Industry" recommended that DOE:[43]

- Develop methods for sharing generation- and transmission-planning data;
- Study and recommend performance-based rates and other transmission pricing methods;
- Help modify reliability rules to reduce congestion;
- Adopt open standards for control centers; and
- Further promote reliability technologies.

In addition, DOE's Power Outage Study Team "Findings and Recommendations to Enhance Reliability from the Summer of 1999" proposed:[44]

- An increased federal leadership role in electricity reliability issues;

- Support for market rules for customer demand response;
- Support for interconnection standards for distributed generation;
- Support for mandatory reliability standards;
- Sharing of "best practices" for distribution;
- Use of uniform definitions and measurements for reliability information;
- Development of real-time system monitoring and control equipment; and
- Improvement of analytic models for load forecasts and power-system simulation.

DOE has acted on some of these recommendations, but it has not followed through on all of them due to limited resources, a lack of focus, and a lack of accountability. DOE will improve on this record in two steps. First, DOE commits to addressing administratively the concerns of

[43]Download from http://vm1.hqadmin.doe.gov/seab/esrfinal.pdf

[44]Download from http://www.pi.energy.gov/pilibrary.html

focus and accountability. Second, DOE will work with the Administration and Congress to identify and allocate appropriate resources.

The department is committed to implementing the recommendations of the National Transmission Grid Study to ensure needed, beneficial investments in the nation's transmission system. To accomplish this task, the department will reorganize itself to combine its divergent electricity delivery system resources into a single, focused Office of Electric Transmission and Distribution.

This new program office will:

- Fund transmission- and distribution-system R&D;
- Promote and foster the deployment of new transmission- and distribution-system technologies;
- Develop the data and analytical tools necessary to assess the reliability and performance of the transmission and distribution system;
- Conduct research on electricity market designs and evaluation of market performance;
- Designate national-interest transmission bottlenecks;
- Approve cross-border transmission lines; and
- Support the Power Marketing Administrations' efforts to eliminate transmission bottlenecks, introduce new technologies that increase the reliability and efficiency of the transmission system, and help ensure that best practices are shared.

For DOE to become a leader in shaping electricity policy, this new Office of Electric Transmission and Distribution must be responsible and accountable for our efforts to improve the system.

DOE has many tools at its disposal to carry out these responsibilities. In the fall of 2001, DOE executed two memoranda of understanding to address electricity issues that affect both state and federal interests. These partnerships, with the National Governors Association and the Western Governors' Association, respectively, should provide a solid basis for implementing many of this study's recommendations.

In addition, DOE has the authority to propose rules and forward them to the FERC for debate. Although not often used in the past, DOE will actively review and pursue appropriate opportunities to use this authority in the future.

DOE, in its leadership role for the development of electricity policies, must change its organizational structure, become proactive in FERC rulemakings, encourage the use of new technologies as a solution to transmission system problems, and identify and help eliminate the nation's most significant bottlenecks. DOE must work with regions, states, and localities to ensure that national-interest transmission bottlenecks are remedied appropriately.

RECOMMENDATION

- DOE will create an Office of Electric Transmission and Distribution.

Consolidated List of Recommendations

Section 2—The National Interest in Relieving Transmission Bottlenecks

Next Steps Toward Relieving Transmission Bottlenecks

- DOE, through a rulemaking, will determine how to identify and designate transmission bottlenecks that significantly impact national interests.

- DOE will further develop the analytic tools and methods needed for comprehensive analysis to determine national-interest transmission bottlenecks.

- In an open public process, DOE will assess the nation's electricity system every two years to identify national-interest transmission bottlenecks.

Section 3—Relieving Transmission Bottlenecks By Completing the Transition to Competitive Regional Wholesale Electricity Markets

Establishing Regional Transmission Organizations

- RTOs should be responsible for maintaining the reliability of the grid and ensuring that transmission bottlenecks are addressed.

- DOE, with industry, will assess current system monitoring and control technologies that support efficient, reliable, and secure operation of RTOs and coordinate development of a plan for future research and development.

- DOE will work with FERC and stakeholders to develop objective standards for evaluating the performance of RTOs and will collect the information necessary for this assessment.

- DOE will work with the Energy Information Administration (EIA), FERC, National Governors Association (NGA), the National Association of Regulatory Utility Commissioners (NARUC), the National Association of State Energy Officials (NASEO), industry, and consumer representatives to determine what economic and reliability data related to the transmission and the electricity system should be collected at the federal level and under what circumstances these data should be made publicly available.

- NGA and NARUC should identify state laws that could hinder RTO development.

- DOE will review federal laws that may prevent PMAs from full participation in RTOs, direct them to participate in the creation of RTOs, and take actions to facilitate their joining RTOs.

- DOE will work with TVA to help it address any issues that inhibit its participation in wholesale competitive markets, including full participation in an RTO.

Increasing Regulatory Certainty and Focus

- DOE will work with NGA, regional governors' associations, NARUC, and other appropriate state-based organizations to promote innovative methods for recovering the costs of new transmission-related investments. These methods should consider situations where rate freezes are in effect and also examine incentive regulation approaches that reward transmission investments in proportion to the improvements they provide to the system.

- DOE will research and identify performance metrics and evaluate designs for performance-based regulation.

- The Department of Treasury should evaluate tax law changes related to electricity modernization. Treasury should review its current regulations regarding the application of private use limitations to facilities financed with tax exempt bonds in light of dynamics in the industry and proceed to update and finalize its regulations. This will give greater certainty to public power authorities providing open access to their transmission and distribution facilities.

- Entrepreneurial efforts to build merchant transmission lines that pose no financial risk to ratepayers and that provide overall system benefits should be encouraged.

- DOE and the Department of Treasury will evaluate whether tax law changes may be necessary to provide appropriate treatment for the transfer of transmission assets to independent transmission companies.

Section 4—Relieving Transmission Bottlenecks Through Better Operations

Pricing Transmission Services to Reflect True Costs

- DOE, working with FERC, will continue to research and test market-based approaches for transmission operations, including congestion management and pricing of transmission losses and other transmission services.

Increasing the Role of Voluntary Customer Load Reduction, and Targeted Energy Efficiency and Distributed Generation

- DOE will work with FERC, the states, and industry and conduct research on programs and technologies to enhance voluntary customer load reduction in response to transmission system emergencies and market price signals.

- DOE will work with states and industry to educate consumers on successful voluntary load-reduction programs. DOE will disseminate information on successful approaches and technologies.

- DOE will continue to work with NGA, regional governors' associations, and NARUC to remove regulatory barriers to voluntary customer load-reduction programs, and targeted energy-efficiency and distributed-generation programs that address transmission bottlenecks and lower costs to consumers.

- IEEE should expeditiously complete its technical interconnection standards for distributed generation.

- DOE will work with NGA and NARUC to develop and promote the adoption of standard interconnection agreements, rules, and business procedures for distributed generation.

Using Improved Real-Time Data and Analysis of Transmission System Conditions

- DOE will work with industry to demonstrate and document cost-effective uses of dynamic transmission system analysis.

Ensuring Mandatory Compliance with Reliability Rules

- Federal legislation should make compliance with reliability standards mandatory.

- Current reliability standards should be reviewed in an open forum to ensure that they are technically sound, nondiscriminatory, resource neutral, and can be enforced with federal oversight.

- Penalties for noncompliance with reliability rules should be commensurate with the costs and risks imposed on the transmission system, generators, and end users by noncompliance. Penalties collected should be used to reduce rates for consumers.

- DOE will work with industry and NARUC to promote development and sharing of best transmission and distribution system operations and management practices.

- DOE will work with FERC, state PUCs, and industry to ensure the routine collection of consistent data on the frequency, duration, extent (number of customers and amount of load affected), and costs of reliability and power quality events, to better assess the value of reliability to the nation's consumers.

Section 5—Relieving Transmission Bottlenecks Through Effective Investments

Implementing Regional Transmission Planning

- DOE will work with the electricity industry and state and federal regulators to identify the type of electricity system data that should be made available in the planning process to facilitate the development of market-based transmission solutions and devise a process for making that information available.

Accelerating the Siting and Permitting of Needed Transmission Facilities

- FERC and DOE should work with states, pertinent federal agencies, and Native American tribes to form cooperative regional transmission siting forums to develop regional siting protocols.

- Utilities and state utility commissions should develop an inventory of underutilized rights of way and space on existing transmission towers. DOE will work with PMAs and TVA to conduct a comparable evaluation.

- DOE will work with NGA, regional governors' associations, NARUC, and other appropriate state-based organizations to develop a list of "best practices" for transmission siting.

- DOE will undertake demonstration programs to support the use of innovative approaches to transmission planning and siting (e.g., open planning processes, consideration of a wide range of alternatives, incorporation of innovative or uncommonly employed technologies, use of alternative mitigation measures, etc.).

- Federal agencies should be required to participate in regional siting forums and meet these forums' deadlines for reviews or complete reviews within 18 months, whichever occurs first.

- All federal agencies with land management responsibilities or responsibilities for oversight of non-federal lands should assist FERC-approved RTOs in the development of transmission plans.

- Congress should grant FERC limited federal siting authority that could only be used when national-interest transmission bottlenecks are in jeopardy of not being addressed and where regional bodies have determined that a transmission facility is preferred among all possible alternatives.

- The Council on Environmental Quality should continue to coordinate efforts with the Secretary of the Interior, Secretary of Energy, Secretary of Agriculture, Secretary of Defense, and Administrator of the EPA to ensure that federal permits to construct or modify facilities on federal lands are acted upon according to timelines agreed to in any FERC-approved regional protocol. The agencies should work together to re-evaluate the development of transmission corridors across federal lands and identify the current and potential future use of existing transmission corridors on federal lands.

Ensuring the Timely Introduction of Advanced Technologies

- DOE will work with NARUC to develop guidance for state regulators and utilities on evaluating the risks of investment in innovative new technologies that advance public interests. These guidelines will help determine when a technology is a reasonable performance risk and how to weigh the costs and benefits of using a new versus an established technology.

- The PMAs and TVA should maintain their leadership of demonstration efforts to evaluate advanced transmission-related technologies that enhance reliability and lower costs to consumers

- DOE will develop national transmission-technology testing facilities that encourage partnering with industry to demonstrate advanced technologies in controlled environments. Working with TVA, DOE will create an industry cost-shared transmission line testing center at DOE's Oak Ridge National Laboratory (with at least a 50% industry cost share).

- DOE will accelerate development and demonstration of its technologies, including high-temperature superconductivity, advanced conductors, energy storage, real-time system monitoring and control, voluntary load reduction technologies and programs, and interconnection and integration of distributed energy resources.

- DOE will work with industry to develop innovative programs that fund transmission-related R&D, with special attention to technologies that are critical to addressing transmission bottlenecks.

Enhancing the Physical and Cyber Security of the Transmission System

- DOE will work with industry to evaluate the feasibility of adopting modular designs and standards for substation and other transmission equipment to facilitate rapid replacement.

- DOE and the national laboratories will continue to develop cost-effective technologies that improve the security of, protect against, mitigate the impacts of, and improve the ability to recover from disruptive incidents within the energy infrastructure.

- DOE will continue to develop energy infrastructure assurance best practices through vulnerability and risk assessments.

- DOE will work with industry to evaluate the costs and benefits associated with maintaining a reserve supply of transmission equipment that is funded by transmission rates. This reserve would be a resource in case of major outages resulting from terrorism or natural disasters.

- DOE will continue to work with industry to promote education and awareness in the industry about critical transmission infrastructure issues.

- DOE will continue to work closely with industry on implementation plans that respond to attacks on our transmission infrastructure.

- DOE will continue to provide training in critical infrastructure protection matters and energy emergency operations to state government agencies and to private industry.

- DOE will study the Eastern and Western AC Interconnections to assess the costs and benefits, including impacts on national security, of a series of smaller interconnections that are electrically independent of one another with DC links between them.

- DOE will work with industry and the states to develop standardized security guidelines to help reduce the cost of facility protection and facilitate consequence management.

Section 6—DOE's Commitment and Leadership

- DOE will create an Office of Electric Transmission and Distribution.

Appendix A

Policy Office Electricity Modeling System (POEMS) and Documentation for Transmission Analysis

Overview of POEMS

The Policy Office Electricity Modeling System (POEMS) integrates the Energy Information Administration (EIA) National Energy Modeling System (NEMS) with the detailed electricity market model TRADELEC™, developed by OnLocation, Inc. NEMS is an integrated energy model with supply and demand modules representing the U.S. energy system. In POEMS, TRADELEC™ replaces the Electricity Market Module of NEMS to add detail and disaggregation. TRADELEC™ was designed specifically for analyzing competitive electricity markets and the transition from regulated markets. TRADELEC™ incorporates the features necessary to analyze key policy questions: stranded costs, consumer prices, mix of new construction, impact of increased electricity trading, and interaction with environmental policies.

POEMS has been used to support DOE's analysis of the Comprehensive Electricity Competition Act proposed by the Clinton Administration. For various participants in electricity markets, POEMS has been used to assess regional markets, forecasting electricity prices, supply, and demand under alternative economic and fuel price scenarios. The model has also been used to assess the impact of alternative environmental policies on utility industry capital turnover and inter-fuel substitution.

For the National Transmission Grid Study, the dispatch and trade portion of TRADELEC™ was used as a stand-alone model with generating capacity, fuel prices, and electricity demands held constant. In other words, the other fuel supply and demand modules were not used, and the capacity expansion module was turned off. The analysis focused on a single year (2002). Hence, the impacts of changes in these other variables is small and detract from the focus on transmission and trade flows. Therefore, documentation included in this appendix focuses on the dispatch and trade portions of TRADELEC™ and does not describe its other modules and features, (e.g., capacity expansion, retail pricing, and demand response.)

TRADELEC™ Electricity Model

The heart of the TRADELEC™ model is market-driven electricity trade over the existing electricity transmission system. Electricity trade is solved as a function of relative prices, transmission availability, and a hurdle rate that is designed to reflect the additional costs of handling market trading. TRADELEC™ represents transmission inter-ties at existing transfer interfaces. Current and future transmission bottlenecks may limit trade flows among certain buyers and sellers when transmission capacity is reached. This would result in final regional price differences that exceed the cost of transmission and trading.

The trading function is critical in determining competitive prices for electric power and in measuring efficiency gains from restructuring the electricity industry. By explicitly solving trade relationships, TRADELEC™ offers insights into pricing patterns and motivations for interregional trading.

In the absence of transmission constraints, electricity prices nationwide would converge to a single value with local delivery prices varying only by differences in the cost of transmission (including line losses) and distribution services. However, the tendency in competitive markets toward a single price does not mean that there will be no market separation. Because transmission is neither unconstrained nor without cost, separable regional electricity markets are likely to be observed as model solutions evolve. Additional regional constraints, such as region-specific pollution abatement measures, could further increase regional price differences even in fully competitive power markets.

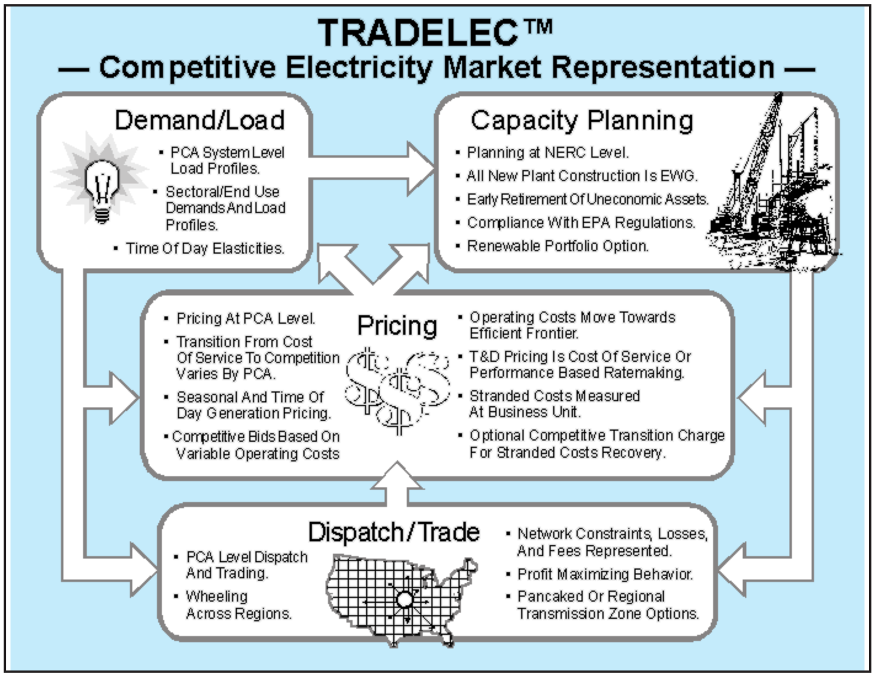


Figure 1: Components of the TRADELEC™ Model

Model Description and Structural Assumptions

Electricity Demands and Load Shapes

A unique aspect of POEMS is its representation of the load-duration curves with vertical rather than horizontal time blocks. This approach ensures that trades among regions are fulfilling the same requirements and that power generated at one time (such as during night hours) is not being used to satisfy power demands at another time (such as during peak daytime hours). The definition of the time blocks is flexible. For this transmission study, the annual load in each region is represented by total of 864 load slices: 24 hours for three typical day types (weekday, weekend day, and peak day) within each of the 12 months.

Dispatch and Trade

TRADELEC™ is a network model of electricity dispatch, trade, capacity expansion, and pricing, as shown in Figure 1. The model operates using POEMS' 69 regions or power centers, illustrated in Figure 2. These regions are combinations of the roughly 150 power control areas in the U.S. although some power pools are disaggregated to reflect transmission constraints between zones. POEMS regions are represented as a series of nodes, connected by transmission inter-ties with specific transfer capabilities. There are more than 300 transmission paths in POEMS. Supply resources within each POEMS region, consisting of utility plants, exempt wholesale generators, traditional and nontraditional cogenerators, and firm power contracts, are represented in considerable detail. Plant characteristics, such as capacity, heat rate, and forced and maintenance outage rates, are represented based on data in EIA filings and the North American Electric Reliability Council Generating Availability Data System data. TRADELEC™ incorporates financial, operational, and physical data representing virtually every significant operating electric utility in the U.S. and the transmission inter-ties among them.

Representation of Generation Plants

The plant input file to POEMS consists of virtually all existing units in the U.S. Plants currently under construction that are expected to be on-line during the year 2002 are included as well. Each unit in the plant input file is combined with like units to form dispatchable groups. The process of combining units is flexible, but, at a minimum, combined units serve the same demand region and are physically located in the same supply region, use the same fuels with the same type of prime mover, and have the same in-service period. Dispatchable capacity groups also have similar heat rates, and renewable groups have similar utilization patterns. Currently, there are more than 7,000 plant groupings in the model. There are over 100 dispatchable plant groupings per POEMS region on average, with the largest POEMS regions having 300 to 500 plant groups. A merit order dispatch algorithm is initially employed to determine generation in each time segment prior to trade.

Trade

Network interregional trade is solved to maximize the economic gains from trade by ordering trades in descending order, starting with the trade that contributes the largest efficiency gains first. Succeeding trades continue until available transmission opportunities or all possible gains are exhausted. The primary economic and physical limits to trade are imposed by means of alternative scenarios for transmission fees, losses, transmission capacity, and hurdle rates. Thus, integrated interregional trade is modeled to operate in much the same fashion as a full-fledged, time-block power auction.

Transmission Costs and Capacity

POEMS transmission path and nodal trading limits were derived from a number of sources, including the Western States Coordinating Council (WSCC) 2001 Path Rating Catalog and various power flow cases filed with the Federal Energy Regulatory Commission (FERC) and evaluated using the Power Technologies Inc. PSS/E power-flow modeling system.

Transmission costs are reflected through representation of transmission tariffs that can be implemented on a POEMS region or Regional Transmission Organization (RTO) level. RTO definitions are flexible and can be changed for each scenario. The model uses pancaked transmission fees, in which a trade is assessed a fee for each region that it passes through, or regional postage stamp fees, where one tariff is established for each RTO that is composed of several POEMS regions. (The use of these fee structures is described in the section below on transmission study scenarios.) Transmission is treated as cost of service, and any revenue collected through wholesale trade is used to offset the transmission costs borne by retail customers. The wholesale transmission fees are set to a percentage (generally in the range of 50 to 80 percent) of the average FERC Order 888 stage one, pro forma, point-to-point tariff.

Transmission losses are modeled as a nonlinear, distance sensitive measure. In addition, a user-specified "hurdle level" is input to limit transactions to those that provide a specified minimum level of economic gain. The hurdle rate can be adjusted to reflect reductions in potential inefficiencies and transactions costs as markets provide greater incentives to exploit profitable trades. The market simulation is conducted within each of the time and season load slices that are modeled, and chronological simultaneity is maintained.

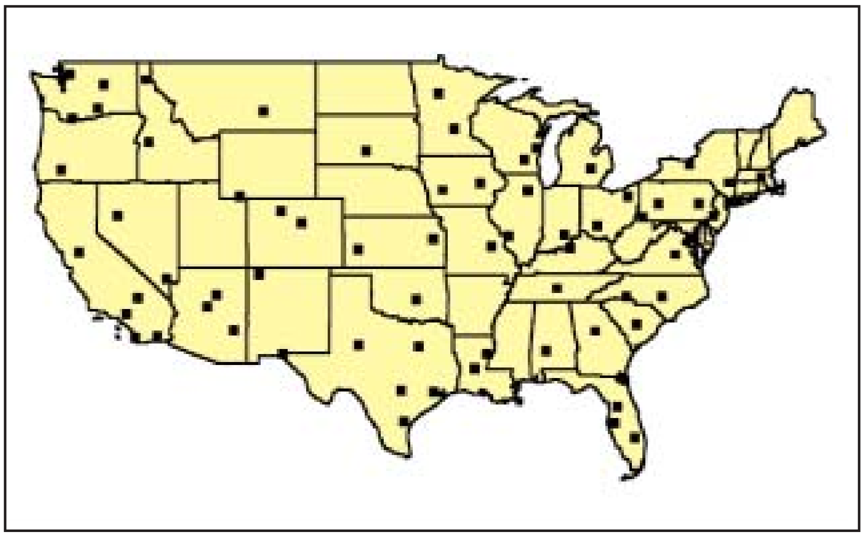


Figure 2: Current TRADELEC™ Regions.

Pricing

Wholesale generation prices are established for each POEMS region for each time and season load slice. The market-clearing price equals the marginal cost or bid price of the most expensive generating unit that is operating. This next marginal unit could be native to the POEMS region or determined through trade with other POEMS regions.

The competitive bid price for each unit is assumed to be its marginal cost in accord with the standard characterization of competitive markets. Marginal costs are the sum of fuel costs and the variable portion of operating and maintenance (O&M) costs.

Fixed and Variable O&M Costs

POEMS initially puts all O&M costs into a fixed O&M account and allows the user to determine how much of the fixed costs should be considered variable. For this transmission study, one-half of O&M cost is assumed to be included in generator bid prices. In addition, historical levels of O&M costs are expected to decrease over time because of the pressures of competition. POEMS includes a feature that allows the user to specify O&M cost targets by plant type along with a specification of a percentage progress towards that target by plant type and year. Competitive pressures are also expected to spill over into the regulated segment of the industry. POEMS allows the user to specify transmission and distribution productivity improvements. Competition is also expected to result in heat rate improvements, which affect the generation price. POEMS includes a feature that allows the user to specify target heat rates by plant type along with a specification of a percentage improvement towards that target by plant type and year.

Transmission Scenarios

All the POEMS scenarios are projections based on expected electricity demand, capacity, and fuel prices for the year 2002.

Current Markets

The Current Markets case is an approximation of the current status of transmission policy. Several regions are represented as RTOs with postage-stamp transmission fees. Under postage stamp fees, transmission assets within an RTO are pooled on a fixed-cost basis. Each member of the RTO pays a single charge for access to the transmission grid; there are no additional charges for each transaction. A fee is only paid for transactions that cross RTO borders. The remaining regions are assumed to have pancaked rates, in which a separate fee is assessed for movement across each power center. The transmission fees are established based on 50 percent of calculated FERC pro forma tariffs. In addition, the gain from all trades must exceed a hurdle rate of $3.00 per MWh, which represents the transaction costs and barriers associated with arranging transmission paths and finding trading partners.

POEMS tracks electricity generation and prices for each of the 69-regions both before and after any trade among the region occurs. The current markets case was used to estimate the benefits of wholesale electricity trade given the current physical and institutional operation of the transmission grid by comparing electricity production costs and prices before and after trade. It does not distinguish increased trade due to wholesale competition from economy trades that routinely occurred among neighboring utilities prior to FERC Orders 888 and 889.

No Congestion For Four ISOs

A No Congestion case was constructed in which the transmission paths within four major ISOs were increased so that no economic flows were prevented. The four ISOs are PJM, New York, New England, and California.

Transmission Fee

In the Transmission Fee case, there are five large RTOs, and each is assumed to have a postage-stamp rate structure. The hurdle rate is reduced to $1.50 per MWh to reflect reduced transaction costs expected from large RTOs.

This analysis is not a complete estimate of the benefits of RTOs, nor does it represent DOE's position on appropriate geographic boundaries for RTOs. This analysis only illustrates the importance of transmission fees in shaping trade and congestion patterns. Eliminating pancaked rates is only one of the expected benefits of RTOs.

Calculation of Economic Benefits of Trade

There are several ways to measure the economic benefits of trade. Two measures have been adopted in this study. The first is the reduction in net generation costs that results from trade. Exporters will have an increase in fuel and operating costs because they are producing more power while importers will have reduced costs. Assuming competitive markets in which power plant owners bid their marginal operating costs, trading will always result in a net reduction in generation costs. Some regions rely heavily on imports and do not maintain sufficient, even expensive, capacity to meet their native loads. For these regions, we assessed a $100-per-MWh generation cost for unmet demand and used this value to calculate reductions in generation costs. For example, if a region is unable to meet its own demand and imports power for $70 per MWh, the generation cost savings is $30 ($100-$70), multiplied by the amount of the imports.

A second measure of benefit is the impact on consumer prices. The change in wholesale prices can affect consumer prices in one of two ways. If the area remains under traditional cost-of-service regulation, wholesale costs and revenues are treated as utility expenses that flow through to consumer rates. We have assumed that 75 percent of the gain, either the additional margin made by exporters or the reduced net costs of the importers, is passed through to the consumer. The other 25 percent would be allowed to go to the shareholders as an incentive for utilities to maximize the benefits of trade.

For regions that have moved to full retail competition, consumer prices will, on average, follow wholesale prices. The consumer savings from trade are computed as the change in prices before and after trade, multiplied by total demand. In general, the impact will be larger than in regulated regions where only the amount of electricity that is traded is used in the computation of benefits. The regions that are considered to have competitive pricing at the retail level are the same as those that have RTOs in the Base Case: PJM, New York, New England, ERCOT, and California.

The change in production costs and consumer costs for each of the scenarios modeled in POEMS are given in Table 1.

POEMS underestimates the savings to consumers from wholesale electricity trade and the costs of congestion for three reasons. First, POEMS does not capture the effects of

Table 1

Region	Base Case Transmission Fee Type	Transmission Fee Region
PJM—Pennsylvania, New Jersey, Maryland	postage stamp	Northeast
NEPX—New England	postage stamp	Northeast
NYPP—New York	postage stamp	Northeast
ECAR—East Central Area Reliability Coordination Agreement	pancaked	Midwest
MAIN—Mid-America Interconnected Network	pancaked	Midwest
MAPP—Mid-Continent Area Power Pool	pancaked	Midwest
SPP—Southwest Power Pool	pancaked	Midwest
ERCOT—Electric Reliability Council of Texas	postage stamp	ERCOT
FRCC—Florida	pancaked	Southeast
SERC—Southeastern Electric Reliability Council (excluding Florida)	pancaked	Southeast
WSCC/AZN—Arizona/ New Mexico	pancaked	West
WSCC/CNV—California	postage stamp	West
WSCC/NWP—Northwest Power Pool	pancaked	West
WSCC/RA—Rocky Mountain Area	pancaked	West

Table 2: Annual Economic Costs (Millions)

Scenario	East		West		Total	
	Generation Cost (change from base)	Consumer Costs (change from base)	Generation Cost (change from base)	Consumer Costs (change from base)	Generation Cost (change from base)	Consumer Costs (change from base)
Current Trade*	-$3,254	-$4,248	-$8,944	-$8,351	$-12,198	-$12,599
No Congestion Within Four ISOs	NA	NA	NA	NA	-$89	-$157
Transmission Fee	-$375	-$726	-$35	-$307	-$410	-$1,033

*For the current trade case, the change in generation costs and consumer costs represents the decrease in costs that results from the base case level of wholesale electricity trade among the model's 69 subregions compared to a case in which no wholesale trading is allowed. For the remaining cases, the reported savings are the change from the current trade case.

price spikes. POEMS assumes that prices are determined by the marginal costs of the last generator needed to meet load in each subregion. In reality, however, price spikes often occur when supplies become tight and additional electricity cannot be imported. Prices might also rise in constrained regions if generators are able to exercise market power. Within competitive markets, transmission investment to reduce congestion might sometimes lead to only small changes in generation costs, but the mere presence of additional transmission capacity creates contestability in each of the local markets that will curb potential market power and reduce prices to consumers. These benefits are not captured by POEMS.

DOE calculated the increase in congestion costs resulting from prices spikes for four regions in the U.S.: California ISO, PJM, New York ISO, and ISO New England. Price spikes are assumed to occur during the hours when at least one transmission link into the region was congested and demand was greater than 90 percent of peak demand. Total congestion costs (cost to consumers) for these four regions combined are initially estimated to be $157 million annually (without price spikes). When prices spike an additional $50 per MWh during these periods, congestion costs nearly double to $300 million. When prices spike an additional $100 per MWh during these periods, congestion costs nearly triple to $447 million.

Second, POEMS captures only the benefits of trade between regions and does not address trade within regions. For example, all of New England is represented as a single region within the model, so benefits from trade within New England are not reflected in the analysis. Accordingly, the model does not represent transmission constraints within regions and does not account for these congestion costs in the analysis. California's Path 15, which is often congested, is not specifically represented in POEMS.

Finally, POEMS is not designed to analyze reliability benefits. Increased transmission capacity will generally improve the overall reliability of the grid and allows regions to share capacity reserves. Although the risk of blackouts is generally small, blackouts usually entail very high economic costs. As such, even a small reductions in the risk of a blackout will have substantial benefits.

Appendix B

List of Participants at DOE National Transmission Grid Study Public Workshops and Written Comments Received by DOE

Detroit, MI Public Workshop • September 24, 2001

American Electric Power*

American Electric Power*

Consumers Energy Group*

Detroit Edison Company*

Ecostar Power

Enron

EPRI

First Energy Corp

International Transmission Company*

Michigan Electric Transmission Company

Michigan Public Service Commission*

National Grid USA*

Northeast Power Coordinating Council

Public Service Electric and Gas

Public Utilities Commission of Ohio*

US Department of Agriculture, Rural Utilities Service

Xcel Energy Services

* Offered public comment at workshop

Atlanta, GA Public Workshop • September 26, 2001

2M Design Consultants

ABB

Alabama Public Service Commission*

American Electric Power

Army Environmental Policy Institute

Balch & Binghem

Central Electric Power Cooperative*

Central Maine Power*

Certified Living

City of Griffin

Dalton Utilities

Dynegy

EnerVision

Enron

Florida Public Service Commission

Georgia Public Service Commission

Georgia Transmission Corporation

Kentucky Public Service Commission

Large Public Power Council*

Municipal Electric Power of Georgia*

MidAmerican Energy

Midwest ISO*

Mirant Corporation*

Northeast Power Coordinating Council*

PG&E National Energy Group

PJM Interconnection*

Reliant Resources

RETX*

Rural Electric Service*

Santee Cooper

South Carolina Public Service Commission*

Southeastern Electric Reliability Council

Southern States Energy Board

Southern Company*

Southwire Corporation

Troutman Sanders

Tennessee Valley Authority

US Department of Agriculture/Rural Utilities Service

* Offered public comment at workshop

Phoenix, AZ Public Workshop • September 28, 2001

ABB

Arizona Public Service

Arizona Residential Utility Consumer Office

Arizona Corporation Commission*

Arizona Department of Interior

Arizona Governor's Office*

Arizona House of Representatives

Arizona Municipal Power Users

Arizona State Senate

Bonneville Power Administration

California Independent System Operator

Chelan Public Utility District

City Public Service, San Antonio

Colorado River Energy Distributors Association*

Delaney Power Consultants

Dow Jones News

Electricity Consumers' Alliance*

Enron

EPRI*

KR Saline & Associates

Kansas Corporation Commission

Navaho Tribal Utility Authority

Navigant Consulting

Oregon Office of Energy*

PG&E National Energy Group

Pinnacle West Capital Corp

Pinnacle West Energy

Public Service Company of New Mexico

Power Up Corp*

R.W. Beck

Reliant Resources

RTO West

Salt River Project

San Carlos Irrigation Project

State Senate

Southwest Power Pool

Southwest Transmission Cooperative*

Tucson Electric Power

Tri-States Generation and Transmission Association

US Bureau of Reclamation

Western Area Power Administration*

Valmont Industries

Wellton Mohawk Irrigation & Drainage District

Western Governor's Association*

Williams Energy

Wyoming Business Council

* Offered public comment at workshop.

Written Comments Received by DOE

ABB

American Electric Power

American Public Power Association

American Superconductor

American Transmission Company

Arizona Public Service Company

Bandag

Carolina Power & Light

City of Griffin Electric Department

Dynegy

EPRI

Elucem

Georgia Public Service Commission

International Transmission Company

Kentucky Public Service Commission

Mid-Area Continent Power Pool

Midwest Independent Support Operations

Municipal Electric Authority of Georgia

National Association of Regulatory Utility Commissioners

National Electrical Manufacturers Association

National Grid USA

National Rural Electric Cooperatives Association

New Jersey Division of the Ratepayer Advocates

New York Independent System Operator

Northeast Power Coordinating Council

Northern Carolina Utilities Commission

Oregon Office of Energy

Power Up Corporation

Public Service Company of New Mexico

Public Service Enterprises Group

Retail Energy Transaction Exchange

Rick Cleckler

South Florida Regional Planning Council

Salt River Project

Southern California Edison

Southern Company Services

Southwest Transmission Cooperative

Thrust Power Systems

Xcel Energy

Appendix C: Glossary

This glossary provides definitions of terms used throughout the report and some others that are related to the field but not expressly mentioned.

Adequacy—Ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Ancillary Services—Interconnected Operations Services identified by the U.S. Federal Energy Regulatory Commission (Order No. 888 issued April 24, 1996) as necessary to effect a transfer of electricity between purchasing and selling entities and which a transmission provider must include in an open-access transmission tariff. See also Interconnected Operations Services.

Apparent Power—Product of the volts and amperes. It comprises both real and reactive power, usually expressed in kilovolt-amperes (kVA) or megavolt-amperes (MVA).

Automatic Generation Control (AGC)—Equipment that automatically adjusts a control area's generation to maintain its interchange schedule plus its share of frequency regulation.

Availability—Measure of time that a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.

Bulk Power System—The portion of an electric power system that encompasses the generation resources, system control, and high-voltage transmission system.

Capability—see Installed Capability and Operable Capability.

Capacity—The rated continuous load-carrying ability, expressed in megawatts (MW), megavolt-amperes (MVA), or megavolt-amperes-reactive (MVAR) of generation, transmission, or other electrical equipment.

Cascading—Uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

Clearing Price—see Energy Clearing Price.

Contingency—Unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

Contract Path—Specific contiguous electrical path from a point of receipt to a point of delivery for which transfer rights have been contracted.

Control Area—Electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

Current Limiter—Device that, when added to an electric system, is designed to limit damaging levels of current in the system. In the Consolidated Edison distribution system, current limiters (in the form of fusible links) are used to protect low-voltage conductors in the underground distribution system.

Curtailment—Reduction in the scheduled capacity or energy delivery.

Demand Elasticity—Measure of how the quantity of a good (e.g., electricity) demanded responds to a change in its price.

Demand-Side Management—Programs that affect customer use of electricity, both the timing (sometimes referred to as load management) and the amount (sometimes referred to as energy efficiency).

Dispatch—Operating control of an integrated electric system involving operations such as assignment of levels of output to specific generating stations and other sources of supply; control of transmission lines, substations, and equipment; operation of principal interties and switching; and scheduling of energy transactions.

Distribution Network—A network of electrical lines from a substation (which is the terminus of the transmission network) to a series of transformers (and eventually to the ultimate customer).

Distribution System—Portion of an electric system that "transports" electricity from the bulk-power system to retail customers, consisting primarily of low-voltage lines and transformers.

Disturbance—Unplanned event that produces an abnormal system condition.

Electrical Energy—The generation or use of electric power by a device over a period of time, expressed in kilowatt-hour (kWh), megawatt-hour (MWh), or gigawatt-hour (GWh).

Electric System or Electric Power System—An interconnected combination of generation, transmission, and distribution components that make up an electric utility, an electric utility and one or more independent power producers (IPPs), or group of utilities and one or more IPPs.

Electric Utility—Corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and is defined as a utility under the statutes and rules by which it is regulated. An electric utility can be investor-owned, cooperatively owned, or government-owned (owned by a federal agency, crown corporation, state, provincial government, municipal government, and public power district).

Emergency—Any abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the reliability of the electric system.

Energy Clearing Price—The price at which the market is able to match the last unit of energy a specific seller is willing to sell with the last unit of energy a specific purchaser is willing to buy.

Federal Energy Regulatory Commission (FERC)—Independent federal agency within the U.S. Department of Energy that, among other responsibilities, regulates the transmission and wholesale sales of electricity in interstate commerce.

Firm Power or Purchase—Power or power-producing capacity intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.

Forced Outage—Removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable because of unanticipated failure.

Frequency—Rate, in cycles per second (or Hertz, Hz), at which voltage and current oscillate in electric power systems. The reference frequency in North American Interconnections is 60 Hz.

Generating Reserve—see Reserve.

Generating Unit—An electric generator together with its prime mover (e.g., steam from boiler).

Grid—System of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the requirements of the customers connected to the grid at various points. Gridco is sometimes used to identify an independent company responsible for the operation of the grid.

Independent System Operator (ISO)—A neutral operator responsible for maintaining the generation-load balance of the system in real time. The ISO performs its function by monitoring and controlling the transmission system and some generating units to ensure that generation matches loads.

Installed Capability—Seasonal (i.e., winter and summer) maximum load-carrying ability of a generating unit, excluding capacity required for station use.

Interconnected Operations Services (IOS)—Services that transmission providers may offer voluntarily to a transmission customer under Federal Energy Regulatory Commission Order No. 888 in addition to ancillary services.

Interconnection—When capitalized, any one of the major electric system networks in North America. When not capitalized, the facilities that connect two systems or control areas. In addition, an interconnection refers to the facilities that connect a nonutility generator to a control area or system.

Interface—Specific set of transmission elements between two areas or between two areas that make up one or more electric systems.

Interruptible Rate—Electricity rate that, in accordance with contractual arrangements, allows interruption of consumer load by direct control of the utility system operator or by action of the consumer at the direct request of the system operator. It usually involves commercial and industrial consumers. In some instances, the load reduction may be affected by direct action of the system operator (remote tripping) after notice to the consumer in accordance with contractual provisions.

Load—A consumer of electric energy; also the amount of power (sometimes called demand) consumed by a utility system, individual customer, or electrical device.

Load Pocket—Geographical area in which electricity demand sometimes exceeds local generation capability and in which there is an electricity import limitation as a result of transmission constraints.

Load Shedding—The process of deliberately removing (either manually or automatically) preselected customer demand from a power system in response to an abnormal condition in order to maintain the integrity of the system and minimize overall customer outages.

Market Clearing Price of Electricity—see Energy Clearing Price.

Marketers—Commercial entities that buy and sell electricity.

Must-Run Resources—Generation designated to operate at a specific level and not available for dispatch.

Network Distribution—Method of distributing electric power to a densely populated area, where a network or grid of low-voltage conductors covers an area of several city blocks to a few square miles. The grid is solidly connected and is fed from multiple distribution feeders.

Nonfirm Power or Purchase—Power or power-producing capacity supplied or available under a commitment having limited or no assured availability.

Nonspinning Reserve—Generation capacity that is not being utilized but that can be activated and used to provide assistance with little notification.

North American Electric Reliability Council (NERC)—A not-for-profit company formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America. NERC consists of 10 Regional Reliability Councils and one Affiliate whose members account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The members of these Councils are from all segments of the electricity supply industry—investor-owned, federal, rural electric cooperative, state/municipal, and provincial utilities, independent power producers, and power marketers. The 10 NERC Regional Reliability Councils are East Central Area Reliability Coordination Agreement (ECAR), Electric Reliability Council of Texas (ERCOT), Florida Reliability Coordinating Council (FRCC), Mid-Atlantic Area Council (MAAC), Mid-America Interconnected Network (MAIN), Mid-Continent Area Power Pool (MAPP), Northeast Power Coordinating Council (NPCC), Southeastern Electric Reliability Council (SERC), Southwest Power Pool (SPP), and Western Systems Coordinating Council (WSCC). The Affiliate is the Alaskan Systems Coordination Council (ASCC).

Open-Access Same-Time Information System (OASIS)—An electronic posting system for transmission access data that allows all transmission customers to view the data simultaneously.

Operable Capability—The portion of installed capability of a generating unit that is in operation or available to operate in the hour.

Operating Reserve—That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It includes both spinning and nonspinning reserve.

Peak Demand or Load—The greatest demand that occurs during a specified period of time.

Power Pool—Entity established to coordinate short-term operations to maintain system stability and achieve least-cost dispatch. The dispatch provides backup supplies, short-term excess sales, reactive power support, and spinning reserve. Historically, some of these services were provided on an unpriced basis as part of the power pool members' utility franchise obligations. Coordinating short-term operations includes the aggregation and firming of power from various generators, arranging exchanges between generators, and establishing (or enforcing) the rules of conduct for wholesale transactions. The pool may own, manage, and/or operate the transmission lines (i.e., wires) or be an independent entity that manages the transactions between entities. Often, the power pool is not meant to provide transmission access and pricing or to provide settlement mechanisms if differences between contracted volumes among buyers and sellers exist.

Reactive Power—Portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kVAR) or megavars (MVAR).

Real Power—Rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

Reliability—Degree of performance of the elements of the bulk power system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system—adequacy and security.

Reserve—Electric power generating capacity in excess of the system load projected for a given time period. It consists of two sources: spinning reserve and supplemental reserve.

Retail Sales—With regard to the electric industry, electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small end-use classes, such as agriculture and street lighting, also are included.

Schedule—Agreed-upon transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the contracting parties and the control area(s) involved in the transaction.

Security—Ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system elements.

Security Coordinator—One of 23 entities established by NERC with the responsibility and authority to direct actions aimed at maintaining real-time security for a control area, group of control areas, NERC subregion, or NERC region.

Short-Notice or Short-Term Transaction—Transaction for the transfer of net energy from one region to another, made with little time between the transaction and the transfer (typically, less than one hour).

Spinning Reserve—Ancillary service that provides additional capacity from electricity generators that are on line, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur.

Stability—Ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.

Supplemental Reserve—Ancillary service that provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually 10 minutes.

System—see Electric System.

System Operator—Individual at an electric system control center whose responsibility it is to monitor and control that electric system in real time.

Tariff—Schedule detailing the terms, conditions, and rate information applicable to various types of electric service.

Topology—Structure and layout of a system.

Transmission—Interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Unit—see Generating Unit.

Unit Commitment—Process of determining which generators should be operated each day to meet the daily demand of the system.

Utility—see Electric Utility.

Volt-Ampere-Reactive (VAR)—Unit of measure of the power that maintains the constantly varying electric and magnetic fields associated with alternating-current circuits. See Reactive Power.

Voltage—The unit of measure of electric potential.

Voltage Collapse—An event that occurs when an electric system does not have adequate reactive support to maintain voltage stability. Voltage collapse may result in outage of system elements and may include interruption in service to customers.

Wholesale Electricity Market—Purchase and sale of power, according to agreements with varying lengths and lead times, among power marketers, power producers, and other wholesale entities.