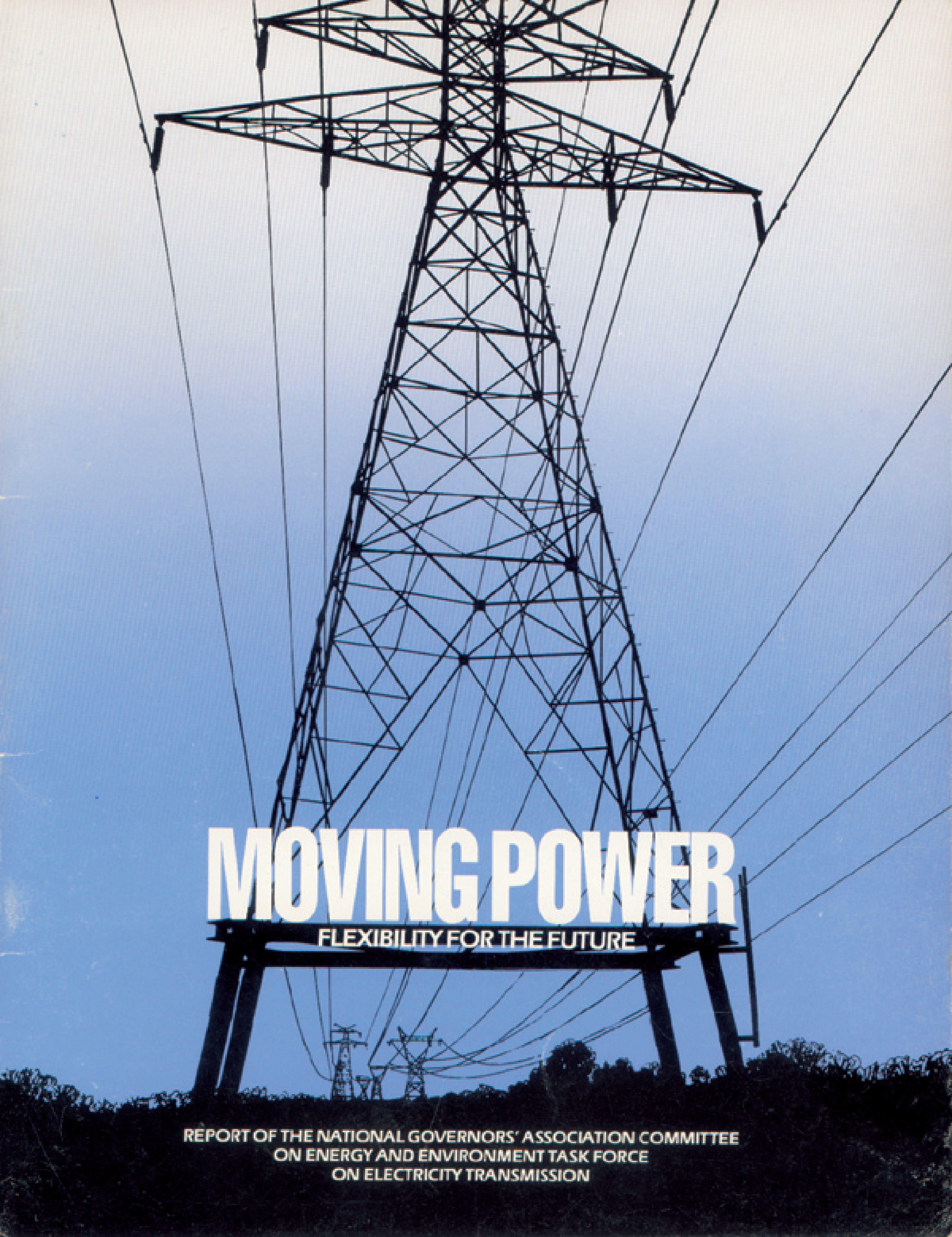

# MOVING POWER

## FLEXIBILITY FOR THE FUTURE

REPORT OF THE NATIONAL GOVERNORS' ASSOCIATION COMMITTEE
ON ENERGY AND ENVIRONMENT TASK FORCE
ON ELECTRICITY TRANSMISSION

# Moving Power:
# Flexibility for the Future

Report of the
National Governors' Association
Committee on Energy and Environment
Task Force on Electricity Transmission

# Acknowledgments


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American Electric Power Co.
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Florida Power & Light
General Public Utilities
MAIN Coordination Center (reliability council)
Montana Public Service Commission
National Association of Regulatory Utility Commissioners
National Electric Reliability Council
National Regulatory Research Institute
National Rural Electric Cooperatives Association
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New England Power Pool
Northwest Power Planning Council
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Pacific Power & Light
Pennsylvania Power & Light
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# Foreword

Electricity is the universal energy form. More than 97 million customers -- virtually every home, shop, and factory in the nation -- use electricity, and virtually all of us are directly affected by its price and availability. Most of us take electricity for granted; we simply turn a switch and expect that it will be there, instantly.

Yet, in the past decade we have seen significant increases in the cost of electricity, with rates rising more than 250 percent for residential customers during the 1970s and early 1980s. At the same time, significant regional disparities in electricity costs and capacity margins have developed. Today some areas of the country have far more electrical generating capacity than they can use, with billions of dollars invested in generating plants that are under-utilized. Other areas foresee the need to secure additional electricity supplies in the near term. To ensure healthy economies, all states should have adequate but not excessive supplies of low cost electrical energy.

The electric utility industry has responded to these price increases and huge regional supply disparities in diverse ways, including the development of new kinds of transactions among utilities and new interest in moving large amounts of power over long distances. From 1976 to 1983, bulk sales of electricity among utility systems increased 67 percent faster than sales to ultimate customers, and the value of bulk power transactions has reached $40 billion per year. There is increasing interest in longer-term, firm sales among utilities. These sales allow utilities to meet their load requirements more cost effectively by buying power wholesale rather than by building generating units. Bulk power transactions save money for electricity consumers, and for utilities with large amounts of excess power, they represent an important source of income.

The key to these bulk power sales is the nation's electricity transmission system. While the Governors believe our transmission system is currently technologically adequate and reliable, they have expressed concern that it could be incapable of supporting an increased level of economical power transactions in regional and national markets. In 1986, the National Governors' Association recommended the development of a strong national electricity transmission policy. There were at least three reasons for the Governors' concern with the adequacy of the current transmission system. First, an inherent degree of uncertainty in projected demand growth, fuel costs, pollution control requirements, and other factors suggest that there will continue to be important opportunities in the future for cost savings by moving large amounts of power among utilities or regions. Second, a stronger transmission system will increase the reliability of our utility systems; for example, increased transmission capacity could help utilities or regions deal with an unanticipated loss of supply, should that occur. Finally, an enhanced transmission system would allow more market discipline in electricity prices.

Reflecting these concerns, the NGA established a task force on electricity transmission, which we co-chair. The task force, which includes representatives of twenty-one states, solicited advice and suggestions from public and private utilities, citizens' groups, and the federal government. It sought to lay the foundation for understanding the nation's transmission system, and for identifying issues which are related to its development.

During the past six months, the task force has studied possible impediments to the increased transmission of electricity, with special attention to state certification and siting procedures and to utility planning and development programs. It took a broad view of the transmission network, but clearly, further analysis would be required to evaluate any specific transmission lines or interchanges. Moreover, there are very important issues regarding access to the transmission system which are beyond the scope of this report. Many of those issues will need to be resolved before the nation's transmission system can be developed to its fullest potential.

This report represents the task force's observations and findings to date, and outlines several broad policy options which Governors and federal decisionmakers may wish to consider. Though many hundreds of hours of work by the task force and its advisors have gone into the development of this report, we believe there must be additional work in a second phase to evaluate further the data we have gathered and to develop consensus policy recommendations for the Governors' consideration.

Finally, we wish to extend our appreciation to those many individuals whose hard work and commitment made the development of this report possible.

Gov. James Thompson, Illinois
Co-Chairman, Committee Task Force
on Electricity Transmission

Gov. Arch A. Moore, Jr., West Virginia
Chairman, Committee on Energy, and Environment

# I. Scope and Methodology

There are numerous reasons why a utility might choose to construct or not construct a new transmission line, including the fact that the line simply might not be economical. Regulatory and institutional factors, however, determine in part whether or not a project is perceived to be economically feasible by the utility, its ratepayers, or its regulators. A project which would be assessed as economically sound under one type of rate treatment may well appear to be uneconomical under another. Even when a transmission project would clearly generate net total benefits, regulatory or institutional factors affecting the distribution of those benefits can result in at least one affected group concluding that the line is "un-economic" or undesirable. In short, the way the utility industry is organized and regulated can create a disparity between the total economic value of a project (including its social costs and benefits), and its "accounting value" which reflects whether, and by whom, those benefits can be realized.

While the task force did not seek to determine which projects, or even how many, could be economically attractive, it did attempt to identify factors which clearly discourage additional development of the nation's electricity transmission system. The task force sought to identify areas in which regulatory and institutional factors -- which we have referred to as "impediments" -- might lead utilities, regulators, or the public to conclude that a project is not feasible or desirable, even though it otherwise would be economically attractive.

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The task force considered two major sources of impediments: those arising from state approval (siting and certification) procedures, and those which may result from the way transmission is considered in state and utility planning activities. "Planning" was defined by the group in a broad sense to include the institutional and regulatory factors which shape the planning process.

A number of major issues concerning wholesale utility markets which have been the subject of substantial public policy debate are not addressed by this report. These include debate over the desirability of deregulating wholesale electricity markets, promoting or requiring expanded access to transmission lines owned by third parties (electricity wheeling), and the appropriate rate regulation of wholesale sales. Each of these issues is important in any overall-assessment of electricity markets, and in any determination of the role which transmission resources should play in shaping or facilitating those markets. The policy debate over these issues, however, has been extensive and is readily available in the literature. The task force recognizes that the issue of access to transmission lines is particularly interrelated with transmission development in a number of ways. The amount of transmission capacity available affects the usefulness of access to that capacity; likewise, concern over who may have access to the transmission system, and on what terms, may affect current decisionmaking with regard to transmission development. Nevertheless, the task force chose to consider overall transmission need and capacity, rather than focus on the exact use of that capacity.

In developing its report, the task force examined the literature on the impediments to transmission development and devoted substantial effort to working directly with state and industry sources. Specifically, the task force relied on the following sources of information:

- **Experiences of task force members.** Task force members represented states with a substantial diversity of experience in transmission development and regulation and the task force relied heavily upon these experiences in developing an overall picture of state and regional differences.

- **Presentations by, and discussions with, industry representatives and observers.** At each of the task force meetings, industry representatives from around the country were asked to describe their company's operations and to discuss their transmission planning and development concerns. In addition, the task force heard presentations from non-utility organizations conducting on-going research on these issues. A number of key organizations and companies participated in the discussions at each task force session.

- **Written surveys.** The task force developed separate written surveys for state regulators, utility executives, and the nine regional electric reliability councils. The state survey was sent to each state public utility commission (PUC), energy office, and energy facility siting board, as well as to any other state agencies identified as having a role in siting and certification of new transmission lines. The utility survey was sent to over 400 electric utility entities, including those suggested by the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association. Responses were received from forty-six states, as well as from 45 percent of the electric utilities surveyed.

- **State and utility siting, certification and planning documents.** Each of the written surveys asked respondents to provide examples of documents prepared in the course of planning or obtaining approval for new lines. A large number of respondents provided this information, allowing for better interpretation of the quantitative survey responses, as well as a more detailed understanding of utility operations and individual state regulatory requirements and procedures.

- **Interviews with selected utilities.** As a corollary to the written survey of utility companies, state task force representatives interviewed thirty-four selected utilities to develop a better understanding of their perspectives, and to help interpret responses received in the written survey. Because of time constraints, this report reflects only an initial assessment of the information obtained from these interviews.

- **Existing literature.** The task force reviewed a number of valuable reports addressing various aspects of the electricity industry and wholesale markets in particular.

While the task force sought consensus, it did not require unanimity of opinion, and some members may disagree with its observations and conclusions in whole or in part.

# II. Background

The movement of electricity on alternating current lines, the predominant method of transmission used in the United States, differs from the movement of other products in one important respect: electricity moves instantaneously from the point of generation to the point of consumption over all available paths, and cannot be dispatched over particular routes. Movement usually involves more than a single, direct transmission line. The movement of power from points of generation to points of consumption utilizes the entire transmission system. Power flows are generally but not precisely predictable.

There are actually three distinct alternating current (AC) transmission systems operating in the United States and Canada: one comprising most of the eastern U.S.; one covering much of the state of Texas; and one serving the western states. The utilities operating in each of these distinct areas must operate in synchronization to serve their loads. Within these large synchronous areas; power moves instantaneously through the transmission network in response to a surge in demand or loss of a power station without regard to individual utility service areas. Individual utility operations must be able to respond accordingly.

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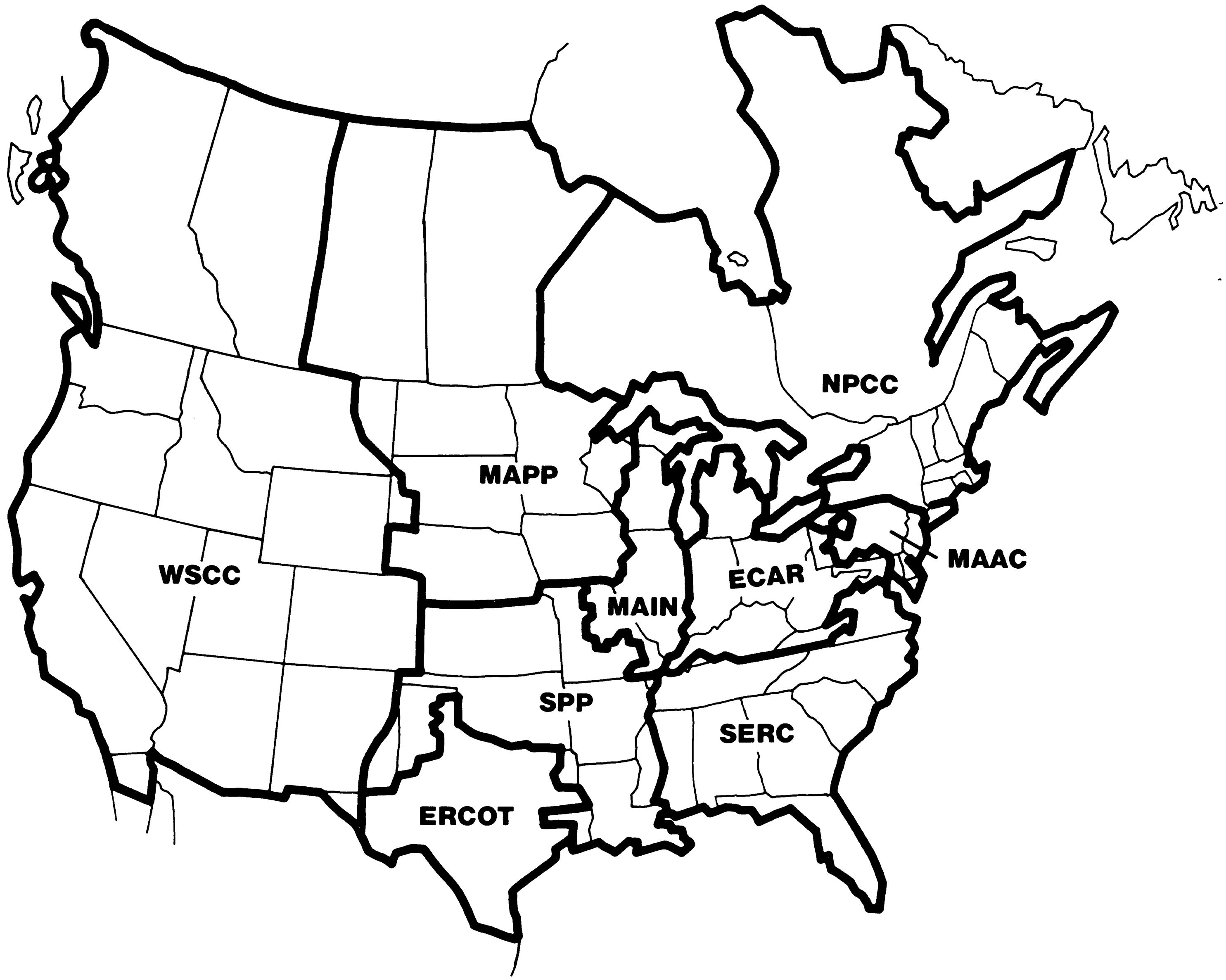
In order to ensure reliability of service, individual utilities and the nine regional reliability councils have established reliability criteria. These generally involve specification of reserve margins which take into account the utility's ability to rely on another utility to provide emergency supplies. Specifications for inter-connections between systems are also considered among reliability criteria. Reliability criteria differ among utilities and regions, depending upon both the physical characteristics of the system (shorter or greater distances between generating and load centers, load characteristics, and larger or smaller generating and transmission facilities) and the desired degree of protection against failure. See Figure 1 for a map of electric reliability regions.

## DEVELOPMENT OF THE UTILITY INDUSTRY

The investor owned-electric utility industry and some public companies developed in a vertically-integrated fashion, with the same company typically owning generation, transmission, and local distribution facilities. Sources of generation were usually located close to load or demand centers. In the early history of electricity, this structure allowed states to create specific franchised service territories for individual utilities, giving the utility a monopoly in return for assuming an obligation to serve its assigned territory. Although this basic structure continues to underlie the industry, inter-utility operations and coordination are now extensive, traversing not only individual service territories, but state boundaries as well. Indeed, although the industry was built and generally regulated on the basis of service territories, it depends upon an integrated transmission system for efficient and reliable operation.

Individual utilities may establish holding companies and power pools, participate in less structured brokerage sales arrangements, or arrange bilateral sales with neighboring utilities. The inter-utility transactions facilitated by these arrangements have grown substantially over the last several decades. The National Coal Council reports that such arrangements accounted for 5.6 percent of aggregate generation in 1953 and 20.1 percent in 1983. Transmission networks, originally used to meet native load requirements, make these arrangements possible.

**Figure 1**
**North American Electric Reliability Council**




**ECAR**
East Central Area Reliability Coordination Agreement

**ERCOT**
Electric Reliability Council of Texas

**MAAC**
Mid-Atlantic Area Council

**MAIN**
Mid-America Interconnected Network

**MAPP**
Mid-continent Area Power Pool

**NPCC**
Northeast Power Coordinating Council

**SERC**
Southeastern Electric Reliability Council

**SPP**
Southwest Power Pool

**WSCC**
Western Sytems Coordinating Council

*AFFILIATE*

**ASCC**
Alaska Systems Coordinating Council

# Types of Inter-utility Transactions

Unfortunately, the terminology used to describe the types of wholesale sales made by utilities is not entirely uniform, nor does it fully account for all of the variations in these transactions or for new types of transactions currently being developed. The Federal Energy Regulatory Commission (FERC), which regulates inter-utility sales, divides these sales into two broad categories:

Requirements sales. These are long-term, firm power sales made to utilities lacking an alternative source for meeting native load requirements. A "full-requirements" customer depends on the requirements sale to meet all of its load, while a "partial-requirements" customer has at least one other source of power. In both cases, however, the requirements sale is distinguished by the fact that the purchaser depends upon the power as if it were self-generated and the seller considers the purchaser's requirements essentially as if they were its own for purposes of planning and capacity development.

Coordination sales. These are sales between utilities which allow for either a reduction in costs or maintenance of reliability. Coordination sales are made from capacity that is temporarily not needed for native load and are voluntary in the sense that the purchasing utility does not depend upon the purchase in order to meet its native load. These sales are typically covered by bilateral contracts covering the conditions and terms of sales between the two companies. Individual sales, however, are frequently at the discretion of both parties and may be only a matter or hours or days in duration. Moreover, and there is frequently a presumption that sales may occur in either direction, depending upon prevailing economic conditions. Because these sales are made for cost-saving purposes (as opposed to reliability purposes), they are frequently referred to as economy sales.

A variety of wholesale sales do not fall neatly into either category. For example, power purchased to replace the Three Mile Island outage is in a sense a reliability purchase, since it is bought on a long-term, firm basis to meet basic load requirements. However, it does not fit the traditional model of a sale considered as part of each utility's long range planning.

Much of the task force's interest has focussed on the possibility of using transmission for long-term power sales which are sufficiently firm in nature that they can replace the need for additional local capacity. The substantial purchases of power by California utilities from Bonneville, or of power from Quebec by the New England Power Pool are examples of this type of wholesale sale. These sales, like coordination sales are voluntary and made for purposes of cost reduction, but very much unlike coordination sales, they cannot be based on temporarily available generating capacity. For purposes of this report, we refer to these as "demand sales" because they involve the need for commitment of generating capacity on a long-term basis.

*When they connect individual utilities, transmission lines enhance system reliability by allowing for power exchanges in emergencies, and by allowing for inter-utility sales of power where there is an economic advantage for the utilities involved.*

When they connect individual utilities, transmission lines enhance system reliability by allowing for power exchanges in emergencies, and by allowing for inter-utility sales of power where there is an economic advantage for the utilities involved. With improvements in transmission technology, they have also encouraged the development of cost-effective power sources hundreds of miles away from major load centers. The Pacific Inter-tie, based on the development of hydropower by the Bonneville Power Administration, is a case in point.

In addition to improving reliability and allowing for economy sales, the development of an extensive inter-utility transmission network can reduce generating costs in two ways. Individual utilities can reduce the amount of generating capacity margin (the difference between total installed generating capacity and peak demand) needed to meet planned and unexpected outages and deratings of generating equipment without interrupting electricity supply to customers. Then too, the transmission network can allow utilities to capture the economies of scale associated with larger generating units.

Individual lines are built to meet the specific utility requirements of reliability, economy transfers, and internal movement to load centers, and the lines serve these purposes simultaneously as power actually moves over the entire system. Thus in assessing the adequacy of the transmission system to meet any given purpose it is important to think of electricity operations as a whole.

The development of higher voltage, more efficient transmission technology has further spurred the growth and use of transmission resources. Since 1965, an expensive network of 500 KV lines has been developed, and the largest transmission lines now being installed (765 kV) have quadruple the capacity of the largest lines (300-400 kV) installed in the 1950s and 1960s. Figure 2 shows the extra high voltage lines in service in America in January, 1986.

From 1970 to 1974, annual additions to extra high voltage (EHV) lines averaged 3,786 circuit miles. The average miles added annually dropped to 2,926 circuit miles in the period from 1975 to 1984, and are projected to only average 1,551 circuit miles annually from 1985 to 1995. Because new transmission lines can take a decade or more to complete, however, these projections are subject to substantial uncertainty. It is possible that future additions could be significantly less than currently planned.

*Notwithstanding the additions in transmission line mileage from 1970 to 1984 and the added carrying capacity of high voltage lines, the transmission system is currently operating close to capacity.*

Notwithstanding the additions in transmission line mileage from 1970 to 1984 and the added carrying capacity of high voltage lines, the transmission system is currently operating close to capacity. In its 1985 Reliability Review, the North American Electric Reliability Council, responsible for ensuring the reliability of industry operations, concluded:

> The transmission systems continue to be heavily loaded a high percentage of the time to maximize economy energy transfers. As a result, there is a greater vulnerability to system disturbances and customer service interruptions. Building more transmission lines would increase the capability to transfer economy energy and, at the same time, increase the capability to respond to emergencies.

Substantial power transfers are occurring throughout the United States, and these transfers have resulted in significant savings for utilities and their ratepayers. Yet some transmission facilities are already substantially loaded. Opportunities for additional savings through sales of power by utilities with excess generating capacity may be more limited than if adequate transmission capacity were available. The task force was informed, for example, that power from Midwestern utilities with large current surpluses could be sold to neighboring regions, if additional transmission capacity were available. If the surplus is of sufficient duration, it may be possible to plan and complete new facilities which pay for themselves through increased firm sales, although the line itself could continue to provide benefits beyond a specific transaction. However, where there are constraints on the availability of transmission capacity, utilities which anticipate a near-term need for additional power cannot reliably consider power purchases as an alternative to investment in expensive new generating facilities.

*Opportunities for additional savings through sales of power by utilities with excess generating capacity may be more limited than if adequate transmission capacity were available.*

## LIMITATIONS OF THE CURRENT SYSTEM

The present transmission system has an excellent record of reliable service and provides substantial sales of power on an economical basis. The vast majority of the "economy" power transactions over the transmission network, however, are to take advantage of differences in short-term or variable costs, such as shifts in relative fuel prices. The system was not, for the most part, built to allow utilities to plan for the sale or purchase of substantial amounts of power on a long-term firm basis. An expanded transmission system could allow for additional economy transactions of the kind currently being made. It could also provide an additional source of savings by allowing for longer-term, firm sales, which provide more flexibility and opportunity in planning for and using generating capacity.

Even though it may be difficult to make sufficiently timely improvements to allow for sales from current areas of surplus to areas of need, the task force has identified several reasons why an expanded and enhanced transmission system could be desirable in the long-run.

- First, sufficient availability of transmission capacity could allow for the future development of generating capacity in areas where there is a clear cost savings due to the availability of indigenous resources or other siting advantages. The latter factor could be increasingly important if it continues to become more difficult to site plants near the population centers which use the power.

- Second, uncertainties in demand forecasting and in the timing of additions to supply suggest that new areas of surplus and deficit power are likely to continue to develop in the future, making it desirable to have transmission capacity at hand to allow for movement of power between these areas. Obviously, the direction of such future power flows cannot be foreseen with great precision, but a strong and flexible transmission system can help ensure that transmission capacity is available to accommodate them.

- Third, the likelihood of unforeseeable supply disruptions -- such as the 1973 oil embargo or the accident at Three Mile Island -- also make it desirable or necessary to have the capacity to send power long distances for extended periods of time. As an example, studies have shown that while the transmission system allowed the nation to "backout" substantial quantities of oil-fired electrical generation after the oil embargo, additional backouts would have been possible and economical had there been additional transmission capacity. A stronger transmission system enhances the reliability of supply.

- Finally, increased availability of transmission capacity would allow expanded and more competitive wholesale markets, with each utility having more opportunities for purchase or sale of power, if the regulatory system promotes such competition.

The task force notes that there is considerable variation among both utilities and states in their operations, and that nearly every generalization has exceptions. There are notable examples of transmission lines which have been built specifically to allow for purchase of power which would otherwise have had to be obtained from new self-owned generating capacity. Even though some of these examples may represent special cases they provided the task force with valuable insights in considering the possibilities for further development of transmission resources.

Many of the policy options identified at the conclusion of this report are currently in practice in at least one state, and likewise provide important opportunities for the states to assess alternative regulatory models.

# Brokerage Arrangements, Power Pools, and Holding Companies

Although wholesale utility sales tend to be made on a bilateral basis (even where power is transferred through lines owned by a third utility, it is often in the form of two bilateral sales), there are a number of ways in which utilities have organized to provide for dispatch among more than two utilities, including brokerage arrangements, public utility holding companies, and power pools.

The brokerage arrangement is a way to facilitate the most efficient combination of bilateral sales at any given time. Under this system, information on desired sales and purchases is collected hourly and an algorithm (such as a high-low match) is used to match up individual buyers and sellers who can then make the transaction. The decision to buy or sell, and at what price, is left with the individual company. Utilities operating in the state of Florida use this mechanism for coordinating sales.

Although there are a number of ways in which power pools are organized, they generally operate as a central dispatcher, choosing which sources of generation from among its member utilities will be used to meet the aggregate demand of all member utilities. The choice of which power sources to use is based on the marginal cost of each individual source. The power pool can be considered an agent for purchasing power from each seller, on a least cost basis, and then simultaneously selling that power to each member utility as required by its retail demand. Power pools can be more or less strong in the amount of authority granted to the pool to control the operations of its member utilities. (See FERC's publication, Power Pooling in the United States, December 1981 for detailed information on power pool operations and individual power pools.)

Electric utility holding companies are legal entities which own a number of individual utilities. The holding company itself can consolidate the operations of member utilities to a lesser or greater degree and frequently operates to coordinate planning and investment among the member companies to provide long-run savings, in addition to using economic dispatch to achieve short-run savings. Under the Public Utility Holding Company Act, a number of regulatory functions normally exercised by the state become the purview of the Federal Energy Regulatory Commission.

# III. Siting and Certification

State regulation of electric utilities can be divided into three principal components: determination of the need for a new facility ("certification"), approval of a site ("siting") for a new facility, and establishment of rates (including determination of costs which may be recovered through rates). Although the ratemaking function of state utility commissions has traditionally been the primary state regulatory role, the certification and siting functions have increased in importance over the last decade. This has been due to skyrocketing capital costs, unpredictable demand and increasing difficulty in the siting of any locally undesirable facility.

State certification of need and siting requirements help the state ensure that electricity development occurs in an orderly and useful way, and in a manner consistent with other public needs and interests. While state procedures may be mechanically flawed in some respects, they are crucial to ensuring balance between legitimate but competing public needs.

## STATE PRACTICES AND REGULATORY STRUCTURE

The predominant feature of state siting and certification practices is their enormous variety.

The task force survey of state regulatory agencies identified a number of specific ways in which state practices differ significantly, including the number of agencies involved in the siting and certification decision. State agencies involved in approval of a transmission project may include any or all of the following: the public utility commission, the state energy office, an energy facility siting board, a state environmental department, and a state land use agency. In one state, Delaware, the transportation department has authority over line siting. In several states, such as Alabama, approval to develop projects is contained within the utility charter and no siting approval or certification is required from any state agency, although the state will subsequently determine allowable costs for ratemaking purposes.

The principal state agency responsible for approval of transmission projects tends to be the public utility commission. In sixteen states, the state energy office also has regulatory responsibilities for project approval, generally in the area of electricity planning and determination of need. Twelve states have distinct energy facility siting boards which have responsibility for siting and/or certifying new transmission lines. These are usually either independent agencies or part of the state energy office, although in Florida the siting board consists of the Governor and his cabinet. Finally, state environmental offices are often involved in the siting process, either by a requirement for direct approval or because of the need to issue various environmental and land use permits. Formal environmental approval may also be required.

Another important variant of state regulatory practices involves the number of filings, and hearings involved in obtaining project approval. The number of applications required to receive both kinds of approval (certification of need and approval of the proposed site) varies substantially, and the time typically required between initial filing and final approval can range from two months to three years.

In addition to state approval, various federal approvals may be required for transmission lines which traverse federal property, involve a federal power marketing authority, or concern federal environmental or coastal regulations. Traversing Indian lands poses unique siting circumstances.

*The task force found that consolidation of the approval process within a single agency appears to improve the predictability and certainty of the regulatory process, and may increase the speed with which the state acts on project proposals.*

The task force found that consolidation of the approval process within a single agency (even if that agency must work with other state agencies) appears to improve the predictability and certainty of the regulatory process, and may increase the speed with which the state acts on project proposals. Perhaps more importantly, such consolidated procedures seem to encourage utilities to consider undertaking transmission projects and to reduce the chances that a project will lose its economic appeal during regulatory delays.

States also differ in the role local jurisdictions play in the final approval of projects. In most states, the state regulatory process includes consultation with local officials. In twelve states, local jurisdictions have authority to approve or disapprove the portion of projects within the jurisdiction, and may effectively thwart state approval. In some states, however, local jurisdictions are entirely preempted from disapproving a project, generally if it involves a larger line or one which crosses local jurisdictional boundaries.

The task force believes that the relation between state and local approval authorities is a key factor in the ability to successfully site lines. The efforts of utilities to build the Baltimore-Washington 500 kv loop, for example, has been stalled for over a decade by the opposition of local jurisdictions, despite approval by Virginia and Maryland. More frequently, the need to obtain local approvals can result in costly roundabout siting to avoid reluctant jurisdictions, or approvals by neighboring jurisdictions with incompatible requirements tied to the approval. The additional cost and time involved in meeting local requirements can be sufficient to make a project uneconomical even if all necessary approvals can eventually be obtained.

## CRITERIA FOR LINE APPROVAL

The task force found that in addition to the organization and operation of state regulatory procedures, criteria for line approval are a significant factor in how readily lines can be sited. The factors which must be considered in determining the need and location of a new or upgraded transmission line differ substantially from those which are relevant for a generating facility. For example, health, safety, and siting considerations will be different for the two types of facilities. Nonetheless, and despite the fact that many states have recently developed siting and certification requirements, these requirements tend not to include specific factors for transmission projects. In states which have recently considered the need for additional transmission facilities, Florida and Montana, for example, specific criteria have been developed which do seem to improve the approval process.

The task force found that where criteria for approval are more specific, and directed towards the particulars of transmission siting, there is more certainty and probably less delay in the decision process.

The advantage of specific criteria in expediting the process of line approval may be that they help remove generic issues, such as overall environmental effects, from consideration in the approval of each line. Montana, for example, has developed specific guidelines for transmission corridor width based on health concerns, and uses these guidelines to approve or disapprove plans for individual lines. It is recognized that states would necessarily differ in the criteria they might choose to develop for transmission siting.

In addition to specific criteria, most states have an over-arching requirement that utility investments be in the "public interest" before they can obtain a certificate of public convenience and necessity for a given project. In addition to the criteria required for issuance of a certificate of need, many states include a "used and useful" or "prudency" standard during the ratemaking process. As a factor in determining need, the public interest criterion frequently dominates controversies over line siting, and underlie many of the specific issues which arise with regard to health and environmental concerns, aesthetics, and land use conflicts.

Within most states, the debate over the appropriate application of the public interest involves balancing the local costs of new transmission facilities with the more diverse benefits which will result from the new line. Local costs can be significant, including the need to tear down existing housing, the loss of recreational space, and the need to alter, possibly at considerable expense, local land use plans and agricultural or commercial practices.

Debate over the appropriate definition of the public interest is significantly more complicated in the case of a multi-state project, where an individual state may incur a substantial portion of a project's costs (including local social and economic costs), but not a comparable portion of its benefits. In some states, such as Wisconsin, a multi-state project which does not include off-setting benefits within the state cannot be approved.

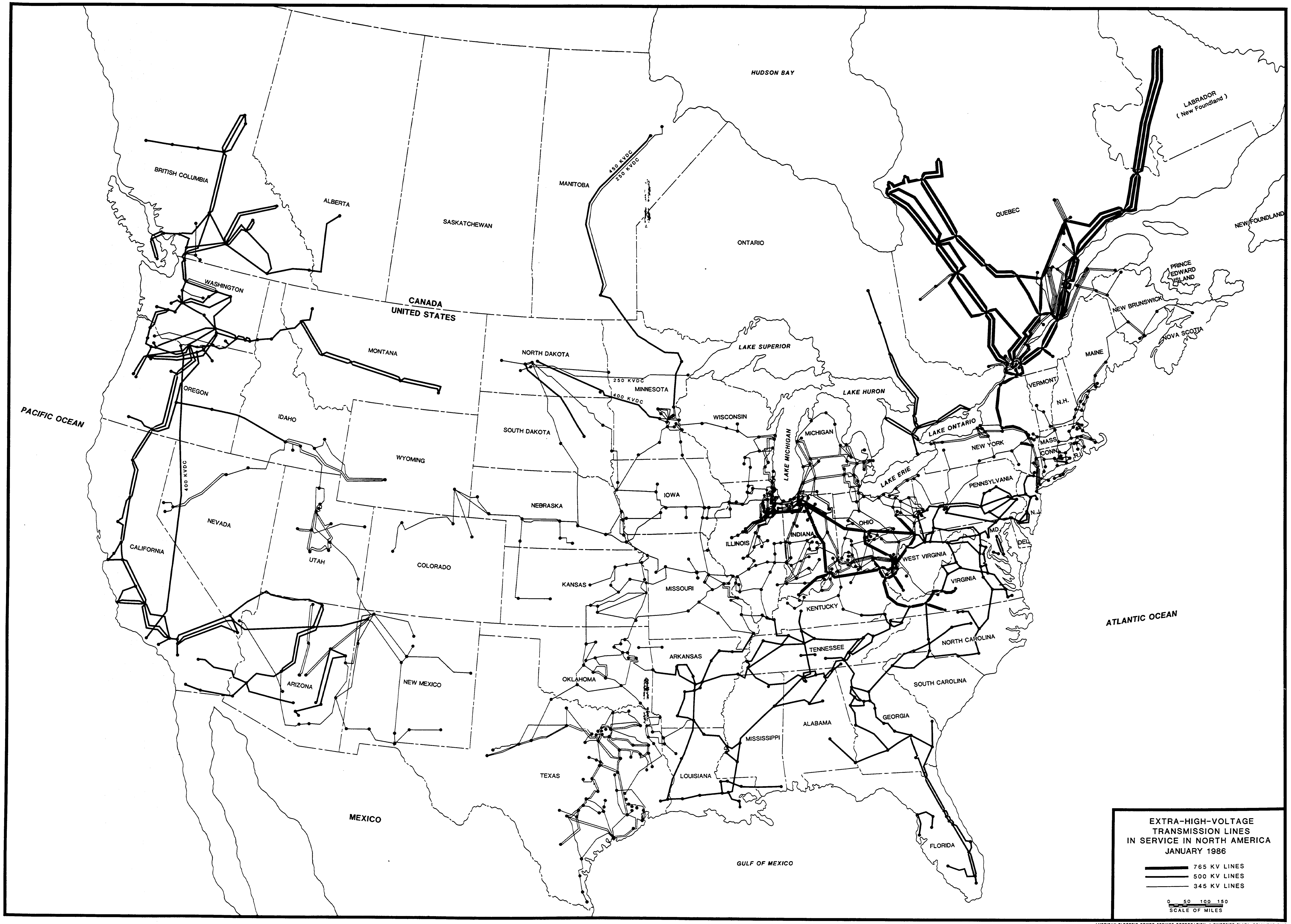
*Debate over the appropriate definition of the public interest is significantly more complicated in the case of a multi-state project, where an individual state may incur a substantial portion of a project's costs but not a comparable portion of its benefits.*

Because the cost savings from increased reliability can be substantial for utilities even when they do not anticipate being able to use the line for power purchases or sales, new AC lines can often be found to be in the public interest even when their principal purpose is to serve neighboring or distant utilities. Absent substantiation of such benefits, however, the task force found that it may be necessary to develop ways to compensate local citizens or ratepayers of intermediate states. In the case of direct current lines, intermediate utilities cannot use the line even for reliability purposes without constructing expensive converter stations or terminal facilities.

Differences in both state siting and certification procedures and in the regulatory process itself may frustrate efforts to develop multi-state lines, even when those lines would be acceptable to each of the states involved. For example, the states involved may differ by as much as a year regarding the timing of required hearings. They may also require information to be developed or presented in different ways. Where divergent requirements appear to be a serious factor in discouraging development of multi-state lines, states may be able to coordinate the process through mechanisms such as joint hearings.

## EMINENT DOMAIN AND LAND ACQUISITION

The task force found that the manner in which land can actually be acquired for a transmission project can affect the ability of a utility successfully to build a line. States usually grant public utilities eminent domain powers as part of the utility franchise, but generally the authority cannot be exercised without prior approval of the specific project involved. Approval may involve only certification of need or may also require approval of a specific site. Possibilities for condemnation range from automatic availability of eminent domain in Nebraska (where all power is publicly owned), to some states in which eminent domain for a given project can only be obtained through the courts, with the state's certification of need essentially only constituting evidence that the project may be in the public interest.








Source: American Electric Power Service Corporation

It is important to note that since eminent domain is generally available in the private sector only to utilities, non-utilities usually cannot receive the right to condemn property for a transmission project even if certification and siting approval could otherwise be obtained.

## COORDINATED RIGHTS-OF-WAY

Because transportation corridors of any sort are difficult to site and generally in strong demand, much attention has been focused on ways to use common corridors for multiple purposes, including non-transportation purposes such as parks and recreational facilities. Electric transmission lines are, in fact, sometimes sited along highway or railway corridors, although the rights-of-way may actually lie next to each other rather than being coincident. There are both physical and statutory limitations to the extent to which corridors can be used for multiple purposes, however. Currently, lines can be sited within corridors for interstate highways only as an exception to policy and under strictly controlled conditions showing that they will not adversely affect the design, safety, or operation of the highway, and provided they are serviceable without access to the roadway or ramps. The Federal Highway Administration is at present reconsidering aspects of this policy through rulemaking.

The task force identified one strong example of a statutory requirement to coordinate the development of transportation corridors. The Federal Power Act requires the Department of Interior to pre-identify corridors for all types of uses, including electric transmission, on federally managed lands. This requirement is designed to minimize the impact of corridors on other land uses.

# IV. Transmission Planning and Development

Long-range planning by utilities is conducted on a twenty-year time frame on a regular basis, and, in most cases, utilities must regularly submit these plans to the state. In addition, several states conduct independent forecasts and electricity development plans of their own. The current strong emphasis on forecasting and supply planning is due principally to two factors. The first is the increasing lead times associated with the highly capital-intensive projects typical of the industry. Lead times for both large generating facilities and transmission facilities can be more than a decade, so that planning on less than a twenty-year horizon can result in failure to provide sufficient capacity or the need to use more expensive technologies with shorter lead times.

*Every fuel source for generating electricity involves significant future uncertainties.*

Increasing uncertainties over future demand and the cost of various supply options also affect utility planning. Whereas for a thirty-year period after World War II utilities were able to assume a 7 percent or so growth rate, that rate dropped precipitously in the 1970s, and changes in the growth rate have become more difficult to predict. Likewise, every fuel source for generating electricity involves significant future uncertainties. There is uncertainty over the future of nuclear power as a source of generation, over future environmental control requirements for coal-fired facilities, over the cost and availability of oil and gas, and over the long-term availability of hydro power.

State, federal, and, in some cases, regional agencies, as well as utilities, regularly assess future needs for power and develop plans for best meeting those needs. The dual nature of the electric utility industry -- built and regulated in part on the basis of discrete service territories, but dependent for its efficient operation on an integrated transmission network -- creates a number of problems in ensuring that planners are able to consider opportunities for savings through development and use of the transmission system. If, for example, planning is focused on the need to reliably meet local service requirements, the size and configuration of the lines built will be different than if opportunities to market power are a major goal of the planning process.

*In its 1986-87 Winter Assessment, the North American Electric Reliability Council noted that while sufficient transmission capability exists, there are areas where critical limitations exist during peak demand periods.*

Because of the fact that power flows over the transmission grid do not respect either utility or state boundaries, the scale of planning -- whether it is at the level of individual service territories, holding companies or power pools, states, multi-state regions, or even at the level of the full area encompassed by synchronous operations -- is a key factor. Many feel it is the most important factor in whether or not planners succeed in identifying opportunities for savings through transmission development. There are clearly times, for example, when the most efficient means of opening up wholesale sales opportunities is through elimination of a bottleneck outside the planning area. Likewise, planners will likely not focus on the improvement of bottlenecks within the planning area in order to facilitate additional transactions outside it. For example, in its 1986-87 Winter Assessment, the North American Electric Reliability Council noted that while sufficient transmission capability exists, there are areas where critical limitations exist during peak demand periods, the consequences of which are felt beyond the confines of the specific geographic area.

Finally, planners at different levels may evaluate the same project differently; whereas the benefits on a regional basis may be clear, the project may impose costs on a particular state or utility which may not be evident at the broader planning level.

Taken together, these two factors have made it both more important and more difficult to assess potential future needs and to identify alternative sources of power supply.

## UTILITY PLANNING

Utility planning generally involves the development of a list of supply alternatives, but very few of the utility planning documents examined by the task force explicitly include options for long-term purchase of power as a substitute for development of self-owned generation (or note the lack of any such opportunity).

It is, of course, difficult to consider firm power purchases over a system not fully designed to accommodate them, yet the development of such a system is contingent upon identification in long-range planning of the potential purchases and sales opportunities such a system would provide. The North American Electric Reliability Council has suggested that one of the reasons planning documents do not identify many options for power purchases is that there are significant impediments to the development of transmission lines. Utilities are not likely to pursue options that have uncertainty. If these impediments can be reduced, utilities can begin to look seriously at power purchase/sale options.

Long-range utility planners almost always identify a list of required additions to generating capacity, usually in the order in which they would be brought on line as demand increases. There is a recognized connection in utility planning between the need for new generation and the need for additional transmission facilities to accommodate that generation, but determination of transmission requirements are frequently ancillary or iterative to, rather than integral to the determination of the need for new generating capacity. Where transmission needs are calculated for reliability purposes, rather than as a means of integrating new generating supply into the network, utilities must clearly coordinate the planning and development of the lines. Yet, even here, the process seems to be iterative in that utilities file their individual plans and then compare them with filings from other utilities. This process may assure that the line will function as an integrated whole, but it does not necessarily assure that the optimum configuration of lines will be built.

*For a variety of reasons, including the obligation to serve, utility planning is inherently focused on meeting obligations of the utility's service territory, rather than serving as a vehicle for identifying broader market opportunities or facilitating the ability of other utilities to meet their service obligations.*

For a variety of reasons, including the obligation to serve, utility planning is inherently focused on meeting obligations of the utility's service territory, rather than serving as a vehicle for identifying broader market opportunities or facilitating the ability of other utilities to meet their service obligations. As such, planning has not evolved as a tool for ensuring that the transmission projects identified and developed are adequate to meet the potential needs of neighboring utilities, with the exception of providing for mutual reliability and for smaller scale bilateral exchanges.

There are exceptions to this observation which the task force believes illustrates the potential value of generation and transmission planning on a larger scale. The New England Power Pool (NEPOOL), for example, develops joint plans for generating and transmission resources for all of its member companies in a way which is designed to minimize the joint costs of operating these systems. Likewise, the American Electric Power (AEP) holding company plans and develops resources on a regional basis, a process which has resulted in its investment in lines which are substantially larger than those generally built in the area. The transmission system does appear to be more heavily developed in cases where utilities are organized into holding companies or power pools for planning purposes, and experience indicates that in cases where planning does not occur on a multi-utility level, the transmission system is not likely to be sufficiently developed to accommodate all economically viable transactions.

The regional reliability councils also provide some opportunity for inter-utility planning. The councils' primary objective, however, is to facilitate reliability, and they do not officially evaluate the plans of utilities within the region in the potential for economy or demand sales. In addition, the councils vary with regard to their ability to impose changes in utility plans even if the plans appear to be inadequate.

## STATE PLANNING

Because the benefits of transmission capacity extend beyond the service territory of individual utilities, the task force believes state-wide planning of electricity needs, and the possibilities of meeting those needs through transmission development, are a necessary (although probably not sufficient) condition to help ensure that potential benefits are identified and realized. This seems to be true whether or not planning is a function of the state's economic regulation.

*It is clear that over the last fifteen years or so, states have made a concerted effort to increase their consideration of the planning documents submitted by utilities.*

It is clear that over the last fifteen years or so, states have made a concerted effort to increase their consideration of the planning documents submitted by utilities. In only a few cases, such as California and New York, however, do states conduct independent forecasts and analyses of desired investment in generating and transmission capacity. These independent analyses are expensive, but have the advantage of providing a means of assessing utility plans, as well as allowing the state to consider electricity development in the context of overall energy use and development -- a decided advantage for states whose economies are closely tied to a particular fuel market or on electricity intensive industry.

Thirty-one states require utilities to submit planning documents on a regular basis. In general, these documents provide a basis for future assessment of utility filings for new projects, but the task force found that states are often not able to make effective use of planning information for these reasons:

- States may not have jurisdiction over all utilities in the state. For example, in some states, regulatory authority does not extend to public or cooperative companies.

- The regulatory process may not ensure that utility planning reports are included in the state's consideration of approval of individual projects.

- States may not consolidate and compare plans of individual utilities to ensure that their plans are consistent with each other and with the overall needs of the ratepayers in the state.

- Utilities may not be required to consider sources of power (or revenues) outside the service territory, that is, they may not consider the potential for sales or purchases of power over the planning period.

Yet these factors -- the degree to which the utility network is covered by state authority, the connection between long-range plans and specific investments, the relationship between individual utility plans, and the types of information required -- seem to be critical in allowing the state to ensure that utility planning efforts result in the development of generating and transmission capacity in a way which will best serve the needs of the state's ratepayers in general.

## MULTI-STATE PLANNING

*Planning on a multi-state or regional basis can help identify even larger sources of savings from improved coordination of generation and transmission capacity development.*

Just as state-wide planning can help ensure that opportunities for extra-utility trade are identified, planning on a multi-state or regional basis can help identify even larger sources of savings from improved coordination of generation and transmission capacity development. Indeed, the task force found that a half-dozen or so states, and perhaps up to a dozen states in the west, might have to be taken into consideration before areas of general excess capacity could be matched with areas of insufficient capacity, a condition which individual state-wide planning efforts would not likely identify.

In addition to helping to identify desirable projects, multi-state communication (formal or informal) helps individual state planning efforts in several ways. First, interstate facility siting is frustrated by differences in state criteria for approval and procedures. The variation in these procedures, described above, may even include contradictory requirements for approval. Second, to the extent that state and utility planning efforts rely on purchases of power from outside the state, they may be assuming the availability of an identical power source, or, likewise, several states may be approving construction of new generating capacity to serve the same export market. Multi-state communication can help avoid these possibilities for double-counting.

The degree of cooperation among states varies across the country. However, the task force found only one case, the Northwest Power Planning Council, in which regional planning is practiced through statutory requirement, and only one other case, the Power Planning Committee and the State Energy Offices of the New England states under the auspices of the New England Governors' Conference, in which state and utility officials meet on a regular basis to consider long-range planning options. There are, however, a number of less formal ways in which state regulators meet, such as through the National Association of Regulatory Utility Commissioners (NARUC), and the Western Interstate Energy Board (WIEB). In addition, state regulatory officials are regularly invited to meet with each of the nine regional reliability councils. While these associations do not exist for the purpose of facilitating interstate planning, they do help ensure that interstate communication is achieved. WIEB, in particular, has helped establish more formal communication among state and utility representatives in the Western states. Finally, bilateral state coordination may occur on an ad-hoc basis, particularly if a particular project is under consideration.

The task force found in no case where a state is bound to certify or site a transmission or generation facility which is identified as desirable through a multi-state planning effort.

## PATTERNS OF OWNERSHIP

The development of electric utilities as distinct service territories has resulted in a pattern of transmission lines which also reflect service territory boundaries. Although utility interconnections require an obvious degree of coordination, they have generally been developed on a bilateral basis, with each utility building and owning that portion of the inter-utility line(s) located within its territory.

The high economic value associated with transmission availability for reliability purposes, plus the opportunity for mutual use of lines, has resulted in some willingness of utilities to build bilateral connections which are sufficient to accommodate sales in addition to those immediately required by the utility. Despite this fact, the current system of ownership has not generally promoted the building of larger lines for use by multiple utilities, and especially for purposes of demand sales. Furthermore, it does not assure a line configuration which optimizes the usefulness of the overall system.

One of the limitations of transmission investment based on service territories is that transmission interconnections are developed for the mutual use of contiguous utilities. A broad array of legal, regulatory, economic, and perhaps physical impediments must be overcome for the non-contiguous utility to establish an inter-tie.

This pattern of ownership, coupled with the phenomenon of unintended power flows, also affects the way bottlenecks to transmission may be resolved. Because power flows along all available paths, inter-utility sales of power will involve a number of lines, not just the "contractual path" immediately connecting the two utilities. The flow of power outside of the contractual path, through lines owned and operated by utilities which are not parties to the sale, is referred to as parallel or unintended power flow. Utilities usually operate under an assumption, not empirically tested, that the inadvertent flow of power over other utilities' lines from small transactions will be sufficiently mutual that none of the utilities are badly constrained in their own use of lines. However, where large amounts of electricity flow in substantially the same direction over a period of time, utilities in the unintended path of that flow have found that both their generation and their use of the transmission grid have been adversely affected. Figures 3 and 4 illustrate unintended power flows.

*Because power flows along all available paths, inter-utility sales of power will involve a number of lines, not just the "contractual path" immediately connecting the two utilities.*

*Utilities in the unintended path of that flow have found that both their generation and their use of the transmission grid have been adversely affected.*

Under current wholesale price regulations, compensation for use of transmission facilities accrues only to utilities which are party to the transaction, and not to those which unintentionally carry power but are not parties to the contract. Although utilities finding themselves subject to substantial unintended flows may occasionally be able to negotiate compensation for the use of their lines, there is no regulatory mechanism forcing such compensation.

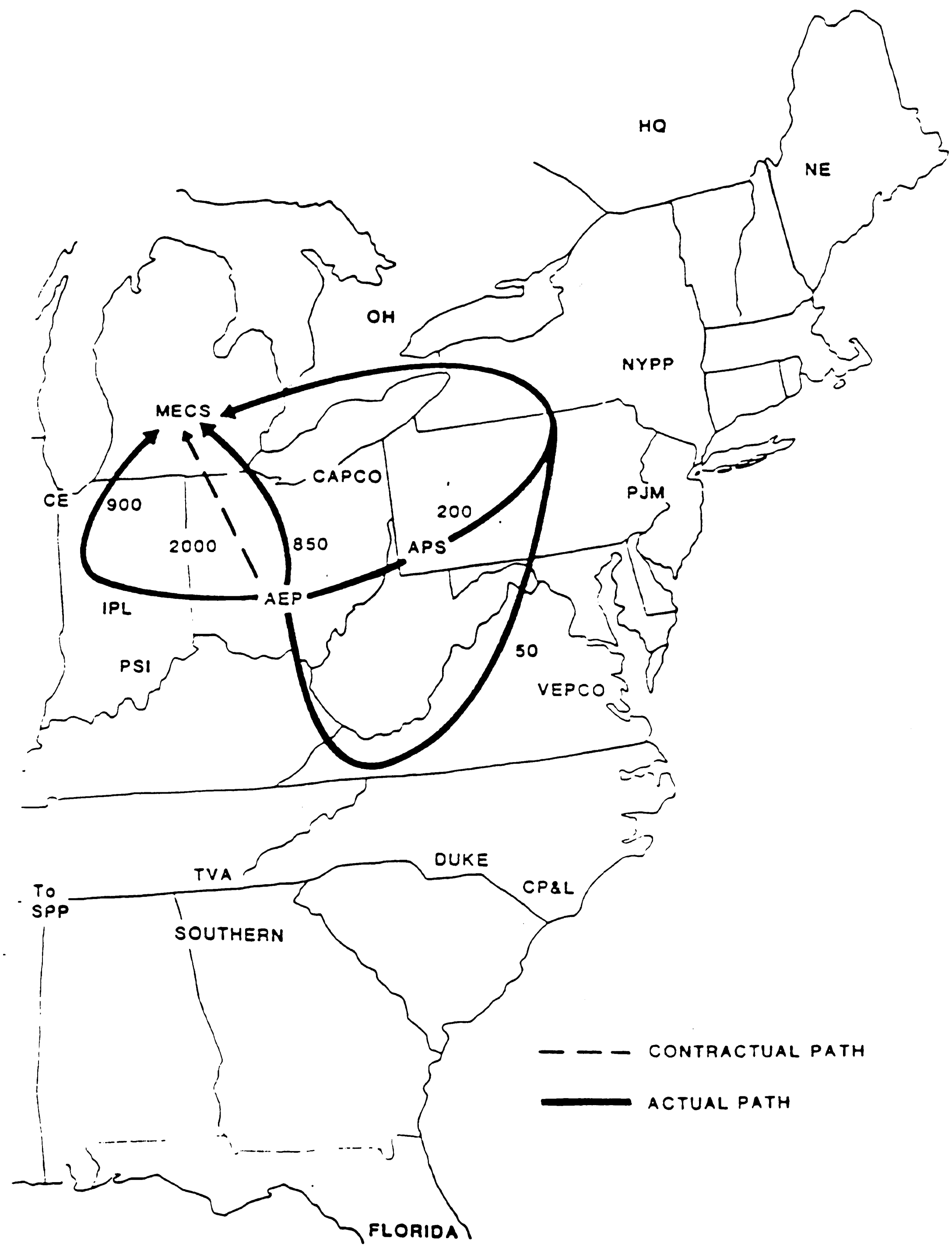
The western experience with inadvertant power flows is particularly worthy of note. Such flows are sufficiently compelling to motivate some western utilities to incur considerable expense to install phase shifters. These devices guard the owner's system from inadvertant flows, but may cause their neighbors to suffer the same adverse affects they seek to avoid themselves. It should be noted that the installation of phase shifters commenced after the abandonment of the Western States' Coordinating Council experiment of compensating disadvantaged utilities.

Unintended power flows mean that the bottleneck to increased sales between two utilities, even when those utilities are directly interconnected, may lie along lines owned by a third utility. Yet utilities are unlikely to enhance their own lines simply to facilitate sales between two other companies when compensation for the investment is not provided for, especially when it might be competing for the same sales. Utilities considering building additional capacity within their service territories, for internal movement of power or to facilitate sales, generally commit to incurring 100 percent of the costs while recognizing that their use of the lines may be restricted due to unintended power flows from other utilities.

These limitations have been overcome in some instances, generally through the development of jointly owned transmission projects, or through highly integrated planning conducted through a power pool, holding company, or similar format. The task force notes, however, that joint ownership of transmission projects may be prohibited by state laws regarding the issuance of bonds, which may require specific and exclusive title to the development by the issuer.

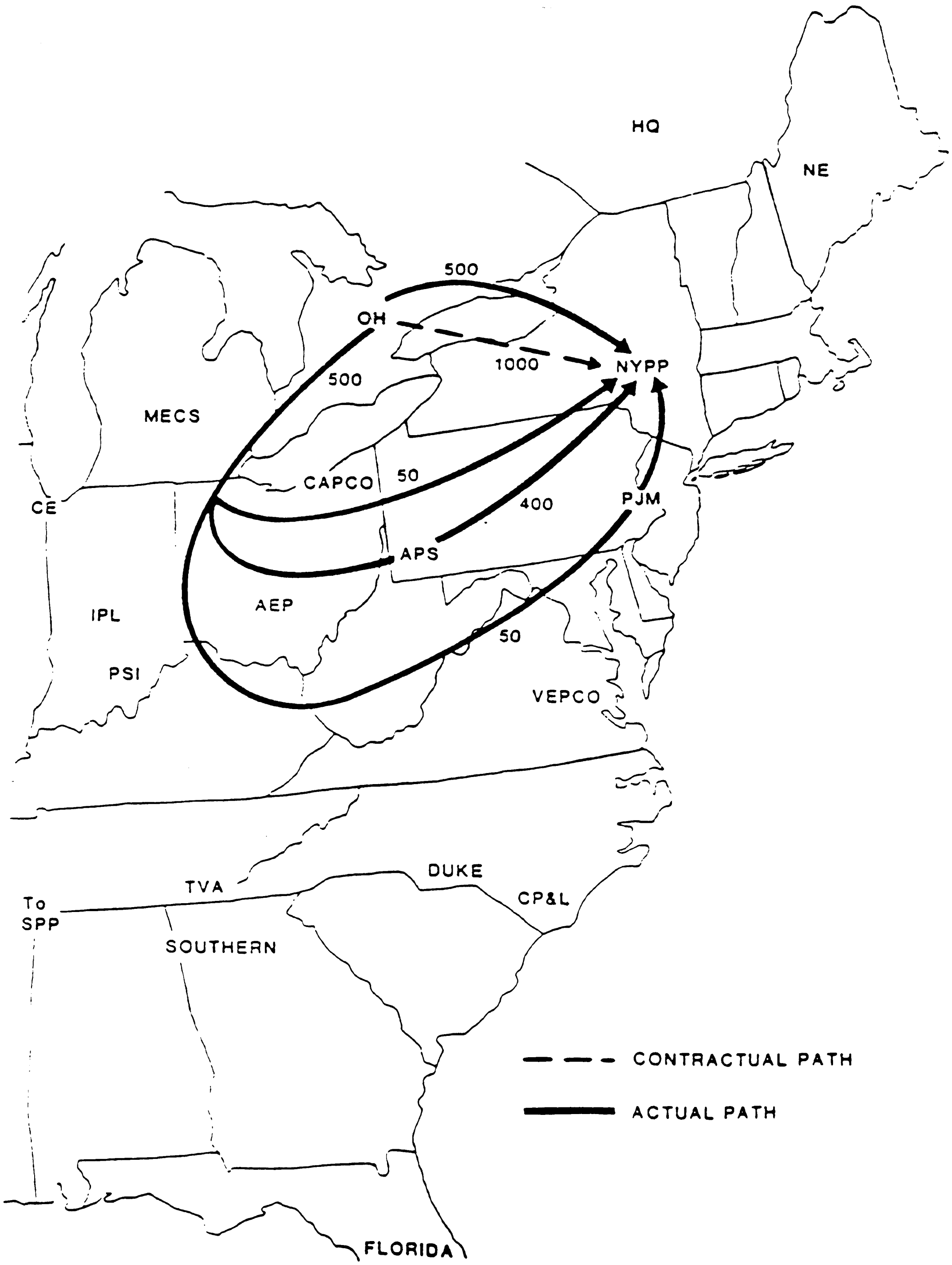
State and utility officials both noted that the pattern of line development and ownership is due at least in part to regulatory requirements (and stockholder demands) which discourage investment which would benefit those other than local

**Figure 3**
**Unintended Power Flows: 2000 MW from American Electric Power to Michigan Electric Coordinating System**




Source: American Electric Power Co.

## Figure 4
## Unintended Power Flows: 1000 MW from Ontario Hydro to New York Power Pool




Source: American Electric Power Co.

ratepayers. Work of the regional reliability councils counters the service territory oriented development of transmission lines to some extent by providing a forum for assessing regional reliability requirements and working with individual utilities to ensure development of required lines. The councils do not, however, provide any mechanism for considering lines which might be desirable principally for economically favorable sales.

## STATE AND FEDERAL REGULATORY PRACTICES

The regulation of inter-utility transactions is split between federal and state agencies, with states generally having authority over the approval of utility investments, and the Federal Energy Regulatory Administration (FERC) authority over wholesale rates. A number of difficult issues have emerged with regard to the exact nature and propriety of current jurisdictional relationships between state and federal regulatory authorities (including, in the case of utility holding companies, the Security and Exchange Commission). As identified more broadly in the NGA's 1983 report on regional regulation, there may be a number of jurisdictional "mismatches" between state and federal authority, and, possibly, some regulatory "gaps" which should be filled. Two such concerns identified by the task force are the apparent disjuncture in regulatory authority over transmission services -- with the FERC having virtually plenary authority over its pricing and the states having similar authority over siting and certification -- and, the closely related issue of whether there is a gap in federal authority to mandate adequate levels of transmission access, and what authority states may have to fill that gap. Another issue of serious concern regards the effect of federal regulations on state planning activities through, for example, the limited ability of state regulators to influence the supply planning decisions of major multi-state utility holding companies, which dominate supply in some regions, or uncertainties regarding state options for the development and use of cogenerated or non-system power sources.

It should be noted that the National Governors' Association has adopted policy recommending that jurisdiction over intrastate wholesale transactions should be shifted to individual states or to regional regulatory bodies, at the option of the state or states involved.

Many of these issues, especially those relating to the re-evaluation of economic regulation, are being considered in a variety of proceedings at both the state and federal levels (such as state rate and supply planning proceedings and the FERC's electricity inquiry) and, in the case of the state/federal jurisdictional questions, before the courts. The resolution of these issues will have a large effect on the future development of the transmission network, and the effectiveness of state siting, certification, and planning efforts in directing that development.

*Insofar as the electricity industry becomes increasingly regional in nature, the planning and siting of transmission facilities will necessarily assume an increasingly interstate character.*

Despite these on-going considerations, the two larger issues of concern to this task force -- the planning of transmission capacity and the processes for siting transmission facilities -- are not being as thoroughly explored. Yet both critically affect the adequacy of the transmission system. Insofar as the electricity industry becomes increasingly regional in nature, the planning and siting of transmission facilities will necessarily assume an increasingly interstate character. It is likely that interested parties will call for federal preemption in siting and certification. The task force believes that states may moot the arguments for such preemption by acting in a coordinated fashion to facilitate interstate transactions.

# V. Findings

The task force has identified a number of impediments to further development of transmission capacity, some of which involve state processes for certifying and siting new lines. Of those involving state regulation, lack of a definitive time table for the regulatory process appears to be one of the biggest causes of delay. The involvement of multiple state agencies (including poor coordination among agencies), a lack of clarity regarding regulatory requirements, and local jurisdictional hurdles are also important sources of delay, at least in part because they complicate the resolution of issues raised by intervenors during the decision process. For multi-state lines, differing state and/or state-federal requirements are an important factor discouraging line development.

The task force suggests that there is a legitimate and important role for states in the approval of generating and transmission capacity. In fact, the importance of this role has increased with the growing number of joint utility projects and the increasing financial risks associated with these large projects. The state regulatory goal should be one of balancing various public interests, and of balancing the local costs and regional benefits associated with individual projects. Yet, in order to be successful, state siting and certification processes must be timely, and must provide certainty. In addition, the task force believes that regulatory goals are not likely to be fully achieved if the approval process is not well coordinated with the utility planning and development programs.

The task force also found that, by and large, long range planning (by both states and utilities) focuses on and is driven by generating capacity needs. This focus seems to result from an institutional and regulatory framework which promotes consideration of needs within rather than between utility systems. In particular, the fact that transmission lines are generally developed and owned by the utility within whose service territory they reside, but will be used by non-owners as part of the whole system, creates economic and regulatory disincentives to the optimal development of the transmission grid.

Larger-scale transmission projects, which better reflect the needs of the overall system rather than its individual components, may only be achievable if regulatory requirements actually promote greater inter-utility coordination and cooperation on transmission development.

# VI. Policy Options

The task force identified a number of policy options which address the regulatory and institutional impediments to an expanded electricity transmission system. The options listed below focus on ways to encourage the development of lines which will facilitate demand power sales.

The task force believes that all of the options identified could be implemented, though not all may be desirable, by various methods, parties, and degrees. Thus, for example, clarification of regulatory requirements could be accomplished through statutory or regulatory changes, and could be done in coordination with state agencies, agencies in other states, and local authorities. Most of the options could, in some form, be implemented by individual states, by groups of states cooperating voluntarily, by federally recognized state compacts, or by federal preemption if states fail to adequately deal with the problem. Although a number of options are described briefly, no attempt is made to identify a "preferable" option, or to systematically identify potential benefits or drawbacks to the option.

*The policy options identified by the task force are not policy recommendations.*

It is important to emphasize again that the policy options identified by the task force are not policy recommendations. Rather, they represent the variety of options potentially available which specifically address the impediments identified by the group. After further deliberation, the task force may develop recommendations for consideration by the National Governors' Association.

The options identified include:

**OPTIONS:**

**1. Streamlining and Clarifying State Approval Procedures**

There are several basic ways in which states can expedite the approval process. States can consolidate agency consideration of requests for approval, either by locating all regulatory authority in a single agency or by having a single agency coordinate the activities of other agencies involved in approval (such as by arranging for joint hearings or avoiding duplication of requirements to file findings). Another method would involve establishing time limits for each stage in the approval process and for final approval of the application. States could also develop clear statutory and regulatory criteria for approval, including criteria which address the specific problems of determining need and siting for transmission facilities. Finally, the process can be streamlined by providing for state preemption of local requirements for larger lines and/or for lines which cross local jurisdictional boundaries.

**2. Integrating Planning and Approval Processes**

Several opportunities exist to further the siting and certification process. Requiring utilities to specify anticipated land requirements for transmission facilities can allow the state to assess, in broad terms, requests for certification of need for individual lines as well as to anticipate the need to approve corridors in the near future.

A form of "resource banking" could be used as a bridge between the planning and certification processes to reduce the lead time for final approval. Potential corridors could be sited and preserved from further development in anticipation of need to develop a line within say, five years. If the need does not materialize, the corridor could be reopened for other types of development. Although this option has been used by states to expedite siting and approval of generating facilities successfully, it would likely be more difficult to implement for transmission corridors, due to their linear nature and the large amounts of land involved. A corrollary to preestablishment of corridors would be provision for multiple purposes, such as highway rights-of-way, pipeline corridors, etc.

**3. Encouraging Multi-State Siting and Certification**

States may jointly hold hearings on siting and certification applications for multi-state projects. This option includes a range of possibilities for integrating state requirements, from holding mutual hearings to allowing joint filings and investigations of those filings. Provision can also be made for multi-state arbitration in cases of incompatible findings by individual states. This option could include allowing for individual denials to be overturned, as well as coordinating state-by-state approval contingencies. The task force has noted that if the states themselves are perceived as a bottleneck to the siting and certification of interstate projects, the federal government may assume a formal role in the certification and siting for such projects, possibly including the provision of federal eminent domain for the aquisition of interstate rights-of-way.

**4. Enhancing State Planning Efforts**

States could ensure that their planning, certification, and siting jurisdiction extends to all utilities in the state, including municipally and cooperatively owned companies. They can use the information collected from utility planning documents in a clearinghouse fashion, to help ensure that, in general, utilities within the state are not relying on the availability of purchases from the same sources, or intending to sell power to the same buyers. In addition, states can use their review of utility plans to look for opportunities to consolidate or better coordinate generation and transmission plans. For example, where plans indicate that two utilities are interested in building new lines in the same general area, the state planning agency might look at the possibility of developing a single, larger line as a more cost-effective alternative. In effect, the state planning process becomes a way of identifying economies of scale in coordination of investments which might not be evident to individual utilities. Information from state planning efforts could be linked to the siting and certification process to ensure that the actual lines developed reflect these considerations. The aggregated information contained in utility plans can also help the state determine where anticipated cogenerated power might be most valuable, and determine the availability of transmission resources to allow for efficient use of off-system power throughout the state.

**5. Requiring More Thorough Development of Transmission Options in Utility Planning**

As a part of utility planning requirements, states could require consideration of power purchases as a supply option (as many utilities are now required to evaluate the potential for using conservation as a supply option). In addition, utilities could be encouraged or required to consult with or account for the transmission requirements of all neighboring utilities as an explicit component of their own planning, where "transmission requirements" include the potential for long-term, firm power sales or purchases. Certification of need for individual projects could be made contingent upon this long-term planning coordination with all other utilities and at least the larger sources of anticipated cogenerated and off-system power sources.

**6. Promoting Multi-State Planning Efforts**

Multi-state transmission planning efforts could be enhanced in a number of ways. These include increasing informal communication among state regulatory agencies with regard to planning activities; establishing regular exchange of state forecasts and plans to allow for regular comparison of expectations; establishing consistent methodologies for developing state plans and for assessing utility plans, including, at a minimum, establishing agreed-upon definitions and data standards; and instituting formal multi-state planning in which anticipated demand and supply alternatives are considered on a regional basis. The final option could be implemented through Congressionally approved multi-state compacts.

**7. Eliminating Structural Impediments to Transmission Development**

Transmission development could be encouraged on a broader scale than it is currently. States could use the state planning, certification, and siting process in a number of ways to encourage joint transmission projects. Siting approval could be made contingent upon the utility successfully showing that it sought ways to consolidate the need of new corridors. Determination of need could be based on need of the line in general, rather than on a utility-by-utility basis.

Both state and federal ratemaking could be structured to ensure that transmission projects are not disfavored over investments in generating capacity, and especially that cost recovery is not jeopardized because the line is a joint undertaking or will serve functions other than improving reliability in the service territory. Establishment of a pricing mechanism to compensate utilities for major unintended power flows would help ensure that utility investments in transmission development will be recoverable. In addition, wholesale rate regulations could be refined to reflect the increasing variety in current wholesale sales arrangements, and the fact that under an expanded transmission system, these new types of sales would likely grow. In order to ensure participation by utilities and states along the entire corridor of a proposed line, wholesale rates would have to provide a mechanism for ensuring benefit to individuals and utilities all along the corridor. Finally, state bonding requirements could be changed to allow the use of industrial development bonds for the construction of jointly-owned facilities.

Finally, states could undertake the development of transmission resources as a public enterprise, possibly focusing on those situations in which a given project would improve the system overall but would not be sufficiently beneficial to any individual utility.

**8. Building On-going Informal Communication Among State and Federal Regulators, Utility Representatives, and Public Interest Organizations**

One of the difficulties in assessing the function and operation of a transmission network is that it must be examined from a variety of levels: individual service territories, state systems, regions of the country (loosely defined and shifting depending upon the issue at hand), or the entire synchronous area. Thus, it may be useful to sustain voluntary, but regular, dialogue among state and federal officials, industry representatives and consumer organizations on each of these levels. At the state and federal officials, joint boards could be developed for considering specific projects.

TABLE I

STATE SITING AND CERTIFICATION REQUIREMENTS

| STATE | CERTIFICATION AUTHORTIES | SITING AUTHORITIES | LEAD AGENCY (Siting) | AUTHORITY TO OVERRIDE OTHER AGENCIES? | NON-STATE APPROVAL REQUIRED (Where applicable) | COMMENTS |
|---|---|---|---|---|---|---|
| Alabama | Not required | Not required | | | | Certificate not required for "ordinary extensions of the existing system in the usual course of business" |
| Alaska | Not required | Not required | | | local jurisdictions tribal entities | Siting by local zoning, planning boards |
| Am. Samoa | Environ | Environ | Am. Samoa Power Authority | yes | | Approval not required for most lines; ASPA is a semi-autonomous gov't utility & sole agency for electricity generation & transmission |
| Arizona | Not required | PUC, Environ | PUC | yes | tribal entities US Dept of Interior | |
| Arkansas | PUC | PUC, Environ | PUC | no | | |
| California | PUC, Siting | PUC, Siting | Depends on type of line | yes | | Siting board is Calif. Energy Commission |
| Colorado | | | | | | |
| Connecticut | Siting | Siting | Siting | yes | fed. power authority Corps of Engineers | Siting Council's jurisdiction is exclusive |
| Delaware | Not required | DOT | | | Corp of Engineers Local jurisdictions | DOT franchises rights-of-way under its control |
| D.C. | PUC | Not required | | | | Have not received requests for new construction |
| Florida | PUC | Siting, Environ | Siting Board | yes | | Siting Board comprised of Governor & cabinet Various environ, water agenies give approval |
| Georgia | Not required | Land | Not applicable | | US Dept of Interior | Dept of Natural Resources has authority where historic/ ecological concerns |
| Guam | | | | | | |
| Hawaii | Land | PUC, Land | Not answered | | | Construction costs can be excluded from the ratebase if PUC does not find project necessary before construction |
| Idaho | PUC | PUC | PUC | yes | | PUC certifies only investor owned utilities, only 1st entry of transm. into county; may override local planning & zoning requirements |
| Illinois | PUC | PUC | PUC | yes | | Joint siting & certification process |
| Indiana | Not required | Not required | Not answered | | local, federal power authority | Joint siting & certification process |
| Iowa | PUC | PUC | PUC | Not applicable | cities | Approval by cities required if eminant domain to be exer-cized within city jurisdic. |
| Kansas | PUC | PUC | PUC | no | | Lines 230 kV+ require full formal siting review, smaller lines approved more routinely |
| Kentucky | PUC | PUC | PUC | yes | | Site approval only for 400kV + |

| STATE | CERTIFICATION AUTHORTIES | SITING AUTHORITIES | LEAD AGENCY (Siting) | AUTHORITY TO OVERRIDE OTHER AGENCIES? | NON-STATE APPROVAL REQUIRED (Where applicable) | COMMENTS |
|---|---|---|---|---|---|---|
| Louisiana | Not required | | | | US Corp of Engineers | Depts of Transportation & Natural Resources have siting jurisdication over state lands |
| Maine | PUC | Land, Environ | Land or Environ | no | | Board of Environmental Protection approves all forms of development which may affect the environment |
| Maryland | PUC | PUC | PUC | yes | counties | Local zoning variances must be obtained by utility. |
| Massachusetts | PUC, Siting | PUC, Siting | | | local conservation commissions, cities | |
| Michigan | PUC | Land | | | cities | Certif. only if outside service territory; Dept. of Natural Resources sites only if on land it admins. |
| Minnesota | PUC | Siting | Environ | yes | | |
| Misssissippi | PUC | PUC | PUC | no | | Joint siting & certfication |
| Missouri | PUC | PUC | PUC | | | Siting & Certif. necessary only if outside service territory |
| Montana | Siting | Siting | Siting | yes | | Board of Natural Resources and Conservation grants certificates under Montana Major Facility Siting Act |
| Nebraska | Power Board | | | | | Electric utilities in Neb. are all publically owned; individual utilities responsible for siting; Neb. Power Review Board responsible for certification. |
| Nevada | PUC | PUC, Environ | PUC | no | local & regional jurisdictions, tribal entities | |
| New Hampshire | PUC | Siting | Siting | no | | Bulk Power Supply Facility Site Evaluation Committee approves sites |
| New Jersey | PUC | PUC, Siting Land, Environ | Siting | yes | cities | Certif. only if condemnation necessary. PUC siting only to override local restrictions. Environmental agency only for coastal lands. Energy Facility Review Board approval if conflicts |
| New Mexico | PUC | | | | county, tribal entity | |
| New York | PUC | PUC | PUC | | fed. power authority | Siting & certification are joint process in NY |
| North Carolina | Not required | Not required | | | | |
| North Dakota | PUC | PUC | PUC | yes | | |
| Northern Mariana Islands | | | | | | |
| Ohio | Siting | Siting | Siting | | | Power Siting Board comprised of PUC Chair, Dirs. of Environmental Protection, Health, Development, natural resources, agriculture, and a consumer representative |
| Oklahoma | Not required | Not required | | | | |

| STATE | CERTIFICATION AUTHORTIES | SITING AUTHORITIES | LEAD AGENCY (Siting) | AUTHORITY TO OVERRIDE OTHER AGENCIES? | NON-STATE APPROVAL REQUIRED (Where applicable) | COMMENTS |
|---|---|---|---|---|---|---|
| Oregon | Siting | Siting | Siting | yes | | Joint siting & certif. process |
| Pennsylvania | PUC | PUC | PUC | | | |
| Puerto Rico | | | | | | |
| Rhode Island | PUC, Siting | PUC, Siting | Siting | yes | | PUC for lines less than 345kV Siting Board for 345kV+ lines Siting board new, no cases yet |
| South Carolina | | | | | | |
| South Dakota | Not required | PUC | PUC | | | |
| Tennessee | Not required | Not required | | | fed. power authority | Tennessee Valley Authority is responsible for power development in most of state |
| Texas | | | | | | |
| Utah | PUC | | | | localities, fed. power authority, U.S. Dept of Interior, BLM | |
| Vermont | PUC | PUC | PUC | yes | | Joint siting & certif. process |
| Virgin Islands | | | | | | |
| Virginia | PUC | PUC | PUC | yes | | SCC certifies lines of 150 kV or more; approves corridor to minimize environmental impact |
| Washington | | | | | | |
| West Virginia | PUC | PUC, Environ | PUC | no | | Dept of Natl Resources does not site, but grants necessary permits |
| Wisconsin | PUC | PUC, Environ | PUC | no | tribal entities, US Dept of Interior | May override local ordinances |
| Wyoming | PUC | PUC, Siting, Land | PUC | | county, tribal entity, fed. power authority, US DOI, US Forest Service | Joint siting & certif. process Dept of Public Lands has siting authority only on public lands; Industrial Siting Council also involved in siting. |

TABLE 2

STATE PLANNING REQUIREMENTS

| STATE | INDEPENDENT PLANNING AGENCY | COMMENTS | STATE PLANNING TIMEFRAMES | UTILIZED FOR CERTIF. OF GENERATING CAPACITY | UTILIZED FOR CERTIF. OF TRANSMISSION CAPACITY | UTILIZED FOR SITING TRANSMISSION | UTILIZED FOR RATEMAKING |
|---|---|---|---|---|---|---|---|
| Alabama | Energy Office | | 10 & 20 yrs | | | | |
| Alaska | Alaska Power Authority | | 10 & 20 yrs | Not applicable | | | |
| Am. Samoa | Am. Samoa Power Authority | ASPA is semi-autonomous govt. entity responsible for electric power production | Five yrs | Usually considered | Usually considered | Usually considered | Usually considered |
| Arizona | None | | | | | | |
| Arkansas | None | | | | | | |
| California | Energy Office | Calif. Energy Commission | Five & 20 yrs | Required | Required | | Required |
| Colorado | | | | | | | |
| Connecticut | None | | | | | | |
| Delaware | None | | | Not answered | | | |
| D.C. | None | DC Energy Office prepares plans but does not include independent forecasts | 10 yrs | Not answered | | | |
| Florida | Energy Office | Florida Electric Power Generating Group (FCG) is a voluntary organization of utilities which prepares state-wide planning; Florida PSC reviews reasonableness & holds public hearings. | 10 & 20 yrs | Required | Required | Required | Required |
| Georgia | None | State PSC has employed consultants to evalute utility forecasts & prepare their own | | Not applicable | | | |
| Guam | | | | | | | |
| Hawaii | None | | | | | | |
| Idaho | | Planning through Northwest Power Planning Council | Twenty yrs. | Not applicable | | | |
| Illinois | PUC, Dept of Energy & Natl Resources | Ill. is currently in the process of implementing plans for certif., siting, & ratemaking | Twenty yrs. | | | | |
| Indiana | PUC | Uses university-based forecasting group | Twenty yrs. | Required | | | Required |
| Iowa | None | | | Not applicable | | | |
| Kansas | PUC | KCC will begin independent forecasts in 1987 | Five yrs. | Will be considered | Will be considered | Will be considered | Will be considered |
| Kentucky | None | | | Not applicable | | | |
| Louisiana | Not answered | | | Not answered | | | |
| Maine | PUC, Energy | | 15 yrs. | Required | Required | Required | Required |
| Maryland | PUC, Siting | Dept of Natural Resources has a Power Plant Research Program | 10 & 20 yrs. | Required | Required | Required | Required |
| Massachusetts | Energy | | 15 yrs. | | | | |
| Michigan | PUC, Energy | | Up to 5 yrs. | Not applicable | | | |

| STATE | INDEPENDENT PLANNING AGENCY | COMMENTS | STATE PLANNING TIMEFRAMES | UTILIZED FOR CERTIF. OF GENERATING CAPACITY | UTILIZED FOR CERTIF. OF TRANSMISSION CAPACITY | UTILIZED FOR SITING TRANSMISSION | UTILIZED FOR RATEMAKING |
|---|---|---|---|---|---|---|---|
| Minnesota | PUC, Energy | Plans are not required, but are prepared in conjunction with need for power approval for individual utility project | 15 yrs. | Usually considered | Usually considered | | |
| Mississippi | None | Energy & Transportation Board prepares Mississippi Energy and Transportation plan | | Not answered | | | |
| Missouri | None | | | Not applicable | | | |
| Montana | Environment | Dept of Natural Resources and Conservation prepares plans as needed for siting applications | Twenty yrs. | Not applicable | | | |
| Nebraska | PUC, Energy | Nebraska Power Association & Power Review Board prepare forecasts | Twenty yrs. | Usually considered | Usually considered | Usually considered | |
| Nevada | PUC, Energy | Office of Community Services prepares forecasts & works with WSCC reliability council | Five, 10, 20 yr | Required | Required | Required | Required |
| New Hampshire | None | | | Not answered | | | |
| New Jersey | Energy Office | | 15 yrs. | Required | Usually considered | Usually considered | Usually considered |
| New Mexico | None | | | | | | |
| New York | Energy Office | | 16 yrs. | Required | Required | Required | |
| North Carolina | PUC | | 15 yrs. | Required | | | |
| North Dakota | None | | | | | | |
| Northern Mariana Islands | | | | | | | |
| Ohio | PUC | Prepares demand forecasts only | Five, 10, 20 yr | | | | |
| Oklahoma | PUC | | 10 yrs. | | | | |
| Oregon | Energy Office | | Twenty yrs. | Required | Required | Required | |
| Pennsylvania | PUC | | Twenty yrs. | Usually considered | Required | Required | Required |
| Puerto Rico | | | | | | | |
| Rhode Island | Energy | New state planning process | 15 yrs. | Required | Required | Required | Usually considered |
| South Carolina | | | | | | | |
| South Dakota | None | | | Not answered | | | |
| Tennessee | None | | | Not applicable | | | |
| Texas | | | | | | | |
| Utah | PUC | | Twenty-5 yrs. | Usually considered | Usually considered | | |
| Vermont | PUC | | Twenty yrs. | Required | Required | Required | |
| Virgin Islands | | | | | | | |
| Virginia | Energy Office | Just beginning planning process. SCC reviews utility forecast methodologies | Five, 10, 20 yr | Required | | | |
| Washington | | | | | | | |
| West Virginia | PUC, Energy | | Twenty yrs. | Required | Required | Required | Usually considered |
| Wisconsin | PUC, Energy | | Five yrs. | Not answered | | | |
| Wyoming | PUC | | Not answered | | | | |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