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Federal and State Jurisdiction

This section identifies the major state/federal jurisdictional issues which arise in a more competitive electric market and details the positions of the major competitor groups and views of Alaska stakeholders. State and federal jurisdictional issues in Alaska promise to be far simpler than in the lower-48 for policymakers considering comprehensive regulatory changes to the electric utility industry.

Existing jurisdictional allocations between the states and the federal government lower-48 have worked reasonably well for more than fifty years. When Congress enacted the Federal Power Act in 1935, it established what the Supreme Court has termed a "bright line" between federal and state jurisdiction. The Act provides, in relevant part, that FERC shall have jurisdiction over wholesale sales of electric energy (i.e., sales for resale) and interstate transmission. The Act reserves to the states jurisdiction over "facilities used in local distribution."

Until recently, utility markets were primarily local in nature. Utilities generally were vertically integrated in discrete geographic locations, for the most part in one state, as they built their own generation and transmission facilities to serve native load. This inherently retail market enabled state authorities to exercise the bulk of regulatory authority over the costs and revenues of the electric utility industry. And while the wholesale interstate market grew steadily – especially as transmission technology and computer information exchanges improved – market transactions were still largely local. Disputes between federal and state regulators were relatively few as the existing

"bright" jurisdictional line between transmission and distribution illuminated the way to federal/state comity.

The local nature of electricity markets began to change in the late 1970's. Congress enacted the Public Utility Regulatory Policies Act of 1978 ("PURPA"). PURPA for the first time introduced new players into the market for the production of electricity for resale. The Energy Policy Act of 1992 ("EPAAct"), dramatically increased the competitive market for wholesale generation by amending the Public Utility Holding Company Act of 1935 to permit the development, ownership, and operation of another new class of generating facilities, exempt wholesale generators (EWGs).

EPAAct also granted the Federal Energy Regulatory Commission ("FERC") the express authority to order wholesale wheeling under certain conditions. Until EPAAct, open transmission access tariffs – generally achieved by the FERC in exchange for approvals such as merger authority or to sell at market-based rates – had been the exception, not the rule. In the wake of the Energy Policy Act the FERC issued Order 888/889, which requires all jurisdictional utilities to adopt essentially identical open-access transmission tariffs. In addition, some states have begun considering, and now ordering, retail wheeling. Alaska is not required to comply with Order 888.

In the post-EPAAct era, electricity markets in the lower-48 are evolving faster than most people had expected. New market entrants are providing a variety of new transactions (long-term, spot) and new products and services (both financial and physical) to consumers throughout the nation. Buyers and sellers in different and often distant states have a greater opportunity to transact with each other than ever before. Regional transactions that were unheard of five years ago are today commonplace. Regional electricity markets are expanding, and a national electricity market is just around the corner.

This emerging market is clearly interstate in nature. As buyers and sellers in different states transact in a regional market, the actions of any one state regulatory body will affect the nation's ability to realize efficiency gains. For example, developing regional markets can be hindered if disputes arise between states seeking to maximize competitive gains for their ratepayers. New institutions to address these concerns are being developed, such as regional transmission groups, independent system operators and power exchanges, but they are being developed within the confines of the existing jurisdictional framework.

In Alaska, the market is entirely intrastate which eliminates many of the jurisdictional issues faces in the lower-48. It does not, however, necessarily preclude the effects of "date certain" federal legislation, or other federal statutes requiring industry reform or restructuring.

The views of major competitor groups on the issues associated with the role of competition, the jurisdiction to prescribe retail wheeling, and the distribution of authority between state and federal authorities are provided in Tables 5.1, 5.2 and 5.3.

Stranded Investment

The move toward open and competitive markets for electric power raises the possibility that many utility investments might currently be overvalued relative to new market determined values, or may not be recoverable at all. "Uneconomic" investments which could become "stranded" in the transition to competitive markets fall into two broad categories:

- **Stranded Assets.** Stranded assets include *ratebase assets* such as investments in power plants, wholesale power contracts, and transmission and distribution facilities whose fixed costs may not be recoverable from sales revenues; and *regulatory assets*, such as deferred cost accounts, that may be uneconomic to recover in rates,
- **Stranded Liabilities.** Stranded liabilities are contractual obligations to purchase fuel or power with terms above market prices. The above market, or "uneconomic," portion of fuel and purchased power contracts may become stranded.

The critical and most visible factor affecting transition costs is the gap between the current regulated prices to retail customers and the potentially lower "unregulated" prices in new competitive markets. In the regulated world, "just and reasonable" rates are set in such a way to ensure recovery of prudently incurred costs. In a competitive market, prices will not be set by average "bundled" costs, but by the equilibrium in the power markets. Because competitive market prices may have little or no relation to the historical average embedded costs of utilities, this raises the possibility that many utility assets and liabilities may be valued lower in the marketplace than currently on the books.

The views of the major competitor groups on stranded investment are provided in Table 5.4. Further discussion of stranded investment is provided in Section 8 of this report, "Stranded Costs" and in Section 11, "Modeling".

Mergers and Acquisitions

There have been numerous popular predictions of a potential "wave" of mergers and acquisitions leaving in its aftermath perhaps no more than five national generating companies. Predications of utility industry

consolidation on such a massive scale have, however, been met with skepticism by some.

Several considerations are pertinent to this disagreement.

Evidence from recent M&A activity in the electric power industry as well as in other industries – most pertinently, gas pipeline and distribution acquisitions – suggests that such transactions typically involve substantial premiums above book values. An important reason for paying these premiums is the theoretical potential for achieving substantial economies in some aspect of the of the merged companies' business. For utilities, such benefits might come from accessing new markets, from economics of scale gained by the consolidation of common facilities, or from obtaining new, low-cost sources of power. For instance, the proposed acquisition of CEA by MEA anticipates financing cost savings of \$100 million and an equity premium of \$42.5 million - \$500 for each of CEA's 85,000 customers.

In gauging the future of utility mergers and acquisitions, one important consideration is that under traditional ratemaking practice, the shareholders of a utility that acquires another company are generally obliged to absorb any premium paid for the acquisition, while cost reductions that result from the combination are "flowed through" to the ratepayers. The FERC's action on several mergers, including Utah Power & Light by PacifiCorp and Public Service of New Hampshire by Northeast Utilities demonstrates that federal regulators may condition approval of consolidations on terms that may be unacceptable to many companies. It has also been suggested that many important benefits could be achieved through contractual agreement without the necessary complexities involved in a change of ownership.

The views of the major competitor groups on mergers and acquisitions are provided in Table 5.5.

Market Power and the Competitiveness of the Electric Power Industry

Utility merger-mania, now averaging almost one major announcement per month, is forcefully interjecting a new set of public policy issues into the discussions of electric utility restructuring: to what extent could the exercise of market power by electricity generators compromise the economic efficiencies and public welfare benefits believed to result from more open and competitive markets? For the Federal Energy Regulatory Commission (FERC) and state regulatory agencies, the potential increase in the market power of regional electricity generators raises some fundamental questions:

- What are the public policy standards that should guide the regulatory bodies in assessing horizontal market power?
- What are the appropriate analytical methods that should be used to measure market power?
- To what extent must utility control of generation resources be broken up prior to restructuring in order to ensure the future competitiveness of markets?

Thus far the judicial and regulatory analysis and treatment of market power in the electric utility industry has been rather narrow. For the past 60 years, the horizontal market power of electricity generators has not been a significant regulatory or antitrust issue. This is not because some utilities do not have market power. Rather, pervasive regulation under the current industry structure has effectively restricted utilities' ability to exercise market power. Almost all the antitrust case law brought under the Sherman Act, as well as recent judicial and regulatory proceedings broadening FERC's legal authority, have focused on the role of the transmission system, and not the generation sector, in enhancing or retarding competition.

Historically, the FERC has relied extensively on market power tests that are derived from antitrust precedent. In recent merger cases, the FERC has moved away from applying standards of "consistency [of a merger] with the public interest" to using merger proceedings to advance its restructuring agenda "to enhance and promote increases in the competitiveness of bulk power markets."

On December 18, 1996, the FERC issued a "Policy Statement" designed to revise and streamline its 30-year old policy for evaluating public utility mergers. The Commission will use the screening approach of the Department of Justice and the Federal Trade Commission's 1992 Horizontal Merger Guidelines to determine if a merger will result in an increase in market power.

However, these guidelines are coming under increasing criticism as the result of their inadequacy in addressing two fundamental concepts:

- The definition of what constitutes a "market" in the context of a competitive power industry
- The ability to *exercise* market power, not the existence of a significant market share, is the critical analytical question.

Reliance on static measurements of capacity concentration as defined in the Merger Guidelines, it is argued, cannot account for the critical aspects that differentiate the electric power industry from other industries, and as a result, miss the operational aspects of electricity

market which could allow generators to influence market prices. Some of these critical operational aspects include:

- Electricity markets are extremely temporal.
- Transmission constraints and costs can effectively isolate areas from competitors.
- Buyer and seller groups are constantly changing.
- Geographic scope of the relevant market changes constantly in relation to market clearing prices and transmission costs and constraints.
- Electricity is not a monolithic product, but has widely differentiated value according to how, when, and where it is sold.

More appropriate market simulation techniques and analytic methodologies to analyze the degree to which the exercise of market power by large generating companies could compromise public policy interests need to be employed.

The views of the major competitor groups on market power are provided in Table 5.6.

Transmission Operations and Governance

While the FERC has jurisdiction over most facilities used in the transmission of electric energy, this jurisdiction is not all-encompassing. Under the Federal Power Act ("FPA"), FERC has the authority to regulate the interstate transmission of electric energy and sale of wholesale electric energy. Under section 211 of the Federal Power Act, any electric utility, federal power marketing agency, or any other person generating electric energy or sale for resale, may apply to the Commission for an order requiring a transmitting utility to provide transmission services. The FPA also contains provisions explicitly applicable to some public power entities.

Unless specifically provided for in the FPA, or unless a public power entity's transmission facilities are the subject of a section 211 request, FERC cannot require nonjurisdictional utilities to provide access to their transmission facilities.

Nonetheless, FERC has urged nonjurisdictional utilities to comply with its open access rules. FERC Order 888/889 asserts that nonjurisdictional utilities must provide open access to their transmission systems in a manner that is "reciprocal" to what the Commission will require of investor-owned utilities. Already, there is a debate about what constitutes "reciprocal" treatment. Santee Cooper, a South Carolina public power agency, was the first non-jurisdictional utility to

voluntarily file an open-access transmission tariff. Santee Cooper, however, argued that there are substantial differences between jurisdictional and nonjurisdictional utilities that will have to be taken into account by the Commission. These differences may or may not warrant different treatment. However, without FERC jurisdiction, users of Santee Cooper have no forum for challenging these assertions. In sum, the FERC does not have the same all-encompassing jurisdiction over all power transmission. This may inhibit the development of a more competitive wholesale electric market.

The views of the major competitor groups on transmission operations and governance are provided in Table 5.7. Additional discussion of transmission issues is provided in Section 6 of this report, "Network Integrity".

The Public Utility Holding Company Act (PUHCA)

The Public Utility Holding Company Act was passed in 1935 in response to problems associated with the ownership of utilities by holding companies. The PUHCA requires all public utility holding companies, except those entitled to an exemption, to register with the Securities and Exchange Commission (SEC) thereby becoming subject to its regulations. A holding company is defined as any company which directly or indirectly owns or controls 10 percent or more of the outstanding voting securities of an electric utility or gas distribution company.

The SEC regulations of holding companies subject to the PUHCA include:

- The SEC may require corporate reorganization and require equitable redistribution of voting power;
- The SEC may restrict holding company operations to those "necessary or appropriate" to a defined service territory and require divestiture of non-utility businesses which are not "functionally related" to its utility business;
- The SEC has broad oversight and approval functions related to a holding company's "financial integrity" – decisions including security transactions, dividends, loan and debt portfolio transactions and operational contract activities;
- Under Section 9, the SEC retains important oversight and approval functions regarding a holding company or its subsidiary from acquiring securities or assets in *any* business.

Most utilities are exempt from these regulations. The statutory exemptions include:

- A holding company, and each utility subsidiary from which the holding company derives its income, must be incorporated in the same state and must be "predominately intrastate" in character, and must carry on their businesses substantially in the incorporating state.
- A holding company must be "predominately a public utility company" and its utility operations must not extend beyond its state of incorporation and contiguous states. Generally, the exemption can be retained as long as the gross revenues of the subsidiaries in noncontiguous states do not exceed 25 percent of the holding company's consolidated revenues from utility operations.
- Holding companies which are not "primarily engaged" in utility businesses, that is, the utility business is an "incident" or "accessory" to the holding company's nonutility businesses and accounts for no more than 10 percent of its revenues.

The restrictions of the PUHCA are regarded by its critics as a significant barrier to growth to the IPP industry and to multi-state integrated energy service companies. They argue that some modifications, or repeal, of the Act are necessary. The views of the major competitor groups on PUHCA are provided in Table 5.8.

Public Utility Regulatory Policy Act of 1978 (PURPA)

PURPA authorized the Federal Energy Regulatory Commission (FERC) to establish rules to encourage "small power production" and cogeneration by nonutility companies and to encourage the sale of electricity to utilities. The law provides an assured market and price structure of these power producers.

The FERC subsequently developed rules to implement PURPA's mandates, the key features of which were:

- **Qualifying Facilities (QFs):** The FERC established two kinds of facilities as qualified to require utilities to buy power: (1) "Small Power Producers" with capacity less than 80 MW, for which at least 75 percent of the energy input must come from biomass, waste burning, renewable resources, or geothermal heat, and (2) cogenerators, for which there is no maximum or minimum size.
- **Avoided Cost:** The concept of "avoided cost" was established as the way of determining how to price the electricity sold by QFs. It was defined as: "the incremental cost to an electric utility of electric energy or capacity which, but for the purchase, the utility would generate itself or purchase from another source." Most

administrative estimates of marginal costs turned out to be far in excess of actual production costs and have left the purchasing utilities with uneconomic power purchase contracts.

- **Limits of Ownership of QFs:** No more than 50 percent interest in a QF could be owned by an electric utility, utility holding company, or any partially owned subsidiary of either.

The views of the major competitor groups on PURPA are provided in Table 5.9.

Access to Lower Than Market Capital

Historically, municipally-owned and cooperatively owned utilities have enjoyed the use of below market financing sources, such as tax-exempt municipal bonds and RUS subsidized loans. One of the flash points in the recent debate has focused on "subsidies" in the form of tax exemptions and their effect on competition, taxpayers, and rural communities. On January 22, 1998, the Internal Revenue Service issued temporary regulations (that went into effect on February 23, 1998) that enable government-owned electric utilities, such as large municipal systems with excess generating capacity, to sell electricity in emerging competitive markets. The regulations allow such utilities the use of tax-exempt bonds to finance facilities that generate and transmit power for the purpose of competing against other electricity suppliers.

In an competitive market for electricity, in which privately-owned and publicly owned utilities compete with one another, the use of tax exempt financing, and other forms of government subsidized capital, are being drawn into question. The principal question is the extent to which publicly financed facilities can be used to compete in the marketplace outside of the municipality, county, or public power district for which they were intended. Table 5.10 presents the positions of the major competitor groups on the issues of access to lower than market capital.

Annexation

Annexation is an important public policy tool that allowed local governments to meet their obligation to serve new residents and promote economic development on behalf of the community.

The ability of municipal utilities to expand their service territories through annexation is being drawn into question in the context of competitive markets.

The views of the major competitor groups on annexation are provided in Table 5.11.

Open Records and Public Meetings Laws

Currently, public-owned utilities are required to open all meetings to the public and provide all planning and financial information to the public record according to strict open records and public meetings laws. The fact that investor-owned utilities, independent power producers and marketers do not have the same requirements, and their ability to access important planning and financial information of public utilities, affords them a potentially large competitive advantage in more open and competitive markets. Access to information in a competitive retail market raises three principal questions:

- How should utilities provide competitors and utility affiliates with comparable access to relevant customer information to assure that no one receives an unfair competitive advantage?
- How should regulators ensure that customer proprietary information is protected and that sensitive individual customer information not be divulged?
- How should regulators ensure public access to information that will allow consumers to meaningfully compare alternatives?

The views of the major competitor groups on open records and public meetings laws are provided in Table 5.12.

System Benefits Charge

One common method for funding public policy programs in a restructured industry environment is through the implementation of a charge in distribution rates, or through the collection of a set percentage of utility revenues. Such charges, often termed "system benefits charges" spread the cost of program support broadly among all customers that take at distribution level or who buy utility power.

System benefits charges are much like an industry-specific tax or fee. The funds collected are allocated to a specific account or a specific purpose. Distribution of the funds requires some level of administrative and accounting oversight, usually by the utility regulator. System benefits charges have the obvious effect of reducing the overall potential for savings as a result of restructuring. This could be a significant issue affecting the balance of costs and benefits in a state like Alaska, electric rates may not be amenable to significant reductions through competition. As with taxes and fees, there are important issues raised about the way in which charges are collected. Today, all customers share in the costs of services that are provided to smaller groups of customers. Load retention rates and low income programs are just two examples. If a system benefit charge were collected as a

fixed percentage of electricity sold at the distribution meter, for example, large customers that take service at the transmission level may be exempted from the charge.

The views of the major competitor groups on a system benefits charge are provided in Table 5.13.

TABLE 5.1
Competitive Advantage of Provider Groups: Role of Competition

Issue	Investor-Owned Utilities	Municipally-Owned Utilities	Cooperatively-Owned Utilities	Marketers	Independent Power Producers
The scope and character of competition, especially with regard to how competition is implemented, is critical to the benefits consumers may realize from more open and competitive markets.	EEl supports a competitive electricity market where the transition to competition occurs in a fair and orderly manner. Such a market is defined as one in which all consumers benefit from competition, past commitments are respected, and all competitors stand on equal footing. Consumers must receive the benefits of competition through improved efficiencies, not by cost-shifting or cost-avoidance.	APPA endorses competition as the best means to provide lower electricity rates for all consumers. Public power systems serve an important and distinct role in the market, and are well situated to participate as viable competitors in a restructured electricity market.	Since the benefits of competition and deregulation arrive last, if ever, in rural areas, it is important to preserve the strengths of the existing rural electric system until the success of a restructured system can be reasonably assured.	Competition should provide all customers meaningful choice, implement open, efficient, liquid and price-competitive energy markets, and encourage the development of new and innovative energy services and technologies at the earliest possible date.	The benefits of competition are far too compelling to let "well enough" alone. Competition will: put downward pressure on costs; provide incentives for the creation and development of innovative products and services; enhance supply reliability by providing proper price signals for construction; assign risks to developers and not to ratepayers; attract new business development; and provide market driven incentives for environmental protection.

TABLE 5.2
Competitive Advantage of Provider Groups: Retail Wheeling/Customer Choice

Issue	Investor-Owned Utilities	Municipally-Owned Utilities	Cooperatively-Owned Utilities	Marketers	Independent Power Producers
Federal legislation could preempt states' authority to implement electric restructuring under state laws and policies.	States should be allowed to determine the pace and shape of the transition to competitive retail electric markets. Any federal legislation must (1) clarify jurisdictional ambiguity; (2) eliminate disparate treatment of electricity suppliers that could frustrate a competitive electricity market; (3) provide for <u>reciprocity</u> among sellers and buyers; and (4) ensure that all costs incurred by electricity providers to meet current regulatory obligations are recovered.	APPA opposes a federal mandate to implement retail access. Public power systems should determine through their own political processes what policies will best serve their communities. APPA supports state and local studies of restructuring to determine benefits and costs.	RECs must retain the right to determine when and how choice of power supply will be implemented for their customers and to establish any necessary procedures. CREA urges lawmakers to allow wholesale wheeling to be fully implemented and its results evaluated before moving to retail competition.	All classes of customers should have meaningful choices among competitive suppliers. State legislatures should clarify existing laws and empower state PUCs to implement customer choice and retail access to all classes of customers, at the earliest possible time.	All customers should have a choice of electricity suppliers. Competition can and should be structured to bring benefits to all customer classes. "Wholesale competition" is a misnomer. Robust, efficient and effective wholesale competition requires access to retail markets. Retail competition is a critical component of a workable market structure, providing the liquidity, market depth, and price visibility essential for robust competition, effective risk management, and desirable capital deployment.

TABLE 5.3
Competitive Advantage of Provider Groups: State and Federal Authority

Issue	Investor-Owned Utilities	Municipally-Owned Utilities	Cooperatively-Owned Utilities	Marketers	Independent Power Producers
Restructuring raises many fundamental jurisdictional questions regarding the division of regulatory and oversight authority between the FERC, state regulatory agencies, the U.S. Department of Justice, the Federal Trade Commission, and state Attorneys General.	Except where monopoly arrangements are deliberately continued (e.g., the wires or delivery portions of the business), regulators should withdraw from oversight of investment and operating decisions. Open markets should become the major source of protection for consumers, and regulators should not attempt to artificially "level the playing field." Federal legislation should provide for reciprocity so that some states are not disadvantaged while others can benefit from competition.	Proposals to expand FERC jurisdiction over publicly owned utilities are unnecessary and would not benefit consumers or advance the development of a competitive bulk power market. The Energy Policy Act of 1992 already provides authority to FERC to order publicly owned utilities to provide transmission services. If impediments exist in the Federal Power Act, APPA would support statutory changes to clarify that state and local jurisdictions have exclusive authority to order retail access.	NRECA and CREA oppose a federal mandate forcing states to implement retail wheeling. Existing rights of self governance by the cooperative membership must be protected, including self-regulation. CREA supports the wholesale wheeling provisions of the Energy Policy Act of 1992 and endorse its prohibition on the ability of the FERC to mandate retail wheeling to ultimate customers.	Congress should resolve outstanding jurisdictional issues and require FERC to promulgate uniform, non-discriminatory, open-access transmission tariffs, clarify current laws to expand existing stranded cost recovery and mandate a date certain by which the state must complete the transition to a competitive energy market.	Multistate regional markets are less efficient if each state begins retail competition at a different time. For competition to be orderly and fair to all, federal legislation should mandate state restructuring programs should include a "date certain" no later than Jan. 1, 2001.

TABLE 5.4
Competitive Advantage of Provider Groups: Stranded Investment

Issue	Investor-Owned Utilities	Municipally-Owned Utilities	Cooperatively-Owned Utilities	Marketers	Independent Power Producers
The move towards more open and competitive markets raises the possibility that many utility investments might currently be overvalued relative to new market determined values, or may not be recoverable at all.	The recovery of legitimate stranded costs is necessary to prevent cost-shifting from large customers onto residential and small business consumers; to treat utility shareholders fairly; and to promote efficient competition. Recovery of costs incurred to develop today's electric supply and transmission system from all consumers is needed. Without such recovery, consumers will be comparing electricity prices burdened by almost a century of regulation with prices from suppliers which have not been subjected to regulatory commitments. As a result, the most efficient supplier may not be apparent and be selected.	Recovery at wholesale of stranded investment – through transmission, exit, access or other charges – is unjustified and would impede the development of competitive bulk power markets. At the retail level, however, recovery of such costs may be appropriate if retail wheeling is allowed.	If stranded costs are to be recovered, they should be recovered in a competitively neutral manner, without placing an undue burden on residential and small business customers. All stranded costs must be prudently incurred, verifiable, and non-mitigatable. Loss of revenue under existing wholesale power contracts between G&Ts and distribution coops should be recognized as a recoverable stranded cost.	Valid stranded costs associated with generation assets should be collected to the extent that market values for such assets have been determined by reference to legitimate arm's-length sales offerings. Stranded costs should be measured on an aggregated basis and netted against greater than net book values.	Policy makers need to design and implement programs that provide a fair opportunity for utilities to recover stranded costs. This should be done in a manner that fosters, rather than inhibits, the development of robust competitive markets. Utilities should be entitled to full recovery of all legitimate, verifiable, non-mitigatable, prudently incurred, net (eligible) stranded costs, including PUC-approved regulatory commitments and power purchase contracts.

TABLE 5.5
Competitive Advantage of Provider Groups: Mergers and Acquisitions

Issue	Investor-Owned Utilities	Municipally-Owned Utilities	Cooperatively-Owned Utilities	Marketers	Independent Power Producers
The large number of mergers in the electric power industry -- now averaging almost one major announcement per month -- is interjecting a new set of public policy issues into the discussions of electric utility restructuring: to what extent could the exercise of market power by electricity generators compromise the economic efficiencies and public welfare benefits that are believed to result from more open and competitive markets?	Further actions to handicap utilities -- through forced divestiture, banning affiliate sales in the utility's historic service territory, or restricting use of company information and resources -- will limit customer choice and artificially increase costs.	Mergers are frequently anticompetitive because they eliminate competitors and can result in regional dominance of local markets. Mergers must result in affirmative public benefits that could not be achieved through other means. FERC merger policy should be further enhanced to ensure that proposed mergers result in a decrease in or elimination of market power.	The FERC and state regulators should not approve mergers and consolidations of electric and other utilities that do not substantially enhance competition, do not produce net benefits to consumers that cannot be achieved through other means, or reduce available transmission capacity without significant offsetting public benefits. Market power must be restrained. A fair, efficient competitive electric industry will not survive if the market consolidates to a handful of giant companies or if some companies are able to engage in predatory pricing or discriminatory actions.	Mergers and acquisitions should be approved only if they can be demonstrated to be in the best interest of consumers, and contribute to the benefits of fully functioning, efficient electricity markets.	Functional unbundling, cost separation, appropriate codes of conduct, and rules against abuse of affiliate relationships or confidential information must be developed and enforced.

TABLE 5.6
Competitive Advantage of Provider Groups: Market Power

Issue	Investor-Owned Utilities	Municipally-Owned Utilities	Cooperatively-Owned Utilities	Marketers	Independent Power Producers
Restructuring raises the possibility that State and Federal regulatory and enforcement authorities may need to act to: prevent the development of undue market concentration through mergers, acquisitions and affiliated interest agreements; mitigate or remedy existing undue market concentration; and prevent the imposition by incumbent local franchise holders of impediments to entry.	Safeguards at both the state and federal levels currently prohibit or remedy anti-competitive actions.	Any effort to increase effective competition within the U.S. electric industry will hinge on the ability of Congress and the states to address market power issues. Federal legislation and regulation should be updated and strengthened to prevent exercise of market power.	The benefits of competition will be eliminated if electric power generation is concentrated in the hands of a few huge corporations. Customers could suffer if there are few sellers from which to buy and those few sellers are not held accountable to consumer safeguards. Electric utility mergers are reducing the number of competitors and could stunt the growth of competitive markets.	Regulators should ensure against the ability of a generation owner to exercise power, either vertically, in conjunction with transmission and/or distribution assets, or horizontally, due to a concentration of assets in a particular regions. Regulators should require divestiture of generation assets to fully mitigate residual horizontal and vertical market power.	As the industry moves from regulation to competition, it will be necessary to ensure that incumbents cannot engage in anti-competitive actions or practices to preserve their market share.

TABLE 5.7
Competitive Advantage of Provider Groups: Transmission Operations and Governance

Issue	Investor-Owned Utilities	Municipally-Owned Utilities	Cooperatively-Owned Utilities	Marketers	Independent Power Producers
In Order 888, the FERC has stated that prices, terms and conditions and access to the transmission and distribution grids must be compatible with both reliable operation and free and fair competition for electric power. Many of the details regarding the role of independent entities and regulatory oversight are still unresolved.	Restructuring must not degrade safety, reliability, or customer service standards.	FERC must be given clear and specific authority to require development of strong, truly independent system operators in order to eliminate transmission rate pancaking and to otherwise facilitate the development of vigorously competitive regional power markets. If ISOs prove to be ineffective, FERC should be able to order divestiture to independent regional transmission companies.	Today's voluntary system will not suffice in a restructured industry. A self-regulating organization will be more flexible and efficient than a government agency. General oversight from appropriate agencies of government is appropriate. There is the need for independent regional security coordinators.	FERC should require that all jurisdictional transmission services be unbundled and that all electricity providers reserve, purchase, schedule and curtail transmission services under the same uniform, non-discriminatory, open-access transmission tariff. FERC should regionalize the U.S. electric grid under independent management and operational control with incentives to optimize throughput.	FERC Order 888 has not, by itself, guaranteed fair access to transmission services. Translating the "open access" principles into operational reality requires much more work at both the federal and state levels. The regional transmission grid requires independent management, as well as non-discriminatory methods of pricing transmission services.

TABLE 5.8
Competitive Advantage of Provider Groups: The Public Utility Holding Company Act

Issue	Investor-Owned Utilities	Municipally-Owned Utilities	Cooperatively-Owned Utilities	Marketers	Independent Power Producers
The Public Utility Holding Company Act (PUHCA) was passed in 1935 in response to problems associated with ownership of utilities by holding companies. The PUHCA requires all public utility holding companies, except those entitled to an exemption, to register with the SEC, thereby becoming subject to its regulations.	PUHCA prevents holding companies from being able to act quickly and flexibly to obtain financing at lower rates, to expand into new competitive lines of businesses, and to restructure to meet changing needs and opportunities in an increasingly competitive electricity market. No other businesses are required to obtain such approvals from the SEC.	PUHCA still provides important protections for captive ratepayers that no other law confers. It must be preserved to guard against potential market power abuses of large holding companies. PUHCA repeal in the absence of appropriate safeguards puts consumers at risk.	Congress should replace PUHCA with legislation that takes a more practical approach to control of market dominance by focusing on the substance of consumer protection and market power abuses rather than focusing on artificial corporate structures.	Congress should not replace PUHCA until it has clarified the FERC's authority with regard its authority to order regionalization of the nation's power grid under truly independent and accountable management, and prohibit financial conflicts of interest between the owners of generation, transmission, and distribution assets within a region.	PUHCA should be replaced with new structural and functional mandates to ensure robust competitive markets. To guard against cross-subsidization between regulated and unregulated segments of the industry, the monopoly and competitive holdings of the electric utilities must be divided into separate and distinct subsidiaries.

TABLE 5.9
Competitive Advantage of Provider Groups: Public Utility Regulatory Policies Act

Issue	Investor-Owned Utilities	Municipally-Owned Utilities	Cooperatively-Owned Utilities	Marketers	Independent Power Producers
In 1978, PURPA authorized the FERC to establish rules to encourage "small power production" and cogeneration by nonutility companies and to encourage the sale of electricity to utilities. Most of these sales are under long term contracts with pricing terms and conditions well above current whole market rates.	The substitution of the judgment of government for that of private parties as to what power should be purchased and on what price, terms and conditions, e.g., <u>Public Utility Regulatory Policies Act</u>, should be eliminated. Repeal outdated laws such as PURPA, which requires utilities to purchase power whether or not it is needed. As the electric power industry moves rapidly from highly regulated to more open and competitive markets, PURPA remains a barrier to achieving one of the most fundamental goals of competition: the creation of a truly competitive and level playing field on which suppliers compete for customers on equal terms.	PURPA has played an important role in fostering competition in the bulk power market and encouraging development of renewable energy resources. Repeal of PURPA is premature until reasonable assurances can be given that competitive markets will develop and can be sustained over time, and adequate provisions are made for renewable resources.		Regulators must permit competitive suppliers to take risks and design regulations, rates, tariffs and operational protocols to separate the regulated and unregulated business functions so that unregulated entities are not indirectly subsidized by a utility's rate structure, lack of risk, or guaranteed returns.	All market participants should have the same opportunity to build, own and operate generation facilities. Barriers to entry, including technical restrictions under PURPA should be eliminated. Other barriers include requirements for certificates of public convenience and necessity, state and federal regulation of power supply costs and other corporate regulation, and exclusive franchise territories.

TABLE 5.10
Competitive Advantage of Provider Groups: Access to Lower than Market Capital

Issue	Investor-Owned Utilities	Municipally-Owned Utilities	Cooperatively-Owned Utilities	Marketers	Independent Power Producers
In a competitive market for electricity, in which privately-owned and publicly-owned utilities compete with one another, the use of tax exempt financing, and other forms of government subsidized capital, are being drawn into question.	Ensure that all power suppliers can participate equally in competitive markets without government subsidies and ensure that rules are not established to benefit some while creating disadvantages for others. If a public power entity wishes to compete outside its traditional service territory, it should be subject to the same financial and regulatory requirements as investor-owned utilities	Tax exempt financing should be used to advance legitimate government purposes and provide for services essential to the well being of communities.	Current IRS regulations do not adequately distinguish between sales to traditional customers of public utilities, and sales to customers outside a city's or special district's jurisdiction. If the customers are outside of the municipality's jurisdiction, then the utility has elected to become a commercial entity and no legitimate governmental purpose can be served.	The use of tax-exempt financing, or other forms of government subsidized financing for assets used in competitive markets should be prohibited.	Any assets used in a competitive market should not be subsidized by the use of tax exempt financing.

TABLE 5.11
Competitive Advantage of Provider Groups: Annexation

Issue	Investor-Owned Utilities	Municipally-Owned Utilities	Cooperatively-Owned Utilities	Marketers	Independent Power Producers
The ability of municipally-owned utilities to expand their service territories through annexation is being drawn into question in the context of competitive markets.	Exclusive service territories should be eliminated. Bans, limits, and territorial restrictions undercut competition by removing a competitor from the market and diminish customer choice	Annexation is an important public policy tool that allows local governments to meet their obligation to serve new residents and promote economic development on behalf of the community. Proposals to preempt state authority and erect barriers to municipal service are unwarranted and counterproductive.	The integrity of distribution territories must be preserved. The only long-term, permanent solution lies in the amendment of at least four articles of the state constitution.	A competitive market with true customer choice is not characterized by captive customers. Current rules that discriminate with regard customer access are serious roadblocks to full and fair competition.	Monopoly franchise territories, including the ability to annex customers, runs counter to the notion of open and competitive markets in which all customers have choice. All customers should have the ability to choose their generation suppliers, with appropriate consumer safeguards to ensure against unfair practices. All competitive services should be offered competitively, including metering, billing and customer accounts.

TABLE 5.12
Competitive Advantage of Provider Groups: Open Records and Public Meetings Laws

Issue	Investor-Owned Utilities	Municipally-Owned Utilities	Cooperatively-Owned Utilities	Marketers	Independent Power Producers
Access to information in a competitive retail market raises three principal questions: - How should utilities provide competitors and utility affiliates with comparable access to relevant customer information to assure that no one receives an unfair competitive advantage? - How should regulators ensure that customer proprietary information is protected and that sensitive individual customer information not be divulged? - How should regulators ensure public access to information that will allow consumers to meaningful compare alternatives?	Standards of conduct should include a requirement that regulated transmission and distribution companies share market information equally and simultaneously with all competitors including the utilities' affiliates. Standards of conduct should define what types of information are important and require that customer-specific information be kept confidential unless customers approve its release.	Full and open access to market information must be assured. Uniform market information is necessary to guard against abuse of market power in the form of predatory pricing, and to ensure that retail customers do not pay disproportionate rates due to deals made to secure lucrative commercial or industrial contracts. Federal and state regulatory agencies and legislative bodies must reject requests for secrecy that would permit utilities to hold themselves unaccountable to both the consumers they serve and other competitors in the marketplace.	Restructuring legislation must include provisions that public power utilities are entitled to the same protections regarding public documents and meetings that IOUs currently enjoy.	FERC should require, under strict enforceable penalties for non-compliance, that all transactions -- including those involving captive, pre-existing or "grandfathered" customers -- be reported and available to the marketplace.	All market participants should be subject to the same reporting requirements. Reporting should be limited to only those areas that are required to ensure fair competition and adequate consumer and environmental safeguards.

TABLE 5.13
Competitive Advantage of Provider Groups: System Benefits Charge

Issue	Investor-Owned Utilities	Municipally-Owned Utilities	Cooperatively-Owned Utilities	Marketers	Independent Power Producers
The imposition of a systems benefits charge to recover the costs associated with specified public policy programs could have disproportionate effects on competitor groups depending on how broadly it is mandated and how uniformly it is implemented.	Make certain that all power suppliers share the cost of programs now provided by local utilities, such as environmental programs, low-income assistance and the obligation to serve all customers.		Supports funding public benefits programs but is concerned that universal service could end up competing for funding with other benefit programs, such as energy efficiency and renewables research and development. Given the importance of universal service, low income assistance programs should be supported by dedicated funds.	Systems benefits charges should be implemented only if the market is unable to satisfactorily deliver certain public policy goods, and only if the charges are applied equitably to all customers.	Set pro-competitive policies that enhance environmental and social benefits. System benefit charges should complement – rather than compromise – the benefits of competition.

NETWORK
INTEGRITY

Reliability Issues

Issue

On July 2nd and then again on August 10, 1996, the US experienced the worst electric power disturbances in more than 30 years. The wide spread outages of electric service, which affected 7.5 million customers in 14 states, caused a reexamination of the controls on the operation of bulk transmission – the most significant reexamination since the Northeast outage of 1965 that led to the present system of regional electric reliability councils. The outages, coming as they did in the middle of industry restructuring debates, turned attention toward the effects of competition. The press focused on this linkage through front-page stories questioning the ability of the transmission system to work under competition, and the Congress and the FERC challenged the industry to state its case on whether competition threatens reliability.

The 1996 outages were a vivid reminder of the fundamental dependence of the economy and society on reliable electric power – a dependence that is increasing. It is not just household lights and VCR clocks that go out. It is streetlights, cash registers, credit verification systems, air control radar, production processes, and a host of other functions that are so embedded in daily life that they are taken for granted, yet impossible to accomplish with today's technology and without reliable power. Not surprisingly, even the US Department of Defense takes notice of grid operations. With this added dependence has come heightened sensitivity, which translates into heightened political reaction.

When it comes to essentials like electricity, the public is of two minds about markets and competition. Public enthusiasm is high when competition produces more choices, lower prices, and innovative product and service offerings. But it ebbs rather quickly when markets produce pain or when the public perceives an outcome as unfair. If the public and policy makers begin to associate poorer electric reliability with increased competition, pressures to rethink the desirability of industry restructuring will mount.

Alaska Dynamic

The principal questions is not the extent to which increased competition has contributed to transmission breakdowns in the lower-48, but rather how to maintain system reliability while restructuring the industry and freeing competitive forces. So far these very real issues have been

glossed over in most states in the restructuring process, concentrating primarily on ensuring fair and open electricity markets while simply assuming the real world of equipment and engineers would seamlessly fall into place. This would be a critical mistake in Alaska. The transmission system in Alaska lacks some of the grid features which help backup and protect transmission systems in the lower-48. The lack of redundancy and looping in the system, together with the inability to call on neighboring interconnected systems for emergency power, increases the need for Alaska policy makers to take seriously the operational and technical details of restructuring as they effect transmission reliability.

Assessment

If there is one common denominator among everyone interviewed, it is that there needs to be some organized system to assure reliability in the bulk electric industry. "The mission should be to insure reliability while at the same time promoting the policy goals of the restructuring process." The great majority, with only one or two exceptions, propose some form of a self-regulating industry organization with a close working relationship with government oversight groups such as the FERC and the APUC. All the stakeholders in Alaska felt very strongly that reliability could not be compromised in any way as the result of restructuring. Given the harsh winter climate, electric power disruptions of more than a few hours can quickly become public health and safety emergencies.

Many stakeholders pointed to the inherent conflict they saw between the voluntary nature of the organization currently operating the railbelt transmission system, and the dynamics of a competitive market that may have few penalties to help enforce action. Alaska has a rather "loose" structure compared to the very tight power pools and holding company systems that dominate the Eastern US. Reinforcements and additions to the system come through voluntary agreement. The Alaska Systems Coordinating Council cannot compel utilities to act - at most they apply peer pressure. The system has worked well in an era when utilities did not compete with each other, had incentives to cooperate, and could recoup costs through the regulatory process. In an era of increasing competition, many expressed concern that cooperation may be one of the first victims.

Key Questions

- How do you assure reliability in the context of more open and competitive markets?
- What is the most appropriate structure to balance the needs for system reliability and open market requirements for non-discriminatory open access?
- Will remuneration be adequate to encourage transmission expansion in a timely manner?
- Will restructuring and unbundling of generation, as a competitive function, from the regulated functions of transmission and distribution result in a loss of economies of scope across functions and increase reliability costs?

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Legitimately Complex Topic

Reliability of electric service is a legitimately complex, technical topic. It encompasses all aspects of providing reliable electric service to customers, which is made more challenging by the fact that electricity has to be produced and delivered on demand. Producing and delivering electricity on demand is challenging because, unlike most products, electricity cannot be stored in large quantities in an economical manner. Also, electrical systems are highly interconnected. As a result, disturbances at the generation level can lead instantaneously to problems at the transmission level, and vice versa. This poses additional challenges to system design and operations personnel. Key features of electric systems are shown in Table 6.1.

Reliability encompasses planning and operational issues at the bulk power (generation and transmission) and distribution levels. The planning issues typically address resource adequacy and system security. Resource adequacy refers to having sufficient resources in place in a timely manner to produce and deliver power on demand and to provide a "buffer" - reserve margin - to cover contingencies associated with unplanned electricity demand increases and unplanned electricity supply reductions. These contingencies can affect both production and delivery.

System security refers to having sufficient equipment and procedures in place to avoid harm to customers and to the electric system in the case of disturbances. Disturbances can include adverse weather, equipment failures, and other events that could lead to an overload of the system. Because of the highly integrated nature of these systems and the inability to store electricity, effective system security requires a high degree of coordination, communication and control on a real-time basis.

The electric generators and the "loads" in homes and businesses that use it, have to be in delicate balance at all times to maintain system stability. To keep the frequency of the alternating current nearly constant, the peaks and valleys of alternating current and voltage must be in suitable relation to each other to maintain line voltages at desired levels.

The primary purposes of electric reliability standards for system operators are to maintain these frequency and voltage conditions and, ultimately, to keep electricity flows from overheating lines. Setting such reliability standards involves highly sophisticated technical matters, as well as sensitivity to the commercial consequences. Each system has system control organizations that schedule exchanges of electric power. They must do this in accordance with the requirements of system security, for example, making sure the system can at all times withstand certain kinds of equipment failures.

It is important to note that the electric grid has essentially no switches for routing power and, therefore, controlling the grid means mainly controlling the operation of generators attached to the grid. The flows of electricity from all the generators are superimposed on each other so that the constraints on each system controller are determined, to some extent, by the actions of all the others. To keep grids operating within desired limits, and to avoid, in the extreme, cascading failures and blackouts, the operators must follow a set of common rules that set boundaries within which commercial transactions can take place. Because electric current shifts instantaneously to other lines when one line fails, the system must always have sufficient margins to accommodate such failures. The system operators who manage the network in a competitive mode must ensure not only that transactions take place, but also that the new conditions do not trigger failures like

the Northeast blackout of 1965 or the Western outages of 1996. Reliability activities are provided in Table 6.2.

Dependence on Skilled Operators

The operation of the grid depends on the experience of those in charge, relying on informal rules, judgement, and cooperative behavior. Protection devices and computers are crucial, but people are still the critical component. To a surprising degree, therefore, the system is vulnerable to human error. In the recent utility downsizing, some cutbacks in technical departments have reduced the organizational skill base. In any future plan for system operators, there has to be provision for ensuring adequate technical muscle and the right incentives to maintain and improve the system.

Electricity is Different

Several unique characteristics distinguish the electrical utility industry from other industries. These characteristics have significant implications for maintaining reliability in a restructured environment and must be given specific consideration in the development of a competitive model. Some of the more important characteristics include:

- electricity must be generated at the same time that it is consumed since storing electricity in large amounts is difficult and expensive;
- electricity consumption varies widely depending on the time of day and the season;
- electricity moves at the speed of light and many operational decisions must be made and implemented very quickly or automatically;
- changes anywhere in the interconnected electrical system impact all other points of the system;
- electric system conditions are constantly changing with changes in load, generation and transmission line configurations;
- the addition of new electric infrastructure (generating units and transmission lines) is capital intensive and subject to long lead times.

As a result of these attributes, the interconnected electric system represents, in many respects, a communal property which must be operated in a coordinated manner. In other words, individual problems within an individual electrical system can impact a larger interconnected system if certain safeguards and restrictions are not developed and formalized.

The industry is also characterized by vertically integrated utilities that have historically owned and operated generation, transmission, and distribution facilities. These individually-owned utility systems have been connected together to form the interconnected electrical grid. Developed over decades of vertical integration, the system is generally built around large central station generating facilities located in remote areas and high voltage transmission lines primarily designed to transmit power from remote areas to load centers. The services that the traditional vertically integrated utilities perform that can effect generation and transmission system reliability are provided in Table 6.3.

A secondary function of these lines has been to facilitate transfers of energy from one area to another during periods of emergency or in response to economic advantages that can be captured as a result of differences in generation costs or load diversity between utility systems. However, the transmission system often has inadequate capacity at certain times of the day or certain times of the year. These transmission constraints effectively limit competition among suppliers since substantial levels of generation are often required within specific geographic regions (control areas) to maintain reliability when sufficient supplies cannot be imported. The required level of local generation varies as system conditions (load, unit dispatch, transmission configurations, etc.) change. This means that local generators may face little competition at certain times.

Most restructuring plans in the lower-48 provide for the functional separation of generation, transmission and distribution. These plans tend to defer consideration of many of the complications imposed by unbundling until the plans are actually being implemented. Since few restructuring plans have actually been fully implemented, there are many unresolved issues.

One complication is that there is no clear delineation between the various functions. The separation of generation and transmission is particularly problematic since the two functions are substitutable in many respects. It should also be noted that generating unit dispatch is one the most effective ways of controlling transmission line loadings. The separation of generation, transmission and distribution may also have indirect reliability implications in that unbundling may fundamentally alter the respective oversight authorities of state and federal regulatory authorities. This is further complicated by the lack of a clear delineation between distribution and transmission facilities. The institutions that have responsibility for reliability are shown in Table 6.4.

Generation

One of the major uncertainties in the restructuring debate is whether competitive markets will produce sufficient generating reserves in a

timely manner – this is not a current concern in Alaska. Indeed, the BVI study concludes that no new generating capacity is required in the Railbelt for more than 20 years.

A distinguishing characteristic of electricity supply is the high degree of interdependence between generation and transmission. As a result of this interdependence, disturbances in generation may lead to transmission problems. For example, a major generation unit outage can quickly lead to an overload condition on the transmission system, which may result in transmission outages and loss of delivered power. Similarly, disturbances in transmission may lead to generation problems. A transmission outage from adverse weather or an overload condition may quickly lead to generation outages and loss of delivered power.

Some states have indicated that they will assure adequate reserves by placing requirements for reserve capacity on suppliers who are doing business within those states. Reserve requirements would presumably be imposed in conjunction with supplier certification or registration requirements. Such an approach may be very difficult to administer and/or enforce since state regulators may be unable to verify that reserves are in fact available for specific transactions. In other words, it could be difficult to prevent the same reserves from being sold several times if they exist at all. Reserve requirements may also limit competition by discouraging potential suppliers from competing in markets where reserve requirements have been imposed.

A competitive generation market may influence the type of generating units that are added since competitive concerns will encourage entrepreneurs to seek a quicker return on their investments. This could mean that units with higher capital costs and longer construction lead times, such as hydropower units, are less likely to be built. This may have reliability implications in that there could be a greater reliance on natural gas and less fuel diversity. While this may not be a concern from a natural gas production perspective, it could be a concern from a gas infrastructure perspective.

Transmission

The unbundling of transmission services has been a prerequisite for competition in most states that have restructured. This was recognized in FERC Order No. 888 where the FERC attempted to stimulate wholesale competition by requiring that utilities offer open access transmission services. This unbundling of transmission has given rise to new operational complexities for the interconnected grid. These complexities are generally associated with the fact that financial transactions do not typically reflect actual physical flows of electricity. For example, bulk power transactions are generally based on fixed "contract paths" which do not vary with ongoing changes in physical

electrical conditions. "Contract path" arrangements are established individually on an assumed set of conditions. Such assumptions include static electric loads, fixed levels of generation from specific generating units and fixed transmission configurations. These conditions are constantly changing since load is never static, generation sources change frequently, and transmission configurations are often modified as a result of transmission line outages and changes in generation. Consequently, actual power flows differ dramatically from their assumed "contract path."

These differences can result in increased power flows on utility systems that are not directly involved in the "contract path" transaction. Increased flows, which are typically referred to as loop or parallel path flows, can result in an overload of transmission facilities. In other words, virtually all power supply transactions can impose actual flows on a third party utility system and can potentially jeopardize the reliability of that system without providing any compensation to that third party.

The interconnection of electrical facilities also means that a failure or overload of a specific transmission line can result in the rapid, almost instantaneous, failure of connected facilities. Consequently, the electrical grid is operated in a manner that is intended to prevent a cascading outage from being triggered by a single contingency. This means that utility operators frequently take steps to relieve flows on critical transmission facilities that are approaching their physical limits in anticipation of potential contingencies. Parallel or loop flows greatly complicate this process since utility operators must, in most instances, evaluate outside conditions (generator dispatch, scheduled power flow transactions and grid configurations of other utilities) in order to identify potential problems and rely on other utility operators to take corrective action once potential problems are identified. This complexity is compounded by the fact that wholesale competition is likely to increase the number of power flow transactions.

A failure to anticipate loop flows and a lack of coordination among utility operators can significantly impact the reliability of the bulk power system. This is evidenced by two major outages that were experienced in the western interconnected electrical grid in 1996.

The North America Electric Reliability Council (NERC) is currently working on improved information systems and operating procedures to enhance the ability of system operators to anticipate and respond to the operational complexities associated with increased wholesale competition. These steps will not be fully implemented for several years, and its critics argue that they will only have the capability of handling little more than the current level of wholesale transactions reliably. Although the system has managed to avoid cascading outages thus far, at least in the East, there is concern that outages can occur

under certain circumstances if the NERC systems and procedures are not put into place relatively soon. Any further increase in the number of bulk power transactions associated with additional wholesale transactions or with the advent of retail competition could generate the need for additional systems and/or procedures. It should also be noted that NERC is a voluntary organization and that compliance with NERC procedures is not formally mandated at this time. Therefore, it is not clear what actions will be taken in the event that a party refuses to take corrective action to relieve flows on another party's system. This may be likely since power supply agreements are currently based on "contract paths" and do not typically reflect actual power flows.

The development of independent system operators (ISOs) for interconnected transmission systems within various regions can facilitate improved communications and coordinated operations and resolve some of the above problems. There are, however, certain trade-offs associated with ISOs which may have reliability implications. There are also significant obstacles to the development of ISOs, particularly in areas where power pools do not currently exist. ISOs must cover broad regions in order to truly enhance operations. Consequently, the formation of an effective ISO will, for the most part, require agreement among a number of utilities with, in many cases, diverse interests. Such an agreement would require a utility, in conjunction with other utilities, to turn over operational control and planning responsibility for its transmission facilities to an independent third party (the ISO). This would obviously raise a number of complicated issues including:

- utility compensation for the use of its transmission system;
- ISO governance;
- joint planning procedures;
- construction of jointly planned transmission additions; and,
- issues associated with the functional separation of transmission and generation.

The development of ISOs will also impose additional costs. These costs may be substantial. In fact, it cost approximately \$1 billion to establish an ISO and power exchange in California.

The development of ISOs and transmission unbundling also give rise to the potential loss of certain efficiencies associated with the joint operation and installation of transmission and generation facilities. Utilities have historically added and operated facilities in a manner which was intended to minimize total bulk power costs. Nondiscriminatory transmission access and independent operation of transmission facilities may result in the loss of some of these efficiencies since it will be very difficult to plan for a least-cost combination of

transmission and generation additions in a competitive ISO structured environment.

Under certain ISO proposals, utilities will continue to own both transmission and generation facilities. Under this type of arrangement, a utility may own generation facilities that have enhanced values that are attributable to transmission constraints. In this instance, a utility may be reluctant to make a good faith commitment to add needed transmission facilities required by the ISO since such an addition may not be in the utility's financial interest. Since the structure of an ISO may effectively prohibit the ISO from owning transmission additions and the ISO may not have the "right of eminent domain" to condemn property, the ISO may be dependent on a utility to construct the needed addition even though the addition is not in that utility's interests. This would increase the difficulties of adding needed transmission facilities; a process that is already extremely difficult.

The functional separation of transmission and generation may also cause operational and scheduling problems as well. The scheduling of maintenance activities may be complicated by such separation since generation can be dispatched to relieve constraints caused by transmission line maintenance. Likewise, transmission systems can be used to deliver electricity to areas normally served by specific generating units during periods when those units are taken off-line for maintenance. Consequently, maintenance schedules must be coordinated to assure reliable service. The competitive interests of generators may not always coincide with transmission maintenance schedules and the ISO may have a limited ability to resolve such conflicts.

Such conflicts require that transmission system operators have some operational control over specific generating facilities at certain times in order to maintain transmission and grid reliability. Such control must be balanced against competitive interests if restructuring is to produce reliable electric supplies at competitive prices. It will be very difficult to achieve an appropriate balance given the dynamic nature of our electric system. In short, the extent to which ISOs control generating facilities could greatly impact the level of actual competition between suppliers. Consequently, the determination of control needed by the ISO could ultimately dictate the success or failure of restructuring. A summary of ISO functions and governance structures is provided in Tables 6.5 and 6.6.

The separation of generation and transmission facilities also has implications for the certification and siting of such facilities. Deregulation of generation may effectively eliminate public need determinations for new generating facilities since such facilities would be added in response to market signals rather than an administrative determination of need. This has implications for the siting of

transmission lines in two respects. First, many transmission lines are built to connect generating facilities to the bulk power grid. In this instance, the location of generating facilities would dictate, in large measure, the location of transmission lines. This could result in either an effective bypass of the public approval process for transmission lines or create even greater financial risk for power plant developers. Second, transmission lines and generating facilities are, as noted earlier, substitutable in certain respects. In some instances, it may be more practical and cost effective to add a generating facility as opposed to a transmission line to relieve local supply constraints.

Deregulation of generation would in effect eliminate obligations to construct generating units and regulators may not have the ability to compel construction of the least cost alternative. This may make it difficult for regulators to approve a transmission line on the basis of public need. Reliability could be impacted if transmission routing approvals are delayed as a result of these siting complications or if the risks of developing generating units are increased.

Jurisdictional Implications of Unbundling

The separation of the various electric utility functions and the deregulation of generation could also have indirect implications for reliability since restructuring may result in a fundamental shift of responsibility and regulatory authority. The FERC acknowledges this prospect but has noted that states will continue to have some oversight authority. In Order No. 888, the FERC notes:

Although jurisdictional boundaries may shift as a result of restructuring programs in wholesale and retail markets, we do not believe this will change fundamental state regulatory authorities, including authority to regulate the vast majority of generation asset costs, the siting of generation and transmission facilities, and decisions regarding retail service territories.

The FERC has also indicated that states will continue to have authority over distribution services. Despite the fact the Alaska is not subject to Order 888, the distinction between distribution and transmission services is very important. Given the FERC's positions regarding the regulatory authority of state regulatory commissions, states may continue to have some limited ability to assure an adequate supply of electricity. However, the extent of this jurisdiction is also unclear. One certainty is that states will have less oversight and less ability to assure reliability as a result of restructuring.

Despite noting that states will continue to have continued oversight authority, the FERC maintains that it will have authority over retail wheeling services once retail customers are granted access to competitive suppliers. Given the FERC's position, retail wheeling will

result in a further transfer of regulatory responsibilities from the states to the FERC. This could mean that regulatory oversight over transmission reliability is largely a FERC responsibility in the future. While this does not necessarily mean that reliability will be negatively impacted, it does raise questions regarding the consideration of local or state interests and creates the possibility that service reliability will be given less focus. A summary of FERC ISO principles are provided in Table 6.7.

Distribution

Electric utility restructuring will have fewer reliability implications for distribution than for other functions. Distribution functions will continue to be regulated in much the same manner as they are today, with the potential for greater service quality monitoring. Restructuring could, however, have indirect implications for maintaining distribution service reliability given the jurisdictional uncertainty discussed above and competitive pressures for utilities to cut costs. Thus far, utilities have not limited cost cutting measures to competitive services and have reduced staffing levels across all functions. These measures could adversely affect distribution service quality if austerity measures are extreme.

Utility companies perform distribution reliability functions within their defined service territories based on the traditional "obligation to serve" retail customers. The boundary between distribution facilities and metering facilities may provide a natural separation for possible "wires" and metering services that might not necessarily be contracted for with the same service supplier. However, reliability spans all service categories. One possible method of ensuring reliable service might be to assign appropriate and fair cost responsibilities to those services that enhance or promote such service, and to fairly penalize those actions that detract from it.

Retail open access will require changes to, or redefinition of, current approaches and practices relating to reliability, quality of service and obligation to provide service. Functional unbundling of distribution services would provide a mechanism for the definition of optional and mandatory services similar to what has been done in relation to transmission services. Retail open access also gives attention to such concepts as "the supplier of last resort," "universal service customer" and "default supplier."

With the possible advent of retail open access in Alaska, Commission jurisdiction over suppliers must be clearly defined. A certification, licensing or qualification process could be considered that evaluates the managerial, technical and financial capability of suppliers, similar to that in the telecommunications and natural gas industries. It is also necessary for the service levels and actions in all service territories to be

consistent. While retail open access should promote competition, native customers should be protected from any adverse impacts of new suppliers operating within their local areas.

Conclusions

Electric utility restructuring may have a number of implications for electric service reliability. Proponents of a rapid movement to retail competition for electricity argue that competitive pressures will cause suppliers to develop new and innovative products and services which will enhance reliability since service quality will be an important consideration for almost all electricity consumers. This may be true over the longer term provided that restructuring policies and initiatives provide both suppliers and consumers with proper incentives and responsibilities.

While restructuring could potentially enhance reliability in the future, there are a number of uncertainties associated with restructuring which could jeopardize reliability if competitive policies are ill-conceived or poorly implemented. In any event, there are a significant number of complicated issues that must be addressed or closely monitored in a transition to a competitive electric industry and it must be recognized that the development of information systems and ISOs will take time. It should also be recognized that the establishment of ISOs and information systems may be costly. These reliability related issues and uncertainties should be considered and addressed, to the extent possible, in the development and implementation of a competitive model. Specific measures for ensuring continued reliability are described in the discussion of market structures. A summary of implications for reliability as the result of restructuring are provided in Table 6.8. The position of the National Association of Regulatory Utility Commissioners (NARUC) on reliability is at Table 6.9.

Renewable Sources of Electric Supply, Energy Efficiency, the Environment, Energy Research & Development and Product Innovations

Issue

In addition to the expanding menu of measures and mechanisms for addressing network integrity from within the existing electricity system, technological and service innovations hold potential for bringing new tools to the endeavor. Some of the most exciting developments in electric services involve technology and service options that are simultaneously smaller, cleaner, more modular, and capable of generating energy or reducing demand. A nascent but significant exploration of distributed energy systems and services that combine information technology, value-added product innovations and "virtual" energy service providers into flexible product and service menus is emerging in the wake of electric utility restructuring. From the network integrity perspective, these smaller, technologically sophisticated approaches offer an opportunity to more effectively and efficiently target solutions at problems and to manage risk through diversification of the system.

One frequently articulated metaphor is that of the desktop computer and the Internet. The "electric Internet" metaphor contemplates a web of large and small generation interconnected through an intelligent information network that allows both mass customization in customer service and pathway robustness in network operations and maintenance. Under this model, network congestion is not an immutable relic of physics as much as a transient characteristic seamlessly and intelligently overcome by a system manager with central-station generation, bulk transmission, distributed generation, distribution feeders, targeted load curtailment, and price signals to draw from the solutions toolkit.

Electricity strategists who see the potential for this kind of infrastructure transformation are increasingly turning their attention to renewable energy and energy efficiency services and technologies for a variety of reasons. Many believe the inherent modularity and short construction

lead times of these technologies and services fit well with a more volatile and competitive electricity market. Research and development on new technologies, in turn, may yield competitive advantage in what is expected to be a rapidly evolving marketplace. From such a broadly based portfolio, it is argued, the competitive energy services provider can stay ahead of the competition by constantly drawing on an evolving menu of capabilities, and at the same time maintain the levels of service quality and product innovation necessary to maintain a competitive edge. In many parts of the country, environmental issues may become a significant potential distracter and risk factor that can be hedged against with these options. Despite, and perhaps because of significant progress made in environmental improvement over the last three decades, the risks of environmental regulation and the costs of accompanying control mean the issue occupies a relatively important position in any list of business planning concerns.

Market-based retail competition in the electricity sector, however, may favor low-priced electricity supply to the detriment of less mature markets for renewable energy, energy efficiency and emerging technologies. Microturbines with but a few years of commercialization experience cannot, and in the end, will not compete on the same terms as a 1,000 MW coal-fired steam turbine plant. Because of this practical reality, a number of studies suggest that market-based retail competition could result in an overall increase in emissions of pollutants. One hope of a number of policy makers is that properly structured open and competitive markets could enhance overall system performance and simultaneously benefit renewables, efficiency, new technology development and environmental protection.

Alaska Dynamic

Alaska already enjoys significant diversity of generation capability in the Railbelt, though rural Alaska is significantly dependent on diesel fuel for electricity generation. The reasons for these conditions are a matter of obvious economics and technology. Diesel fuel offers an available, concentrated source of energy that can be safely transported and stored. Diesel generator systems are an established technology and sufficiently robust to withstand the extreme conditions characterizing the Alaskan bush. As a result, diesel fuel accounts for nearly almost 15 percent of electricity generation in the state.

In Alaska as a whole, utilities rely on natural gas for over one-half of the electricity generated, though gas-fired generation is dependent on proximity to resources and therefore is most heavily relied upon in the Railbelt. Another 20 percent of generation in Alaska derives from hydroelectric facilities, reflecting the excellent hydropower resource in the State. Coal is used to generate less than 5 percent of the electricity

for Alaska. Figure 6.1 compares Alaska and US net generation by source.

Environmentally, Alaska's electricity generation portfolio mix is markedly cleaner than that in the lower-48 in terms of sulfur dioxide (SO₂) and carbon dioxide (CO₂) emissions. A table comparing emissions amounts and rates for Alaska and the United States as a whole is at Table 6.10.

There remain large untapped resources of both renewable energy supplies and energy efficiency potential in Alaska. Perhaps the greatest near-term potential lies in small hydropower and wind energy generation resources, and in building envelope efficiency improvements. Most stakeholders believe that regulated air pollution issues are being adequately addressed as a result of legislation and regulation. There is some concern, though, that absent environmental measures in restructuring legislation, power plants that pollute more will enjoy an unfair competitive advantage in restructured markets, and that this could lead to more pollution. The near-term concern is whether the renewable energy, energy efficiency, and other new energy industries in Alaska could emerge and survive in the more competitive marketplace, and if support mechanisms are created, whether their costs are acceptable to policy makers.

Implications

Any policy decision to support the emergence of renewable energy, energy efficiency and other new technology and service industries in a more competitive environment flows from a determination that: (1) these industries are desirable features of the new competitive markets, and (2) these industries will not emerge or succeed without support. The mechanisms most commonly suggested to support these sub-markets are essentially financial in nature, addressing the price disadvantage these emerging industries face. Public funding mechanisms or portfolio standards seek to direct more resources toward these industries than a market focused on price might otherwise allocate. Public funding mechanisms necessarily have the effect of reducing the overall level of savings made available by electricity restructuring. Whether this impact is significant will depend on the overall magnitude of savings and costs.

Some structural changes may serve to enhance the opportunity for these industries to succeed and may not require direct collection and distribution of funds. These changes could also offer the benefit of creating more favorable conditions for the development of a competitive market in general. However, experience to date suggests that such structural mechanisms alone would not deliver the same level of industry support in the short term. Advocates of renewable energy and

energy efficiency in particular argue that short term success is critical, and that these industries may not exist in the long term without short term support.

Assessment

Most stakeholders would not object to renewable energy and energy efficiency products and services becoming available to customers in a market-based retail competition structure, though there is little expressed intent to provide those services on a competitive basis from among Alaska's utilities. Few stakeholders call for policy support for renewables and efficiency, except for rural and low income customers. Unlike most of the states in the lower-48, the concept of specific funding or market penetration provisions (e.g. renewable portfolio standards) has not been a major issue of discussion in the restructuring debate in Alaska. Some stakeholders assert that financial and other supports are inconsistent with free-market competition, and that such supports should not be provided for renewable energy and energy efficiency. Most stakeholders in Alaska appear to feel that environmental regulation and legislation is sufficient to address current environmental issues associated with the generation of electricity.

Key Decisions

Environment:

- Are environmental regulations and laws in force today sufficient to protect environmental values in a more competitive electric utility industry?
- Is there a serious potential for increased emissions under retail competition in the electric industry?
- If so, are there measures which should be adopted as part of restructuring which would reduce the risk of adverse environment consequences at acceptable costs?

Renewable energy, energy efficiency, and other emergent industries:

- Is it a measure of restructuring success that viable renewable energy, energy efficiency, and other industries will offer products and services to customers? Why?
- Are structural or financial mechanisms or provisions required to ensure that outcome?
- What kinds of mechanisms or provisions are best suited for accomplishing public policy goals in Alaska?

- To what extent should such mechanisms be included in restructuring legislation?

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Potential Impacts of Restructuring on Renewables, Efficiency, Emergent Technologies, and the Environment

The generation, transmission and consumption of electricity, like all human activity, results in environmental impacts. One issue on the policy landscape for several years has been the role of renewable energy, energy efficiency, new technologies and environmental impacts in economic regulation and in the provision of electricity services.

Advocates of renewables, efficiency and the environment have worked to increase opportunities for renewable energy and energy efficiency development and use within the electricity system, and for increased attention for environmental issues. Significant progress has been made in Alaska in recent years in increasing use of renewable energy and in institutionalizing energy efficiency programs such as low income weatherization, energy audits, and others. Absent electricity restructuring, the prospect for continued growth in renewable energy appears promising as a wide range of renewable energy research and development projects are currently underway in Alaska. A listing of those projects is set out in Table 6.11.

An issue of significant debate is whether emissions of some regulated pollutants and of carbon dioxide (an unregulated emission resulting from fossil fuel combustion) are causing climate change on a global scale. While the technical and scientific issues are not yet resolved fully, negotiations and debate regarding a greenhouse gas emissions treaty

have been under way for several years and will likely continue. Table 6.12 sets out the US EPA's estimates for climate change impacts on Alaska under some global warming scenarios.

An important question arising from the electric utility restructuring debate is whether retail competition will accelerate or retard the development of renewable energy and energy efficiency, as well as other small scale electric generation and system technologies, and whether restructuring will create environmental benefits or problems. On the one hand, survey data and recent experience in the lower-48 demonstrates strong public support for renewables and efficiency. All things being equal, this demand should translate to growth in those industries under competition. However, no comprehensive assessment of Alaskans' views on so-called "green power" or other electricity service options has been reported. Moreover, the dominant focus on profitability in competitive markets could chill or eliminate the markets for renewables, efficiency, and other emergent technologies due to higher first costs or other market barriers facing these options.

Competition will likely create incentives for increased reliance on natural gas fuel or cost-effective hydropower resources where they are available. Market forces could alternatively lead to increased emissions due to increased reliance on older, more fully depreciated power plants, or provide the incentive for utilities to retrofit and upgrade those facilities in order to improve competitive position.

The outcome of these issues could be left to the operation of markets and existing environmental laws and regulations. Under that scenario, the kinds of markets created by restructuring will be the dominant issue affecting the development of renewables, energy efficiency, and other new energy technologies and services. State and federal laws will determine the levels of emissions from the electricity generation sector. An alternative approach would be to craft market structures in such a way that they encourage renewables, efficiency and new technology development, and to create mechanisms to support the emergent markets for these products and services. Likewise, enhanced environmental performance objectives for the power plant fleet could be implemented as part of electric utility restructuring in order to ensure that the process becomes a vehicle for reducing, or at least not increasing, emissions of pollutants. In summary, electric utility restructuring is not, by definition, inherently supportive or antagonistic to renewables, efficiency, new technology and the environment.

Policy Mechanisms to Address Impacts

Policy makers in Alaska can draw on a large menu of options for ensuring that the alternative energy industries succeed in a restructured system and that environmental quality does not suffer.

As electric utility restructuring has been debated in Congress, a number of proposals relating to renewable energy, energy efficiency, and other public purpose programs have emerged from proposed legislation. A summary of these proposals is reported in Table 6.13.

Renewables - Virtually all stakeholders agree that "green power" markets are a desirable mechanism for linking renewable energy development directly to customer demand, even if they are unsure about the level of interest for such products among Alaska customers. Ensuring that a restructured industry creates conditions conducive to the emergence of these markets requires attention to a broad range of market structure and related issues. Green markets depend on customer awareness and education, opportunity for competitive entry, access to customer billing information, transmission access, and a number of other issues.

Advocates of renewable energy development have also offered a number of more aggressive mechanisms for ensuring success. These include a minimum content or renewable portfolio standard, production incentives, customer rebates, emissions taxes and tax incentives. Each of these options offers both advantages and disadvantages. The key disadvantage of more aggressive mechanisms is that they generally require direct or indirect funding support, and therefore have the potential of reducing the overall level of economic savings from restructuring.

Energy Efficiency - Many energy experts believe that substantial savings in energy bills are possible through increased reliance on energy efficiency resources and services. As with renewable energy, one policy option for tapping those resources is reliance on the development of competitive markets. A number of structural issues will impact the success of energy efficiency marketing in a restructured industry, including vertical co-ownership relationships between generators and distributors of electricity, customer awareness, access to customer information and other issues.

Specific policy options for increasing the potential for successful energy efficiency markets include customer rebates, the creation of an efficiency trust fund, standard offers, and emissions taxes. Because these options each bear some financial and/or administrative costs, there is a potential for reducing the level of savings from competition.

Other New Technologies - Other new technologies arriving on the scene include smart meters, microturbines, fuel cells, and energy storage systems. As new market entrants, these technologies face first-cost barriers to successful commercialization. Options for supporting new technology development and deployment include public funding mechanisms, research and development consortia, government programs and similar non-discriminatory mechanisms.

Environment – Pollution or emissions control, whether through “end-of-the-pipe” controls and limits, or through the increased use of non-polluting renewable energy or energy efficiency resources, involves a policy dynamic with two key elements. First, there is the issue of the costs of control, and the economic incentives these costs send to electricity suppliers and distributors. Because coal and oil facilities emit sulfur dioxide as a byproduct of combustion, the use of these resources is impacted by the current cost of control for these emissions. If the cost of SO₂ control climbs high enough, suppliers will increasingly consider alternative generation technologies if they are available. Any consideration of changes in control requirements requires consideration of the impacts of cost on the price of electricity and on the utilization of generation facilities.

The second key component to the dynamic involves risk, specifically the risks of more stringent regulations and of the character of customer demand for certain kinds of generation. Risks are especially important in the electricity generation business because existing plants represent significant capital investments, and because new plant additions involve both long construction times and useful lives. The nuclear power experience in the lower-48 typifies the impacts of these risks. Nuclear power plant pollution can be controlled (to the extent long-term disposal of radioactive waste constitutes satisfactory control) and, once completed, these plants generate electricity at a relatively low variable cost. However, public perceptions about the safety of nuclear plants and the extremely high capital cost investments required to construct a plant (so-called “lumpy investment”) have effectively precluded the construction of a single new nuclear facility in the United States. The last nuclear plant order that wasn’t subsequently cancelled was in 1973. Another important variant on the risk dynamic is the susceptibility of the electricity industry to risk inherent in excessive reliance on single technology or fuel options. One important policy question that should be addressed as electric utility restructuring is contemplated is whether competition will reduce or increase the overall risk profile of the industry in Alaska.

Options to ensure the preservation or enhancement of the environment in a restructured electric industry include emissions taxes, cap and trade regimes, and more stringent regulatory requirements for generators. These options vary significantly in their approach – from reliance on traditional control strategies to relatively new market-oriented approaches involving tradable pollution permits. In addition to the costs and administrative oversight issues, some stakeholders express concern that the imposition of requirements more stringent than those required by law could place Alaska’s economy at a competitive disadvantage in attracting new businesses to the State. The costs of pollution control are ultimately reflected in the price of electricity sold. Others point to the risk reduction benefits of reducing emissions today.

They argue that these benefits justify taking some action to further diversify the generation mix in Alaska with low-pollution energy generation alternatives.

Current Programs and Expected Impacts

Alaska is currently hosting a broad range of energy technology research and development activities. Initiatives such as the Denali Commission, and legislation such as that recently discussed by Senator Murkowski may create further opportunities of this type. Chugach Electric is conducting or planning technology projects involving both wind energy and fuel cells. Kotzebue Electric has already begun a project to install several wind turbines, and claims considerable diesel fuel savings as a result. Of course, in the end not all resource development is economically feasible. Alaska utilities and agencies are moving at a measured but positive pace in gaining experience with these technology efforts.

Change in energy efficiency, renewable energy, energy technology and other "public purpose" programs is virtually certainty under restructuring. While the exact nature of these changes is impossible to predict, it is possible that utilities end all public purpose programs unless these programs are mandated under law or regulation, or the market otherwise creates incentives for their continuation. The potential market entry of competitive green power, energy efficiency and distributed generation providers could result in a broader range of customer options and choices of service providers, given suitable market structures and opportunities.

Formerly regulated utilities will likely transfer energy efficiency, renewable energy and technology development program activities to unregulated, affiliate or subsidiary entities. Regulatory oversight may become necessary to ensure that unfair cross-subsidization of services from default customer revenues does not occur. Absent specific measures in restructuring legislation, environmental programs and oversight will no longer be an issue of utility regulation, but will become the sole purview of environmental regulators. Finally, unless specific funding mechanisms are instituted, low income energy assistance and weatherization programs face an uncertain future due to funding cuts in Washington, D.C. and budget pressures in Juneau.

Experience in Other States

While only a few states have opened retail electric markets to competition, several more have conducted retail access pilot programs. As a result, some information is available about how renewable energy, energy efficiency and environmental issues fare under restructuring. State minimum renewable energy requirements, both proposed and adopted, are reported in Table 6.14. Table 6.15 sets out state public

benefit funding for renewable energy, efficiency, and research and development.

There are some important limitations on what can be learned by reviewing the experiences in other states, however. First, all retail pilot programs conducted to date have included a high degree of artificiality in their structure. In the New England pilot programs, for example, electricity rates available to customers did not reflect projected stranded costs. Second, these pilot programs allowed a maximum number of market participants or limited the number of customers eligible to participate in the exercise. Finally, some pilots have operated under a portfolio approach where a range of power supply options were offered to customers through the incumbent utility. In no case has a pilot project been responsible for leading to the development of new generation resources or the large-scale demonstration of new technologies. In all cases, artificial conditions may have been responsible for both stimulating and hindering participation by customers and marketers.

In the highly structured pilot programs conducted to date, a high percentage of market participants attempted to distinguish their supply products on the basis of environmental traits. Several marketers offered subscription incentives with an environmental twist – tree seedlings, bird feeders, and the like – to customers who chose their service. Some product claims were blatantly misleading to customers. In other cases, this marketing was essentially “green-washing,” in an attempt to apply an environmental veneer to a product that was essentially repackaged system power.

The establishment of the independent non-profit Green-e Certification program (www.green-e.org) for green power products was in part motivated by a concern that green power markets would be characterized by confusing claims that were difficult for ordinary customers to understand. Similar concerns exist for a broad range of potential product and service offerings in competitive markets.

The most likely driver for the emergence of these value-added green products in pilot programs, and in the states that have moved to retail competition is the limited range of prices in which marketers have been forced to compete. In the absence of real price competition, marketers will naturally seek to establish other unique distinguishing attributes for their power supply products. A table summarizing customer participation in retail competition pilot programs is included at Table 6.16.

The first retail competition markets in which significant customers have switched suppliers are in California and Pennsylvania. Although the opening date for Massachusetts precedes California's, the fact that default service prices were set at a rate below the wholesale market

clearing price in Massachusetts has all but eliminated competition in that state. In both California and Pennsylvania significant numbers of customers have subscribed to green power products. Again, unique features of the markets in those states have a major effect on this outcome. In California, the relatively high level of stranded cost recovery afforded to incumbent utilities is reflected in a "Competitive Transition Charge" that all customers must pay. The magnitude of this charge, in conjunction with other fixed costs, has made it very difficult for price-based competition to emerge. On the other hand, the system of charges has made green power pricing more attractive. The combined effect of relatively low prices for renewable resources, the presence of publicly funded incentives for renewables, and the structure of competitive rates in California has been that well over half the residential customers that have switched in California are now buying a green power product. Approximately 15 different green power products are available to customers in California. However, the overall level of switching has only totaled approximately 1 percent of eligible customers. At the one-year anniversary of the onset of competition in California's retail electricity market, just under 100,000 out of 11 million customers have switched suppliers.

The Pennsylvania retail market was structured substantially differently from that in California. Customers there may receive rate discounts on their electricity only if they switch providers. The credit customers receive for switching, known as a "shopping credit," is set to offset the cost of energy avoided when a customer no longer buys electricity from the incumbent provider. Shopping credits in Pennsylvania have been high enough that a large number of competitors (including incumbent utility affiliates) have entered the market. Though precise numbers are not available, it is estimated that in the first nine months of the market, nearly 400,000 Pennsylvania customers have switched suppliers. Of those, approximately 1/3, or 125,000 are believed to be buying one of five different green power products offered.

The experiences of pilot programs and the markets that have opened to retail competition demonstrate that there are willing and able power marketers, and green power marketers, ready to compete for customers in the lower-48. Whether these markets will grow sufficiently to become self-sustaining, however, is far from certain. Critical issues relating to market structure and competitive margins ultimately will dictate the success of retail markets under electricity restructuring.

Funding Mechanisms

The various states that have considered or passed restructuring legislation have considered a wide range of options for funding public benefits programs.

Renewable energy - Two primary approaches have been developed for supporting renewable energy development in restructured electricity markets. The direct approach relies upon the collection of funds through a broadly-based, non-discriminatory systems benefits charge or other mechanism. Under this approach funds are distributed through a variety of means, including rebates to customers, production incentives to generators, or credits to marketers for kilowatt-hours sold.

The indirect approach involves the use of a renewable portfolio standard (RPS). The RPS mechanism involves the legislative setting of a minimal percentage of renewable energy that must be reflected in the portfolio of each electricity supplier operating in the jurisdiction. Suppliers have the choice of either directly acquiring renewable energy supply from generators for resale, building their own renewable energy generating facilities, or buying renewable energy credits from suppliers with capacity in excess of the RPS level. In order to allow generators to find the most cost-effective renewable energy resources, credits are tradable among suppliers, though they cannot be banked against future RPS obligations. The RPS approach has the effect of changing the overall cost of supply, and therefore any premium costs for renewable energy would be both broadly distributed across the market and passed along to customers. The Clinton Administration is expected to announce their electric industry restructuring bill that will include a RPS. The potential impacts of this standard is provided in Table 6.17.

Energy efficiency - Policy options for supporting energy efficiency market development are also both direct and indirect. Direct funding again involves a system benefits charge or similar mechanism for collecting a pool of funds. These funds can be distributed as rebates, incentives to energy service companies, or to/through agencies with administrative responsibility for programs like low-income weatherization. If an obligation to conduct energy efficiency programs is imposed on the distribution service provider, such funds could be used to offset program costs.

Indirect funding mechanisms include efficiency codes and standards and standard offer mechanisms. Codes and standards have the impact of accelerating market transformation for efficient appliances and products, but can raise per unit costs. Standard offers operate like the efficiency equivalent of PURPA's obligation to purchase energy from qualifying facilities. Under a standard offer program, a distribution utility is required to calculate its avoided cost of energy and to establish deemed values for energy savings potential from various energy efficiency measures. Energy services companies then have the right to submit qualifying proposals to deliver energy savings in return for the pre-set standard offer payment. These energy service companies would only profit if they deliver the energy savings at a cost less than the standard offer prices.

Environment – Renewable energy and energy efficiency resources generally offer significant environmental benefits over conventional generation and use of electrical energy. Programs to promote these resources are therefore one of the more common policy approaches to ensuring that electric utility restructuring benefits, or at least does not degrade the quality of the environment.

Most public policy programs aimed at directly improving environmental quality impose the costs of pollution control on the source of the emissions. In that manner, funding for these improvements is indirect, and is passed to customers of the source of the pollution.

Direct funding mechanisms include taxes and pollution fees charged on the basis of emissions rates. Revenues generated in this fashion can be directed to environmental improvement programs, or to fund specific pollution controls. For example, an emissions fee charged as a percent of the price of kilowatt-hours sold at the distribution level could be aggregated to offset the cost of adding scrubbing units to the generation plant providing the electricity.

A third option for advancing environmental objectives involves tradable pollution permits and is often termed a "cap and trade" system. Under this approach an overall volumetric ceiling is established for a particular pollutant. Tradable permits, or allowances, are then distributed and traded among sources. All emitting facilities must demonstrate that they hold allowances equal to their annual emissions. In this manner, individual emitters can interact in a market environment which assigns an economic value to each allowance. The cap and trade system was adopted for control of SO₂ emissions under the 1990 Amendments to the Federal Clean Air Act, and has proven to be an extremely cost effective method for meeting environmental objectives. A similar approach has been discussed as a possible implementation mechanism for any limitations of carbon dioxide emissions. Though the costs of pollution control are still reflected in the price of goods and services sold, the cap and trade system is seen as offering a cost effective strategy for reducing those costs through the application of market forces.

Any funding mechanism supporting renewable energy, energy efficiency, environmental protection, or other public purpose programs imposes some level of costs, whether for the programs themselves or for administrative oversight and compliance monitoring. These costs will directly or indirectly be reflected in the price of electricity, and could impact the level of savings resulting from the introduction of market forces to the electricity industry.

A summary of the rate impacts of various funding mechanisms for public purpose programs is included in Table 6.18.

Green Pricing Programs

Some fifty different green pricing programs have been introduced in the United States in the last several years. Under a green pricing program, utility customers are offered an opportunity to buy a special tariffed service based on renewable energy supply or to make other personal investments in renewable energy resources. These optional programs have been created to offer the potential for development of renewable resources without imposing costs on customers who do not wish to participate. In addition, utilities have used green pricing programs as a means of building customer loyalty in advance of retail competition, and to gain operational experience with the introduction of renewable resources into the electricity system. States with utilities offering green pricing programs include Colorado, Florida, Hawaii, Nevada, New York, California (offered by municipal utility companies), Wisconsin, Arizona, Texas, Michigan, Minnesota, Nebraska, Oregon, Washington, Nebraska and New Mexico. The pace of new program introduction has been steadily increasing from three in 1993 to thirteen in 1998.

Program types - One review of 41 of the existing green pricing programs revealed a number of different approaches to the service:

- 24 energy tariff programs, average monthly premium \$6.50
- 12 contribution programs, average contribution \$1.80
- 3 capacity tariff programs, average monthly premium \$7.50
- 2 lease/finance programs, average monthly premium \$50.00

Customer participation - As of the end of 1998, these 41 green pricing programs involved approximately 45,000 participating customers. Programs not constrained by project size have, on average, achieved penetration rates of 1-2 percent after 1-2 years. Most green pricing programs have not tried to market to commercial customers. Those that have - PSCo's (Colorado) WindSource program, Fort Collins (Colorado) Municipal Utility, and Traverse City Power & Light program (Michigan municipal utility) - have received good responses.

Overall, US green pricing programs support some 37 megawatts of new renewable resources and approximately 6 megawatts of existing resources. A summary of green pricing programs is contained in Table 6.19.

Existing law and regulation

Alaska utility law and regulation says little about renewable energy, energy efficiency, and the environment. Regulators are empowered to consider a energy conservation issues in setting just and reasonable rates. The APUC has also established regulations for implementing the

federal Public Utility Regulatory Policy Act, and allowing for customers with small generation units to interconnect with the electric system.

Stakeholder Views

All stakeholders in Alaska express support for environmental quality. Likewise, very few stakeholders express opposition to the development of renewable energy, energy efficiency and new technology industries in Alaska.

As discussed above, alternative energy advocates are generally concerned that a restructured electric industry which focuses primarily on profitability may not create the kinds of incentives and opportunities necessary to ensure the viability of these options. They would assert that the public benefits associated with these options justifies support with broadly based public funding mechanisms and/or careful market structure design. They point to large numbers of customers who have expressed support for new technologies through polls, surveys, and the relatively recent experience with green pricing programs. They further argue that electric utility restructuring should be used as an opportunity to establish these industries and to create a policy pathway toward an improved environment.

Other stakeholders argue that renewable energy, energy efficiency or any other energy alternatives are wholly private goods, and that only those customers willing to voluntarily support them should be asked to pay. Some stakeholders believe that renewable energy, and to a lesser extent, energy efficiency programs are not and will not be cost-effective resources suitable for widespread use in the electricity system. As a result, they also argue that these resources should be supported only through voluntarily funding of niche applications, like green power markets. These stakeholders also argue that existing environmental laws and regulations provide adequate protection of human health and the environment, and that more stringent laws would impose unacceptable economic costs on all electricity customers.

Finally, a group of stakeholders are relatively indifferent to the issues concerning the deployment of energy efficiency, renewable energy, and other energy technologies and to changes in environmental laws and regulations. But they stress that if public funding mechanisms are created certain conditions must attach. These conditions are that any public funding mechanisms imposed must be non-discriminatory in impact, and that the total level of funding support should not be so great as to obviate the savings generated from competitive market operations. A summary of stakeholder views is reported in Table 6.20.

Dealing with the Impacts of Retail Competition

As discussed above, electric utility restructuring involves the interaction of a multitude of individual policy decisions. Alaskans in Anchorage and the Railbelt enjoy electricity services at relatively low prices per unit of energy. Unlike a number of states that have already moved toward competitive market structures, Alaska is unlikely to present a significant opportunity for price savings for ordinary electric service (2 percent to 5 percent as opposed to 10 percent to 15 percent). As a result, the pool of potential savings with which to fund public purpose programs will likely be more limited in Alaska than in many other states. To the extent that funding requests on behalf of renewable energy, energy efficiency, the environment, or any other emerging options dip into this pool of available savings, a balancing of costs and benefits is in order. On one side of the ledger are the direct funding costs for these programs. On the other are the economic and non-economic benefits associated with increased resource diversity, reduced environmental impacts, incentives to new industries and businesses to operate in Alaska, and the public support these options enjoy from much of the public.

Limited opportunities for system wide savings do not, by themselves dictate a course of inaction on renewable energy, energy efficiency, environmental initiatives and other public purpose matters. Rather, they create strong pressure for policy makers to craft carefully targeted program and policy options, and to focus on low or no-cost alternatives. As discussed above, market structure and the allocation of transition costs and competitive opportunities can have a profound impact on whether robust, self-sustaining markets for alternative technologies and services will arise in a competitive market environment.

Many mechanisms designed to accomplish other policy goals can provide important support for the emergence of these new markets. Customer education programs can help overcome the critical information barrier that has prevented the emergence of robust markets in other settings. Disclosure and labeling requirements for electricity services not only empower customers to act as their own agents in the marketplace, but will provide those customers who have a preference as to generation sources with an opportunity to understand the impact of their decisions.

Fair access to metering and billing systems and services for all competitive marketers will overcome a crucial obstacle encountered by green marketers in California. The creation of a forward-priced power exchange or similar institution will allow the creation of competitive independent secondary markets like the "green power exchange" now operating in California, and overcome a significant problem associated with obtaining reliable energy supplies. The lesson of the Pennsylvania

restructuring experience is that what is good for one market competitor is generally good for the entire market.

Policy options available to address renewable energy, efficiency, and environment issues are detailed in Table 6.21.

Value Added Products and Services

Today many electric utilities offer customers more than just electricity services. Utilities in Alaska offer energy audits, Internet service and other services to customers. One of the great hopes of electric utility restructuring is that by unleashing utilities from comprehensive regulation, and by encouraging market entry by new competitive entities, customers will be empowered not just to select their electricity supplier, but to buy products, supply and services from the well-stocked shelves of a robust energy services market.

One primary objective of electric utility restructuring is the commoditization of electrons – turning the trade for electric supply into a commodity market. For that reason much policy emphasis in the lower-48 and much discussion in Alaska has been devoted to creating a fully competitive generation market capable of efficiently delivering power over open-access transmission systems to willing wholesale customers. A commodity market for electrons linked by competitive dispatch systems offers what many believe to be significant system efficiencies and the potential for cost savings. For a relatively few large customers, commoditization of electrons offers the opportunity to obtain power at competitive prices, free from the costs associated with cost of service regulation and monopoly pricing.

But creating a commodity market offers little excitement to small residential and small commercial customers who are often more interested in customer service than mere delivery of a commodity product. For these customers, it is the work that electricity does that is of interest. Many observers believe that a significant proportion of customers will one day actively purchase value-added products and services built on electricity supply markets.

The value-added services market is also of great interest to many would-be marketers of electricity services. The reasons for this interest are clear. As competition generates savings by reducing inefficiencies, it also progressively reduces profit margins. Mature commodity markets typically operate on the thinnest of margins. These markets are typically populated by relatively few large players capable of leveraging economies of scale into profitable enterprises. Margins are typically larger in value-added markets for products and services, where marketers combine commodity product as a feedstock with special features and enhancements shaped to appeal to retail customers. Smaller companies can more easily enter, and exit, the value-added

services markets, bringing entrepreneurial innovation and new marketing concepts to the business.

Experience informs only the first round of value-added service innovations likely to emerge. More innovations doubtless will arise from the imaginations of entrepreneurs. The first round includes special service pricing packages like real-time or flat-bill pricing, specialized supply products like green power, complementary service products like energy efficiency services, electricity services bundled with electric appliances like heating and air conditioning equipment, and electricity bundled with other services such as internet access, home security, and telecommunications services. Figure 6.1 shows how profits are based on strategic positioning and value-based pricing. While each of these innovations has both benefits and disadvantages, many observers believe that competitive electricity markets will be enriched by the efforts of competitors seeking to find the right formula to attract customer dollars. A review of value added product and service innovations is set out in Table 6.22.

The most significant public policy issue arising in connection with the emergence of value-added markets is the relationship between competitive marketers and monopoly suppliers of regulated products. The public policy concerns are twofold. First, there is a concern that captive customers will be charged for the costs of supporting a competitive business through their rates. The second public policy concern is that utilities that cross-subsidize their competitive operations will enjoy a market advantage over other competitors and effectively preclude their market entry. In the end, public policy makers must weigh the benefits of having additional competitors offering non-utility services to customers against the potential for unfair cross-subsidization. The issue is further complicated when non-utility services are offered by cooperative and municipal utilities, because these utilities are in effect managed by their customers.

Policy makers have several options for ensuring that improper cross-subsidization does not occur. These options range from detailed data collection to outright prohibition of unfair business practices. These options imply both administrative and compliance costs that rise in proportion to the level of oversight and regulation contemplated. Policy options to address competition in non-electricity service markets are set out in Table 6.23.

TABLE 6.1
Key Features of Electric Systems

Feature	Comment
Need for continuous and near instantaneous balancing of generation and load	Involves metering, computing, telecommunications, and control equipment to monitor loads, generation, and transmission systems to adjust generation output to match load.
Generation and load must be in delicate balance to maintain system frequency at 60Hz	If generation exceeds load, the frequency increases, and if load exceeds generation, then the frequency drops. Departures from the nominal 60 Hz by even ± 0.1 Hz are rare. If frequency departs by as much as ± 1 Hz, the system will either shed load or drop generators to restore frequency. Beyond some point, perhaps, 58 Hz, the system will crash.
Passive nature of the transmission network	Today's transmission systems have very few "control valves" or "booster pumps" to regulate electrical flows on individual lines. Control actions are limited primarily to adjusting generation outputs and to opening and closing switches to reconfigure the network.
Every action can affect all other activities on the grid	The activities of all players must be closely coordinated, often across large geographic areas.
Outages can increase in severity and cascade over large areas on interconnected grids	Failure of a single element can, if not managed properly, cause the subsequent rapid failure of many additional elements, disrupting the entire transmission system.
The need to be ready for possible contingencies, more than current operating conditions, dominates the design and operation of bulk power systems	It is usually not the present flow through a line or transformer that limits allowable transfers of power, but rather the flow that would occur when another element fails.

TABLE 6.2
Reliability Activities

Observe the network	Observe current (real-time) frequency, voltage, current, and power-flow conditions at each node and in each element to determine if failure of an element or voltage collapse is imminent.
Analyze and model the system	Using computer models and data on current operating conditions such as current flows and voltages, anticipate conditions in individual pieces of equipment (such as lines and transformers) that are not directly observable; estimate what will happen if an element fails; determine whether a proposed transaction can be accommodated; and deal with normal uncertainties, such as load-forecast errors and the effects of temperature and wind speed on real-time thermal limits.
Communicate and coordinate	Coordinate with other control-area operators to assure that activities do not threaten the integrity of the interconnected grid.
Take control actions	Maintain system operation within acceptable limits (primarily changes in generation output, transmission switching to a lesser extent, and load shedding as a last resort).
Monitor and enforce compliance	Ensure that all market participants (generators, aggregators, marketers, transmission operator, and loads) are consistently meeting reliability requirements.
Plan for future conditions	Make improvements and additions (e.g., new generation, transmission lines, transformers, load control, and FACTS 1 devices) to improve reliability and relieve constraints. Improve communications and controls to enable more market participants to engage in reliability-enhancing activities. Improve capabilities to observe and model the system, thus allowing safe operation of the system closer to actual physical limits and better use of existing resources.
Get incentives right	Ensure that price signals and contractual arrangements (for generators, transmission, and loads) evoke reliability-enhancing behavior in the most economically efficient manner. These signals must provide adequate incentive to invest without overcompensating investors.

TABLE 6.3
Traditional Vertically Integrated Utility Services Affecting Generation and Transmission System Reliability

Function	Time Scale	Description
Automatic protection	Instantaneous	Minimize damage to equipment and service interruptions caused by faults and equipment failures
Disturbance response	Instantaneous to minutes to hours	Adjust generation, breakers, and other transmission equipment to restore system to scheduled frequency and generation/load balance quickly and safely
Regulation and voltage control	Seconds to minutes	Adjust generation to match scheduled flows across transmission system interties plus actual system load. Adjust generation and transmission resources to maintain system voltages
Economic dispatch	Minutes to hours	Adjust committed units to maintain frequency and the generation/load area-interchange balance at minimum cost subject to transmission, voltage, and reserve-margin constraints
Transmission loading relief	Minutes to hours	Curtail transactions and re-dispatch generation to reduce power flows through critical transmission elements
Unit commitment	Hour ahead to week ahead	Decide when to start up and shut down generating units, respecting unit ramp-up and down rates, startup costs, and minimum runtimes and loadings
Transmission scheduling	Hour ahead to year ahead	Schedule individual transactions and reservations of transmission capacity
Maintenance scheduling	1 to 3 years	Schedule and coordinate planned generating-unit and transmission equipment maintenance to maintain reliability and to minimize cost
Transmission planning	2 to 10 years	Design regional and local system additions to maintain reliability and to minimize cost
Generation planning	2 to 10 years	Develop a least-cost mix of new generating units, retirements, life extensions, and repowering based on long-term load forecasts

Source: Research Triangle Institute, Reliability Considerations in Electric Industry Restructuring, March 1999.

TABLE 6.4
Today's Reliability Institutions

Institution	Description
System Operators and Security Coordinators	System Operators and Security Coordinators rely on communications with each other, access to essential system information, and real-time monitoring and control of certain facilities to maintain reliability. When an emergency occurs, the control-area operator acts – both through communication and direct physical action – to ensure the integrity of security of the system.
NERC	The North American Electric Reliability Council is a voluntary, industry-constituted governing body that develops standards, guidelines, and criteria for assuring system security and evaluating system adequacy. NERC has been funded by regional reliability councils, which adapt the NERC rules to meet their need of their regions. Historically, the reliability councils have functioned without external enforcement powers, depending on voluntary compliance with standards and peer pressure.
FERC	The Federal Energy Regulatory Commission is the federal agency with jurisdiction over bulk power markets, including interstate transmission systems. As part of these responsibilities, FERC implements policies to assure that the owners and operators of bulk power transmission facilities under the agency's jurisdiction provide nondiscriminatory service to all participants in wholesale power markets. Historically, FERC has not involved itself in reliability functions. Increasingly, some parties are calling on FERC to exercise its authorities by addressing reliability issues that intersect with commercial needs of the industry.

TABLE 6.5
Summary of ISO Functions

ERCOT ISO	PJM ISO	California ISO	NEPOOL ISO	NYPP ISO
NERC Regional Reliability Council became the ISO No load and generation balance – Policeman Line load relief Direct dispatch for transmission congestion Administer OASIS Administer transmission tariff and loss compensation Provide a forum for coordinated regional transmission planning Develop operating and reliability guides	Operate the PJM control area Manage and administer the competitive energy market Direct and coordinate the operation of the designated transmission facilities Administer the transmission tariff, including determination of available transfer capability Performing system impact studies Schedule transmission service Curtailing transmission service Coordinate regional transmission planning Support the administration and implementation of an agreement to establish necessary reserve levels and sharing of such reserves	System reliability, security, stability Controls dispatch of generation and transmission Compile and validate schedule feasibility Administer transmission tariff Perform congestion management function Obtain unbundled ancillary services from market Settlements for grid access, congestion, ancillary services Real time control of all ancillary services	Control area operator Controls bulk transmission system operation Dispatches all generation subject to participant self scheduling Administers market settlement rules and regional transmission tariff	Control area operator Direct the operation and maintain the reliability of the bulk power system Provide transmission service and ancillary services to eligible customers under the tariff Coordinate maintenance scheduling of the bulk power transmission system Coordinate planned outages and schedules for generating units under contract to provide installed capacity to the bulk power system Facilitate the financial settlement of ISO and Power Exchange transactions Require customers entering into service agreements under the tariff to maintain appropriate levels of installed and operating capacity.

Source: <http://www.psc.state.ga.us/electricindust/appendix8.htm>

TABLE 6.6
Summary of ISO Governance Structures

ERCOT ISO	PJM ISO	California ISO	NEPOOL ISO	NYPP ISO
Board of Directors membership from 6 market groups: IOU, municipal, cooperative, transmission dependent, IPP, power marketers 3 representatives per group 2/3 majority of votes to pass (13 of 18) 2 Board Committees: Executive Committee, Nominating Committee PUC and Office of Public Utility Commission will each have one ex-officio nonvoting member on the Board Board will hire ISO Director and an Executive Director, appoint a Director of Technical Advisory Committee, approve reliability and operating guidelines, approve budgets, etc.	Board of Directors will consist of the President and CEO and 6 Directors serving three-year terms Of the 7 Directors on the Board of PJM Services Company, only 2 may be affiliated with members of the existing PJM pool and may serve on the Board for only the first five years Other directors may not be affiliated with any entity engaged in the generation, transmission, distribution, purchase or sale of electric energy in the Mid-Atlantic region 3 Board Committees: Nominating Committee, Compensation Committee, Audit Committee	Board of Directors comprised of 5 classes of market groups and non-stakeholder: IOU transmission owners (4), government/municipal (4), sellers (3), end-users (4), non-stakeholders (3) No one class may block Board action No two classes may force Board action An entity can be in only one class Board members will serve 3 years initially, then will rotate every 5 years 12 votes required to pass most measures 7 votes required to veto most measures	Board of Directors composed of ten members with no affiliation with any NEPOOL member NEPOOL voting will be conducted in the Management Committee Every NEPOOL member will be entitled to a seat on the Management Committee and a vote Voting bases on a six-factor formula which allocates voting shares on the basis of peak and energy load responsibility, generation ownership, transactions, and transmission ownership 66% majority needed to pass an action 20% needed to block an action 4 Committees below the Management Committee: Regional Market Operations, Regional Transmission Operations, Market Reliability Planning, and Regional Transmission Planning	Board of Directors comprised of 4 classes of market groups: buyers (8), sellers (8), consumer and environmental (4), and transmission providers (8) A vote of 17 of 28 members will be needed to pass any measure Board members will serve 4 year terms, with terms initially set at varying lengths in order to ensure staggered terms 3 standing ISO committees: Operating, Business Issues, Dispute Resolution

Source: <http://www.psc.state.ga.us/electricindust/appendix8.htm>

TABLE 6.7
FERC ISO Principles

FERC Principal	Comment
The ISO's governance should be structured in a fair and non-discriminatory manner.	In Order 888 issued on April 24, 1996, the Commission recognizes that some utilities are exploring the concept of an Independent System Operator and that the tight power pools are considering restructuring proposals that involve an ISO. While FERC does not require utilities to form ISOs, it encourages the formation of properly-structured ISOs. To this end, Order 888 gives the industry some guidance on the principles that the Commission will use in assessing ISO proposals that may be submitted to it in the future. The order states that because an ISO will be a public utility subject to its jurisdiction, the ISO's operating standards and procedures must be approved by the FERC. The principles for ISOs are: The primary purpose of an ISO is to ensure fair and nondiscriminatory access to transmission services and ancillary services for all users of the system. As such, an ISO should be independent of any individual market participant or any one class of participants (e.g., transmission owners or end-users). A governance structure that includes fair representation of all types of users of the system would help ensure that the ISO formulates policies, operates the system, and resolves disputes in a fair and non-discriminatory manner. The ISO's rules of governance, however, should prevent control, and appearance of control, of decision-making by any class of participants.
An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.	To be truly independent, an ISO cannot be owned by any market participant. Transmission owners need to be able to hold the ISO accountable in its fiduciary role, but should not be able to dictate day-to-day operational matters. Employees of the ISO should also be financially independent of market participants. In addition, an ISO should not undertake any contractual arrangement with generation or transmission owners or transmission users that is not at arm's length. In order to ensure independence, a strict conflict of interest standard should be adopted and enforced.
An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner.	An ISO should be responsible for ensuring that all users have non-discriminatory access to the transmission system and all services under ISO control. The portion of the transmission grid operated by a single ISO should be as large as possible, consistent with the agreement of market participants, and the ISO should schedule all transmission on the portion of the grid it controls. An ISO should have clear tariffs for services that neither favor nor disfavor any user or class of users.
An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well-defined and comply with applicable standards set by NERC and the regional reliability council.	Reliability and security of the transmission system are critical functions for a system operator. As part of this responsibility an ISO should oversee all maintenance of the transmission facilities under its control, including any day-to-day maintenance contracted to be performed by others. An ISO may also have a role with respect to reliability planning. In any case, the ISO should be responsible for ensuring that services (for all users, including new users) can be provided reliably, and for developing and implementing policies related to curtailment to ensure the on-going reliability and security of the system.

FERC Principal	Comment
An ISO should have control over the operation of interconnected transmission facilities within its region.	An ISO is an operator of a designated set of transmission facilities.
An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.	A key function of an ISO will be to accommodate transactions made in a competitive market while remaining at arm's length from those transactions. The ISO may need to exercise some level of operational control over generation facilities in order to regulate and balance the power system, especially when transmission constraints limit trading over interfaces in some circumstances. It is important that the ISO's operational control be exercised in accordance with the trading rules established by the governing body. The trading rules should promote efficiency in the marketplace. In addition the ISO should provide, or cause to be provided, the ancillary services described in this Rule.
The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open market.	Management and administration of the ISO should be carried out in an efficient manner. In addition to personnel and administrative functions, an ISO could perform certain operational functions, such as: determination of appropriate system expansions, transmission maintenance, administering transmission contracts, operation of a settlements system, and operation of an energy auction. The ISO should use competitive procurement, to the extent possible, for all services provided by the ISO that are needed to operate the system. All procedures and protocols should be publicly available.
An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption. An ISO or an RTG of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.	Appropriate price signals are essential to achieve efficient investment in generation and transmission and consumption of energy. The pricing policies pursued by the ISO should reflect a number of attributes, including affording non-discriminatory access to services, ensuring cost recovery for transmission owners and those providing ancillary services, ensuring reliability and stability of the system and providing efficient price signals of the costs of using the transmission grid. In particular, the Commission would consider transmission pricing proposals for addressing network congestion that are consistent with our Transmission Pricing Policy Statement. In addition, an ISO should conduct such studies and coordinate with market participants including RTGs, as may be necessary to identify transmission constraints on its system, loop flow impacts between its system and neighboring systems, and other factors that might affect system operation or expansion.
An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission's requirements.	A free-flow of information between the ISO and market participants is required for an ISO to perform its functions and for market participants to efficiently participate in the market. At a minimum, information on system operation, conditions, available capacity and constraints, and all contracts or other service arrangements of the ISO should be made publicly available. This information should be made available on an OASIS operated by the ISO.

FERC Principal	Comment
An ISO should develop mechanisms to coordinate with neighboring control areas.	An ISO will be required to coordinate power scheduling with other entities operating transmission systems. Such coordination is necessary to ensure provision of transmission services that cross system boundaries and to ensure reliability and stability of the systems. The mechanisms by which ISOs and other transmission operators coordinate can be left to those parties to determine.
An ISO should establish an ADR process to resolve disputes in the first instance.	An ISO should provide for a voluntary dispute resolution process that allows parties to resolve technical, financial, and other issues without resort to filing complaints at the Commission. We would encourage the ISO to establish rules and procedures to implement alternative dispute resolution processes.

TABLE 6.8
Subtle Changes from Competition

New Challenges	Comment	Implications
Communication is both more difficult and less respected	More parties need to be contacted to take corrective actions. With a system dependent on voluntary cooperation, the speed of response is limited at present by the speed of telephone conversation. The more parties that must act to solve a problem, the longer the time delay and the greater the chance of noncooperation.	The move to insert some added public oversight of grid operations is growing.
Voluntary guidelines must interact with new incentives	Competition introduces new economic incentives into this system of voluntary compliance. In a competitive environment, compliance will have to be balanced against its economic consequences.	Operating guidelines will turn away from voluntary cooperation and toward mandatory compliance.
Unbundling is adding grid complexity	A greater number of electricity suppliers, increasingly complex interchange schedules, and the unbundling of ancillary services such as voltage support – are all part of the move to competition. Heavier and less predictable power flows put more stress on the transmission system. The flows can be accommodated, but they require more attention on the part of the operators and engineers.	Centralized control of the grid is getting a more receptive hearing.
Skill has emigrated	Some of the most skilled practitioners of grid control are taking early retirement packages or are accepting lucrative offers to join power marketing firms.	This loss of experience could have an impact on proficiency and reliability.
Deferred spending on maintenance	Uncertainty about the direction of restructuring and the expectation that cost recovery will be constrained is causing utilities to defer spending on maintenance. As a consequence, equipment is not being inspected as often, new investment is being limited, and the speed of recovery from disturbances has been slowed.	Restructuring will proceed, but its pace will increasingly be determined by solutions to the reliability issue -- to make sure the physical system works.

TABLE 6.9
NARUC Convention Floor Resolution No. 21
Resolution on Electric System Reliability

WHEREAS, The reliability of electric service, including the adequacy of supply and the security of system operations, is essential to the economic well-being and domestic security of the nation; and

WHEREAS, There is a national interest in a transmission network that is reliable and available to support competitive and efficient electricity markets; and

WHEREAS, Historically, the high level of electric reliability experienced in the United States has been achieved through the voluntary efforts of the electric utility industry, through the North American Electric Reliability Council (NERC) and the regional reliability councils, to police themselves with federal and state regulatory oversight; and

WHEREAS, More competition in the electricity industry means the commercial incentives affecting both the owners of the transmission system and the parties transacting business on the system will be complex and not always consistent with the voluntary spirit of cooperation on which the NERC system relies; and

WHEREAS, The existing NERC system is already facing pressures from the expansion of wholesale competition regardless of the pace at which retail competition may be broadly introduced; and

WHEREAS, Facility siting, environmental standards, and energy policy issues are currently in the purview of many of the states; and

WHEREAS, Some states have established and exercise the authority to impose sanctions against those who engage in actions which abuse, misuse, or manipulate the grid in a manner which threatens reliability to the detriment of the state's local retail markets; and

WHEREAS, Absolute reliability is not physically possible and reliability of transmission does not have infinite economic value; and

WHEREAS, The public interest in a reliable and cost-efficient transmission system requires that the level of reliability to be achieved and the standards and criteria to be complied with be established with public input and oversight; now, therefore, be it

RESOLVED, By the National Association of Regulatory Utility Commissioners, convened at its 109th Annual Convention in Boston, Massachusetts, that actions by Congress and the States to ensure a reliable electricity transmission system should be consistent with, or include the following:

1. Reliability standards and criteria addressing both the planning and the operation for the bulk transmission system should be comprehensive and should consider: the economic value of reliability, the practical engineering of the network, and a full range of alternatives to additional transmission line investments.
2. The level of reliability to be achieved and the standards and criteria to be complied with must be established with public input and oversight. This is necessary to both preserve the public interest and prevent anti-competitive abuses with respect to the transmission system. Governance of the NERC and the regional councils should be fairly representative of all industry interests and should include mechanisms to allow input from federal and state regulatory authorities and other public interest groups while preserving independent regulatory oversight. Meetings to establish reliability criteria and standards should be open to public input.
3. Federal agencies and federal legislation should facilitate effective decision-making by the states and recognize the authority of the states to create regional mechanisms including but not limited to inter-state compacts, or regional reliability boards, for the purpose of addressing transmission reliability issues.
4. Where state authority exists to impose sanctions against those who engage in actions which abuse, misuse, or manipulate the grid in a manner which threatens reliability to the detriment of the state's local retail markets, it should be preserved.
5. Responsibility for compliance with both operational and planning reliability standards and criteria should be clearly established. Sanctions for violation of standards and criteria should be clearly established, and sufficient authority should exist to enforce compliance and impose sanctions if necessary. Enforcement of compliance with reliability standards and criteria should be non-discriminatory. Enforcement of operational standards and criteria should be supervised by the FERC in cooperation with the states through existing state authority, joint boards, or other mechanisms. Enforcement of compliance with planning and system adequacy standards should rest first with the states and regional bodies.

6. The NERC and regional reliability council system should be strengthened to enable reliability standards and criteria to be mandatory for those who own, operate, or use the transmission network. Any reliability standards or operational criteria, the compliance with which is to be made mandatory, must be subject to government regulatory oversight; and be it further
RESOLVED, That, either separately or as part of any electric industry restructuring legislation, Congress should, consistent with the preceding six principles, explicitly affirm the public interest in transmission grid reliability, the need for mandatory compliance with reliability standards, and provision of an explicit grant of authority to the states and to FERC to act in cooperation to enforce the necessary standards; and be it further
RESOLVED, That the working group on reliability shall further study, refine, and define the principles set forth in this resolution and make recommendations to the appropriate NARUC standing committees.

Sponsored by Committee on Electricity

Adopted by the NARUC Executive Committee on November 11, 1997

TABLE 6.10
Emissions from Electric Utilities – Alaska (1996)

	Carbon Dioxide (CO₂)	Sulfur Dioxide (SO₂)	Nitrogen Oxide (NO_x)
Alaska Emissions from Utilities (tons)	2,937,571	2,917	16,465
Alaska Emission Rate (lbs/MWh)	1,179.20	1.17	6.61
US Emissions from Utilities (tons)	2,480,615,000	13,070,000	8,224,000
US Emission Rate (lbs/MWh)	1439.29	7.58	4.77

Source: US EPA, EGRID

TABLE 6.11
Renewable Energy Projects in Alaska

Project Name	Budget	Description
Atka Hydroelectric Design	\$100,000	Conduct final design and engineering; develop a materials list and logistics; and, obtain necessary permits required for construction of a hydroelectric project near Atka. The 271 kilowatt facility would be located on Chuniisax Creek at an elevation of about 175 feet and approximately six-tenths of a mile southwest of Atka. Water would flow from an impoundment through 1,060 feet of 30-inch pipe to the powerhouse. A 2,625-foot transmission line would intertie the plant to the community's existing electrical system. Total cost of the hydroelectric project is estimated to be \$750,000 including engineering and design.
Cooper Landing Cooper Creek Stream Gauging	\$43,800	Gauge Cooper Creek stream flow, near Cooper Landing, for possible small-scale hydroelectric development by Chugach Electric Association. Work includes recording river stage data, making discharge measurements, establish stage/discharge relationship and enter information into the U.S. Geological Survey database. The information also is published in the USGS annual report. The Division of Energy managed the project on behalf of the U.S. Geological Survey and Chugach Electric Association.
Cordova Power Creek Hydroelectric Project	\$15,406,170	Design and construct a hydroelectric generating facility for Cordova Electric Cooperative located on Power Creek approximately 6 miles northeast of Cordova. The facility would consist of a diversion dam and intake structure; tunnel and pipeline power conduit conveying water approximately 5,900 feet; powerhouse with three generating units with a total installed capacity of 6.0 megawatts; a 7.2 mile buried transmission line; and, approximately 2.5 miles of access road. The Division would administer State and Federal Grant funding.
Cordova Humpback Creek Hydroelectric	\$60,000	Humpback Creek is a run-of-river hydroelectric project located seven miles from Cordova by boat. It has been in operation since 1991. The plant is operated by remote control from Cordova. This project will upgrade existing control systems and provide additional, more reliable control system including better protection and monitoring of the three turbines, penstock and intake structure. The project also will enable more kilowatt hours of electricity production by making more efficient use of the turbines depending on water flow in Humpback Creek. With increased generation, the cost per kilowatt hour will decrease because diesel generator fuel consumption will be decreased, lowering the monthly fuel surcharge. This savings which will be passed directly to Cordova Electric Cooperative consumers. Total final cost of the improvements is anticipated to be about \$200,000.
Cordova Tidal Power Feasibility	\$527,000	Assess feasibility of a 5 megawatt low-head hydroelectric power plant using tidal energy in Cordova. The scope of work included providing funding and oversight for the project which would assess capital cost, system efficiency, power output and operating costs of a tidal energy facility. Tidal Electric Alaska Inc. (TEA) has been awarded a grant for \$200,000 from the Alaska Science and Technology Foundation (ASTF).

Project Name	Budget	Description
Dorothy Lake Stream Gauging	\$150,600	This project, in cooperation with Alaska Electric Light & Power and the U.S. Geological Survey, is conducting stream gauging for hydroelectric potential at the outlet of Dorothy Lake near Juneau from FY1997 through FY2001. The USGS will collect site data, analyze and publish it once it has been reviewed. All data, preliminary and final, will be available to AEL&P and the public. Federal funding is U.S. Geological Survey; local funding is Alaska Electric Light and Power. Technical oversight and coordination is provided by the Division.
Gustavus Stream Gauging	\$10,734	Install and operate a stream gauging station on Fall Creek near Gustavus in Southeast Alaska. Project will gather continuous water levels, stream temperature data and daily stream discharge for possible development of a small-scale hydroelectric project. Federal contribution is from the U.S. Geological Survey. Local contribution is from Gustavus Electric Company. The Division of Energy managed the project on behalf of the participants.
Kotzebue Wind Demonstration	\$1,071,000	Develop wind energy conversion systems for village power use. Under the scope of work, three village-sized wind turbines - Atlantic Orient Model 15/50 -- will be installed at a site selected for wind farm potential by Kotzebue Electric Association. These wind machines, which have been shipped to KEA, are designed for cold weather application. Separate from the wind turbine test is a requirement for completion of a written economic and technical performance assessment. The assessment will monitor performance for three years after the date of installation. Local contribution is from Kotzebue Electric Association. Federal funding is from the National Renewable Energy Laboratory (NREL). The first turbine was placed on line in May 1997.
Kotzebue Wind Feasibility	\$46,688	Evaluate the wind resources in the Kotzebue area and begin to examine the feasibility of using wind energy conversion systems to replace diesel-fired power generation at Kotzebue Electric Association. Under the scope of work, KEA will evaluate wind resources of the villages in the Kotzebue/Seward Peninsula area. Kotzebue Electric Association contributed labor, equipment and travel to the project. KEA has purchased four monitoring stations and is finalizing site agreements for their placement.
Lime Village Electrification	\$246,557	Install powerhouse and centralized electric distribution system for Lime Village. Primary power supply system includes diesel generators with photovoltaic cells, battery storage and an AC/DC converter to assist in reducing the peak load. The battery storage and inverters convert direct current to 7200 volts alternating current for distribution.
Old Harbor, AVEC Hydroelectric Project	\$1,000,000	Construct new hydroelectric project on Lagoon Creek near Old Harbor to displace diesel generation and, due to excess capacity, reduce consumption of heating fuel. Work could include, but not be limited to, constructing a concrete diversion structure, 10,259 feet of penstock and a powerhouse. Total anticipated cost is about \$1.6 million.

Project Name	Budget	Description
Statewide Rural Hydro Assessment & Development	\$200,000	Compile and update significant information on existing and proposed hydroelectric projects in rural Alaska; and re-evaluate a limited number with the potential to reduce power costs in the future. A contractor has been retained to summarize data on existing hydro projects in rural Alaska, update information on potential projects and generally assess on a consistent basis the potential of each project to reduce power costs and Power Cost Equalization (PCE) requirements. Phase I tasks include: compile project information and data base; establish costing assumptions and adjust cost data; evaluate projects and characterize their economic potential; and develop a short list of projects that may warrant closer analysis in Phase II. Upon completion of Phase I, two projects were selected for closer analysis: Pyramid Creek in Unalaska and Old Harbor on Kodiak Island.
Statewide Wind Assessments	\$50,000	This project measures wind resources in rural communities to identify those areas that would most likely benefit from supplemental wind generation of electrical power. Wind monitoring equipment will be installed in at least four communities, and wind direction and wind speed data will be collected for one year. The data will be analyzed to determine if installation of wind generation equipment would be justified. The scope of work includes the following: purchase, deliver and install 4-6 anemometers, electronic measuring and recording devices and analysis software; collect and evaluate data; and, hold a workshop to disseminate information and training on wind monitoring. Target sites have been identified on the basis of encouraging wind resource information, potential fuel savings or as representative resource sites. Potential locations considered included Alakanuk, Bethel, Chevak, Cold Bay, Emmonak, Hooper Bay, Kipnuk, Kivalina, Mountain Village, Naknek, Nome, Saint Michael, Sand Point, Shishmaref, Togiak, Unalakleet, Unalaska and Yakutat. Final site selection will be based on community support. A station has been erected at Yakutat. Communities have been contacted and abandoned wind turbine towers have been identified.

Project Name	Budget	Description
Statewide Bioenergy Program	\$184,394	This federally-funded program promotes and facilitates the use of low grade timber, forest and mill wood waste, municipal solid waste and agricultural by products for energy recovery. On-going activities include publishing material in the quarterly newsletter, Energy Update, representing Alaska on the Pacific Northwest and Alaska Regional Bioenergy Task Force, assessing biomass resources, providing technical assistance to public/private sectors in developing and facilitating bioenergy projects. Specific projects include: Small Waste to Energy System Development (SWESD): This task includes preparation of a database of small-scale waste combustion systems. Juneau Waste-to-Energy Feasibility Assessment (JWTE): This is a pass-through grant to Channel Landfill Inc. to study feasibility of recovering 1.5 megawatts of power and waste heat from its Juneau incineration operation. Division is providing technical and administrative oversight. Rural Fuelwood Substitution (RFS): promote installation of small, wood-fired boilers in rural buildings and district heating systems where economically sound and socially beneficial. Wood Residue Assessment (WRA): Update South Tongass Wood Waste Assessment and statewide sawmill residue assessment with Sealaska Corp. McGrath Biomass/Waste Heat (MBWH): wood-fired boiler to supplement diesel waste heat to Federal Aviation administration, school and water plant in cooperation with McGrath Light & Power.
Statewide Energy Conservation	\$714,542	This program supports statewide energy efficiency and conservation efforts. Rebuild America provides rural communities with energy efficiency audits of the school and other community buildings. Energy conservation training and information are provided to maintenance workers, school children and teachers, and interested residents. Institutional Energy Efficiency Grants provide financial incentives for demonstrations of high efficiency lighting and equipment. Technical support is provided as on-going support on high efficiency lighting and equipment.
Tazimina Hydroelectric Project	\$11,580,000	Construct an 824 kilowatt run-of-river hydroelectric project on the Tazimina River near Iliamna. Initially defined by the former Alaska Energy Authority, the project is now being developed by Iliamna-Newhalen-Nondalton Electric Cooperative (INNEC). The Division of Energy is administering State and Federal grant funding with sufficient project oversight to assure proper use of funds and project completion. The project also includes federally-required construction reports and an operations and maintenance report following two years of operation.

Project Name	Budget	Description
Unalaska Pyramid Creek Hydroelectric Project	\$92,000	Initiate permitting and engineering activities for the proposed Pyramid Creek Hydroelectric Project near Unalaska. The City of Unalaska will issue a request for proposals (RFP) for the work.
Wales Displace Diesel Fuel with Wind Energy	\$708,797	The goal of this project is to evaluate the use of wind energy in a small village (Wales) power system to displace 30 percent to 40 percent of the diesel fuel used for electrical generation and space heating. An important component of the project is development of a control system to maximize the value of the energy in the wind. The scope of work includes designing and constructing a wind/diesel hybrid system that will incorporate approximately 150 kW of wind energy into the existing diesel grid in Wales. Switching and control systems are under design. The project is sponsored by the Division of Energy, Environmental Protection Agency, National Renewable Energy Laboratory (NREL) of the U.S. Department of Energy, Kotzebue Electric Association and the Alaska Village Electric Cooperative. Kotzebue Electric Association received funding from the Alaska Science and Technology Foundation (ASTF) to complete the project. Long lead time equipment is on order, all design work is underway.

Source: http://www.eren.doe.gov/state_energy/states_currentefforts.cfm?state=AK

Updated 2/99

TABLE 6.12
US EPA Projections of Impacts on Alaska Related to Global Climate Change

Local Climate Changes

Over the last century, the average temperature in Anchorage, Alaska, has increased 3.9°F, and over the last 41 years of available data, precipitation has increased by approximately 10 percent in many parts of the state. These past trends may or may not continue into the future.

Over the next century, climate in Alaska may change even more. For example, based on projections made by the Intergovernmental Panel on Climate Change and results from the United Kingdom Hadley Centre's climate model (HadCM2), a model that accounts for both greenhouse gases and aerosols, by 2100 temperatures in Alaska could increase by 5°F in spring, summer, and fall (with a range of 2-9°F), and by 10°F in winter (with a range of 4-16°F). Precipitation is estimated to increase slightly in fall and winter (with a range of 0-10 percent) and by 10 percent in spring and summer (with a range of 5-15 percent). Other climate models may show different results, especially regarding estimated changes in precipitation. The impacts described in the sections that follow take into account estimates from different models. The frequency of extreme hot days in summer would increase because of the general warming trend. It is not clear how the severity of storms might be affected.

Human Health

Higher temperatures in Alaska will probably not produce conditions hot enough to cause heat-related deaths. It is also not likely that winter-related deaths will be greatly affected if warming occurs. In urban areas, climate change could increase concentrations of ground-level ozone. For example, high temperatures, strong sunlight, and stable air masses tend to increase urban ozone levels. Although Alaska is in compliance with current ozone air quality standards, increased temperatures could make remaining in compliance more difficult. Ground-level ozone is associated with respiratory illnesses such as asthma, reduced lung function, and respiratory inflammation.

Mosquito-borne diseases of humans have not been reported in Alaska in the 1990s. However, if conditions become warmer and wetter, mosquito populations could increase, thus increasing the risk of transmission of malaria and encephalitis if these diseases are introduced into the area. Increased runoff from heavy rainfall could increase water-borne diseases such as giardia, cryptosporidia, and viral and bacterial gastroenteritides. Developed countries such as the United States should be able to minimize the impacts of these diseases through existing disease prevention and control methods.

Coastal Areas

Sea level rise could lead to flooding of low-lying property, loss of coastal wetlands, erosion of beaches, saltwater contamination of drinking water, and decreased longevity of low-lying roads, causeways, and bridges. In addition, sea level rise could increase the vulnerability of coastal areas to storms and associated flooding. Alaska has 31,400 miles of tidally influenced shoreline.

The shoreline consists largely of fiords, bluffs, beaches, and islands, including the extensive Aleutian chain. The Alaskan coast also supports a wide range of wetland systems. For example, a proposed National Estuarine Research Reserve in Kachemak Bay spans nearly 400,000 acres. Much of Alaska's coast remains undeveloped; however, more than 40 percent of the population currently resides in the coastal city of Anchorage.

Current rates of erosion of Alaska's coastline vary widely because of local terrain and differences in the rates of uplift, as well as the abundance of sea ice and permafrost. In some areas, uplift as a result of tectonic activity is rapid. On average, however, Alaska's coastline is eroding at a rate of 8 feet per year, and this rate could increase with sea level rise.

Along much of Alaska's coast, the rate of sea level rise is nearly equal to or less than the rate of uplift. Accounting for the effects of climate change, sea level may rise a total of 10 inches by 2100, although at some locations a net uplift is most likely. Possible responses to sea level rise include building walls to hold back the sea, allowing the sea to advance and adapting to it, and raising the land (e.g., by replenishing beach sand, elevating houses and infrastructure). Each of these responses will be costly, either in out-of-pocket costs or in lost land and structures.

Water Resources

Alaska has abundant water resources, but water is not always available where and when it is needed. Major Alaskan rivers, the Yukon, Kuskokwim, and Cooper, are among the 10 largest in the United States. There are more than 3 million lakes in the state; two principal aquifers hold large amounts of water. However, environmental, legal, and technological constraints limit the use of these supplies. Glacial-fed streams are often laden with silt, many streams freeze and run dry during the winter, and permafrost limits the availability of groundwater. Rapid population growth in Anchorage, Fairbanks, and Juneau, continued development of mineral and energy resources, and expansion of other industries have increased water demand. In many areas, water distribution systems are strained and there is concern that projected demands could exceed available supplies, especially in the winter.

Runoff in the state varies widely, depending on location and elevation, but largely results from late spring and summer melting of snow and glacial ice. At lower elevations, late summer rains also contribute to runoff. In a warmer climate, winter precipitation could increase in the northern latitude and Arctic regions. At higher latitudes and elevations, increases in precipitation could lead to greater snowfall and snow accumulation. In other regions, warmer winters could lead to less winter precipitation as snow and more as rainfall. Warmer temperatures could mean earlier, more rapid snowmelts and earlier ice breakups. This could increase water availability in the winter, when supplies are traditionally limited. However, river and reservoir systems that rely on glacier or snowmelt for summer flow could find supplies insufficient during critical periods of high demand and little rainfall. Additionally, more rain-on-snow events or sudden winter thaws could cause severe flooding. Higher flows and more rapid snowmelt also could increase stream bank erosion and sediments suspended in glacial-fed streams. Warmer temperatures and shifts in seasonal flows could alter the productivity of fish well adapted to current conditions.

Warmer temperatures would lead to thawing of permafrost, melting of glaciers, and a reduction of ice on lakes and rivers. Thawing of the permafrost can reduce slope stability and increase erosion and landslides, which can threaten roads and bridges and cause local floods. Changes in permafrost also could alter the lake and wetland ecosystems maintained above the impermeable frost layer. Reduced ice cover could improve opportunities for water transport, tourism, and trade. In some areas, reduced ice thickness could result in less severe breakups and ice-jam flooding. However, reduced sea ice in the Bering Sea could render coastal areas more susceptible to erosion and inundation during severe weather events such as storm surges.

Forests

Trees and forests are adapted to specific climate conditions, and as climate warms, forests will change. These changes could include changes in species composition, geographic range, and health and productivity. If conditions also become drier, the current range and density of forests could be reduced and replaced by grasslands and pasture. Even a warmer and wetter climate could lead to changes; trees that are better adapted to these conditions, such as hemlock and Sitka spruce, would thrive. Under these conditions, forests could become more dense. These changes could occur during the lifetimes of today's children, particularly if the change is accelerated by other stresses such as fire, pests, and diseases. Some of these stresses would themselves be worsened by a warmer and drier climate.

With changes in climate, the extent of forested areas in Alaska could increase as warmer temperatures extend forested areas northward and inland. White spruce stands, usually located on south-facing slopes, could be more sensitive to warming than the black spruce stands found on colder, north-facing slopes. Warmer weather could increase the likelihood of insect outbreaks and of subsequent wildfires in the dead fuel left after such an outbreak. If the permafrost melted, the productivity of forests could increase, but this would also be subject to wildfires and a shift in forest composition. The extent of these changes depends on many factors, including whether soils become drier and, if so, how much drier. Hotter, drier weather could increase the frequency and intensity of wildfires, which could change the composition and character of the Alaskan landscape. Warmer and wetter conditions could also affect the character and composition of some of Alaska's forests and the activities that depend on them.

Ecosystems

Alaska is home to many immense and mostly pristine ecosystems. In the southern panhandle and coastal regions, western hemlock-Sitka spruce forests are a valuable timber resource. Farther north, the steep mountains of the Alaska Range give rise to rocky slopes, icefields, and glaciers. Broad valleys separate peaks that often rise to above 12,000 feet. Interrelationships among permafrost, surface water, fire, slope, and soil type result in diverse and complex ecosystems, including shrub communities, bogs, floodplains, and spruce-dominated and mixed-wood forests. At the mouth of the Yukon and Kuskokwim rivers, an Indiana-sized area of wetlands and tundra of the subarctic coastal plain is one of the most important waterfowl nesting areas in North America. Tens of thousands of lakes, ponds, and streams provide a summer home to millions of migrant birds from six continents, including more than half of the continental population of black brant and most of the world's emperor geese, tundra swans, and cackling and Pacific white-fronted geese. In the far north of the state, the tundra of the northern arctic coastal plain stretches from the foothills of the Brooks Range to the Arctic Ocean. Here, many species once common farther south are still abundant, including grizzly bears, lynx, wolverines, eagles, caribou, and wolves. During the short arctic summer, female caribou congregate in the Arctic National Wildlife Refuge in the tens of thousands to give birth and raise their calves. Later in the summer, they begin a migration that will lead them over a route longer than that of any other terrestrial animal. The coastal plain is also frequented by specialized arctic species found only in the polar regions, including polar bears, arctic foxes, collared lemmings, arctic and tundra hares, and muskoxen. The oceans around Alaska are a rich marine resource and provide habitat for endangered northern right, bowhead, sei, blue, fin, humpback, and sperm whales.

Despite the remote and pristine nature of Alaska's ecosystems, they stand at the forefront of potential impacts of global climate change. Warming is projected to be greater at high latitudes than elsewhere in the world, and with sufficient warming, tundra ecosystems are projected to significantly decline. As recorded in tree rings, the western Arctic has experienced a period of steady warming since approximately the 1840s. Glacier retreat, melting permafrost, and reductions in pack ice are all projected to continue. These changes have serious implications for many arctic species. Earlier springs on the arctic coastal plain could reduce plant diversity and could disrupt food resources available to migrating caribou. These warming-induced changes in plant communities appear to be under way. Thawing of permafrost could reduce caribou habitat, cause landslides and erosion, clog salmon spawning rivers with silt, and trigger the loss of areas of boreal forest. Boreal forests could suffer increases in the annual area burned, drought-related dieoffs, and increased susceptibility to insect pests such as the white pine beetle. A predicted increase in forest fires and an eventual transition to younger stands are of particular concern for wildlife species that make extensive use of mature and old-growth forests, such as marten, fisher, and caribou. The low-lying marshes of the Yukon and Kuskokwim rivers are threatened by salinization due to sea level rise and periodic storm surges. Marine resources also could be heavily affected. Warming of lakes and rivers could decrease populations of coho, sockeye, and Chinook salmon in the southern parts of their ranges. Species associated with the pack ice, including arctic cod, polar bear, ring seal, walrus, narwhal, and beluga whale, are estimated to experience population declines or changes in distribution.

Source: <http://www.epa.gov/globalwarming/impacts/stateimp/alaska/index.html>