U.S. TRANSMISSION CAPACITY: PRESENT STATUS AND FUTURE PROSPECTS

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SUMMARY

Transmission lines, substations, circuit breakers, capacitors, and other equipment provide more than just a highway to deliver energy and power from generating units to distribution systems. Transmission systems both complement and substitute for generation. Transmission generally enhances reliability; lowers the cost of electricity delivered to consumers; limits the ability of generators to exercise market power; and provides flexibility to protect against uncertainties about future fuel prices, load growth, generator construction, and other factors affecting the electric system.

Because most of the U.S. transmission grid was constructed by vertically integrated utilities before the 1990s, these legacy systems support only limited amounts of inter-regional power flows and transactions. Thus, existing systems cannot fully support all of society's goals for a modern electric-power system.

This report, using regional and national data on transmission capacity plus transmission plans from a variety of sources, examines the current status of the U.S. transmission system. It also looks at plans to expand transmission capacity over the next decade.

The data show a continuation of past trends. Specifically, transmission capacity is being added at a much slower rate than consumer demand is growing (Fig. S-1). Between 1982 and 1992, transmission capacity per MW of peak demand declined at an average rate of 0.9% per year. During the following decade, capacity declined even more rapidly, at 2.1% per year. Projections suggest that this decline will continue, but at a slower rate during the coming decade, by 1.1% per year from 2002 through 2012.

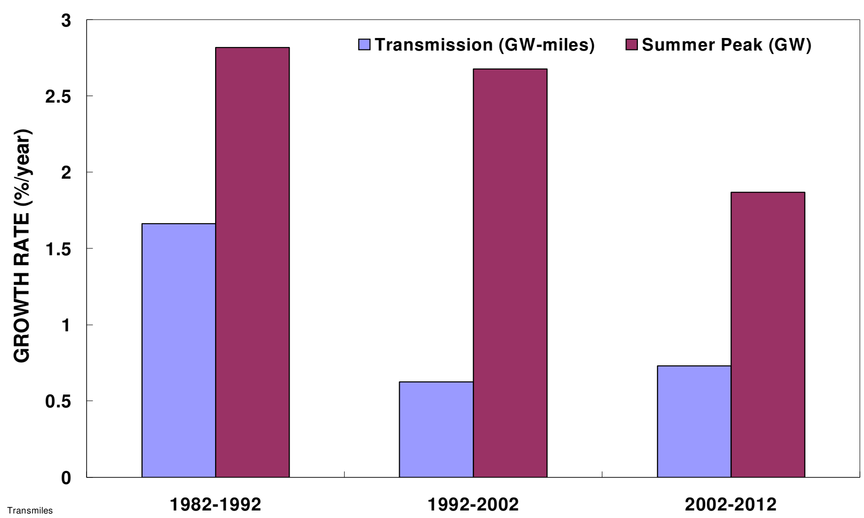

Fig. S-1. Annual average growth rates in U.S. transmission capacity and peak demand for three decades: 1982 to 1992, 1992 to 2002, and projections for 2002 to 2012.

A review of 20 transmission plans and related documents shows enormous variability in the topics covered and the comprehensive and quality of the reports. Roughly half the studies focused on reliability, while the other half focused on economics (reducing congestion to lower the cost of power delivered to consumers). Few reports addressed all the reasons for adding transmission capacity to a system: meet reliability requirements, lower costs to consumers, interconnect new generation and load, replace old or obsolete equipment, and, in some cases, improve local air quality.

In addition to substantial differences among the reports, many transmission owners and regional reliability councils do not publish transmission plans at all. Thus, the geographical coverage of this study is spotty and limited.

Most of the recent and planned investment in transmission facilities is intended to solve local reliability problems and serve growing loads in large population centers. Few projects cross utility or regional boundaries and are planned to move large blocks of low-cost power long distances to support large regional wholesale electricity markets. Thus, many opportunities to lower consumer power costs will be forgone because of insufficient transmission capacity.

LIST OF ACRONYMS

ACC	Arizona Corporation Commission
ATC	American Transmission Company
BPA	Bonneville Power Administration
CRR	Congestion revenue rights
ECAR	East Central Area Reliability Coordination Agreement
EEI	Edison Electric Institute
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FERC	U.S. Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
ISO	Independent system operator
LMP	Locational marginal price
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
MISO	Midwest ISO
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
NTAC	Northwest Transmission Assessment Committee

PJM	Pennsylvania, New Jersey, Maryland Interconnection, LLC
PSC	Public service commission
PUC	Public utility commission
RMR	Reliability must run
ROW	Right of way
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
SSG-WI	Seams Steering Group—Western Interconnection
STEP	Southwest Transmission Expansion Project
TLR	Transmission loading relief
WECC	Western Electricity Coordinating Council

INTRODUCTION

> There's plenty of talk about transmission. But real action on transmission construction is scant. Conferences and reports abound. Projects of all sizes are being proposed. But, except for local reinforcements and new generation interconnections, few transmission construction proposals are moving forward. The vast majority of larger projects are stalled for lack of financial commitment (Mullen 2003).

The August 2003 blackout that hit the Midwest, Northeast, and Ontario was a wake-up call on the U.S. transmission system. Whether one considers the transmission grid adequate, "fragile," "antiquated," or even "third-world" (Burns, Potter, and Wiotkind-Davis 2004), almost everyone agrees that the electricity industry and government policy makers should pay more attention to transmission, in particular construction of needed new facilities.

A survey of state regulators showed considerable concern about transmission adequacy (Mullen 2003): "Just 23% in the Midwest and a paltry 18% in the West described the grid as 'fully adequate.' … Regulators in the Northeast and South were more sanguine. In the Northeast, 40% of respondents described the grid as fully adequate, versus 63% in the South." On a positive note, a survey of 72 top officers in U.S. and Canadian electric utilities found that "Transmission is seen as the most profitable sector [and] where most capital will go" (GF Energy 2004).

This report analyzes recent data and projections on U.S. transmission capacity and capital expenditures on transmission. In addition, this report reviews recent transmission plans and related documents published by electric utilities (both public and private), independent system operators (ISOs), standalone transmission companies, regional reliability councils, and state public utility commissions (PUCs).

The motivation for this project goes well beyond the August 2003 blackout. Indeed, this project is stimulated primarily by the long-term and continuing decline in the amount of transmission capacity relative to peak electrical demand (Hirst 2000; Hirst and Kirby 2001; U.S. Department of Energy 2002).

How much should we invest in the U.S. transmission grid to meet the needs of our growing economy? Estimates range from $27 billion over the next several years (Richardson

2003) to $50 or $100 billion during this decade.* Although this question sounds reasonable, answering it appropriately is fraught with difficulties. Many issues complicate development of a responsible answer:

- Size and shape of load: How do population and economic growth, combined with changing technologies, affect growth in electricity use (MWh) and demand (MW)?

- Location of generating stations: How does the spatial distribution of generation (addition of new units minus retirement of old units) change over time? In particular, are new units primarily built near load centers or in remote locations (e.g., wind- and coal-fired stations)? What is the relationship between the locations of generating units and the topology of the transmission network?

- The importance, as a policy matter, of robust wholesale electricity markets: More transmission will be needed, all else equal, if national policy favors large regional markets for electricity [as does the Federal Energy Regulatory Commission (FERC) through its initiatives promoting regional transmission organizations and standard market design]. On the other hand, if we return to the days of regulated, vertically integrated utilities that trade primarily with their close neighbors, less new transmission will be required.

- Magnitude of production-cost differences among power plants: Large spatial and temporal differences in production costs provide strong economic motivation to build transmission lines to permit the movement of cheap power from generators to load centers.

- Level of bulk-power reliability we want and are willing to pay for: Greater reliability will likely require additional investments in transmission, generation and demand management as well as in improved system control and operations.

- Amount of additional capacity that can be wrung out of today's transmission system: The application of existing and new computing, communications, and control technologies could enhance reliability and permit more transactions to flow across the grid. Other solid-state technologies enhance the ability of the grid to respond rapidly to changes in power flows and voltages to improve stability and voltage control. Better operations permit system operators to run the grid closer to its physical limits without imperiling reliability.

- Use of nontransmission solutions (i.e., suitably located generation and demand-management programs) to transmission problems: More generally, will economic

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*"[Department of Energy] Secretary Spencer Abraham suggested … that $50 billion in new transmission system investment is needed. Others have suggested that the total amount needed is over $100 billion" (White et al. 2003).

signals [especially, locational marginal prices (LMPs) and congestion revenue rights (CRRs), key elements of FERC's standard market design] stimulate the construction of generating units and the creation of demand-management programs at locations that reduce congestion? Will these economic signals motivate construction of appropriately located merchant transmission projects?

As an example of how different answers to these questions might affect the amounts, types, and locations of transmission investment, consider the needs for reliability and economic efficiency. Krapels (2003) suggests that "A few billion well-placed dollars will solve the reliability problem; it will take tens of billions to thoroughly modernize and optimize the grid."

More broadly, new transmission can be built for different purposes, including:

- Interconnection of new load or generation: Facilities required to connect to the transmission grid, but not necessarily to transport power across the grid.
- Reliability: Facilities required to meet NERC, regional reliability council, and other standards, primarily the NERC (1997) *Planning Standards*.
- Economics: Facilities that lower the cost of electricity production by reducing losses and congestion to permit greater use of low-cost generators to serve distant load centers.
- Replacement: Facilities that replace old, worn-out, and/or obsolete equipment.

The amount of money needed for transmission investment will depend on which categories are considered.

Finally, opinions vary widely on the severity of our transmission problems and the need for additional capital expenditures. Huntoon and Metzner (2003) suggest we need "a stable regulatory environment" to address the "myth of the transmission deficit." They believe new transmission needed for reliability purposes should be determined on a regional basis through existing institutions, and transmission needed to relieve congestion should be built on a competitive basis when it is the most efficient solution to congestion. Hirst and Kirby (2001 and 2003) believe that separating reliability from economic needs is very difficult and that substantial investments for both purposes are required. Others believe that serious transmission problems exist but can be addressed in large part with nontransmission solutions, in particular dispersed generation and demand management (White et al. 2003).

Chapter 2 presents data and projections on U.S. transmission capacity from 1978 through 2012. These results show trends over time at the national and regional levels (using the 10 NERC regions, shown in Fig. 1).[*] Chapter 3 provides information from 20 transmission plans and related documents produced by utilities, ISOs, state agencies, and others. Again, the discussion is organized around the NERC regions. Chapter 4 discusses the planning materials

[*]The Eastern Interconnection contains 75% of the nation's summer peak demand, while ERCOT and the Western (WECC) Interconnections contain 8 and 17%, respectively (NERC 2003d).

covered in Chapter 3 and identifies several critical transmission issues in various regions and their resolution. Finally, Chapter 5 presents conclusions from this project.

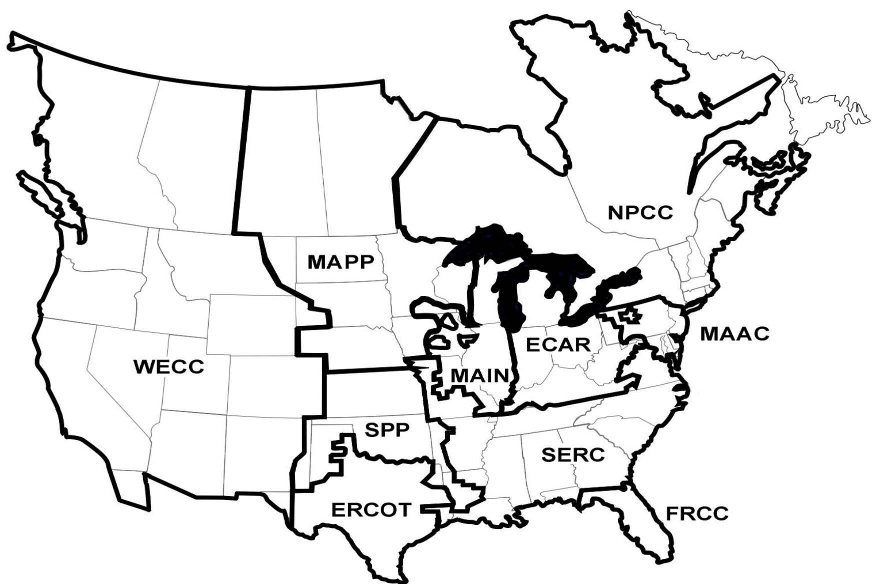

Fig. 1. **Map of the United States showing the locations of the 10 reliability regions. WECC and ERCOT are Interconnections as well as regions. The remaining eight regions are part of the Eastern Interconnection.**

TRANSMISSION CAPACITY: DATA AND PROJECTIONS

HISTORICAL DATA

For the past few decades, the Edison Electric Institute (EEI 2003) has collected and published data each year on the number of circuit miles of transmission lines in the United States.[*] Since 1989, NERC (2003c) has published similar data.[#] Together, these two data sets provide a long historical record on the amount of transmission capacity available to move electricity from generators to distribution systems.

Although these data sets contain much useful information, they suffer from data-quality problems. For example, the NERC data show several occasions when the transmission mileage in a region drops from one year to the next. Almost 20% of the year-to-year changes in historical transmission mileage show declines. It is highly unlikely that a utility would retire a line from service rather than replace the conductors or towers with newer ones (perhaps with higher voltage and MVA ratings).

In addition to data-quality issues, interpreting these data is complicated by the seven issues listed in Chapter 1. In particular, locations of generating units relative to load centers has an enormous effect on the need for transmission. Also, not all transmission facilities add mileage to the system; devices such as transformers, capacitor banks, breakers, meters, and communication systems are important elements of the grid.

I used the NERC data from 1989[§] through 2002 and the EEI data (with a small adjustment to match the NERC data for the years when both data sets were available) for the earlier years to develop a record of transmission capacity (in both circuit miles and MW-miles);

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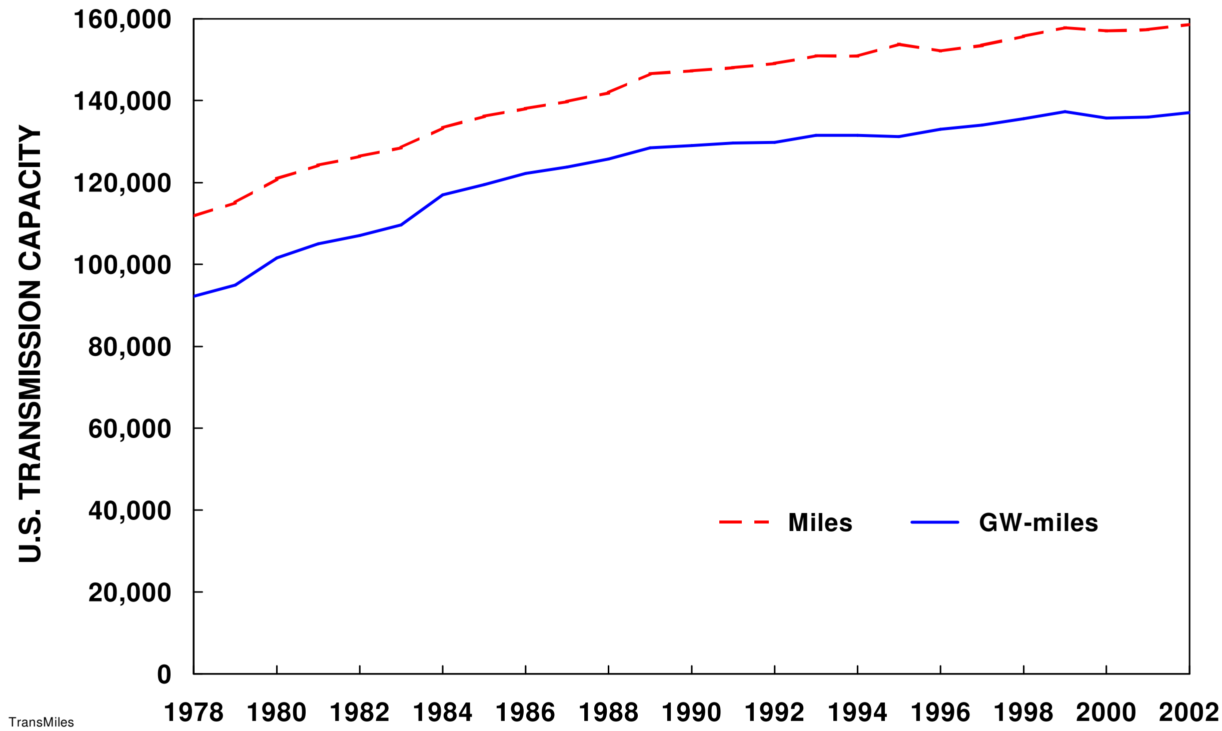
[*]The EEI data have, at various times, included distribution as well as transmission lines, and data from rural coops as well as from other types of utilities. These data are reported for 12 voltage levels ranging from less than 22 kV to 601 kV and over.

[#]The NERC data are based on utility and regional-reliability-council filings to the Energy Information Administration (EIA 2001 and 2002) on forms EIA-411 and 412 and to FERC on its Form-1. EIA-411 collects information on "Proposed Transmission Lines," while EIA-412 and FERC Form-1 collect data on "Existing Transmission Lines." NERC reports transmission mileage for four voltage levels ranging from 230 kV to 765 kV.

[§]These capacity values are as of December 31 for the year stated, i.e., from the end of 1989 through the end of 2002.



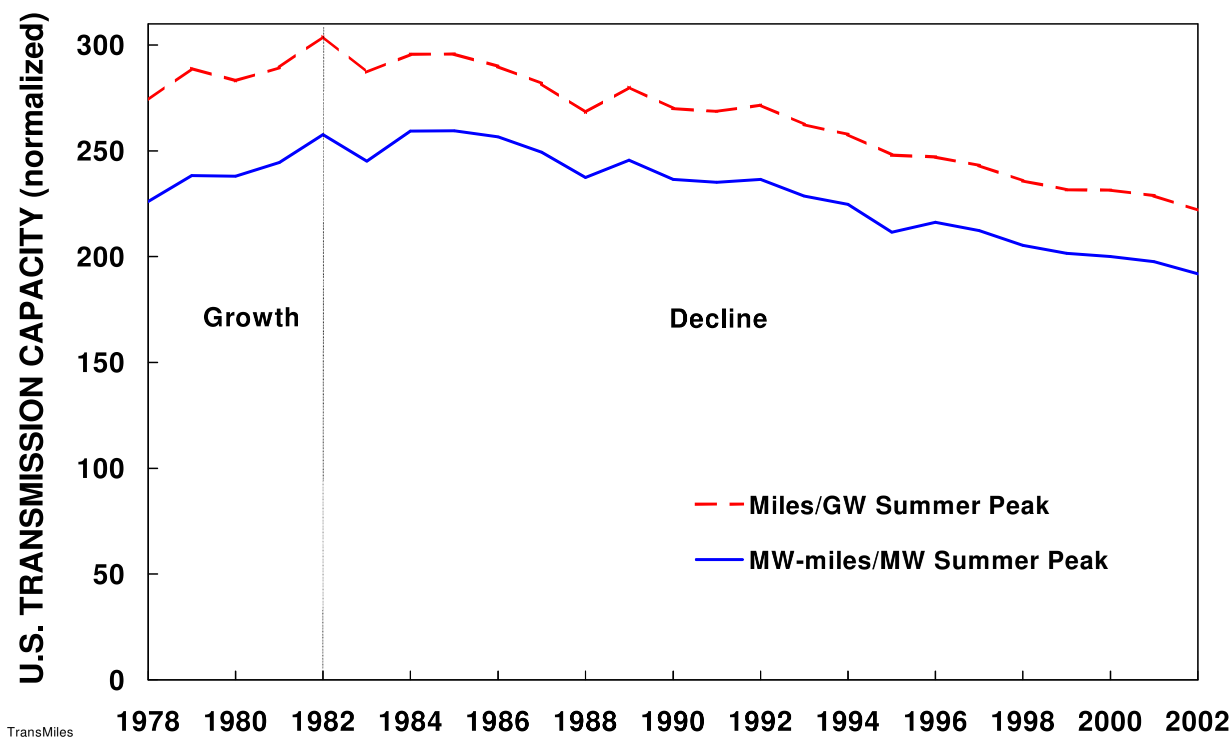


Fig. 2. **U.S. transmission capacity from 1978 through 2002 in miles and GW-miles (top) and normalized by summer peak demand (bottom).**

see top part of Fig. 2. Utilities added transmission lines at a much higher rate during the first four years of this period than during the following 20 years (3.8 v 1.2% per year).

I normalized these capacity figures by peak demand as shown in the bottom part of Fig. 2. Normalized transmission capacity increased from 1978 through 1982 and then declined steadily through 2002. Between 1978 and 1982, normalized transmission capacity (as measured by MW-miles/MW-demand) grew at an average annual rate of 3.3%; during the following 20 years, normalized transmission capacity declined at a rate of 1.5% per year. (The numbers for transmission miles per GW of demand were similar: +2.6%/year for the first four years and −1.6%/year for the next 20 years.)

EEI (2003) collects data on annual investments in transmission facilities for investor-owned utilities.* As shown in Fig. 3, these data show a steady decline in construction of new transmission facilities from 1975 through 1999, with substantial increases during the final four years (2000 through 2003).# These results are shown in real (i.e., corrected for inflation) 2003 dollars, using the Handy-Whitman Index of electric-utility transmission costs to adjust for inflation from year to year. Between 1975 and 1999, investment fell at an average rate of \$83 million per year; from 1999 through 2003, transmission investment *in*creased at an average annual rate of \$286 million, a substantial reversal of trends. The average level of investment for the last four years was \$3.6 billion,§ 34% higher than the average for the prior four years (\$2.7 billion). It is not clear what accounted for this reversal of trends or whether the change is temporary or long-term.

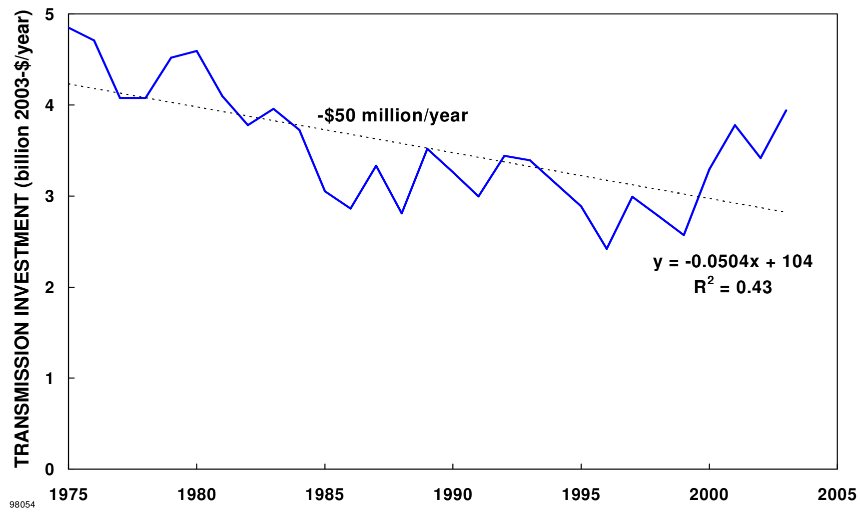


Fig. 3. Annual transmission investments by investor-owned utilities from 1975 through 2003.

These trends in transmission capacity and investment are reflected in bulk-power operating data (NERC 2004). The number of times system operators in the Eastern

*Investor-owned utilities own about three-fourths of the total U.S. transmission grid, with municipal, federal, rural cooperative utilities, and transmission-only companies owning the rest.

#To some extent, this change in trend might be caused by differences in data-collection procedures used by EEI before and after 1999.

§EEI resurveyed utilities to obtain more accurate data. The revised results for 2000 through 2002 were 5% higher than the original numbers shown in Fig. 3.

Interconnection called for Level 2[*] or higher transmission loading relief (TLR) increased from about 300 in 1998 and 1999 to more than 1,000 in 2000 and 2001, with jumps to 1,500 in 2002 and almost 2,000 in 2003 (Fig. 4).[#] Over a five-year period, the need to curtail power transactions or deny requests for new transactions increased by a factor of six.

A recent survey of transmission congestion examined the six operating ISOs (in New England, New York, mid-Atlantic, Midwest, Texas, and California). Dyer (2003) found that the "Total congestion costs experienced by the six ISOs for the four-year period from 1999–2002 totaled approximately $4.8 billion." Congestion in New York accounted for more than half of this total.

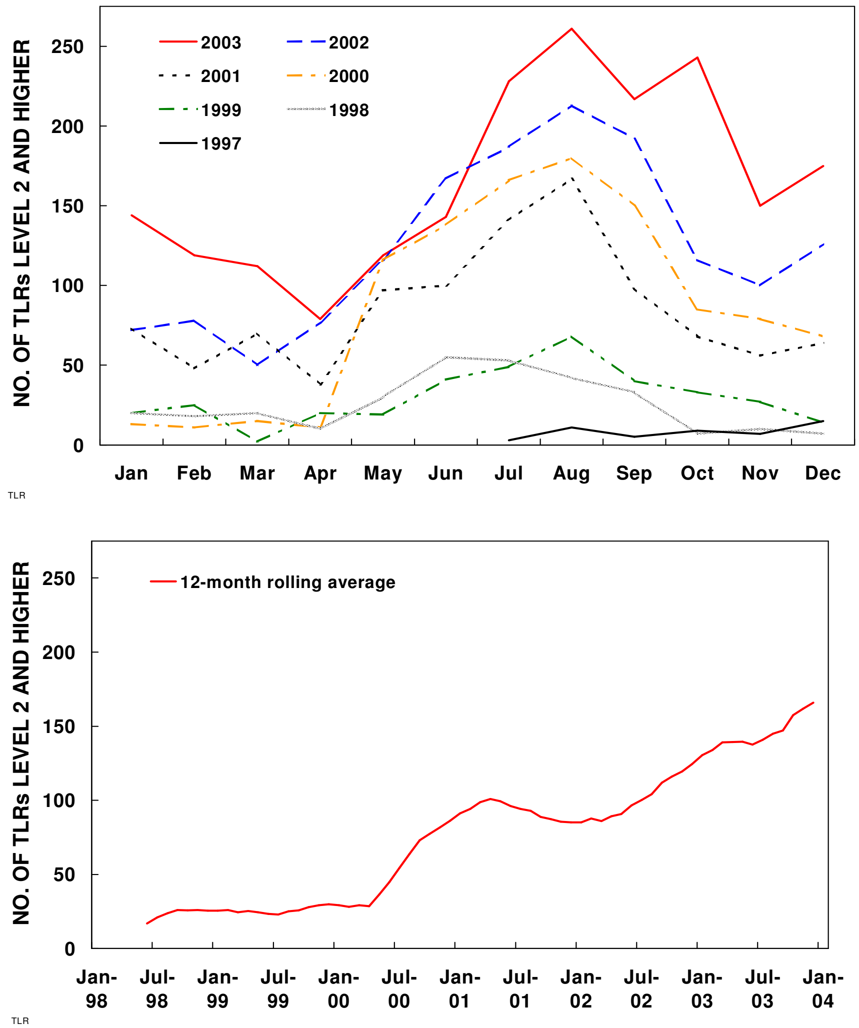


Fig. 4. **Number of Level 2 or higher Transmission Loading Relief calls in the Eastern Interconnection from July 1997 through December 2003 (top) and the 12-month rolling average from July 1998 (bottom).**

[*]NERC has six levels of TLR, ranging from 1 (least severe) to 6 (emergency conditions). Level 2 requires the system operator to "hold Interchange Transactions at current levels to prevent Operating Security Limit violations." Higher levels restrict nonfirm transactions first and then, if necessary, firm transactions.

[#]The patterns and the number of TLRs are, in part, a function of regional differences in weather. For example, the summer 2000 temperatures were low in the north and high in the south, leading to substantial north-to-south electricity flows. According to NERC (2003d), "Because weather patterns are unpredictable, transmission constraints and congestion have the potential to shift from day to day, season to season, and year to year." TLR calls may be affected more by trends in wholesale transactions than trends in peak demands.

CURRENT CONDITIONS

NERC (2003a and b) issues summer and winter reliability assessments, as well as a 10-year assessment (NERC 2003d) each year. Table 1 summarizes the transmission issues noted in each region's report to NERC for the 2003 Summer, 2003/2004 Winter, and 2003–2012 reliability assessments.

Table 1 shows considerable variation among regions in the status of their transmission systems. Some regions, such as FRCC, MAAC, SERC, and WECC, report no serious problems. Others, however note episodic or ongoing problems. For example, imports to southwestern Connecticut remain a serious and perhaps long-term problem in New England. ERCOT faces problems moving the output from generation to the growing urban loads in Dallas-Ft. Worth and Houston. However, ERCOT, unlike some other regions, is able to plan and build new transmission facilities in a timely fashion.* Imports from MAPP to Wisconsin (MAIN) remain a critical concern. Curiously, not one of the NPCC reports mentions the transmission constraints for imports to New York City and Long Island.

PROJECTIONS

Each year, as part of its annual *Reliability Assessment*, NERC (2003d) issues its *Electricity Supply and Demand Database and Software* (NERC 2003c). This database shows planned transmission-line additions for each of the following 10 years, from 2003 through 2012 for the latest version (Fig.5).

The projections are consistent with the historical data: both show continuing declines in normalized transmission capacity. Between 1992 and 2002, 9,600 miles (7,300 GW-miles) of transmission were added; between 2002 and 2012, an additional 10,400 miles (10,300 GW-miles) are expected to be added.

Although normalized transmission capacity declined by almost 19% between 1992 and 2002, it is expected to drop by only 11% during the following decade (2002 to 2012). In other words, transmission capacity is expected to continue to decline during the coming decade, but at a slower rate than during the past decade.

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*According to Jones (2004), "ERCOT is very active in improving its transmission infrastructure and has added over 700 miles of new 345 kV and 200 miles of 138 kV transmission in the past three years. Many more miles are now in the construction and certification phase.

Table 1. Regional transmission issues from recent NERC reliability assessments

	2003 Summer[a]	2003/2004 Winter[b]	2003–2012[c]
NPCC	"In southwestern Connecticut, reliability problems are possible due to transmission constraints;" four transmission upgrades are planned in New England	No issues reported	"transmission systems … meet NPCC criteria and are expected to continue to do so;" SW Connecticut faces serious constraints; Maine and SE Massachusetts/Rhode Island are constrained, resulting in locked-in generation
MAAC	"transmission system is expected to perform adequately"	"bulk transmission system is expected to perform reliably"	"transmission capability over the next five years is expected to meet MAAC criteria requirements;" "sufficient transmission will be added to meet MAAC criteria"
SERC	"SERC has extensive transmission interconnections between its subregions … [which] permit the exchange of large amounts of firm and non-firm power"	"heavy and widely varying electricity flows are anticipated within SERC … driven by excess generation within SERC and external weather conditions"	"transmission capacity is expected to be adequate to supply firm customer demand;" large amounts of merchant generation without firm transmission rights might cause problems
FRCC	"transmission system is expected to perform adequately"		
ECAR	"transmission system will be more constrained this summer;" TLRs may need to be invoked	"transmission system could become constrained"	transmission system expected to "perform well;" construction to begin soon on 765-kV line in southeastern ECAR
MAIN	"transmission system is expected to perform reliably;" constrained interfaces continue to require special operating attention and procedures; "several lines in southern MAIN have experienced heavy loadings requiring TLRs"	"transmission system is expected to perform reliably;" concern over import capabilities from TVA	"transmission system [is expected to] perform adequately … [if] proposed reinforcements are completed on schedule;" integration of new generation "continues to be a major challenge;" "major reinforcements" planned
MAPP	"MAPP continues to monitor the 19 transmission constraints within the Region;" export to MAIN is limited by the Eau Claire-Arpin limit.	"transmission system is adequate to meet firm obligations"	
SPP	"SPP does not anticipate operational issues for the upcoming summer months;" LaCygne-Stilwell 345-kV line to be rebuilt	LaCygne-Stilwell line rebuilt ahead of schedule	"transmission system will reliably serve native network load;" uncertainty over cost recovery limits transmission upgrades

	2003 Summer[a]	2003/2004 Winter[b]	2003–2012[c]
ERCOT	12 "most frequently encountered ERCOT transmission constraints" listed; five major projects to "help mitigate these constraints"	"major ERCOT transmission constraints center around the transfer of generation to serve the load centers of Dallas-Fort Worth and local congestion in the Corpus Christi and Rio Grande Valley areas."	Transfers to Dallas-Ft. Worth and Houston continue to be major constraints; "a number of major transmission projects will be completed"
WECC	"The transmission system is considered adequate for all projected firm transactions and most economy energy transfers."		"Transmission constraints will continue to limit the deliverability of generation to customer demand"

[a]NERC (2003a).
[b]NERC (2003b).
[c]NERC (2003d).

The NERC data and projections show results for each of the 10 reliability regions as well as for the United States as a whole (Fig. 6 and Table 2). Between 1989 and 2002, normalized transmission capacity declined in all 10 regions by amounts ranging from 14 to 27%. The largest declines (more than 25% over this 13-year period) occurred in SERC and NPCC. The smallest declines (less than 20%) occurred in MAPP, SPP, and WECC.

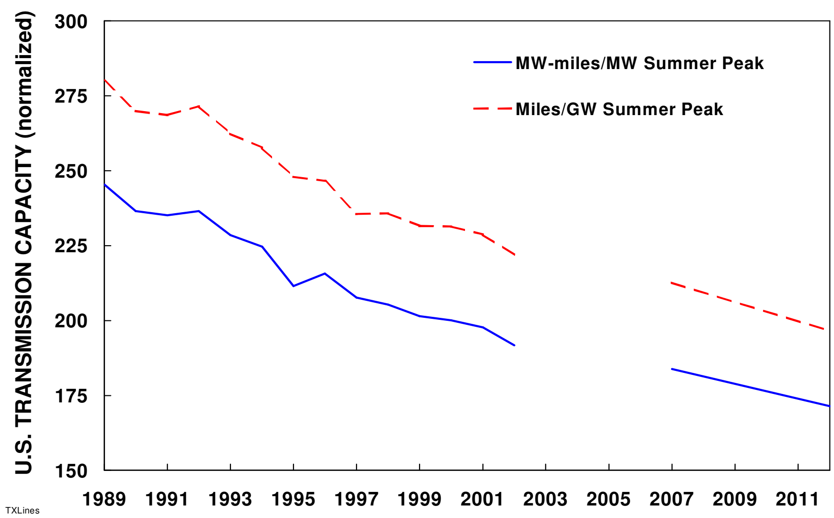
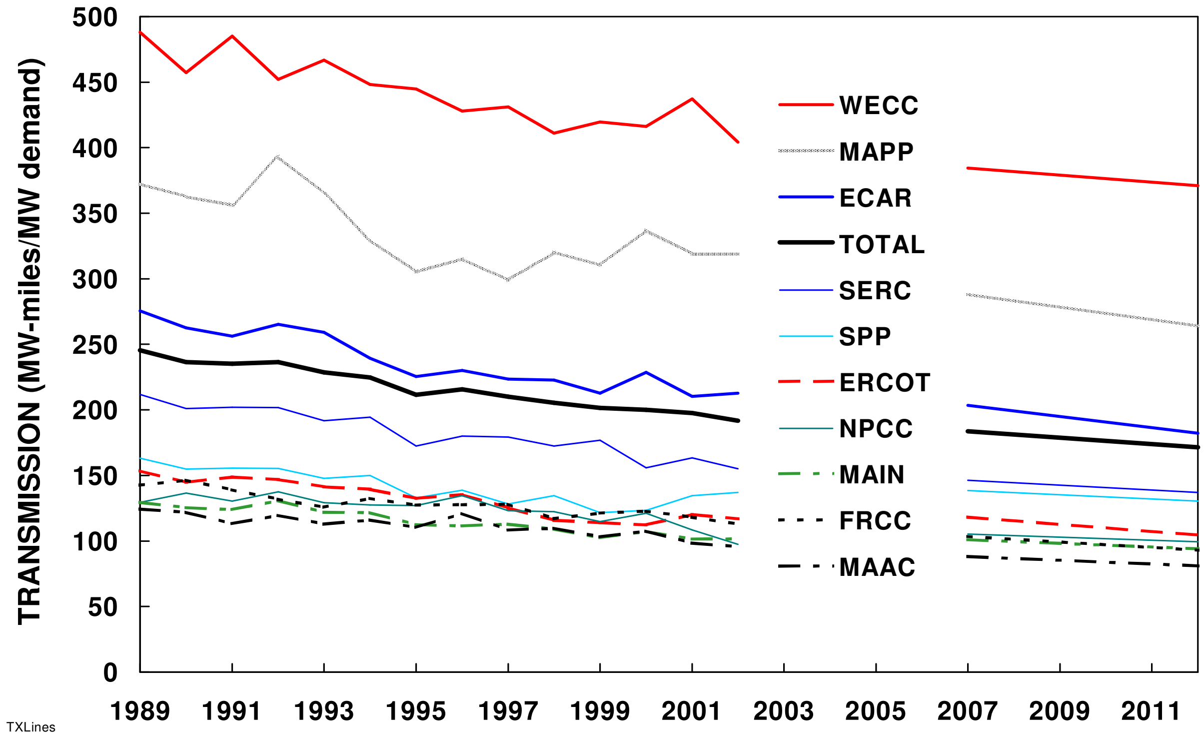


Fig. 5. U.S. transmission capacity normalized by summer peak demand from 1989 through 2002 plus projections for 2007 and 2012.

Over the next 10 years, normalized transmission capacity is expected to vary from +2% (NPCC) to −18% (FRCC) across the regions. All but one region (NPCC) projects declines in normalized capacity, with the largest drops (more than 15%) expected in MAAC, MAPP, and FRCC.



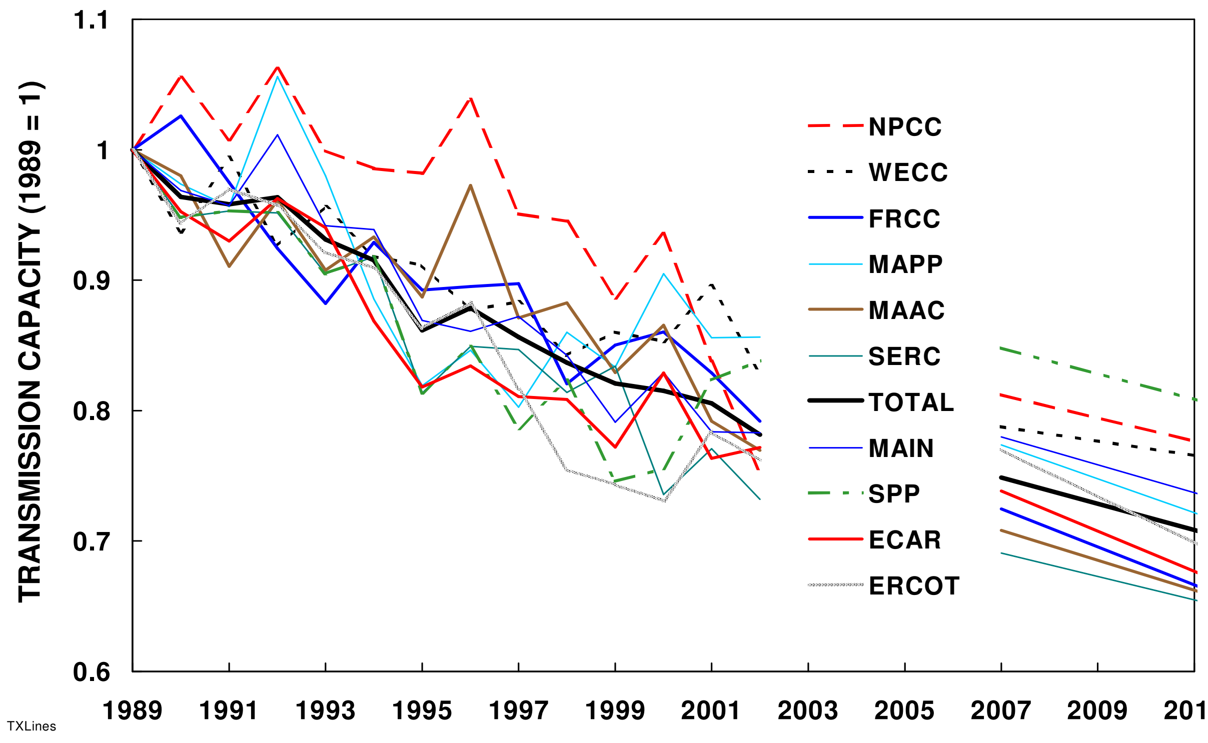


Fig. 6. U.S. transmission capacity for the 10 reliability councils normalized by summer peak demand from 1989 through 2002 with projections for 2007 and 2012 (top) and normalized by 1989 values (bottom).

Table 2. Normalized transmission capacity (MW-miles/MW demand) for the 10 NERC regions and the U.S. as a whole, 1989 through 2002 and projections for 2007 and 2012[a]

	Data														Projections	
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2007	2012
ECAR	**276**	263	256	265	259	239	225	230	223	223	213	228	*210*	213	204	182
ERCOT	**153**	145	149	147	141	139	132	135	125	116	114	*112*	120	117	118	104
FRCC	143	**146**	139	132	126	132	127	128	128	117	121	123	118	*113*	103	93
MAAC	**124**	122	113	120	113	116	110	121	108	110	103	108	98	*96*	88	81
MAIN	129	125	124	**131**	122	121	112	111	113	109	102	107	101	*101*	101	94
MAPP	372	363	356	**393**	365	330	305	315	*299*	320	310	337	319	319	288	264
NPCC	129	137	130	**137**	129	128	127	134	123	122	115	121	108	*97*	105	99
SERC	**212**	201	202	202	192	195	172	180	179	172	177	156	163	*155*	146	137
SPP	**163**	155	156	155	148	150	133	139	128	134	*122*	123	134	137	138	130
WECC	**488**	457	485	452	467	448	445	428	431	411	420	416	437	*404*	384	371
U.S. totals	**245**	237	235	237	229	225	211	216	208	205	201	200	198	*192*	184	171

[a]The **bold** numbers are the maximum values for each region, and the *italic* numbers are the minimum values for the historical period, 1989 through 2002.

Because the individual transmission-owner reports show that almost 70% of the new transmission lines are to be built during the first five years of this 10-year period, the projections for 2007 might be more meaningful than those for 2012. Between 2002 and 2007, normalized transmission capacity is expected to vary from +8% (NPCC) to −10% (MAPP). Three regions show expected increases for this initial 5-year period (ERCOT, SPP, and NPCC), while four regions show declines of 5% or more (SERC, MAAC, FRCC, and MAPP).

Of the 416 transmission projects planned for the next 10 years,* 95% are shorter than 100 miles, with an average length of only 18 miles. These numbers suggest that most planned transmission projects are local in scope and are not intended to address large regional issues. The 21 longer projects (5% of the total) average 170 miles in length.

SUMMARY

Table 3 shows growth in transmission capacity and summer peak demand for three decades, 1982 to 1992, 1992 to 2002, and 2002 to 2012. Although transmission capacity increased during each decade, growth in peak demand was always greater. The gap between the two growth rates was greatest during the middle decade (a 2.1% per year decline in MW-miles/MW demand v 0.9% and 1.1% declines in the first and third decades). This planned reduction in the transmission-capacity gap combined with the recent increases in transmission investment (Fig. 3) offer some optimism about the future of transmission capacity in the United States. However, projections of new transmission capacity have traditionally been optimistic, overstating the construction that actually occurred.

These data and projections provide useful indicators of the state of transmission grids in the United States. However, they are not necessarily accurate measures of transmission adequacy because of the seven factors listed in Chapter 1. Unfortunately, no better regional and national information on U.S. transmission systems exists.

*Only seven of these projects are retirements, with a total of only 220 miles of transmission lines to be retired between 2002 and 2012. Even if transmission lines have a 50-year lifetime, at least 2,500 miles would be retired each year (or, more likely, replaced with newer facilities using the same right of way). The unreasonably small number of retirements is another indication of data-quality problems.

Table 3. Comparisons of growth in transmission capacity and summer peak demand for three decades

	Percentage change per year		
	1982-1992	1992-2002	2002-2012
Transmission (miles)	1.66	0.63	0.73
Transmission (GW-miles)	1.94	0.55	0.63
Summer Peak (GW)	2.82	2.68	1.87
MW-miles/MW demand	-0.85	-2.07	-1.12
Miles/GW demand	-1.12	-2.00	-1.12

REVIEW OF TRANSMISSION PLANS

I reviewed 20 transmission plans and related documents from a variety of sources, including ISOs, regional reliability councils, individual utilities, groups of utilities, state regulators, transmission companies, and consulting firms. The purpose of this review was to identify the key transmission problems in each region and the recommended solutions to these problems. I had intended to use these planning reports to estimate regional and national needs for new transmission in both MW-miles and investment dollars. This review was to be a bottoms-up complement to the data review presented in Chapter 2.

In practice, the coverage of plans was quite spotty in both geography and substance. I likely overlooked some important documents that should have been included in this study. More important, several transmission owners and reliability councils do not make transmission plans available to the public. Two reasons were cited for keeping such studies confidential: national security (especially in the aftermath of 9-11) and competition.

Because of these limitations in plan coverage, the results of this review of transmission reports should be considered suggestive rather than definitive. In addition, I focused less on results (because fewer than expected plans were available) and more on the quality of the plans themselves. I used the planning process proposed by Hirst and Kirby (2002) to draw conclusions about the quality of these 20 planning documents.[*] In brief, Hirst/Kirby suggest that transmission plans include the steps shown in Table 4.

For convenience, the discussion of plans is organized around the 10 regional reliability councils (see Fig. 1 in Chapter 1 for a map showing the locations of these regions). As the U.S. electricity industry continues to evolve (whether towards greater competition or back to more regulation is unclear), the future planning role of the councils is uncertain. Many councils have no planning role per se. Instead, they assess the adequacy of plans developed by their members. The Midwest ISO (MISO) includes transmission systems in three councils (ECAR, MAIN, and MAPP). WECC, both a reliability council and an Interconnection, is enormous, encompassing roughly half the land mass of the contiguous United States.

This chapter briefly describes each of the 20 planning reports. Chapter 4 synthesizes the key issues, findings, and lessons learned from the reviews of these 20 documents.

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[*]Because I did not review the planning processes used by any of these entities, my comments focus solely on their planning reports.

Table 4. Summary of Hirst/Kirby proposed transmission-planning approach

1. What is the purpose of this plan? These purposes could include maintenance of reliability, promotion of competitive electricity markets, support for development of new generation, promotion of economic growth, and so on.

2. Describe the current situation, covering bulk-power operations, wholesale markets, and transmission pricing. What problems (e.g., reliability, congestion, losses, generator market power), if any, occur that are caused by limitations in the transmission system? What transmission projects are under construction or planned for completion within the next few years to address these problems? What are the estimated costs and benefits of these projects? What entities are expected to benefit and to pay for these projects?

3. Describe the likely future bulk-power system(e.g., in five and ten years). What are the levels, patterns, and locations of loads? Describe the region's fleet of generating units, including locations, capacity, and operating costs (or bid prices). What are the likely effects of new generation on use of the transmission system? Given the many uncertainties that affect future fuel prices, loads, generation, transmission, and market rules, create various scenarios that can be used to analyze potential problems and transmission improvements (Steps 4 and 5).

4. What transmission problems, both reliability and commercial, are likely to exist given the scenarios developed in Step 3?

5. What transmission facilities might be added to address the problems identified in Step 4? What effects would these facilities have on compliance with reliability standards, commercial transactions, losses, and regional electricity costs? What are the likely capital costs and benefits of these transmission additions? Can any of these transmission projects be built on a merchant (i.e., for profit and unregulated) basis?

6. What nontransmission alternatives (including suitably located generation and price-responsive load programs as well as alternative transmission-pricing schemes) might be deployed to address the problems identified in Step 4? To what extent can these alternatives address the problems for which the transmission facilities suggested in Step 5 were proposed?

7. Based on the foregoing analyses, recommend transmission pricing, generator locations, demand-management programs, and construction of new transmission facilities. If market participants do not propose the solutions analyzed in Steps 5 and 6, recommend those transmission facilities (from Step 6) that should be built under regulation. Summarize the benefits and costs of these proposed projects. Can the projects ultimately be approved, financed, and built in a timely fashion?

NORTHEAST POWER COORDINATING COUNCIL

The U.S. portion of NPCC is home to two ISOs, ISO New England (which covers all six New England states) and the New York ISO. NPCC also includes the Canadian provinces of Ontario, Quebec, and the Maritimes, which are not covered in this report.

ISO New England

ISO New England (2003) has a well-established planning process and has now published three annual plans. The latest one is well written, accessible to people with different interests and backgrounds (including nonspecialists), and comprehensive. The plan covers reliability and congestion (economics), analyzes local and regional transmission issues, and is open to market solutions (generation, demand management, and merchant transmission) as well as regulated transmission solutions. This plan, which covers 10 years (2003 to 2012), identifies nearly 250 regulated transmission projects that would cost between $1.5 and $3 billion. This large range in estimated cost occurs because specific costs have not been calculated for several of the projects analyzed.

ISO New England develops the plan with its Transmission Expansion Advisory Committee, which has an open membership. The ISO also works closely with the region's transmission owners and with the surrounding control areas (on inter-regional issues).

The most critical areas within New England remain imports into southwestern Connecticut, followed by northwestern Vermont. The cost to address the Connecticut problems is almost $900 million for Phases I and II. The report also identifies major transmission facilities needed to increase imports into the Connecticut and Boston areas.

The resource-adequacy and congestion studies use a simple transportation model that does not address local issues. The transmission planning studies, on the other hand, are much more detailed and consider "thermal, voltage, short circuit and stability limits, and system and equipment performance under potential contingency conditions."

This report is well organized. It includes a 40-page summary, a 165-page technical report, and an appendix of nearly 300 pages. The Technical Report provides detail on the demand forecast, resource capacity and energy issues, distributed resources (including demand response), system dynamic performance, transmission-performance assessments and proposed solutions for each of the New England subregions, and inter-regional coordination. The Appendices provide additional details on the data, assumptions, computer models, and results for each study. Thus, this plan is accessible to different kinds of readers with different policy and technical interests.

The Technical Report illustrates how various improvements can permit existing equipment to be operated closer to its limits; see Table 5. That is, some transmission investments don't add new capacity; instead, they permit existing capacity to be more fully utilized. The cost of these projects is about $39 million.

Table 5. Deerfield and Buxton enhancements and benefits on Maine to New Hampshire transfer limits (MW)

	Existing system	With Deerfield 500 MVAR SVC[a]	With SVC and Sect. 391 Loop	With SVC and 391 Loop, Breakers and 2nd Auto
Voltage	950	1,175	1,250	1,650
Thermal	1,225	1,225	1,325	1,625
Stability[b]	1,400	1,400	1,400	1,400

[a]SVC means static VAR compensator, which provides dynamic voltage support.
[b]Preliminary results suggest that the stability limit can be increased to 1,400 MW.

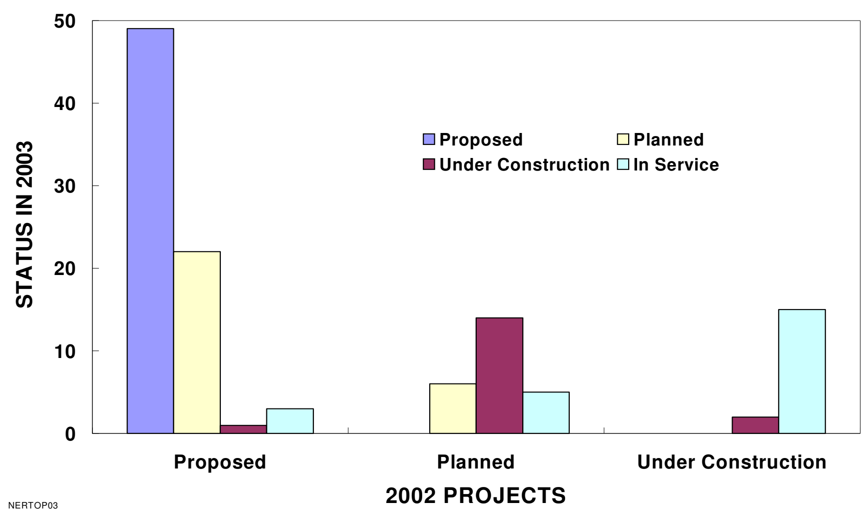

Fig. 7. 2003 status of transmission projects included in the 2002 New England transmission plan.

One measure of success for a transmission plan is the extent to which projects are implemented. As shown in Fig. 7, more than half the projects from the 2002 plan had progressed one or more steps as of a year later. In part, transmission projects are moving ahead in New England because very little transmission construction occurred during the past 15 years. So the region is now playing catchup. For example, three 345-kV lines into the Boston area are under construction. Projects are going ahead now because the need is real and imminent (there is no more fat in the system) and because transmission owners have greater confidence in the ISO and FERC treatment of investments (i.e., assurance they will get paid for investment).

The New England plan provides only a limited discussion of the economics (benefits and costs) of the various transmission projects being considered and planned. Economic analysis of new transmission is complicated by notions of scarcity pricing (i.e., LMP), accounting for reduction in market power, changes in reliability-must-run (RMR) contracts, and loss reductions. However, the New England plan does discuss congestion, LMP, and interface flows. It considers congestion from various perspectives: consumers, producers, and the system as a whole.

National Grid

National Grid (2003), which owns and operates transmission in New England and New York, publishes a *Five Year Statement*. The 2003 *Statement*, the fourth one issued by National Grid, is an assessment of the transmission system in New England and New York, based on likely changes over the next five years (to 2008) in generation and load. This report focuses on system adequacy, an assessment of the amounts of transmission and generation capacity available to serve peak loads. It deals with flows across and among 13 zones in New England and 11 zones in New York, not within each zone.

Although this report is not a transmission plan, it provides valuable information to market participants on the current and likely future status of the transmission grid in this large region. The many charts and tables in this report should help guide market participants on the best locations for new generation and demand-management programs. For example, Fig. 8 shows the likelihood of congestion occurring at key locations within the region, based on a probabilistic analysis.

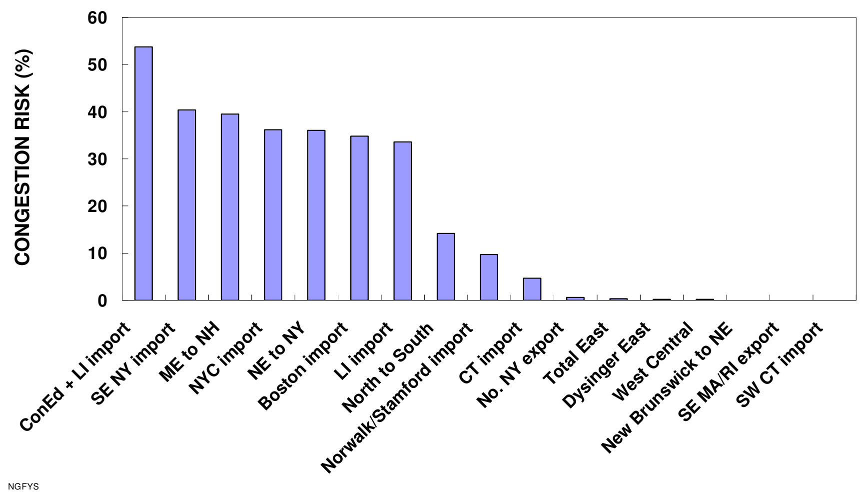

Fig. 8. The likelihood of congestion at 17 boundaries within New England and New York in 2008.

Chapters in this report cover load growth, generation, reserve margins and capacity positions, the current transmission system, deterministic and probabilistic analyses of the ability of the transmission system to handle expected summer-peak power flows, and opportunities for locating new generation.

The report notes that, "At the time this report was prepared, there were no planned transmission reinforcements within New England and New York directed at improving congestion relief (rather than local reliability …)." However some such projects are likely to be proposed soon. According to Hipius (2004):

> Uncertainties related to industry restructuring have slowed the process for considering such projects. Questions such as who pays, how the revenues are

collected and distributed, and how large a return is appropriate given increased risk have made it harder to initiate such projects. New England has mechanisms in place that may enable the utilities to get past these issues more easily than in New York. In fact, projects to relieve congestion in New England have been in the planning stages and are moving toward implementation. In New York, the questions have not been satisfactorily resolved, and the problem is compounded by long-term retail rate freezes. Since transmission costs are not unbundled from retail rates, improving the transmission system could create unrecoverable costs for some utilities. These are not impossible problems to solve, but they are difficult and politically charged. In New York, the costs to construct a truly major system reinforcement (e.g., DC lines into New York City) have been viewed as prohibitive by the utilities, and doubts about their financial viability have always been a deterrent. It may be less costly to live with some level of congestion than to eliminate it entirely. And it's made worse by the fact that upstate utilities would be shooting themselves in the foot to reinforce their transmission paths into southeast New York—upstate utility customers would pay higher locational prices, to the benefit of New York City and Long Island customers, and their reward might be having to pay for all or part of the project! Aside from the paths into southeast New York and Long Island, there is very little congestion on the New York system, so reinforcements into the southeast are the only kinds of projects one might expect to be proposed and built.

The north-to-south diversity in New England and New York suggests there are additional opportunities for cost-effective inter-regional electricity trade with Canada and PJM. With no constraints in the transmission system, imports from Quebec would increase by about 900 MW (20% over baseline conditions), and imports from PJM would decrease by about 400 MW (8%).

Power flows in this region are from the western, northern, and eastern extremities of the system. Transfers progressively increase and become more concentrated as they approach Boston, New York City, Long Island, and Connecticut.

The best places to site new generation are in Boston, southwestern Connecticut, Norwalk/Stamford (in Connecticut), and New York City and Long Island. The worst locations for new generation are Maine and New Hampshire in New England and the Millwood and Dunwoodie regions in upstate New York.

New York ISO

The New York ISO does not yet have a planning process in place. The ISO is working with its stakeholders to develop a formal planning process, initially to focus on reliability, later to develop a comprehensive process that will include congestion. The ISO expects to file its planning approach with FERC in summer 2004.

The ISO and its contractors have published several interesting transmission-planning studies. As part of its reliability responsibilities to NPCC and the New York State Reliability Council, the New York ISO (2002a) analyzed the reliability of the New York transmission grid for the year 2007. This electrical-engineering study included four assessments: (1) load flow and stability analysis to assess the thermal, voltage, and stability performance of the NYISO bulk-power system under normal (design) contingencies; (2) load flow and stability analysis for extreme contingencies; (3) consequences of failure or misoperation of Special Protection Systems; and (4) evaluation of the dynamic control systems on certain generators.

The study is based on the 2002 FERC 715 filings from the utilities. The study lists the proposed transmission improvements through 2007, which "consist of five 345-kV transmission modifications to interconnect new generation, a DC tie between Connecticut and Long Island, a DC tie between Sayreville, NJ and Manhattan, and plans to add about 30 additional miles of 115 and 138 kV transmission."

This study focuses exclusively on reliability with no mention of economic investments in transmission. It looks only at planned generation and transmission projects to see if they will yield a reliable system in 2007. The answer is yes, although close attention needs to be paid to voltage levels in southern New York.

Obessis (2002) reviewed the day-ahead energy market prices in New York to identify the key transmission constraints. Congestion cost electricity consumers $1,240 million in 2000, $570 million in 2001, and $451 million for the first half of 2002. [Recent analysis shows congestion costs of $310 million in 2001, $525 million in 2002, and $688 million in 2003 (Patton 2004).] The Central East interface, in upstate New York, accounted for two-thirds of the total congestion, in and around New York City accounted for one-sixth, and in and around Long Island accounted for the remaining one-sixth. The report states: "Upgrading the noted constraints will not necessarily eliminate or even significantly reduce congestion costs. … [O]ther transmission constraints are likely to be lurking behind the ones noted here, and would themselves cause congestion if the present set are relieved."

The New York ISO (2002b) analyzed "the amount of congestion cost reduction that will result between 2003 and 2010 as a result of the expected generation additions, increased tie capability with neighboring control areas and upgrade of selected internal transmission bottlenecks." This report, however, analyzed only the physics of transmission and did not examine the costs and benefits of transmission investments.

Locational pricing in New York has had a substantial impact on the location of new generation, with large shifts to downstate locations (including New York City and Long Island). Adding new transmission lowers congestion costs, but primarily in the short term (2003) and less so in 2006 and 2010. The reduction in benefits over time is a consequence of the assumed increase in downstate generation. An issue not addressed in this study is whether less generation would (should?) be built downstate if new transmission is constructed.

This report concludes that development of combined-cycle units in the congestion zones "will be the major element …" in providing congestion relief. "… generation development, which is responding to locational market prices, is locating in areas where the capacity additions have a positive impact on congestion costs. The generation expansion scenario results in a close to 60% reduction in congestion costs between 2003 and 2010. Since the opening of the NY wholesale electricity market and the implementation of locational pricing there has been a noticeable shift in the location preference of generation development."

However, although congestion is a persistent problem in the state:

> "… there has not been any major transmission projects proposed to expand the AC transmission network in NY with the primary objective to improve market efficiency. This situation exists even in light of the fact that since January 1, 2000 NY has experienced transmission congestion costs on the order of 2.23 billion dollars or annual rate of 900 million dollars a year. This level of congestion cost is equivalent to slightly more than 75% of the annual revenue requirement (1,155.9 million dollars) necessary to recover the embedded cost of the [New York] transmission assets … ."

Although congestion costs in downstate New York are very high (perhaps the highest in the United States), little transmission is planned to reduce these costs. Four reasons have been suggested for this lack of transmission expansion. First, as noted above, New York has not decided who will pay for new transmission and how. That uncertainty, coupled with retail-rate freezes, inhibits utilities from making what might otherwise be needed investments. Second, building more transmission might not lower overall electricity costs in New York. Instead, such investment might lower costs for downstate consumers at the expense of upstate consumers. That is, the amount of low-cost generating capacity located upstate (upstream of the congested interfaces) is not sufficient to serve the needs of both downstate and upstate consumers. Third, locational pricing is motivating investors to build new generation in and near New York City and Long Island. Finally, the congestion costs are largely hedged through Transmission Congestion Contracts, leading to large differences between net and gross congestion costs..

Conjunction LLC, the developer of a proposed 2,000-MW merchant transmission project from upstate to downstate New York, cancelled an auction of capacity on the proposed DC line in March 2004. It appears that potential buyers of transmission capacity, on this and other merchant projects, are unable to accept the risks associated with long-term commitments. Because of this risk aversion, some merchant developers are seeking regulatory solutions to financing problems (Hipius 2004).

MID-ATLANTIC AREA COUNCIL

MAAC includes some or all of the following states: Pennsylvania, New Jersey, Maryland, Delaware, Virginia and the District of Columbia. MAAC contains one control area, PJM. (PJM West includes parts of ECAR and MAIN.)

Although PJM has an extensive planning process, its focus has been on generator interconnection and reliability. PJM is nearing completion of its Economic Planning Process in response to FERC's (2003) approval of PJM's process for assessing the economic need for new transmission. FERC recognizes that these issues are difficult, complicated, and not yet fully resolved. To illustrate, should congestion be measured on the basis of the actual power flows across congested interfaces or the amounts that would flow if the constraints were relieved? Should congestion be measured from the perspective of retail customers, generators, or both?

However, PJM's long history of LMPs and CRRs provides powerful economic signals to investors in new generation (and demand-management programs) on where to best locate new power plants (and demand-management programs), reducing the need for new transmission. Congestion costs for PJM amount to $400 to $500 million a year, 6 to 9% of total PJM billings (PJM 2004). In March 2004, PJM opened a market window for solutions to congestion on 34 PJM transmission facilities (PR Newswire 2004). This 1-year window is intended to encourage market participants to propose generation, merchant transmission, distributed generation, or demand-management programs to reduce congestion on these facilities.

PJM's (2003) latest plan accommodates over 175 generator interconnection requests and six merchant transmission projects, and contains more than 200 transmission upgrades to address reliability requirements through 2007 (Table 6). To date, PJM's transmission plans call for nearly $700 million in investment, of which over $225 million has been completed (Gass 2004).

The PJM plan is primarily a compilation of the projects needed to interconnect new generation to the PJM grid and those needed to comply with NERC and MAAC reliability requirements. The latest report identified four sets of potential reliability problems; projects have been identified and scheduled to resolve these problems. The projects include: adding static and dynamic reactive support to solve voltage magnitude and voltage drop problems, replacing transformers to remedy thermal overload problems, upgrading the current carrying capability of a transmission line to eliminate overloads under contingency conditions, and replacing circuit breakers with larger circuit breakers where their fault interrupting capability is inadequate. However, the PJM plan contains no information on nontransmission alternatives and no assessment of the economic benefits (e.g., reduction of congestion costs) of new transmission. Future PJM plans will identify projects required for economics, consistent with the aforementioned Economic Planning Process.

Table 6. Executive Summary of PJM Regional Transmission Expansion Plan

PJM's 2003 RTEPlan recommends transmission enhancements to meet baseline network system needs over a 2003 through 2007 time frame and to meet the needs of 132 proposed generation projects representing 27,500 MW in PJM Generator Interconnection Queues A through H.

August 2000 Plan: Board of Managers approved first RTEPlan, encompassing more than $550 million of network reinforcement transmission upgrades and direct interconnection facilities for the 45 generation projects in Queue A, representing more than 18,100 MW of capacity.

August 2000 Addendum: Reliability Committee approved Addendum to the August 2000 RTEPlan prompted by the withdrawal of two Queue A projects, resulting in a reduction of $175 million of transmission upgrade costs.

June 2001 Plan: Board of Managers approved second RTEPlan including $420 million for network reinforcement upgrades and direct interconnection facilities associated with 43 generation projects in Queues B and C, representing more than 12,500 MW of capacity.

June 2001 Addenda: Reliability Committee approved three Addenda to the June 2001 RTEPlan prompted by the withdrawal of generation projects from Queues A, B, and C, resulting in a reduction of $190 million in transmission upgrade costs. Committee also approved increase of $31 million in Queue B/C baseline costs based on updated cost estimates.

October 2002 Plan: Board of Managers approved third RTEPlan, including $144 million for network reinforcements costs and direct interconnection facilities associated with 39 generation projects in Queues D, E and F, representing 8,600 MW of generating capacity.

June 2003 Plan: Board of Managers approved fourth RTEPlan, including $148 million for network reinforcement costs and direct connection facilities associated with 41 generation projects and one merchant transmission project in Queues G and H. Two expedited merchant transmission projects in Queue J were also approved.

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL

SERC is the largest NERC region as measured by total generation and load. SERC includes parts or all of 13 southeastern and south central states. The Region is divided into four subregions: Entergy, Southern, Tennessee Valley Authority, and Virginia-Carolinas.

I was unable to identify any published transmission plans for this region. However, I did find two relevant planning documents, and I obtained transmission-planning data (on a confidential basis) from a few utilities within the region.

The Southeastern Association of Regulatory Commissioners (2002) assessed the generation and transmission infrastructure within this region, including the role of the states in planning and siting generation and transmission, and development of regional transmission organizations. The information on transmission in this report comes entirely from the NERC ES&D data base (discussed in Chapter 2).

The assessment notes that "the SERC transmission systems meet NERC and SERC reliability criteria and should have adequate capability to supply forecast demand and energy requirements under normal and contingency conditions. Interregional transfer studies indicate that the ability to transfer power between SERC and other regions, above contractually committed uses, has become marginal on some interfaces."[*]

SERC (2003) publishes an annual reliability review, which looks at demand and energy, supply resources and additions thereto, and existing and planned transmission. This assessment looks only at reliability issues, with no attention given to the economics of imports, exports, and intraregional transfers. The latest assessment states:

> Joint planning studies for the near term horizon continue to indicate that bulk transmission system performance in the SERC Region is adequate to meet projected peak demands and provide contracted firm transmission services. In some instances, operating procedures continue to be utilized to facilitate transfers. The ability to transfer power above contractually committed uses, both intra-regionally and inter-regionally, continues to be marginal on some interfaces under both studied and actual operating conditions. This is a reliability concern because it impacts the geographic diversity of external resources that can be called upon during emergency import scenarios that may result from large unit outages.

SERC completed its second annual Survey of Transmission Development on annual capital expenditures for transmission construction from 2003 through 2007. The five-year total is $6.3 billion, of which $200 million is to interconnect new generation. The 2002 actual figure was lower than the forecast ($1.0 v $1.3 billion), and the 2003 forecasts are lower than the 2002 forecasts, probably because of a slowdown in construction of new generation. The survey shows that all the planned transmission is inside SERC, with no connections planned to other regions. In addition, almost all the planned transmission is within the individual utility

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[*]Conversations with several transmission planners in SERC suggest that deliverability limits are caused primarily by the many gas-fired merchant power plants built in the southeast that did not obtain firm transmission service.

subregions. Although interesting, the SERC report provides little information on the need for additional transmission (for both reliability and commerce) and says nothing about the costs of individual projects or about nontransmission alternatives.

FLORIDA RELIABILITY COORDINATING COUNCIL

Created in 1996, FRCC encompasses peninsular Florida. Florida may represent the other end of the spectrum from New England in terms of the availability of useful information on transmission planning and plans. Searches of the websites of the Florida Public Service Commission (PSC) and FRCC uncovered no documents related to transmission plans.*

Conversations with staffers at the two organizations provided little information. FRCC provides almost no data to the public, revealing its workings and results only to its members and the PSC. The reasons offered for this tight control on its information concern commercial confidentiality and national security. Commission staff, similarly, provided little guidance on the availability of transmission information. In the end, I obtained only one document (FRCC 2003) that contained any information on transmission: a two-page table that lists proposed transmission lines (including line ownership, length, in-service date, voltage, and capacity). No narrative accompanied the table to explain the current status of the Florida transmission grid, likely future problems, potential solutions to those problems, and the specific projects and their costs that would resolve these problems.

MIDWEST

As defined here, the Midwest includes ECAR, MAIN, and MAPP. I combined these regions into one section because the Midwest ISO covers parts of all three. Some utilities in ECAR and MAIN are, or plan to become, part of PJM West.

Midwest ISO

MISO includes transmission systems in 15 states, with more than 110,000 miles of transmission. MISO (2003) issued its first transmission plan in mid-2003. It assembles the reliability-related projects from the individual member utilities, discusses plans to do an independent "top-down reliability review" in 2004, and presents a very interesting economic analysis of congestion reduction, based on simulated LMPs. Thus, the focus of this initial plan is on a regional congestion analysis under a variety of generation- and transmission-expansion scenarios.

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*The Commission's December 2002 report, *Review of Electric Utility Ten-Year Site Plans*, and its September 2003 *Statistics of the Florida Electric Utility Industry 2002* might be expected to include information on the transmission system, but neither report contained any such information.

During the two-year period, 2001 and 2002, MISO called TLRs on 110 flowgates, 19 of which accounted for 80% of all the calls. Transmission owners plan to make transmission improvements that will address 12 of these 19 flowgates.

The local plans are "reliability driven," and focus on the 2002 to 2007 period. These transmission-owner projects call for the addition of 3,600 miles of transmission, relative to today's 112,00 miles of transmission. Only about 1,200 of the 3,600 miles to be added represent new right-of-way (ROW), while the rest involve existing ROW. And about two-thirds of the mileage is for lower voltages, 115 and 138 kV, with the rest at 161, 230, and 345 kV. The total cost of these projects is about $1.8 billion. Capacitor banks would add $0.13 billion to the $1.8 billion. Of this nearly $1.9 billion total, 59% is for "native network load," 20% for "generator interconnections," 14% for "transmission service," and 6% for miscellaneous.

MISO's economic analysis is a 6-year plan, from 2002 to 2007. Its results are approximate, intended to show the "relative effects of transmission additions or generation development scenarios." The simulations were based on a security-constrained dispatch model with a full transmission-system model. The analysis examined four generation scenarios and a baseline plus 10 transmission additions. The transmission additions range from about $300 million for 765- and 500-kV lines to $8.8 billion for the long-term vision called the High Voltage Overlay. The high cost of this High Voltage Overlay could not be justified by the reductions in power-production costs. Table 7 lists the results for the most promising transmission projects. This is one of the very few plans that provides estimates of the costs of new transmission projects and the benefits of these investments.

Table 7. MISO analysis of transmission projects, benefits and costs in million $

	Annual benefits[a]	Capital costs	
		Total[b]	Annualized
Rockport - Paradise	1,421 / 670	294	59
Expanded Rockport - Paradise	1,685 / --	844	169
Iowa and S. Minnesota	444 / 304	667	132
SPP expansion	517 / 259	503	101

[a]Reductions in marginal energy costs with gas at $5/MBtu and at $3.24 to $3.85/MBtu.
[b]The fixed charges rate for these projects is 20%.

The first transmission project would cost $294 million, with an annualized cost of $59 million, compared with a reduction in marginal energy costs of about $1.4 billion a year, for a benefit/cost ratio of 24. However, much of the benefit from this project would occur outside MISO, in SPP, SERC, and MAAC, raising difficult issues of who should (and would) pay for these investments.

Like some of the other better transmission plans, this one is well written. It includes an extensive Executive Summary, available separately from the main 300+ page report.

East-Central Area Reliability Coordination Agreement

I was unable to locate any transmission plans within ECAR. The utilities I spoke with do not publish their plans. And, a review of the ECAR website uncovered no transmission-planning reports. Although ECAR's mission does not include planning, ECAR conducts assessments of the transmission system to determine whether the transmission plans of its members will maintain reliability. ECAR's Transmission Facilities Panel has the following functions:

- Maintain surveillance of transmission line construction schedules.
- Develop programs of mutual assistance for times of emergency with regard to exchange of crews and materials.
- Collect and analyze scheduled maintenance practices and unscheduled outages.
- Correlate transmission line performance with types of transmission line design and equipment specifications.

ECAR's Transmission System Performance Panel has the following functions:

- Develop procedures, methods, and criteria for evaluating ECAR bulk power transmission system performance.
- Appraise the reliability of the ECAR bulk power transmission system, both present and future.
- Perform technical studies as required.

Mid-America Interconnected Network

MAIN, located west of ECAR, includes all of Illinois and portions of Missouri, Wisconsin, Iowa, Minnesota and Michigan. American Transmission Company (ATC 2003), a transmission-only entity within MAIN, published its third plan in September 2003. Formed in 2001, ATC owns and operates 8,900 miles of transmission in Wisconsin, upper Michigan, and Illinois. ATC issues a detailed planning report every year, with six-month updates in between. The ATC system is divided into five zones. Planning occurs at the project level (e.g., generator interconnection), zonal level, the ATC level, and regional level (with surrounding utilities and MISO). ATC has a formal public- and customer-involvement process.

Over the next 10 years (2003–2012), ATC plans 38 projects involving 460 miles on new ROW and 70 projects on 1,050 miles of existing ROW. In addition, ATC plans to install 38 new transformers and 34 new capacitor banks. These projects are expected to cost about $1.7 billion. "ATC anticipates total capital expenditures of around $2.8 billion over this same period."[*] The extra $1.1 billion is for generator interconnections, strategic or conceptual projects, small transmission-distribution interconnections, capital-related maintenance projects, and replacements of protective relays. This new investment is equal to the current book value of the ATC transmission system, which is heavily depreciated.

ATC categorizes projects as conceptual, proposed, or planned depending on how far along in the analytical, planning, and regulatory processes the project is. ATC also considers strategic projects, which would "increase transfer capability into the ATC system," and therefore would improve the economics (lower production costs) of power supply to ATC customers. ATC conducts several types of analyses: power-flow analyses for summer onpeak and shoulder peak for 2004, 2008, and 2012; stability analysis ("to ensure that generators remain stable during transmission system contingencies"); and transfer capability assessments.

The ATC report discusses transmission-system characteristics and limitations for each of the five zones, as well as alternative solutions to the identified problems. Issues relate to generator instability, voltage instability, overloaded lines and equipment, low voltages, and the need to import more power from neighboring zones or regions. The ATC plan emphasizes the importance of the Arrowhead-Weston project, a new 220-mile 345-kV line from Minnesota to Wisconsin. Finally, ATC creates two umbrella plans, one for the northern zones and the other for the southern zones. These umbrella plans seek to optimize system performance over all the projects in each zone.

Mid-Continent Area Power Pool

MAPP, located west and north of MAIN, covers the upper midwest and includes the following states and provinces: Minnesota, Nebraska, North Dakota, Manitoba, Saskatchewan, and parts of Wisconsin, Montana, Iowa and South Dakota. The MAPP members own 20,000 miles of transmission.

MAPP (2002) prepares a 10-year plan every two years focusing on voltages of 115 kV and higher. This plan includes sections for each of the five subregions within MAPP. MAPP's Transmission Planning Subcommittee (part of the Regional Transmission Committee) develops the MAPP plan based on the individual utility plans and the plans from the Subregional Planning Groups. The plan includes a section on "A Visionary Concept of Future Transmission" that includes "over 1,900 miles of new 500-kV lines at a cost of about $1.3 billion for lines and substations." The plan focuses on broad regional transfers (economics) and not on local or reliability issues (although the subregional planning groups do look at reliability). This report provides no information on the costs and benefits of these proposed transmission additions.

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[*]This $2.8 billion exceeds the $1.9 billion for all of the MISO transmission owners because the ATC number is for 10 years and the MISO number is for five years, ATC includes lower voltages than did MISO, and ATC looked at a broader range of projects.

Exports from MAPP tend to occur during shoulder periods, when MAPP has low-cost generation not needed to serve load. Imports, on the other hand, tend to occur during peak load conditions. MAPP analyses covered maximum imports and exports during peak load periods and a 72% shoulder period. Analyses were conducted for 2002, 2007, and 2012.

As shown in Fig. 9, MAPP plans to upgrade 1,600 miles of existing transmission lines and build almost 1,800 miles of new lines. On a GW-mile basis, almost two-thirds of the capacity additions will come from new construction.

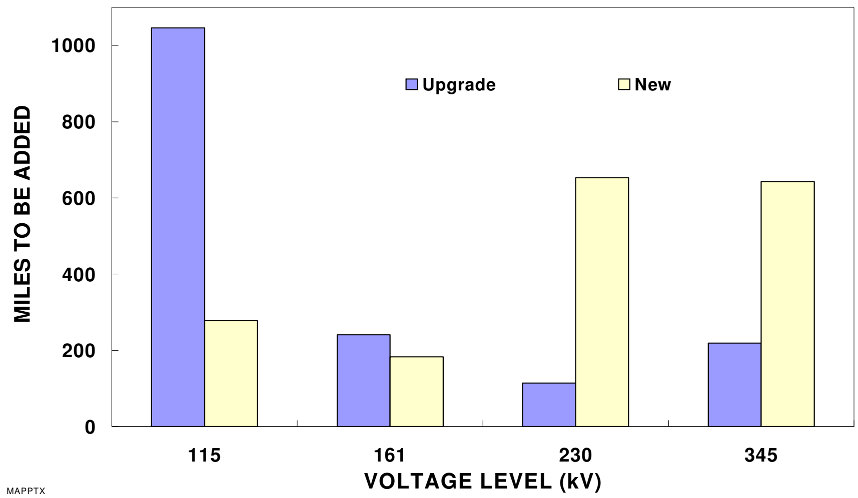

Fig. 9. MAPP plans for transmission additions, as of mid-2002, by voltage level, existing and new rights-of-way.

Minnesota

A 2001 state law requires the Minnesota utilities to submit transmission plans to the Minnesota PUC. Fifteen Minnesota Electric Utilities (2003) prepared the second such report. These utilities own and operate more than 6,500 miles of transmission, worth more than $750 million. "The biennial report is meant to enable the PUC to review transmission projects in the overall context of other regional transmission projects being considered." If the Commission decides a particular project is important enough, it can place it on its "priority electric transmission list," which means the project does not need a separate Certificate of Need to proceed with construction.

This report looks at transmission problems and alternative solutions (transmission only) over the next 10 years. The report clearly notes the advanced age of the Minnesota transmission system and the lack of recent investment:

> Minnesota's electric transmission system has historically been very reliable, but like the grid generally, is experiencing unprecedented demands. Portions of Minnesota's transmission system are 35 to 50 years old, and others date back as far as 80 years. Minnesota's last major transmission facility addition was constructed in coordination with Sherburne County No. 3 generating plant, which went into service in late 1987, nearly twenty years ago. More recent investments … [were] designed to preserve reliability and provide incremental

> improvements in transmission efficiency by taking advantage of new technologies (e.g., capacitor banks to maintain voltage). … This limited expansion of the transmission system over the last two decades has resulted in:
>
> - portions of the system being at or near capacity;
> - the system being unable, without more capacity, to handle load growth; and
> - problems associated with interconnecting and delivering the output of new generation facilities.

The report provides details for each of the six planning zones, including a description of the transmission system, the utilities and their contacts, system inadequacies, and alternative solutions ("… information on alternative means of addressing each inadequacy, studies that are planned to determine the best method to correct each inadequacy, and economic, environmental, and social issues associated with each alternative"). The discussions of these issues are short and general. Usually, cost estimates for each alternative are provided.

This report focuses mostly on local reliability issues, rather than statewide or regional problems. That is, the report does not discuss congestion or the possible benefits of increasing regional transmission capacity for imports or exports to Minnesota. Such broader issues exist in and around the twin cities (Minneapolis-St. Paul). Constraints to the east and south of the cities limit the ability of Xcel Energy to make long-term purchases and sales. For example, the output from a planned low-cost generator in Wisconsin could not be reliably imported to Minnesota because of transmission limitations.

To some extent, the lack of attention to regional issues might be associated with the emergence of MISO as the *regional* planning entity. As this report notes, the regional planning efforts of MISO and MAPP are "in a transition period" as MISO develops. Eight of these 15 Minnesota utilities are either MISO members or have applied for membership.

SOUTHWEST POWER POOL

SPP includes Oklahoma, Kansas, and portions of Mississippi, Missouri, New Mexico, Texas, Arkansas, and Louisiana. SPP routinely performs regional assessments of the transmission system and coordinates studies among its transmission owners.

Begun in 2000, the latest SPP (2001) study identified potential upgrades to relieve known constraints within the region. This plan focused on five interfaces that limit imports to and exports from SPP. This study did not deal with reliability problems (except for some discussion of voltage levels), and it did not look at congestion *within* SPP. The analyses were conducted for the summers of 2004 and 2006. The total cost for the five projects was estimated at $337 million. This plan was very technical and, perhaps as a consequence, difficult to understand.

Subsequently, SPP participated in the transmission planning efforts of MISO, discussed above. These activities continued until termination of the MISO-SPP merger discussions in early 2003.

SPP is now doing a major reliability study, to be completed in late 2004. SPP is not sure how best to conduct an economic assessment of transmission given the uncertainties about what markets and pricing might be like within the region, which is why it is focusing on reliability for now.

ELECTRIC RELIABILITY COUNCIL OF TEXAS

ERCOT, located entirely within Texas, includes about 85% of the state's electrical load. Its 2003 report, the fourth of its annual transmission plans, defines two types of congestion: (1) commercially significant constraints (CSCs) limit flows among the four major zones in ERCOT, and (2) local constraints operate within one of the zones (ERCOT 2003a). From June 2002 through May 2003, CSCs cost $32 million while local constraints cost $206 million, for a total congestion cost of $238 million.[*]

The ERCOT report identifies three CSCs plus five significant local constraints. The report also lists major ERCOT-recommended projects that have been completed, recommended and under development by the transmission owners, and under study or design development. ERCOT transmission owners added over 700 miles of new 345-kV and 200 miles of 138-kV transmission in the past three years, as well as two STATCOMs, switching stations, and other equipment.[#]

This report provides no dollar estimates on the costs to build any of these projects. ERCOT has begun a project to track cost estimates, called Transmission Project and Information Tracking. The report also does not explain how the ERCOT results and recommendations are derived from the outputs of the studies done for the three ERCOT planning regions (South, North, and West). In particular, is the ERCOT plan more than the compilation of the three regional plans? The report mentions but offers no analysis of how generation and demand-management might solve transmission problems. Because the report focuses on the cost of congestion in ERCOT (based on the ISO's expenditures on balancing-

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[*]RMR units (generators run out of merit order) provide a costly solution to congestion. It is not yet clear whether the most economic solution is to continue running RMR units or to build new transmission. This RMR issue occurs primarily in and around large urban areas, especially Dallas-Ft. Worth (and less so in Houston, which has a stronger local transmission system).

[#]The Texas PUC decided that all transmission investments are to be paid for by all retail consumers, thus eliminating the debates that occur in other parts of the country over who should pay for what kinds of transmission investments. Because ERCOT lies entirely within Texas, transmission planning and construction are overseen only by the PUC, not by FERC as well.

energy costs and out-of-merit energy and capacity costs), it does not consider transmission needed to meet NERC planning standards.*

> … this report communicates to generation entities, load-serving entities, other market groups, the public, and the PUCT the nature of transmission constraints and the projects being considered by ERCOT to relieve these constraints. It serves as a starting point for developing proposed projects for approval within the ERCOT Transmission Planning Process, and it may be useful in the preparation of regulatory and other reports that require transmission grid planning information.

This quote suggests this report does not include transmission needed primarily for reliability nor for generator interconnection. The report also notes that "ERCOT performs no specific routing evaluations," which may explain why the report includes no cost estimates for the various projects.

Future ERCOT studies will identify the extent of congestion and the numbers of hours congestion is likely to occur. Such analyses will help determine where new transmission is the preferred solution. The Texas PUC ordered ERCOT to implement nodal pricing by summer 2006. Such economic information (now available only in New England, New York, and PJM) will likely affect transmission planning as well as the locations of new generation.

WESTERN ELECTRICITY COORDINATING COUNCIL

WECC is the largest geographically of the 10 regional councils, with long distances between major power plants and large load centers. Its territory is equivalent to more than half the contiguous area of the United States. WECC includes all or parts of Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming, as well as the Canadian provinces of Alberta and British Columbia, and the northern portion of Baja California in Mexico.

SSG-WI

The Seams Steering Group—Western Interconnection (SSG-WI 2003) developed a transmission study for the entire region. It used 2008 as the baseline, which "includes

*The ERCOT transmission owners simulate system performance under normal (no contingency), N−1, and N−2 conditions to determine compliance with NERC and ERCOT reliability requirements. Transmission owners are required to develop and report plans to resolve criteria violations. ERCOT staff perform spot checks of these assessments. ERCOT staff also conduct their own studies of all projects at or above 345 kV and those involving multiple owners.

generation and transmission infrastructure reasonably certain to be in place by 2008."[*] The study focused on and analyzed three generation scenarios for 2013. These scenarios emphasized different fuels in the mix of generation: natural gas, coal, or renewables. The scenarios consider three different gas prices and two different levels of hydroelectric output. The need for new transmission is more sensitive to the price of gas than to hydro conditions. The transmission investments required for the three 2013 scenarios are: $2.6 billion for gas (1,300 miles of new transmission), $16.7 billion for coal (7,600 miles), and $6.7 for renewables (3,400 miles).

The key findings from this study are

- If new generation is primarily gas fired relatively few transmission additions will be required.
- The development of coal and renewable resources in remote locations will require substantial transmission additions. However, this could be more cost effective from an overall perspective than new natural gas generation because it would lower power production costs substantially.
- There are areas on the grid that will be congested in the near future; solutions to these problems should be investigated in subregional forums.

These findings show the interactions between generation investment and transmission investment. The need for new transmission to support wind farms located far from load centers was also identified in ERCOT (to move wind output from west Texas to the load centers) and Minnesota (to move wind output from the southern part of the state to the Twin Cities).

This study looked only at congestion (economic) issues and did not consider transmission investments that might be needed for reliability. The report examined the 33 major transmission interfaces in the west and not any *intra*control-area issues.

Because the SSG-WI study was conducted over such a large geographical area, it could not analyze transmission on a disaggregate basis. Therefore, this study cannot form the basis for specific investment decisions. Four sub-regional planning groups, coordinated by SSG-WI, do detailed transmission planning, including that needed for reliability. The Central Arizona Transmission System group, formed in 2000, prepared detailed studies, some of which led to construction of new transmission, especially around the Palo Verde substation. CATS, recently

[*] The 2008 case also shows "significant stranding of low-cost generation in Canada and in the Desert Southwest. Approximately 1,300 miles of new 345- and 500-kV line would be required to completely eliminate this identified congestion, which could result in an annual savings in the production cost of generation … totaling at least $110 million."

renamed the Southwest Area Transmission Planning Committee, expanded to include all of Arizona plus New Mexico and parts of Colorado, Nevada and California.

The Southwest Transmission Expansion Project (STEP) is evaluating the economic benefits and costs of new transmission to move generation from Palo Verde to other areas in the west, especially California. The Rocky Mountain Area Transmission Study includes the transmission systems in Montana, Colorado, Idaho, Utah and Wyoming. Finally, the Northwest Transmission Assessment Committee (NTAC) was recently formed to provide "a forum to address the further planning and development of a robust NWPP [Northwest Power Pool] area transmission system. This planning and development would identify future transmission needs by performing studies to identify solutions. The forum would look at expanding current system capability. This would mean more than reliability planning or maintaining current capability" (Northwest Power Pool 2004).

Arizona Corporation Commission

As in Minnesota, the Arizona Corporation Commission (ACC 2002) requires its utilities to file transmission plans every year. The ACC staff then reviews these plans, including discussions with the utilities and open meetings, and prepares a report to the Commissioners on the state of Arizona's transmission grid and the utilities' plans to meet future needs. The Commission is then required by legislation "to issue a written decision on the adequacy of the existing and planned transmission facilities in Arizona to meet the present and future energy needs of the state in a reliable manner." The 2002 assessment is the second one issued by the ACC.

The utility plans must provide: "(1) The size and proposed route of any transmission lines proposed to be constructed. (2) The purpose to be served by each proposed transmission line. (3) The estimated date by which each transmission line will be in operation." These requirements do not encompass any economic information, in particular the cost of each proposed project and its likely benefits. The utility plans include about 50 projects, roughly half of which were in the first biennial assessment.

This is an interesting and well written report. It discusses the existing transmission system and plans to expand the extra-high voltage system (345 kV and above) for regional purposes. The system was originally constructed to move the output from large generation resources in the northeastern and northwestern portions of the state to the major load centers (the Phoenix and Tucson metropolitan areas). The report also examines import constraints to the major load centers (especially Phoenix and Tucson), plans for local areas (the system below 230 kV), and transmission related to merchant generation.

The chapters in this report discuss the existing transmission system, the utility 10-year plans, the extra-high voltage system and several 230- and 500-kV projects to expand it, local import constraints for five regions and the RMR contracts used to relieve congestion in these areas, and local transmission internal to each major load center (for areas with no local generation).

The staff is pleased with the utility plans and the utility responsiveness to staff concerns expressed in the first transmission assessment. This report is much more positive on the state of transmission in Arizona than was true for the first biennial assessment, in large part because important projects are being constructed in Arizona (Table 8).

Table 8. Transmission lines and substations added in Arizona since the first Biennial Transmission Assessment (2001 and 2002)

Description	Voltage (kV)
White Tanks - West Phoenix #1 and #2	230
Browning Substation	500 / 230
Redhawk - Hassayampa #2	500
Palo Verde - Hassayampa Common Bus	500
Gila River - Jojoba #1 and #2	500

The plans to expand transmission around the Palo Verde substation are not enough to accommodate the full output of all the new generation planning to interconnect at this hub. This problem was also cited in the first biennial assessment. About 10,000 MW of generation is now connected to the transmission system at Palo Verde with plans to add another 3,600 MW. The capacity of the transmission system today is only about 7,300 MW, which suggests that up to 6,300 MW of generation could be locked in and unable to deliver its outputs to markets. The STEP effort is addressing these transmission issues.

In addition, load growth in Phoenix, Tucson, and a few other places pose potential problems for transmission imports and suggest the need for more local transmission. Finally, there is little spare capacity on the extra-high voltage system to move power long distances across or within the state.

California

Budhraja et al. (2003a) examined the value of transmission in permitting imports of power from other parts of the WECC. California's transmission import capability totals about 18,200 MW and consists of the following key links:

- 7,900 MW from the Pacific Northwest, built at a cost of $1.6 billion with benefits from 1969 through 1999 of $7.2 billion;
- 1,900 MW from Utah, built at a cost of $1.2 billion primarily to provide access to 1,600 MW of coal-fired generation in Utah;

- 7,500 MW from the Desert southwest, built at a cost of $1.3 billion with benefits from 1971 through 1999 of $5.7 billion; and
- 800 MW from the Baja region of Mexico.

California's import capability increased rapidly from almost nothing in the late 1960s until about 1995 and has been flat since then. "Since the late 1980s, California IOUs have been unsuccessful in gaining regulatory approvals to build major new projects. These include for example: Third Pacific AC Intertie, Palo Verde-Devers No. 2, Path 15 [work on Path 15 is now underway, and the planned operating date for the project is late 2004], Path 26, and Valley-Rainbow."

Failure to gain regulatory approvals were caused by uncertainty about future benefits, especially long-term benefits, economic valuation methodologies that do not recognize the strategic value of transmission, and use of average conditions that ignore the insurance benefits that occur during emergencies and other unusual conditions.

Budhraja et al. (2003b) focuses on the long-term (to 2030) need for additional transmission investments to permit greater imports to California. The report estimates a need for 26,500 MW of import transmission capability.

> Hence, the state needs to expand the current level of 18.2 GW of transmission interconnections by 8.3 GW to meet its future electricity needs. …
>
> Several new interconnection projects are under discussion including Devers-Palo Verde 2, with approximately 1,400 MW of capacity; doubling the interconnection between California and Baja Mexico, adding 800 MW of capacity; and doubling the interconnection to Utah, adding 2,000 MW of capacity. This still leaves a need to develop another 4,000 MW of interconnections in the base case and over 9,000 MW in the higher imports scenario as part of California's Grid of the Future.

The California ISO reviews individual utility transmission plans on an annual basis. The ISO conducts a stakeholder process, analyzes the utility's modeling results, recommends revisions (if necessary) to the utility, and makes final recommendations on whether these projects are economical and should proceed to construction. Thus, the California ISO (2003) plan is primarily a review and compilation of the utility plans. Appendices to the ISO report provide details on the electrical-engineering analyses conducted for the northern and southern portions of California's electric grid for different seasons. This report lists nine "Major New Transmission Projects," but says nothing about the costs and benefits of these projects. Appendix D lists almost 50 major transmission projects, but, again, provides no discussion of these planned facilities.

The California ISO does not conduct independent analyses of the need for new transmission, in particular the need for transmission between and among the utilities (as opposed to the local analyses of the individual utilities themselves). The ISO's key function is to ensure that the utilities have done their studies properly and that the projects proposed by one utility will not have adverse effects within another utility's service area. The STEP process (discussed above) is used to conduct interutility and regional studies between California and the Southwest. The NTAC process (also discussed above) will fill a similar role between California and the Northwest.

The California Energy Commission (2003) noted that:

> Under existing generation and load conditions, the transmission system regularly experiences congestion on major paths that prevents its optimal economic operation. Also, transmission constraints in major load centers such as San Francisco and San Diego affect both the economic and reliable operation of the system. Transmission upgrades, generation additions, and demand-side management actions may provide solutions to these problems. However, the existing transmission planning and permitting processes have not provided effective and timely mechanisms for bringing forward such projects to provide California with a more robust and reliable transmission system.

Bonneville Power Administration (BPA)

BPA operates over 15,000 miles of transmission lines, including connections to Canada, California, the southwest, and eastern Montana. "Despite significant growth in the Northwest population and economy, there has been virtually no substantial transmission construction since 1987" (BPA 2003a). In 2001, BPA identified 20 projects needed to expand and improve the reliability of its transmission grid. Since then, slower economic growth and, especially, the cancellation of several merchant generating units have reduced the need for some of these projects. Six of the 20 projects are under construction or nearing completion.

In December 2003, BPA completed the 9-mile Kangley-Echo Lake 500-kV transmission line at a cost of $40 million, to improve reliability in the Seattle area. It is also working on five other projects needed for reliability plus five needed to interconnect new generation. Although BPA does not issue formal transmission plans, its website provides information on individual projects; see http://www2.transmission.bpa.gov/PlanProj/Transmission_Projects/.

BPA plans to spend almost $1.8 billion over the next five years. This planned expenditure is allocated across different project types as follows (French 2004):

- Main Grid (63%): major new transmission facilities, i.e. 230- and 500-kV additions to the BPA system, including major substations, transmission lines, series and shunt capacitors, and shunt reactors. These projects are usually associated with new generation projects or long-term load growth.

- Area and Customer Service (7%): Similar to Main Grid projects, but usually at 115-kV and lower, smaller in size and scope, often needed to support a customer or a group of customers in a specific location.

- Upgrades and Additions (16%): Small projects that upgrade existing equipment or increase capacity, such as the addition of a sectionalizing breaker to prevent the loss of a substation for a faulted breaker, reconductoring a transmission line with a larger conductor to increase power flow, the addition of a bus tie breaker position to allow maintenance activities to take place without jeopardizing system operation, or upgrading communications and metering facilities to provide additional data.

- System Replacement (14%): Replace old, worn-out, and/or obsolete equipment. Items include many different elements, from circuit breakers and disconnect switches to relays and control equipment, metering facilities, trucks and test equipment.

BPA (2003b) explicitly examines nontransmission solutions to transmission projects. As part of that process, BPA is testing a demand-response program on the Olympic Peninsula. BPA hopes to acquire about 30 MW of peak-demand reduction that would permit it to defer otherwise needed transmission investments.

DISCUSSION OF PLANS

Chapter 3 discussed 20 transmission plans and related documents. This chapter summarizes the key elements of this very diverse set of planning documents. These studies varied considerably in the topics covered, the provision of information on the current status of the transmission system and its uses and problems, alternative solutions to these problems, the costs and benefits of these alternatives, and the clarity of presentation (Table 9).

The studies were roughly split in their focus on transmission needed to maintain reliability v transmission needed to reduce congestion. Few of the studies took a broad view of transmission needs and studied both reliability and economics, as well as interconnection and equipment-replacement issues. In several cases, the analyses of transmission needs for reliability and those for economics were conducted by different groups. This separation makes it difficult to ensure consistency among studies.

The studies generally did not report the projected costs of the transmission projects studied. Even fewer analyzed the potential benefits of these projects and sought to compare costs and benefits; the Midwest ISO and SSG-WI studies were the sole exceptions. Almost all these plans ignored transmission-system losses and the potential for reducing losses. Without a clear understanding of the costs and potential benefits of a transmission project, it is difficult for regulators and stakeholders to consider whether the project should be built and, if so, who should pay for it.

Analyzing the economic benefits of transmission projects is difficult. Reliability projects could be assessed in terms of their ability to reduce the loss-of-load-probability and the value-of-lost-load. While it is possible to calculate changes in LOLP associated with different amounts and location of generation and transmission, estimates of VOLL vary widely. The VOLL is probably very case specific, a function of the particular customer, when the outage occurs, how long it lasts, and whether the customer had advance notice of the outage.

For transmission projects aimed at reducing the cost of power production and delivery, the benefits can be assessed from the perspective of customers, generators, or the system as a whole. Such transmission projects can involve major wealth transfers between consumers and producers in different locations. For example, consumers downstream and suppliers upstream of a constrained interface benefit from construction of transmission facilities that relieve the constraint, but downstream suppliers and upstream consumers can be hurt by such investments.

Table 9. Characteristics of transmission-planning studies reviewed in Chapter 3

Source	Considered:		Analyzed:		Comments
	Reliability	Economics	Costs	Benefits	
Northeast Power Coordinating Council					
ISO New England (2003)	✔	✔	✔		Well written and organized, comprehensive
National Grid (2003)	✔				Useful guide to market participants, not intended to be a plan
Obessis (2002)		✔			Analyzed key constraints, not a plan
New York ISO (2002a)	✔				Traditional electrical-engineering study, not a plan
New York ISO (2002b)		✔			Analyzed reductions in congestion costs from new generation
Mid-Atlantic Area Council					
PJM (2003a)	✔		✔		Focused on generator interconnections and compliance with reliability rules
Southeastern Electric Reliability Council					
Southeastern Assoc. Reg. Comm. (2002)					Assessed infrastructure, not a plan
SERC (2003)	✔				Traditional reliability assessment, not a plan
Florida Reliability Coordinating Council					
No published reports on transmission plans from either FRCC or the Florida PSC					
East Central Area Reliability Coordination Agreement					
Midwest ISO (2003)		✔	✔	✔	Good analysis of congestion costs and solutions, plans to conduct independent reliability assessment
Mid-America Interconnected Network					
ATC (2003)	✔	✔	✔		Comprehensive and ambitious plan, well written
Mid-Continent Area Power Pool					
MAPP (2002)		✔			Focused on regional power transfers, subregional groups focus on reliability

Source	Considered: Reliability	Considered: Economics	Analyzed: Costs	Analyzed: Benefits	Comments
MN Electric Utilities (2003)	✔		✔		Analyzed issues for six planning zones, not for larger region
			Southwest Power Pool		
SPP (2001)		✔			Focused on five interfaces, very technical, hard to read
			Electric Reliability Council of Texas		
ERCOT (2003)		✔			Focused on congestion, its costs, and transmission solutions, well-written
			Western Electricity Coordinating Council		
SSG-WI (2003)		✔	✔	✔	Analyzed transmission needs for alternative generation scenarios, well-written
ACC (2003)	✔	✔	✔		Well-written assessment of utility plans from a statewide perspective
Budhraja et al. (2003a and b)		✔			Transmission needed to import power to California
California ISO (2003)	✔				Sketchy summary report, technical appendices

Such an economic-analysis "approach must address the impact a transmission expansion would have on increasing transmission users' access to generation sources and demand areas, the impact on incentives for new generation investments, and the impact on increasing market competition [and reducing market power]" (California ISO and London Economics International 2003). Such an analysis must also account for the many uncertainties about future demand, amount and location of new generation, fuel prices, and the interactive and decentralized nature of investment decisions for generation and transmission. It is especially difficult to analyze the benefits of new transmission when investors can locate new generators in areas that lack sufficient transmission to move that power to load centers.

None of the studies (except perhaps the ISO New England plan and BPA) analyzed alternatives to the projects presented, both other transmission projects and nontransmission solutions to transmission problems

Many of the planned projects are local. They focus on improving reliability of delivery to large load centers. Few of the projects cut across control-area boundaries and are aimed at increasing transfer capabilities throughout a region. The New England, Midwest, ERCOT, and SSG-WI plans are exceptions to this statement. None of the projects (except for a few merchant DC links and the SSG-WI study) encompass large regional power flows.

As shown by the spotty geographical coverage of the plans, many entities provide little or no public information on transmission. The director of the transmission-planning department in a large utility stated: "We publish those portions of our transmission plan that are necessary to meet regulatory requirements, such as the federal EIA-411 and FERC Form 715 data requests, as well as various state filings. When we request regulatory approval for a specific project, our application focuses on that project as required by state certification rules. None of our regulatory commissions requires the filing of a comprehensive, systemwide transmission plan." Thus, many transmission owners likely prepare plans but do not publish them.

The electricity industry often encounters opposition to its proposals for construction of new transmission lines. Addressing and overcoming such opposition requires that transmission owners explain clearly, and in layperson's terms, why the project is needed, possible alternatives to that project, expected project costs, expected benefits, and who the beneficiaries will be. Closing the gap between current planning reports and best practices provides a clear opportunity to improve prospects for transmission-system enhancement.

The ERCOT (2003b) System Planning charter sets forth a useful structure for analyzing transmission problems and proposed solutions:

- Description of the reliability and/or economic problem that is being solved;
- Description of the proposed project, feasible alternative(s) considered, data, and all studies supporting the need for the project, accurate maps and one line diagrams showing locations of project and feasible alternatives;
- Analysis of rejected alternatives, including cost estimates, effect upon transfer capability, and other factors considered in the comparison of alternatives with the proposed project;
- Assumptions used in computer studies such that credible performance deficiencies can be identified;
- Performance analyses that are consistent with system operating practices and compliant with the ERCOT Planning Criteria;
- Documented process to identify specific performance deficiencies (reliability and economic);
- Stakeholder/market participant review of the assumptions justifying transmission projects based on economic benefits as opposed to reliability criteria violations;
- Consideration of both transmission and non-transmission solutions to performance deficiencies; cost estimates should account for transmission investments, system losses, and congestion relief. To the extent generation dispatch can alleviate reliability needs, both reliability and economic impacts should be considered in the selection of solutions;
- Consideration of alternatives submitted by market participants and due consideration of their transmission project proposals, with an opportunity for timely input by other stakeholders;
- Implementation of planned solutions on a schedule that permits adjustment of scope or schedule when conditions change significantly;

- When resource limitations prevent the timely completion of projects, project service dates should be prioritized considering the severity of need and the project-specific limitations such as construction clearance availability, equipment lead-times, and regulatory approval processes.

Hirst and Kirby (2002) also developed a transmission-planning process, the key elements of which are shown in Fig. 10 and Table 4.

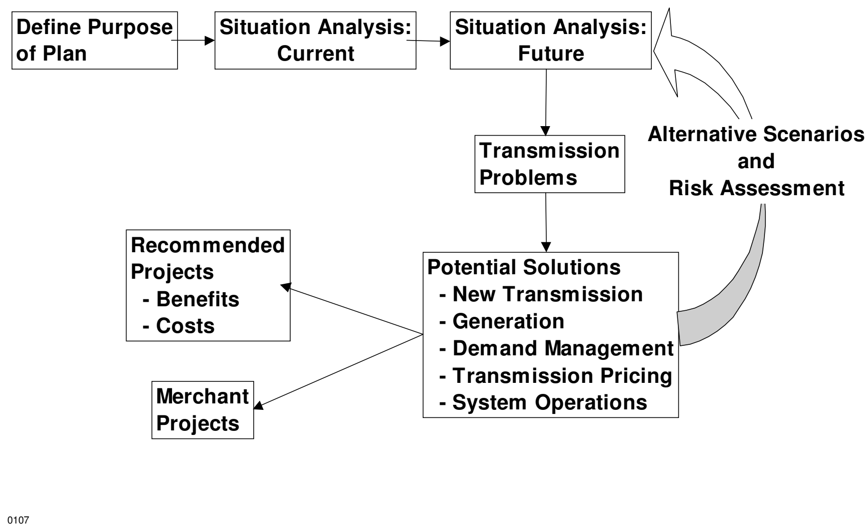

Fig. 10. Proposed transmission planning process.

The Chapter 3 review of published transmission plans shows that only a few of those documents meet the stringent goals of the ERCOT charter and Hirst/Kirby proposal. The planning documents prepared by ISO New England, National Grid, Midwest ISO, American Transmission Company, ERCOT, and SSG-WI are all models that other transmission owners and planners could use to improve the content of their transmission plans and planning reports.

Table 10 lists a few of the key transmission problems throughout the country and the steps being taken to address these problems. This is definitely a partial list, both because I was not privy to all the relevant transmission plans in the United States and because my review of the plans discussed in Chapter 3 probably overlooked some key problems and projects. The table suggests that different regions face different kinds of problems, and that some problems are being addressed and others are not.

Table 10. Incomplete list of key transmission problems and their solutions

Problem	Solution
New England: imports into SW Connecticut and NW Vermont, and also Boston area	Many projects underway, especially for Connecticut and Boston, to expand capacity, although less quickly than would be optimal
New York: Major congestion in moving power from upstate to New York City and Long Island	Additional generating units constructed and planned in congested area; proposals for merchant DC lines, completion of which is uncertain.
SERC: Lots of merchant generation coming online with insufficient transmission to deliver output to distant load centers	
Midwest ISO: Limited import capability from MAPP to MAIN (into Wisconsin); limited transmission from the Dakotas (wind and coal generation) to load centers. Constraints also exist from southern Indiana and Kentucky	ATC proposes Arrowhead-Weston 345-kV line from Minnesota to Wisconsin
ECAR: Long-term reliability problem in southeastern part of region	Construction of Wyoming-Jacksons Ferry 765-kV line, first proposed in 1991, to be completed in 2006
ERCOT: Constraints in moving power from outlying regions to Dallas-Ft. Worth and Houston areas	Many transmission projects completed, underway, and planned
WECC: Need for large new transmission projects a function primarily of generation fuel choices and locations	
California: Imports into San Francisco and San Diego constrained, economics limited over Path 15 and from Palo Verde to southern California	Local generation in and near San Francisco and San Diego; expansion of Path 15 in California underway; proposal for second 500-kV line from Devers to Palo Verde
Pacific Northwest: Reliability problems delivering power to Seattle area	Kangley-Echo Lake 345-kV line completed in late 2003

CONCLUSIONS

NERC's (2003d) latest *Reliability Assessment* noted that

> The pace of transmission investment has lagged behind the rate of load growth and generating capacity additions. Many factors have led to this condition, including the way in which the grid was developed, viable alternatives to the construction of new transmission lines, and public, regulatory, and financial obstacles to the construction of new transmission facilities. In light of these factors, it is likely that transmission owners will increasingly rely on system upgrades rather than new transmission lines for increased transmission capacity.
>
> The North American transmission systems are expected to perform reliably. However, in some areas the transmission system is not adequate to transmit the output of all new generating units to their targeted markets, limiting some economy energy transactions but not adversely impacting reliability.

This assessment is supported by the data NERC collects on installed and planned transmission capacity. These data and projections, discussed in Chapter 2, show a continuation of past trends. Transmission owners continue to add transmission capacity at a much lower rate than consumer demand is growing. These trends are roughly consistent across all 10 reliability regions. Interpreting these trends is difficult because details on the types of transmission construction and the problems these investments are meant to solve are not available. While I consider these trends troubling, others might view them as an indicator of increased efficiency of transmission usage or a consequence of the recent construction of gas-fired generation close to load centers.

However, other analysis indicates that the transmission investments planned for the next several years may not even be enough to replace today's aging infrastructure let alone meet growing demand: "The evidence suggests that investor-owned utilities have reduced transmission and distribution spending to bare-bones levels, that spending will have to rise significantly in the near future in order to meet the needs of customers, and that the higher level of spending will trigger rate hike filings in order to cover the costs of the new capital" (Hyman 2004). And U.S. transmission investment as a share of electric revenue declined from 10% in 1970 to 6% in 1975, 4% in 1980, and just over 1% from 1985 through 2000 (Boston 2004).

The one exception to these declining trends are the EEI data on investments in new transmission facilities made by investor-owned utilities. Although these data show the same long-term decline in construction expenditures, the data from 2000 through 2003 show substantial increases in transmission investments.

Given the value of these NERC and EEI data for understanding transmission issues, more time and attention should be devoted to ensuring complete reporting by all transmission owners, expanding the data collected to cover facilities that add capacity but do not add mileage to the transmission system, verifying the accuracy of these data, analyzing them, and reporting the results of these analyses. Although EIA and FERC collect data on past and projected transmission facilities, neither cleans the data nor publishes summaries. Given the importance of transmission as a policy issue, this situation should change even though tight budgets limit what can reasonably be done. EIA (2004) proposes to expand its data collection on Form EIA-412 to include "Transmission System Upgrades" to existing lines (e.g., reconductor line, install dynamic thermal rating, install capacitors, or install reactors) and terminal stations (e.g., transformer, bus bar, protection system, or switchgear).

The review of transmission plans and related documents (Chapter 3) shows wide variation across utilities and regions. The need for new transmission is not uniform across the country; rather, it is very location specific. Krapels (2003) writes that:

> "In 90 percent of … the United States, it is challenging, but possible, to establish a mix of generation and transmission assets that constitute an efficient power infrastructure. In the other 10 percent, it is extremely difficult to do so, and over time these areas have evolved into 'load pockets.' These are typically densely populated areas where generation facilities were built decades ago, are difficult to refurbish (and thus highly polluting) and where transmission grids are similarly dated and compressed.
>
> The majority of the people in this country live in that 10 percent of the landscape. Thus, the central interest in transmission *policy* should be—but seldom is—in the 10 percent of the landscape that contains the load pockets of the power markets.

Locational prices and congestion revenue rights can help stimulate market solutions to transmission problems. By themselves, however, they are probably not enough. And LMPs and CRRs are used in only a few parts of the country where ISOs are well established (New England, New York, and PJM with plans for the Midwest, ERCOT, and California). The difficulties merchant projects have experienced recently in obtaining long-term commitments from users indicates the limits of this approach. PJM just initiated a process to encourage market solutions to transmission problems. If market participants do not propose solutions within a year, PJM will recommend regulated transmission solutions.

Most of the transmission planned for the next few years is focused on local reliability needs. Other than a few merchant DC projects, I found no plans to build transmission lines to connect large regions. Although the SSG-WI study discusses several such projects, the region's transmission owners and state regulators have not yet committed to their construction. Exacerbating this omission is the lack of an agreed-upon methodology for analyzing the benefits (to whom?) and costs of such projects.

The transmission reports discussed above vary widely in the topics they cover and the quality of their presentation. A few, in my view, are excellent, in particular those prepared by ISO New England, National Grid, the Midwest ISO, American Transmission Company, ERCOT, and SSG-WI. These exemplary documents, as well as the ERCOT charter and Hirst/Kirby proposal, could form the basis for an industrywide effort to define and disseminate a "best practices" approach to the content and reporting of transmission plans. By and large, the best published plans were prepared by ISOs, transmission-only companies, and SSG-WI (which has ISO-like characteristics). This observation emphasizes the importance of deciding what types of entity should conduct certain types of planning (e.g., utilities focus on local reliability problems and regional planning entities focus on broad regional economic issues). It also emphasizes the importance of industry structure (e.g., large regional transmission organizations or vertically integrated utilities) in determining what information needs to be made public.

Several entities either restricted access to their transmission plans or denied access altogether. Restricting access to those with a reasonable use for the information makes sense. However, it may be inappropriate to prohibit all public access to transmission information because of concerns about competition and terrorism. With respect to competition, if the plan is released to *all* current and potential market participants at the same time, none has a competitive advantage. To protect critical infrastructure, sensitive information (e.g., detailed maps showing the nature and location of transmission equipment) could be restricted to those with a clear need to know. But much of the information in transmission plans, because it is prospective, does not fall into this category and could be made available more readily. The electricity industry, on either a regional or national basis, should develop criteria for transmission owners to use in determining which data should be kept confidential for commercial or national-security reasons.

The regional and national data and projections combined with the transmission-planning reports suggest that enough new transmission will likely be built to maintain reliability. However, many economic opportunities to build low-cost power plants in remote locations or to move power from cheap generators to distant load centers will be foregone because sufficient transmission for economic purposes may not be built. If state and federal regulators adopt clear policies to support transmission construction, needed investments—for both reliability and economics—would more likely be built. Such policies include decisions on: whether such investments are to be regulated by state commissions or FERC, appropriate rates of return on such investments, and how and from whom investment costs are to be recovered.

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