Report to:
The Alaska Public Utilities Commission
and the
Alaska State Legislature

Study of Electric Utility Restructuring in Alaska

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Background

The electric power industry in the US is undergoing major changes that are reshaping traditional roles, creating opportunities for new participants, and redefining the scope and character of government regulation.

These changes arise out of the interaction of several driving forces:

- dramatic discrepancies in rates between regions, and between utilities within regions;
- regulatory and public policy support for market competition and customer choice over traditional forms of cost-of-service regulation;
- growing electricity demand resulting from a persistent – albeit modified – linkage with economic growth;
- public perceptions and public policy regarding the dangers and costs of air and water pollution, climate modification, and industrial safety; and
- the current economics of power generation and power purchase, which work against electricity producers whose costs are heavily fixed.

The electric power industry is responding to these forces by experimenting with a host of business strategies: flexible pricing for large customers; increased power purchases; consolidations through mergers and acquisitions; diversification into non-utility businesses; aggressive efforts to contain costs, new service offerings and corporate restructuring. Emerging from these experiments is a less tightly integrated, more diversified, and above all, much more competitive industry. It is an industry that, during the next decade, may shift from the traditional generation, transmission, and distribution relationships to a much more heterogeneous structure. Entities in the new regime may include utility companies fulfilling various traditional roles, independent power producers, regional power producers, independent systems operations, power exchanges, marketers and brokers, and a wide range of novel energy service providers.

But the path from the traditional electric power business to the more competitive industry of the future is strewn with issues and obstacles, some of which may resist resolution and movement more stubbornly that is commonly assumed today. The issues may include disagreements over the rules and procedures that should govern access to transmission and distribution facilities; the division of regulatory authority between federal, state and local government agencies; protection of all customer classes; new demands for more stringent environmental protection; and a number of questions related to cost allocation, cost recovery, and system reliability. How these issues are resolved will control the pace and scope of change in the industry and, in turn, will answer an overarching question of increasing concern: "What are the potential risks, benefits, and impacts of electric utility industry restructuring on all Alaska consumers and the economy of the State as a whole?"

Overview of the Alaska Electricity Industry*

In terms of its electric power industry, Alaska is a patchwork of unconnected grids. Due to its extremely low population density and the distance between population centers around the State, there are many small generators operating independently of one another. Three of the five largest plants in the State are primarily gas-fired plants. Alaska is the Nation's second largest oil producer and oil-fired plants account for a much larger portion of the generation in Alaska than in most other States. Alaska is also a significant producer of natural gas. The State's average electricity price in 1996 was the sixth most expensive in the Nation, since there are few economies of scale and there are no connections to the grid of the forty-eight contiguous States. Some consumers have part of their bills subsidized by the State government.

Only one of the five largest utilities in the State is an investor-owned utility. Alaska Electric Light and Power operates in the Southeast region of the State, in and around the capital, Juneau. Though it operates the fourth largest capability total of any utility, none of its plants is among the five largest in the State.

The five largest plants are operated by the Chugach Electric Association, the Municipality of Anchorage, and the Golden Valley Electric Association. Chugach and Golden Valley are cooperatives. Cooperatives are groups organized under the law into utility companies that generate, transmit, and/or distribute electricity to specified areas not being served by other utilities. Such ventures are generally exempt from Federal income tax. Chugach operates two of the three largest plants in the State including the largest, Beluga, a gas-fired plant west of Anchorage. It also operates Bradley Lake, a hydroelectric plant and the third largest plant in the State.

The Municipality of Anchorage operates the gas-fired George M Sullivan plant. Sullivan is the second-largest plant in the State. The fourth-largest plant is Golden Valley's North Pole plant. It is located in the interior of the State.

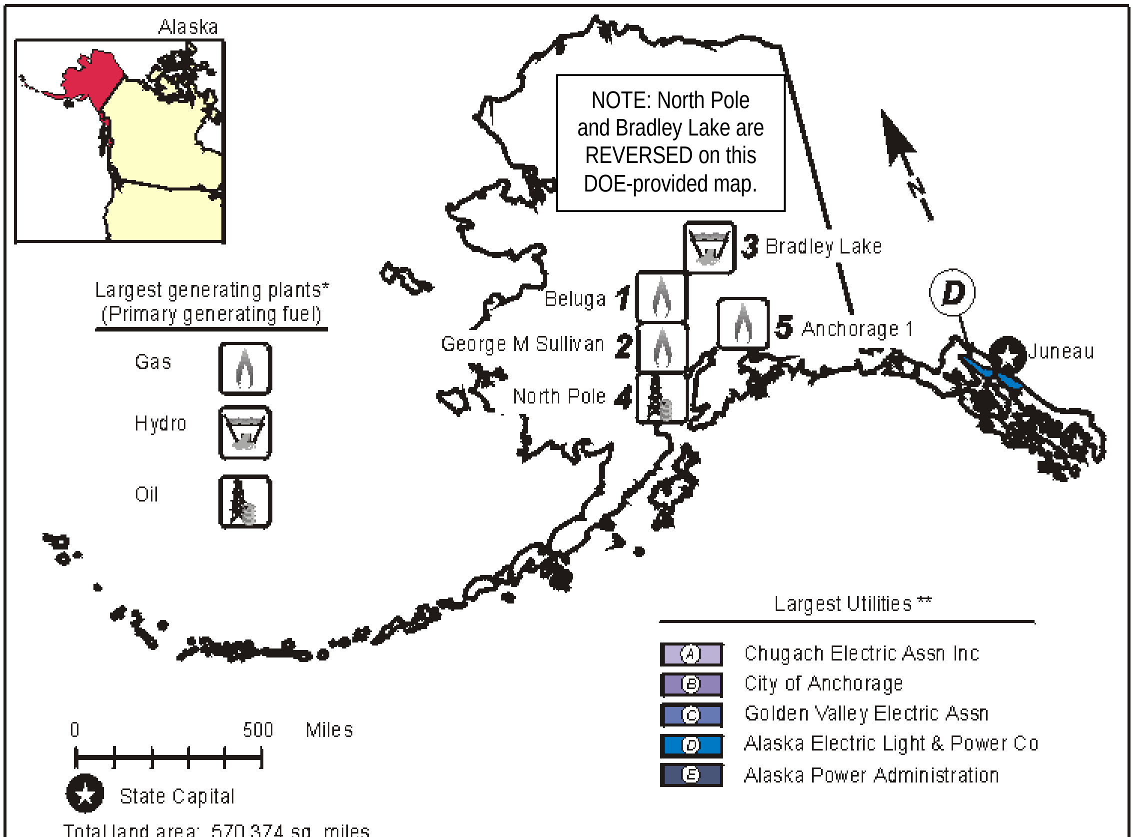
*Source: http://www.eia.doe.gov/cneaf/electricity/st_profiles/alaska/ak.html

Almost half of the State's generation is from utility gas-fired facilities, while another fifth comes from utility renewable sources. Alaska was among the leaders in nonutility shares of capability and generation in 1996. Alaska's emissions of sulfur dioxide, nitrogen oxides, and carbon dioxide were among the lowest in the Nation in both absolute terms and in concentrations per square mile. These low totals are due to the low generation level (ninth lowest in the Nation) and the relatively "clean" means of generation that are utilized in the State.

Legislative action in Alaska has taken a different direction than other States with regard to deregulation. One bill introduced in 1997 would prevent retail competition unless clear evidence exists that it would be in the public interest. However, in January 1998, the largest utility in Alaska, the Chugach Electric Association, urged the Public Utility Commission and the State legislature to allow retail competition in the Greater Anchorage area.

List of Accompanying Tables & Figures

FIGURE 1.1
Alaska's Largest Utilities and Generating Plants



* Numbers in boldface indicate rank order of plants by capability.
** Utilities rank ordered by operated generating capability within the State. Map shows areas of investor-owned utilities only.

FIGURE 1.2
Alaska's Railbelt Service Area

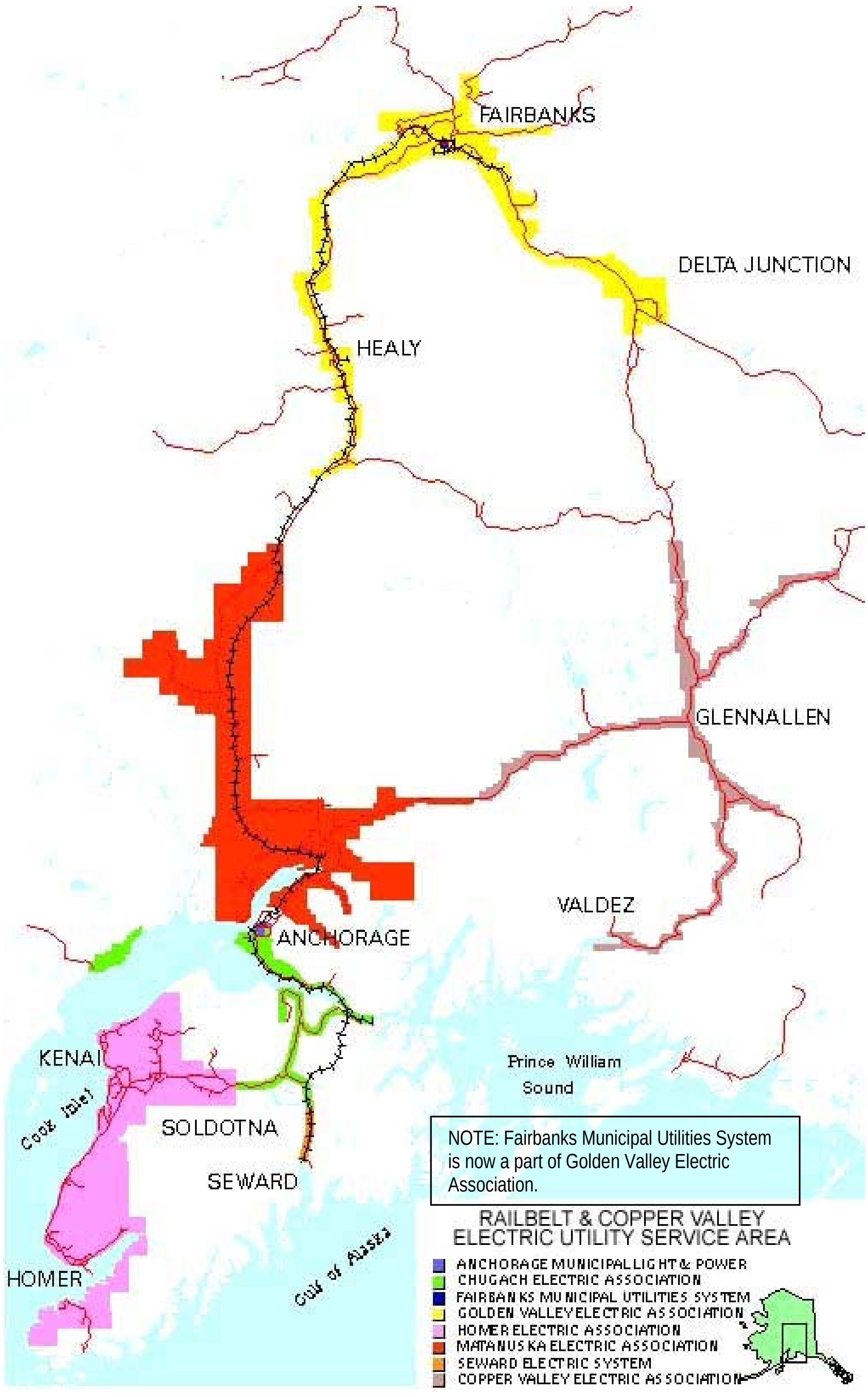


TABLE 1.1
1996 Summary Statistics.

Item	Value	US Rank
NERC Region(s)	ASCC	
Net Exporter or Importer	- -	
State Primary Generating Fuel	Gas	
Population (as of 7/96)	604,966	48
Average Revenue (cents/kWh)	10.24	45
Industry		
Capability (MWe)	2,010	42
Generation (MWh)	6,147,022	43
Capability/person (KWe/person)	3.32	17
Generation/person (MWh/person)	10.16	32
Sulfur Dioxide Emissions (Thousand Short Tons)	16	45
Nitrogen Oxide Emissions (Thousand Short Tons) 30	40	
Carbon Dioxide Emissions (Thousand Short Tons)	7,730	44
Sulfur Dioxide/sq. mile (Tons)	0.03	50
Nitrogen Oxides/sq. mile (Tons)	0.05	49
Carbon Dioxide/sq. mile (Tons)	13.55	51
Utility		
Capability (MWe)	1,734	47
Generation (MWh)	4,982,268	49
Average Age of Coal Plants	30 years	
Average Age of Oil-fired Plants	17 years	
Average Age of Gas-fired Plants	20 years	
Average Age of Nuclear Plants	--	
Average Age of Hydroelectric Plants	18 years	
Average Age of Other Plants	14 years	
Nonutility		
Capability (MWe)	276	35
Percentage Share of Capability	13.7	11
Generation (MWh)	1,164,754	35
Percentage Share of Generation	18.9	10

-- = Not applicable.

TABLE 1.2
Five Largest Utility Plants, 1996
(Uses DOE-EIA data – Does NOT necessarily match modeling data.)

Plant Name	Type	Operating Utility	Net Capability (MWe)
1. Beluga	Gas/Hydro	Chugach Electric Assn. Inc.	334
2. George M Sullivan	Gas/Hydro	Municipality of Anchorage	220
3. Bradley Lake	Hydro	Chugach Electric Assn. Inc.	108
4. North Pole	Oil	Golden Valley Elec Assn. Inc.	106
5. Anchorage 1	Gas	Municipality of Anchorage	79

TABLE 1.3
Top Five Utilities with Largest Generating Capability, and Type, Within the State, 1996
(Megawatts Electric)

Utility	Net Summer Capability	Net Coal Capability	Net Oil Capability	Net Gas Capability	Net Nuclear Capability	Net Hydro/ Other Capability
A. Chugach Electric Assn. Inc.	607	--	38	445	--	125
B. Municipality of Anchorage	299	--	3	297	--	--
C. Golden Valley Elec Assn. Inc.	171	25	146	--	--	--
D. AK Electric Light & Pwr.	109	--	94	--	--	15
E. Alaska Power Administration	108	--	--	--	--	108
Total	**1,294**	**25**	**281**	**742**	**--**	**248**
Percentage of Industry Capability	64.4	--	--	--	--	--

-- = Not available.

FIGURE 1.3
Utility Generating Capability by Primary Energy Source, 1996

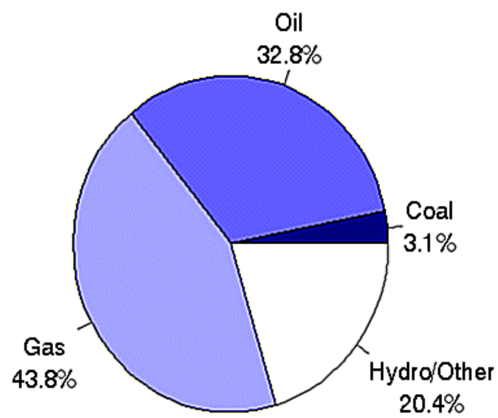


FIGURE 1.4
Utility Generation by Primary Energy Source, 1996

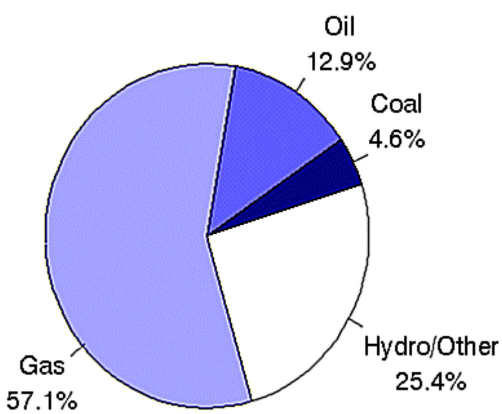


FIGURE 1.5
Energy Consumed at Electric Utilities by Primary Energy Source, 1996

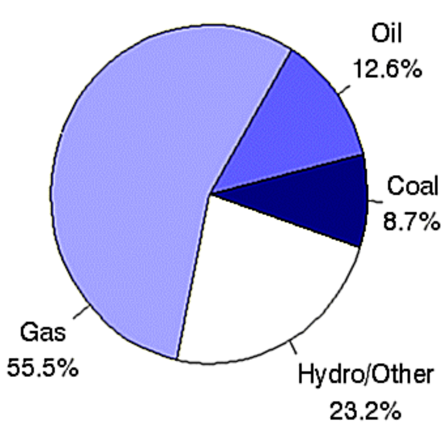
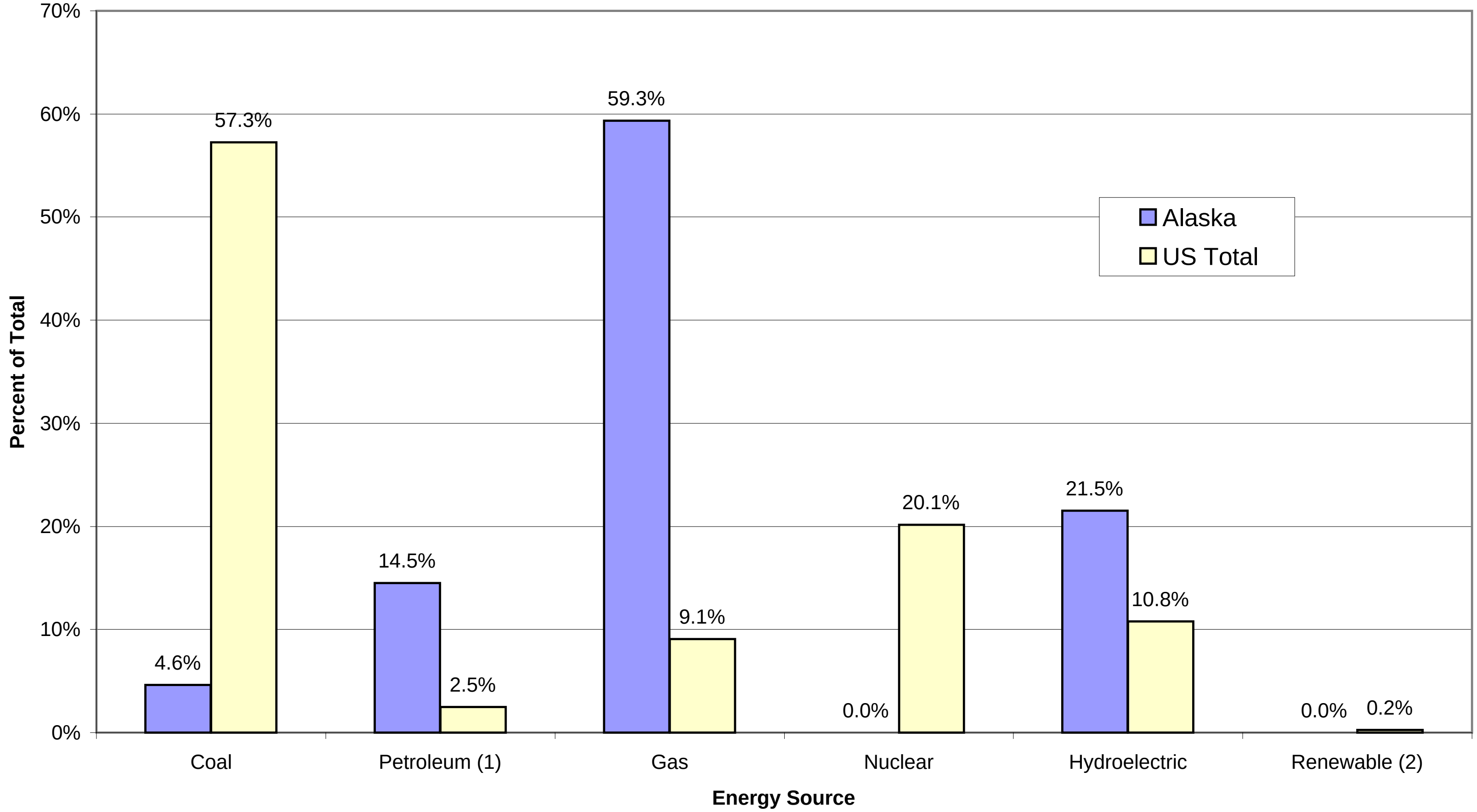


FIGURE 1.6 Net Generation by Energy Source 1997 Source: EIA, Electric Power Annual



Notes:
(1) Includes petroleum coke
(2) Includes geothermal, biomass, wind, solar thermal, and photovoltaic (excludes hydroelectric)

TABLE 1.4
Electric Power Industry Generating Capability by Primary Energy Source, 1986, 1991, and 1996
(Megawatts Electric)

Fuel	1986	1991	1996	Percentage Share 1986	Percentage Share 1991	Percentage Share 1996
Coal	56	56	54	3.3	3.1	2.7
Oil	489	498	569	29.0	27.9	28.3
Gas	722	756	759	42.9	42.3	37.8
Nuclear	--	--	--	--	--	--
Hydro/Other	203	237	353	12.1	13.3	17.6
Total Utility	1,470	1,547	1,734	87.3	86.6	86.3
Total Nonutility	214	240	276	12.7	13.4	13.7
Industry	1,684	1,787	2,010	100.0	100.0	100.0

-- = Not available.

TABLE 1.5
Electric Power Industry Generation of Electricity by Primary Energy Source, 1986, 1991, and 1996
(Thousand Kilowatthours)

Fuel	1986	1991	1996	Percentage Share 1986	Percentage Share 1991	Percentage Share 1996
Coal	292,944	325,914	229,129	5.7	6.3	3.7
Oil	458,956	407,088	643,278	9.0	7.8	10.5
Gas	2,691,148	2,657,316	2,843,998	52.8	51.1	46.3
Nuclear	--	--	--	--	--	--
Hydro/Other	808,724	896,113	1,265,863	15.9	17.2	20.6
Total Utility	4,251,772	4,286,431	4,982,268	83.4	82.4	81.1
Total Nonutility	848,290	917,328	1,164,754	16.6	17.6	18.9
Industry	5,100,062	5,203,759	6,147,022	100.0	100.0	100.0

-- = Not available.

TABLE 1.6
Electric Power Industry Consumption by Primary Energy Source, 1986, 1991 and 1996
(Quadrillion Btu)

Fuel	1986	1991	1996	Percentage Share 1986	Percentage Share 1991	Percentage Share 1996
Coal	0.006	0.006	0.005	6.5	8.7	5.7
Oil	0.006	0.005	0.007	6.4	6.2	8.3
Gas	0.036	0.031	0.031	39.0	42.3	36.5
Nuclear	--	--	--	--	--	--
Hydro/Other	0.008	0.009	0.013	9.2	12.5	15.2
Total Utility	0.056	0.052	0.056	61.2	69.7	65.8
Total Nonutility	0.035	0.022	0.029	38.8	30.3	34.2
Industry	0.091	0.074	0.086	100.0	100.0	100.0

-- = Not available.

FIGURE 1.7
Utility Generation of Electricity by Primary Energy Source, 1986-1996

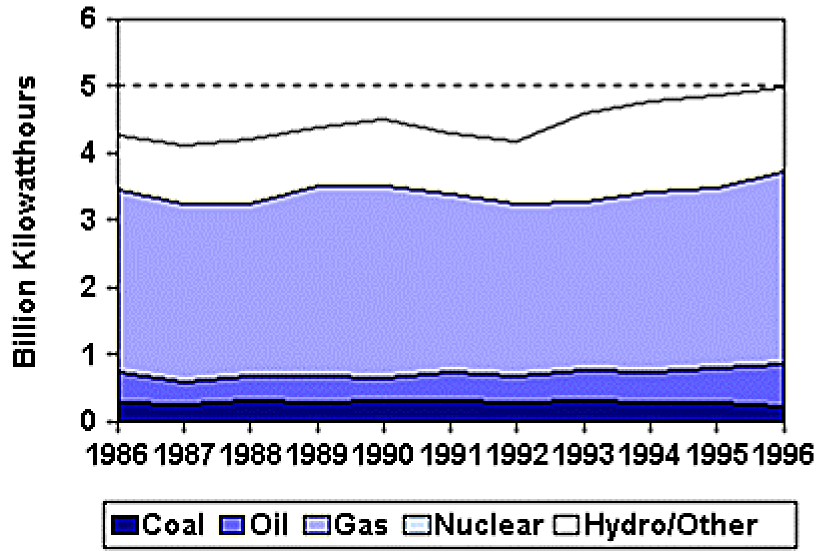


FIGURE 1.8
Utility Delivered fuel Prices for Coal, Oil, and Gas, 1986-1996
(1996 Dollars)

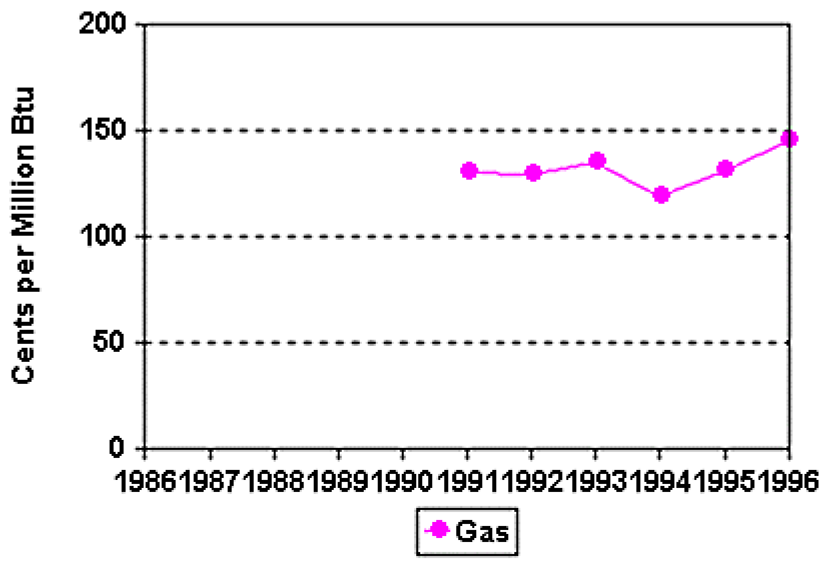


TABLE 1.7
Utility Delivered Fuel Prices for Coal, Oil, and Gas, 1986, 1991, and 1996
(Cents per million Btu, 1996 Dollars)

Fuel	1986	1991	1996	ANNUAL GROWTH RATE 1986-1996 (PERCENT)
Coal	--	--	--	--
Oil	--	--	--	--
Gas	--	129.9	144.6	--

-- = Not available.

TABLE 1.8
Electric Power Industry Emissions Estimates, 1986, 1991, and 1996
(Thousand Short Tons)

Emission Type	1986	1991	1996	Annual Growth Rate 1986-1996 (Percent)
Sulfur Dioxide	8	11	16	7.2
Nitrogen Oxide	25	29	30	1.8
Carbon Dioxide	5,715	6,524	7,730	3.1

-- = Not available.

FIGURE 1.9
Estimated Sulfur Dioxide Emissions, 1986-1996

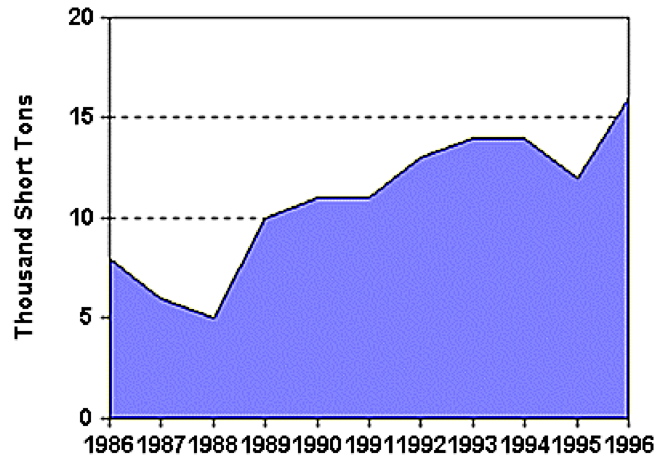


FIGURE 1.10
Estimated Nitrogen Oxide Emissions, 1986-1996

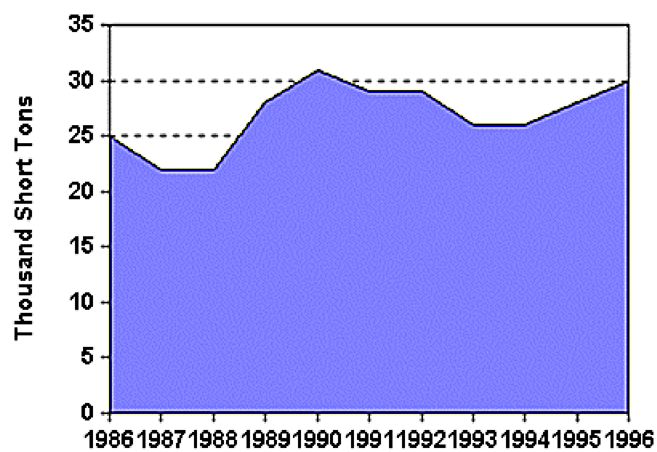


FIGURE 1.11
Estimated Carbon Dioxide Emissions, 1986-1996

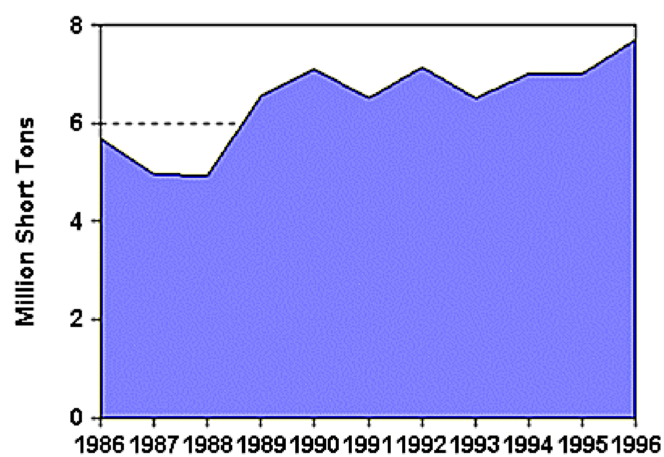


TABLE 1.9
Utility Retail Sales by Sector, 1986, 1991, and 1996 (Megawatthours)

Sector	1986	1991	1996	Annual Growth Rate 1986-1996 (Percent)	Percentage Share 1986	Percentage Share 1991	Percentage Share 1996
Residential	1,616,038	1,602,777	1,766,184	0.9	40.1	37.7	37.0
Commercial	1,776,352	2,005,247	2,249,874	2.4	44.1	47.1	47.1
Industrial	462,944	465,878	584,198	2.4	11.5	10.9	12.2
Other	174,140	181,811	179,306	0.3	4.3	4.3	3.8
Total	4,029,473	4,255,713	4,779,562	1.7	100.0	100.0	100.0

TABLE 1.10
Utility Retail Sales Statistics, 1986, 1991, and 1996

Item	Investor-Owned Utility	Public	Federal	Cooperative	Total
1986					
Number of Utilities	20	22	1	21	64
Number of Retail Customers	16,542	57,788	3	151,816	226,149
Retail Sales (MWh)	285,602	1,305,342	1,617	2,436,912	4,029,473
Percentage of Retail Sales	7.1	32.4	(s)	60.5	100.0
Revenue from Retail Sales (thousand 1996 $)	38,363	136,891	65	281,607	456,946
Percentage of Revenue	8.4	30.0	(s)	61.6	100.0
1991					
Number of Utilities	24	36	1	22	83
Number of Retail Customers	19,702	61,044	2	156,343	237,091
Retail Sales (MWh)	356,454	1,349,999	3,840	2,545,420	4,255,713
Percentage of Retail Sales	8.4	31.7	0.1	59.8	100.0
Revenue from Retail Sales (thousand 1996 $)	44,287	142,741	57	281,906	468,998
Percentage of Revenue	9.4	30.4	(s)	60.1	100.0
1996					
Number of Utilities	23	37	1	20	81
Number of Retail Customers	22,515	60,885	2	172,701	256,103
Retail Sales (MWh)	400,655	1,473,648	5,030	2,900,229	4,779,562
Percentage of Retail Sales	8.4	30.8	0.1	60.7	100.0
Revenue from Retail Sales (thousand 1996 $)	46,535	146,590	110	296,254	489,489
Percentage of Revenue	9.5	30.0	(s)	60.5	100.0

(s) = Nonzero percentage less than 0.05.

Methodology of the Report

This report was prepared by Karl R. Rábago of CH2M HILL and Thomas Feiler of Econergy International Corporation (EIC). Substantial research assistance was provided by Deanna Gamble of CH2M HILL's Anchorage office. Floyd Damron, Director of CH2M HILL's Anchorage office, serves as Project Manager. The consulting firm of Energy & Environmental Economics, Inc. performed modeling tasks on behalf of the principals. A great deal of information was graciously provided by a range of stakeholders in Alaska who contributed their time and thoughts to the authors. The authors are particularly appreciative of the opportunity to attend a meeting of ARECA members in Juneau where the viewpoints and concerns of utility representatives were discussed in person.

The goal of this report is to provide the APUC and the Alaska Legislature with a broad, comprehensive overview of the issues related to electric utility restructuring in the State of Alaska. In the Recommendations section, the authors advise a course of action that improves the chances for competition to succeed. This report does not seek to reach a conclusion on, but rather to inform the essential public policy question of whether electric utility restructuring is in the best interests of the people and the State of Alaska.

The report is organized as follows:

1. Introduction and Overview – Background, industry overview, methodology
2. Recommendations – Discussion of the fundamental elements of electricity competition and an outline for subsequent action.
3. Rural Issues – Non-Anchorage Railbelt utility issues, and issues relating to village electric power systems.
4. Local Choice – Issues relating to local control and oversight of utility services.
5. Wholesale Competition – Issues relating to competitive position and advantage.
6. Network Integrity – Issues relating to reliability and alternative energy resources.
7. Consumer Issues – Issues related to universal service and affordability.
8. Stranded Costs – Issues relating to calculation and allocation of stranded costs.
9. Taxes – Issues relating to tax burdens and impacts.

10. Employment – Issues relating to utility employee impacts.

11. Modeling – Results and conclusions from econometric analysis.

Appendices – Glossary, modeling data, other materials of general application.

The tables and figures accompanying each narrative section were crafted and organized to serve as a ready reference and a distilled compilation of the myriad issues and facts affecting and informing electric utility restructuring. They draw on the broadest possible range of viewpoints and perspectives on restructuring. Preparation of this report was greatly aided by the rich record of information emanating from the Joint Committee on Electric Utility Restructuring.

This report captures what has happened in the restructuring debate around the nation, and the issues and options relevant at the time of its writing. Restructuring is very much a living issue. As this report was prepared several states have acted upon new legislation related to the topic. Bills have passed through one or both legislative houses in New Mexico, Delaware, Virginia, Maryland, and Ohio. And during this time other states, like Utah, have reached a conclusion to table the electric utility restructuring issue. The timing of this report and the nascent nature of those initiatives did not allow them to be fully incorporated into this study. The experiences in these states will no doubt provide new insights and new ideas that may have value in reaching judgments about the best course of action for Alaska.

Though it seems to proceed in fits and starts, the march of restructuring appears generally steady. This sets up a fundamental policy question for decision-makers in Alaska. On the one hand, the longer Alaska waits to move into restructuring, the better the base of knowledge and experience from which to draw. On the other hand, delay may compromise Alaska's ability, and the ability of its electric industry, to harvest the potential benefits of a more competitively structured industry. In the end, the conceptual approach underlying the Legislature's previous work charts the wisest course. That is, Alaska policy makers can come to terms with *how* to accomplish electric utility restructuring in a manner that best serves the interests of the people and the State, while recognizing that there will continue to be debate about *when* restructuring should occur.

The authors look forward to feedback from any and all interested parties concerning the content of this draft report. Recommendations for improvements, identification of errors and other commentary will be gratefully accepted.

Finally, the authors express their sincere appreciation for the opportunity to participate in this important effort. This report would not have been possible without the commitment of time and thought provided the myriad stakeholders involved in this process, and the many staff at CH2M HILL and EIC who supported this effort. It was a special pleasure to work with the professionals at Energy & Environmental Economics on the modeling tasks. Finally, but importantly, a special note of thanks is due to Nancy Voiland-Dow, at CH2M HILL, whose long hours of word processing support were integral to the preparation of both the proposal and this report.

Karl R. Rábago CH2M HILL	Thomas Feiler EIC

June 30, 1999

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Recommendations

Electric utility restructuring is complex. It is nothing short of a fundamental reexamination of one of the most important industries of modern society, and the institutions and relationships that underlie it. Subsequent sections of this report explore the costs and benefits, and the tradeoffs associated with the major categories of issues raised by restructuring.

This section sets out the authors' recommendations on matters of foundation. It recommends a course of action to introduce competitive market forces into the Alaska electricity system in an effort to prepare the system for eventual major transformation. It seeks to draw policy attention to an all-important question seldom fully explored as restructuring has proceeded in other jurisdictions. That question is easy to state and challenging to answer: How should the electricity system in Alaska operate after restructuring has been completed?

This section concludes that the pattern and practice of electric utility restructuring taking shape in the continental United States and in some other parts of the world do not provide a useful template for a prudent course of action for Alaska today. Rather, while there are lessons to be learned and benefits to be gained from these experiences, in the end there are fundamental structural limitations in Alaska that counsel against efforts to directly replicate these models in Alaska today.

There is no restructuring model in existence today that would work in rural Alaska among the villages and cities that are not interconnected to the Railbelt system. As discussed later, there are steps that could be taken to seek out opportunities for improvements among the rural systems and to encourage technological innovations that could complement or even compete with the diesel-fired generation systems currently dominating rural electrical systems. Except for that later discussion, however, the balance of this section addresses the Railbelt.

On the issue of restructuring in the Railbelt, policy makers in Alaska are similarly situated with their counterparts in a number of other states. Colorado, Utah, Wyoming and Nebraska are more like Alaska, when it comes to restructuring, than California, Pennsylvania, and New England. Restructuring, as a concept, has been "sold" on the basis of its ability to reduce rates and save money. Saving money on an essential and ubiquitous service is a good idea. But restructuring, as a concept, has so far been designed to extract savings from high-cost states that presented excellent opportunities to reduce costs quickly and dramatically. The states that moved ahead had already invested significantly in the development of a generation sector with multiple suppliers interacting in coordinated transaction pools over well-developed networks. Much of the groundwork for retail access in those states was laid under regulation.

For Alaska and its peer group of states, the controlling issue is not whether prices are high, but whether they are amenable to dramatic reduction in costs. In this way, the so-called "low-cost" states are in similar position as Alaska.

Alternative Pathways

Alaska faces three alternative pathways. It can "fix the potholes" in its current system and make a serviceable system even better. Alternatively, Alaska policy makers can choose a scenario that focuses on rapidly "commoditizing kilowatts" in an effort to capture primarily wholesale market-derived benefits. Finally, policy makers could choose a course of "controlled evolution," transitioning the current regulated system into a more competitive and diverse marketplace. Each course has its benefits and costs, and between each lie a universe of hybrids, but these three simplified models offer a convenient motif for considering which steps Alaska should take and when it should take them. Table 2.1 details the salient characteristics of these scenarios.

The "fix the potholes" scenario derives from a basic satisfaction with the status quo, though it is accompanied by a recognition that there are things that could be done to improve efficiency today. It puts off to a later day the potential benefits of competition, but similarly avoids the myriad problems that could arise under less-controlled and more competitive markets.

The "kilowatt commoditization" model applies a certain market machismo to the electric industry in Alaska. Under this model, the robust market for kilowatt and kilowatt-hour trade is the primary driver for welfare benefits. Transparency in wholesale prices is one of the principal objectives. Relying on structures to regulate the market, oversight is minimized as regulators assume a policing role. Success under this scenario is highly dependent on underlying market conditions, and would be difficult to implement quickly in Alaska with success. Because regulatory oversight is minimized, market power can be a major problem, potentially leading to a condition of unregulated monopoly or oligopoly in the electricity industry.

"Controlled evolution" envisions building from a platform of commodity markets toward a carefully considered and clearly articulated vision of a restructured industry. The time sacrificed by taking this longer approach is applied to developing not just structural mechanisms, but a body of rules that guide markets toward desired economic and social outcomes. Regulation is ultimately supplanted under this scenario by the constant competitive pressure applied by a diverse range of market entrants with the freedom and incentives to respond to market opportunities.

The evidence is incontrovertible that truly competitive markets allocate resources more efficiently than command and control regulatory regimes. Competition is a tool that if properly used can produce measurable benefits for the people of Alaska. The Black & Veatch study that preceded this effort substantiates this assertion. The modeling conducted in support of this study confirms these findings as well. There are good and valuable reasons for making the electricity business more competitive, in the abstract, and policy makers in Alaska would do well to translate those reasons into concrete goals for restructuring Alaska's electricity industry.

Therefore, this report recommends a commitment to a course of action that improves the chances for competition to succeed. That course involves action to make transmission and dispatch more amenable to competition through open access and competitive dispatch mechanisms. It involves a clear commitment to increase the competitiveness of the generation sector by encouraging the emergence of independent power producers and merchant generation facilities. It involves regulatory initiatives like a comprehensive cost-allocation proceeding. And it suggests an aggressive focus on stimulating competitive behavior in the distribution sector, where new technologies and new approaches to regulation can lay a foundation for an evolutionary transition to full competition.

As indicated in the Interim Report submitted under this contract, the authors recommend that Alaska policy makers proceed along a carefully delineated, though not necessarily fully linear path:

Rural Issues. Initiate and strengthen actions to bring the benefits of new technologies and efficiency improvements to rural Alaskan electricity systems. At this stage, when many of the most promising technologies are still far from fully commercialized, this activity should be limited to pilot exercises and trial deployments to develop both experience and technologies.

Regulatory Inefficiencies. Identify, for subsequent isolation, the key sources of inefficiency within the current system. Likely candidates for improvement include the heavy concentration of generation control, the lack of public awareness, less than optimal dispatch coordination, and a wholesale transactions environment that may harbor significant stranded costs.

That there are inefficiencies inherent in the current regulatory system does not so much reflect a failure of regulation, which after all has played a key role in bringing safe, reliable and affordable power to Alaska. Rather, this task involves identifying those characteristics of the current regulated system most out of alignment with a goal of moving to a competitive industry structure. Several aspects of the current system may well continue with only modest alteration as a result of restructuring. For example, customer protection provisions such as those related to billing disputes, disconnection, and customer information are important components of ensuring that competition does not cause unacceptable hardships to certain customers.

No-Regrets Regulatory Agenda. Initiate and implement a no-regrets regulatory agenda aimed at reducing system inefficiencies while making the regulatory environment more competition-friendly. Actions on this agenda should include, at a minimum: (1) calculation and allocation of component costs in a rational and uniform manner, (2) rationalization of access to and governance of the transmission system to create an "open" architecture, (3) rationalization of generation siting, construction and market development, and (4) implementation of the 1998 Black & Veatch Study power pooling recommendations. (Available at APUC web site.)

These regulatory activities testify to the important role that regulators play in creating the structure of a competitive electricity industry. This agenda should be undertaken with the specific end of competitive markets in mind. Ensuring that the APUC enjoys sufficient jurisdictional authority and resources to accomplish these tasks is a role for the Alaska Legislature.

Opportunities. Inquire into and identify the most promising opportunities for extracting benefits from the electric industry. By crafting electricity restructuring to build upon the strongest aspects of that system, policy makers can ensure that efforts are focused on maximizing value for customers. Abundant supplies of natural gas in the Southcentral Alaska, for example, offer an opportunity to exploit new smaller turbine technologies and to simultaneously enhance diversity of generation size.

Specific restructuring activities should be structured to harvest these potential benefits:

- Mitigate regulatory and structural inefficiencies to produce near-term savings and to encourage efficient market behavior.
- Design any pilot program to reveal the true cost savings from retail competition and/or to encourage technology-based competition to realize the potential for technological innovation to reduce costs. (Please see March 1, 1999 Interim Report, “Recommendations to the Alaska State Legislature and the Alaska Public Utilities Commission Regarding a Retail Pilot Program.”)

- Design efficient commodity markets to enable value-added service innovation.
- Exploit Alaska's small electricity systems to lead the industry trend toward new, modular distributed energy systems.
- Harmonize restructuring agendas in telecommunications, natural gas, and electricity to realize convergence benefits and administrative efficiencies.

Barriers. Identify and prioritize barriers to the introduction of competition. Characteristics of the current system that will impede the progress of restructuring are of two kinds – those that lend themselves to remediation and those that do not. For example, a concerted effort to expand and diversify the pool of competing suppliers of electricity can help alleviate the potential for the exercise of market power. On the other hand, a build-out of the transmission system in the Railbelt to a fully redundant grid of alternative pathways free of bottlenecks will likely remain prohibitively expensive.

Cost of implementation may be the most significant barrier facing the introduction of competition in Alaska's electricity system. Other states have had the opportunity to absorb significant administrative and implementation costs and still deliver savings and other benefits to customers. Still, the authors strongly believe that restructured markets should be designed to carry their own costs. It would be counterproductive policy to replace the current regulatory system in favor of a market based system requiring permanent or excessive subsidies.

Innovation. Craft and initiate innovative solutions to barriers to competition. While some problems do not lend themselves to cost-effective solutions using traditional approaches, the creative application of Alaska-specific strategies and in some cases new energy technologies, can lead the system toward desired policy objectives. For example, large-scale transmission upgrades are not likely to be cost-effective, and the number of competing bulk-power generators may not reach a competitive critical mass for the foreseeable future. However, an alternative approach that creates distribution-level competition may be both less expensive and more robust in a far shorter period of time.

The authors are especially concerned that the small size of the Alaska electricity system – in terms of numbers of suppliers, buyers, and megawatts of capacity, may serve as a significant barrier to the introduction of competition. For that reason, the authors recommend at least initial exploration of two innovative approaches for reaching competitive critical mass.

The first idea involves increasing market liquidity by reducing contract size. For example, a market for 500 kWh contracts would involve more tradable units of commodity than the typical approach of serving customers solely on an all-requirements basis.

Another interesting, though untried concept involves tying the electricity market to another commodity market to increase overall market size and increase liquidity. For example, both gas and electricity could be traded in a BTU market. While this approach has theoretical appeal, actual implementation would require considerable additional study and analysis.

Study and Model. Continue the process of broadly participatory study of the restructuring, and the use of simulation models to test alternative market structures prior to making irretrievable commitments of resources. The restructuring process of an industry as large and important as the electricity business will take years, and will benefit from the committed participation of wide range of stakeholders. In addition, because the stakes are so high, modeling of system characteristics prior to implementation offers a prudent alternative to "ready-shoot-aim" approaches to policy implementation.

One of the great uncertainties associated with electricity restructuring lies in predicting how market participants will actual behave in the face of competition. Traditional models, like those employed in the 1998 Black and Veatch Study and by the authors in the preparation of this report, assume that rather sterile market conditions and rational economic behavior drive market behavior. One option that should be considered in Alaska involves use of retail market simulation modeling as part of the screening process to determine whether restructuring will likely serve the best interests of the people of Alaska. In any event, market trading, dispatch and other market functions should be run on models before they are introduced in the market.

As Table 2.22 reveals, the process of industry restructuring has typically involved multiple legislative and regulatory initiatives to address market inefficiencies woven into the legacy of decades of comprehensive regulation. There is simply no quick path to efficiently functioning markets that deliver maximum economic and social benefit. While the magnitude of issues is much greater for national restructuring initiatives in real terms, restructuring is very much like a fractal image - every degree of magnification reveals a similar degree of complexity.

Twelve Elements of Competition

As explained above, electricity utility restructuring implies a wide range of issues touching virtually every aspect of modern life. The fundamental issues underlying a competitive framework can be synthesized into twelve sets of questions and concerns.

Number of Suppliers. What is the minimum number of sellers required to ensure a liquid supply market and effectively mitigate market power and market collusion? Academic studies and anecdotal evidence suggest that a minimum of eight different and competitively comparable entities may be required in today's age of instant communications, sophisticated analytical capabilities, and networked economies. Based primarily on the modeling results, the authors have serious concerns about whether the number and relative market power of existing generation suppliers is sufficient to sustain robust competition.

Number of Buyers. What are the minimum number of buyers to ensure demand responsiveness (demand elasticity and diversity)? The purchasing market equivalent to monopoly is monopsony. Though the Alaska electric utility system incorporates more mid-level buyers than sellers due to wholesale power transactions, a significant amount of the demand is tied up in long-term contracts. In a competitive market, these contractual relationships would have to be adjusted, and if appropriate, compensation must be arranged, in order to put buyers in the position of influencing competitive supply response to their demand. The number of ultimate customers of electricity in Alaska may also pose a challenge. This is simply a matter of inertia and economies of scale. Small commercial and residential customers have been generally slow to jump on the electricity supply choice bandwagon. Major factors in this trend have been the small price savings offered and the immaturity of value-added markets for energy services. If market penetration rates in Alaska do not significantly outpace those of California, for example, the revenue potential in serving customers who switch may not sustain market entry by serious competitors.

System Reliability. How do you structure and manage the transmission system to ensure system reliability and stability? There is no social or economic value in introducing electricity restructuring if the price to be paid is unreliable service. Competitive markets are, by definition, more volatile and more complex. Structures and rules to ensure transmission reliability are a foundational concern in approaching restructuring.

Non-Discriminatory Access. How do you structure and manage the transmission and distribution system to ensure non-discriminatory access to all facilities? Non-discriminatory access rules must be established to operate seamlessly with transmission management structures and simultaneously engender incentives for competitive entry into the generation supply sector. Much potential for the exercise of market power through control of access rights exists in Alaska today.

Transmission Governance. How do you structure and manage the transmission system to balance system reliability and nondiscriminatory access? The object in "opening up" the transmission system should be to ensure that reliability does not become an opponent of competition.

Fundamentally different changes in the way Alaska manages its transmission system are therefore in order. The first logical step is to design these rules, and the new structures, as part of the implementation of the 1998 Black & Veatch Study recommendations on central dispatch. In addition, Alaska should consider the establishment of an independent system operator, building on the experience and expertise of the Alaska Systems Coordinating Council. A new structure will impose costs, however, and careful review of the costs associated with an independent system operator is in order to ensure that efficiency benefits are not lost to administrative costs.

Market Clearing Mechanism. How can you provide a robust, competitive and credible marketplace where utilities, power marketers, load aggregators, cogenerators and large customers can do business quickly and easily? The burdens and obligations of ensuring safe, reliable and cost-effective electrical service in Alaska today are imposed directly on the utilities and the Public Utilities Commission. While each utility today serves quite effectively as the locus of a marketplace for a broad range of services and interactions, a core principle underlying restructuring is substitution of market forces for monopolies and regulation. The transfer of functions to independent market structures necessarily implies a measure of loss of control. The goal is to establish a neutral "trading floor" where self-interested parties can freely negotiate for the products, terms and conditions that suit their respective needs.

Price Discovery Mechanism. How do you establish an electronic auction mechanism to accept supply and demand bids to determine a market-clearing price for each of the 24 periods in the trading day? The transient nature of electrical energy and the potential complexity of a high volume of purchase and sale transactions implies the need for sophisticated auction mechanisms to allow market participants to plan and execute efficiently. But in this market complexity lies the greatest opportunity to set economically efficient market prices. While the Public Utilities Commission reviews costs and allocations for individual utilities as part of the rate-setting process, the focus is never on more than one utility at a time. In a competitive market, an auction mechanism for all suppliers provides the greatest opportunity for efficient price setting.

Pricing Information. How do you provide real time information to all market participants and interested parties about trading volumes and market clearing prices over the course of a trading day? An auction mechanism with real-time information services overcomes a critical barrier to free market competition – non-discriminatory access to transparent price signals. Regulatory disputes relating to the terms and conditions under which wholesale power is purchased from qualifying facilities is testament to the regulatory burden and inefficiency of the process of administratively managing the determination of avoided costs and interconnection terms.

Settlements and Billing. What is the most cost effective way to coordinate scheduling and arrange delivery of power, and to provide transactions settlement and billing services to buyers and sellers? Monopoly industry structures can create inefficiencies by forcing competitors to accept terms and conditions crafted to preserve and strengthen the market power of the monopolist. While bilateral contract relationships may serve the goal of market efficiency in a robust market characterized by a large number of comparably situated competitors, today's electric utility system is several steps removed from that reality. Faced with a similar problem, several states have created or committed to creating an independent power exchange where diverse parties can "meet" to conduct arms-length business transactions. Such a structure brings costs, however, and an important question of scale arises in the Alaska context. More study is required to determine whether a form of exchange can be created in Alaska that delivers economic and efficiency benefits that would exceed the cost of administration.

Market Monitoring and Compliance. Who has the responsibility for monitoring the activities of market participants to detect practices or behaviors that indicate that the markets are being manipulated to the detriment of their fairness or efficiency? Alaska replicates the current dominant model in which a broadly-empowered administrative agency exercises oversight of monopoly providers in an effort to protect the public interest and serve as a substitute for the forces of competition. As the APUC has moved to introduce competition in other sectors, it has assumed more of a role as the "market police." A similar transition may be appropriate as part of electric industry restructuring in order to both capitalize on APUC experience and to encourage cross-fertilization of ideas and approaches. But the adoption of such a role also brings costs. While in the long term, the costs of regulatory oversight will decline with the introduction of competition, there will actually be a greater need for regulation and the resources to conduct regulation during the transition between phases.

Ease of Entry. Under what circumstances will current ownership of generating resources be maintained, or required to be sold to affiliate companies or new market entrants? Restructuring theory typically advances two alternative, though not mutually exclusive, approaches to address the potential abuse of market power inherent in supply concentration and vertical integration. The first is functional separation, or the institution of rules governing the dealings between the supply, transmission, and distribution functions of a vertically integrated entity. The performance record of functional separation has been spotty. For example, while the Computer III case at the FCC pronounced a framework for governing the relationships between local exchange carriers and affiliated unregulated marketing entities, the costs of regulatory oversight and compliance were seen by many as unacceptable. It is entirely possible that adequately supporting a regulatory oversight function to prevent unfair marketing and other practices, and the regulatory burdens that would flow from that oversight, would themselves become a barrier to the emergence of competitive markets. The alternative approach, and the one that the authors recommend, is structural separation. That is, Alaska policy makers should consider requiring some level of divestiture as a prophylactic measure against improper exercise of market power and to stimulate the growth of a competitive supply sector in the electricity industry.

Ease of Exit. What analytic methodology should be used to calculate and allocate stranded costs? A transition as fundamental as electricity restructuring entails dislocation. Indeed, the value of electric utility assets represents almost 10 percent of the underlying asset base of the US economy. The most significant financial dislocation risk is that associated with the readjustment of the value of capital assets as a result of market pricing. Electric utilities in Alaska have made significant commitments on behalf of the current system, all under an expectation of a reasonable opportunity to recover those investments. Determining the level to which that recovery will be jeopardized by a transition to competition is a difficult and imprecise endeavor. The only thing that can be stated with certainty is that administrative estimates will be wrong. Still, an effort must be made and a course of action selected. The authors feel strongly that relying solely on administrative determinations of stranded costs poses the greatest risk of inaccuracy. Experience in other states demonstrates that markets value resources at higher values than administrative calculations or expectations, and some form of market validation or determination of stranded costs is appropriate.

An initial set of specific recommendations to address each of these competition elements is contained in Table 2.3. As the discussion above reveals, however, resolution of all these issues will likely require significant commitments of resources (easily in the range of millions of dollars over the next several years) and time to explore the issues completely.

Rural Issues

The issues facing rural Alaska electricity systems are fundamentally different from those in the Railbelt and as a result no conventional model of electric utility restructuring is applicable to those systems. Nonetheless, the authors feel strongly that rural electricity issues are and should be on the table. The most obvious cross-cutting issue is the Power Cost Equalization program. Historically funded by legislative appropriation from general revenues, the program faces potential revenue shortfalls in the current Alaska budget climate. One option for creating permanent funding for the program could involve the assessment of a state-wide system benefits charge, creating the electric equivalent of a telephone high-cost assistance fund. The benefits and impacts of such an approach properly occupy a role in the debate about how electric utility restructuring might be implemented in the Railbelt.

One complementary approach to funding the need for support in rural Alaska is to work on reducing the need. Even without considering electric utility restructuring in rural Alaska per se, some innovative new approaches and extensions of current programs may yield savings benefits. The authors propose two promising areas for further investigation and effort.

Electrical service in rural Alaska reflects the available technology for energy conversion to electricity. Not surprisingly, the dominant technology in rural Alaska electricity systems is therefore the diesel-fired generator. For all the benefits of these systems, however, the costs associated with delivery and storage of fuel are a major factor limiting savings potential. Fortunately new technologies are emerging that offer some promise of complementing or even competing with diesel systems to provide electrical energy in rural Alaska. Kotzebue Electric's pilot program with wind turbines, for example, is demonstrating savings today. Fuel cells and microturbines (provided they can be supplied with reliable fuel supplies) are projected to generate electricity very cost-effectively as they are commercialized. Other technologies on the horizon, like improved storage systems, may also have application in rural Alaska.

The authors propose expanded experimentation with these technologies in a rural Alaska setting. One option would be to conduct one or more "technology pilots" in which technology providers are invited to compete for the opportunity to install and operate electric generating systems in selected villages. Such a program would require funding support initially, but could serve to create markets that will eventually become self-supporting.

Another area for effort already under consideration by the Alaska Division of Energy involves "virtual" village aggregation for administrative efficiency. While it may never be cost-effective to physically interconnect most Alaskan villages onto a single electric grid, geographically proximate villages may be able to harvest savings and improve efficiency by more closely coordinating certain administrative functions. In many ways, the benefits of this option have already been proven through cooperative fuel purchase negotiations. The authors propose that state agencies increasingly coordinate their efforts to explore this opportunity. The Alaska Village Electric Cooperative could be an excellent host for such an effort.

Summary of Recommendations

- Continue and expand efforts to improve rural system efficiencies through aggregation of administrative, fuel-purchasing, operations, logistical and other appropriate functions among geographically separate but proximate villages.
- In order to build practical experience in the use and deployment of distributed energy systems which offer potential long-term cost savings, consider the creation of a pilot program based on technology demonstration and deployment, conducted in coordination with government and non-governmental organizations.
- Initiate a specific set of market-friendly regulatory reforms today in order to bring the real competitive opportunity into focus.
- Complete a regulatory agenda that -

  (a) calculates and allocates component costs for Railbelt utilities in a rational and uniform manner (unbundling and cost allocation);

  (b) rationalizes access to, and governance of, the transmission system to create a non-discriminatory open access network while ensuring reliability;

  (c) rationalizes oversight of generation siting and construction to minimize stranded cost exposure and to foster the emergence of a competitive wholesale market with new merchant generators; and

  (d) implements central dispatch / power pooling recommendations of the October 1998 Black & Veatch study in the Railbelt to harvest near-term savings and to facilitate emergence of a competitive wholesale market over the longer term.
- Maximize potential for market success -

  (a) Mitigate regulatory and structural inefficiencies to produce near-term savings and encourage efficient market behavior.

  (b) Design pilot and retail competition to encourage technology-based competition and to realize the potential for technological innovation to reduce costs.

  (c) Design efficient commodity markets to enable value-added service innovation.

  (d) Exploit Alaska's small electricity systems to lead the industry trend toward new, modular distributed energy systems.

(e) Harmonize restructuring agendas in telecommunications, natural gas, and electricity to realize convergence benefits.

- Any market, regardless of size and scope, must carry its own administrative and oversight costs.
- To increase market liquidity, consider contract-based competition in small increments of energy, e.g., 500 kWh contracts.
- To increase market liquidity, consider a BTU Exchange, e.g., create a market exchange where both gas and electricity are traded as BTU contract.
- Consider retail market simulation modeling as part of the decision to move to a full retail competition pilot or retail competition.
- Full retail market opening must be preceded by modeling and simulation in any case.

TABLE 2.1
Electric Utility Industry Restructuring Scenario Descriptions

	FILL THE POT HOLES	KILOWATT COMMODITIZATION	CONTROLLED EVOLUTION
DESCRIPTION	Maintain the status quo; address the most immediate concerns; fix the most immediate problems	Open the market to full retail access with a minimum of legislative and regulatory intervention and address the problems as they arise.	As a matter of public policy, choose objectives and goals and design the structures, rules, and systems to achieve those ends.
GOAL	Optimization and updating of status quo	Lowest price electricity; commoditization of energy; price transparency in wholesale market	Value-added products and services; legislative opportunity to affect public policy agenda
DRIVERS	Local governance and control; uncertainty; mixed restructuring results in other states	Free market ideology; quickest way to capture benefits from improving turbine technology and low gas prices (new entrants)	Customer choice; convergence of energy, communications, and information technologies
FOUNDATION	Regulation	Structures	Rules
NUMBER 1 ISSUE	Urban: system reliability; update regulatory process Rural: Economic development	Urban: Market structure (market power, ISO, PX) Rural: Timing (opt in/opt out)	Urban: Public policy agenda Rural: Jurisdiction
RETAIL ACCESS DATE	No commitment; reevaluate in 2005	2002	2005-2008
STATE MODEL	Idaho	California	Wisconsin
BIGGEST RISK	Stifling innovation; lost opportunities	Exercise of market power	Picking winners
REGULATORY ROLE	Comprehensive oversight and management for public benefit	Remove barriers to commodity competition; ensure markets are structured to operate efficiently	Balanced implementation of legislative goals and objectives
LEGISLATIVE ROLE	Protectionist and populist	Establish limited non-competition public policy goals; provide the PUC with broad authority to usher in commodity markets	Establish public policy goals and objectives and create carefully targeted programs and incentives
MARKET OPERATION	Club collaboration, elaborately structured "competition" within a regulated environment.	Seamless; highly liquid	Value-added products and services; legislative opportunity to affect public policy agenda
WHOLESALE MARKET	Limited number of players; competition primarily in economy energy	Brutal and unforgiving competition	Robust; partially segmented according to retail market demands
RETAIL MARKET	Self generation for large customers; few or averaged choices for small commercial and residential	Very limited choices - price and maybe green; retailers compete for market share using loss-leaders, cross-subsidized marketing	Burgeoning array of novel energy products and services; retailers compete for high value-added markets
UTILITY OWNERS	Local and regional; consolidation of existing players	Highly consolidated; large; international; pressure for divestiture of public generation assets to level playing field	Local and regional in new and nontraditional partnerships and alliances; niche players
NEW ENTRANTS	Exclusive and traditional group; narrow play in quiet market	Many well-capitalized and increasingly sophisticated players in active market - consolidating quickly into few large players	Broad range of companies from non-utility industries team and compete to establish novel products and services in wide open new markets
INVESTMENT CLIMATE	Rate of return based regulation; limited but expanding opportunities for non-utilities	Fluid and sophisticated; risk/reward differentials increase	Vehicle for attracting new industries

TABLE 2.2
Major Deregulation Initiatives to Address Existing Inefficiencies

Industry	Initiatives	Inefficiencies
Natural Gas	Natural Gas Policy Act (1978) FERC Order 436/500 (1985-87) Natural Gas Wellhead Decontrol Act (1989) FERC 636 orders (1992) Expansion of Retail Service Unbundling (1995-current)	Below-market price for wellhead gas Market power exhibited by pipelines Closed access to gas delivery systems
Transportation	Airline Deregulation Act (1978) Motor Carrier Reform Act (1980) Staggers Rail Act (1980)	Cross-subsidies Entry-exit barriers Rigid pricing, service-provision and operation rules Disincentives for productivity growth and operation/planning innovations
UK Electric Power	Privatization (1991) Restructuring (1991) Price-Cap Regulation (1991)	Disincentives for productivity growth Distorted prices Highly monopolistic industry structure Decision making heavily influenced by politics
Financial	Securities Acts Amendments (1975) Depository Institutions Deregulation and Monetary Control Act (1980) Gam-St. Germain Depository Institutions Act (1982) Riegle-Neal Interstate Banking and Branching Efficiency Act (1994)	Lack of price competition in brokerage services Restrictions on the availability of banking services Restrictions on interstate banking operations Below-market ceilings on deposit interest rates
Telecommunications	FCC Carterphone Decision (1968) AT&T Settlement (1982) FCC Computer III Decision (1986) Telecommunications Act (1996)	Rate averaging Barriers to entry in long-distance market Cross-subsidies between interstate rates and local service rates Non-competition in "equipment" markets

Source: "The Outlook for a Restructured U.S. Electric Power Industry: Lessons fromDereg," Kenneth W. Costell & Robert J. Graniere, Electricity Journal, Vol. 10, No. 4 (May 1997).

TABLE 2.3
Initial Process Recommendations to Address Competition Elements

Element	Recommendation
Number of Suppliers	Use computer models to assess market power
Number of Buyers	Use computer models to assess demand responsiveness
System Reliability	Study transmission reliability issues and recommend operating criteria
Non-Discriminatory Access	Design rules and protocols for open access
Transmission Governance	Establish governing principals and draft bylaws
Market Clearing Mechanism	Design and implement power exchange
Price Discovery Mechanism	Design software for aggregating all valid supply bids and demand bids to determine market clearing price
Pricing Information	Design Internet-based real-time information system
Settlements and Billing	Design customer information and billing systems
Market Monitoring and Compliance	Establish rules and protocols to coordinate scheduling and arrange delivery of power, and settle all transactions
Ease of Entry	Study and design rules and procedures for divestiture of generating assets
Ease of Exit	Determine analytic methodology and allocation formulas for possible stranded investment

Effects on Rural Communities, Areas and Consumers

Issue

The potential impacts of electric industry restructuring on rural consumers of electricity, rural communities, and rural areas have several dimensions: structurally – how electricity is provided to rural consumers; and administratively – how governance, consumer protection, and local accountability could be altered. One of the principal concerns for rural consumers is the extent to which the pillars of rural public power – local control and community stewardship – could be affected by restructuring proposals directed at improving economic efficiency, increasing competition, and enhancing customer choice.

Alaska Dynamic

Because of the unique nature of the non-interconnected bush utilities in Alaska, restructuring discussions and policy options focused on the Railbelt utilities are not appropriate for these utilities and communities. Indeed, recommendations for the bush utilities, provided in Section 2, are limited and narrowly focused. This section addresses the issues and policy options for the small, interconnected public utilities in the Railbelt that may be directly impacted by restructuring proposals.

A brief discussion of PCE issues concludes this section.

Representatives from the small Railbelt utilities and rural areas in Alaska feel very strongly that electricity is not merely a commodity, and that local control of retail electricity markets is an essential service necessary for the health, safety, and welfare of rural citizens. The differences in distribution costs between the rural distribution utilities and the Anchorage area utilities (exemplified in dramatic differences in the number of customers per line mile of distribution facilities) raise concerns that rural communities will not be attractive markets for competitive energy service providers and will be bypassed in a fashion similar to commercial airline service following deregulation of the airline industry. The expectation among rural representatives is that rural consumers will lose the economic and customer service benefits of cooperative and municipal utility ownership, without receiving many of the benefits widely believed to flow from more open and competitive markets.

Implications

Any policy decision to support the restructuring of the electric utility industry must consider that the costs and benefits of competitive markets may not be uniformly distributed between urban and rural areas. The implication is that if the policy decision is made to move forward with restructuring, careful attention must be given to remedial actions to ensure that service quality is not unduly compromised and that vulnerable utilities and consumers receive adequate protection. These statutory and/or regulatory actions fall broadly into seven categories: equitable treatment of all consumers; nondiscriminatory access to affordable electric service; safety and reliability; consistency in the standards, regulations and oversight of all retail electric service providers; duplication of retail delivery systems; recovery of stranded costs; and exercise of market power.

Some structural changes in the wholesale markets may provide more uniform benefits to all distribution utilities, but raise a number of difficult questions regarding contractual commitments and liabilities associated with current power supply arrangements, especially take or pay contracts with generation utilities. The principal question currently driving the thinking of most stakeholders centers on the balance between potential cost savings from more efficient bulk power markets and the potential economic losses associated with “cherry picking” of profitable customers, stranded long-term power purchase agreements, and the "WalMart effect” on small communities. Interestingly, there is broad consensus among almost all stakeholders – both advocates of restructuring and defenders of the status quo – that framing the question of the likely effects on rural areas in terms of short-term financial savings and losses is too narrow. A more expansive discussion must be engaged that includes, but is not limited to, the long-term societal effects associated with new distribution channels, and the long-term consumer benefits associated with market-based competition and technology and product innovation.

Assessment

There is broad consensus among the stakeholders that more open and competitive markets for electricity – especially retail competition – will have disparate effects on urban and rural communities and that some level of statutory/regulatory intervention to protect rural utilities and consumers is appropriate. Many feel very strongly that restructuring legislation must incorporate specific protections for small public utilities. However, others feel that statutory and/or regulatory protections are inconsistent with free-market competition. In any case, a large majority of stakeholders feel that statutory and/or regulatory actions can only provide limited and short-lived protection against the forces of competition and the inherent attractiveness of customer choice, regardless of whether customers opt to exercise those choices.

Key Questions

- To what extent should the likely impacts of restructuring on rural communities, rural areas, and rural consumers be defined in broader terms than short-term financial impacts?
- What level of public policy intervention is appropriate to address rural utilities' concerns regarding tax revenues, employment impacts, service quality, and loss of local control of electric service?

List of Accompanying Tables and Figures

Rural Concerns

The deregulation of industries such as airlines, telecommunications and trucking has impacted rural America. The stakeholders representing the rural areas in Alaska, and the small cooperative and municipal utilities, share a common concern that electric industry restructuring will hurt consumers and communities in rural Alaska. The argument is based on the belief that the benefits of more open and competition markets will arrive last, if ever, in the rural areas. Specifically, there are three major areas of concern:

- Loss of Local Control over Electric Service.
- Tax Revenues

- Employment Impacts

Evidence from Other Industries

Several studies have attempted to measure the effects of regulation on a particular industry. These studies range widely in sophistication, from simple comparison of "pre-transformation and post-transformation" actual industry performance to econometric analysis that attempts to explain an industry's characteristics. The major problem with most of these studies is that they are based on empirical observations rather than statistical causality. As such, they fail to measure the effect of one particular event, such as deregulation, on an industry's performance. For example, at the same time that the United Kingdom privatized its electric utilities, it also radically restructured the industry to encourage competition, and instituted a price-cap mechanism to regulate the prices of transmission, distribution, and bundled retail services. Subsequent to these changes in 1991, real prices for most U.K. electricity customers have fallen. However, it cannot be said with much certainty which of several factors was most important, or even contributed to, the decline in prices. In any event, one must be cautious in interpreting the results of studies that attempt to measure the effect of deregulation per se for a specific industry.

Summary tables, Tables 3.1 through 3.3, set out some observations from the experiences of five recently restructured industries.

Loss of Local Control of Electric Service

The conventional wisdom in the electric utility industry today is that intensifying competition in wholesale power markets will lead to the rapid evolution of retail wheeling and, in turn, to the "commoditization" of electricity. As competition moves to the retail level, it is reasoned, only the largest companies with the lowest rates will survive. This seemingly plausible hypothesis has given rise to a surprising amount of controversy. Numerous studies have purported to demonstrate that even modest reductions in electricity rates will lead a sizable fraction of customers to switch suppliers. But numerous competing studies have argued that the most important attributes of customer choice have to do with familiarity, trust, brand identity, customer service, and other non-price criteria such as environmental quality.

The continuing debate regarding the specific factors that influence the relationship between customers and their energy service providers means uncertainty will continue to exist regarding the role that price plays. It is simply not certain whether a hypothetical rate discount of, say, 5 percent during the first few years of restructuring will be accompanied by customer switching of, say, 5 percent, 10 percent or any other specific number.

Moreover, it is unlikely that this uncertainly will be resolved in the near future. The most that can be asserted with confidence is that as retail markets mature, electricity customers will be faced with a plethora of new and innovative service offerings that will redefine the role of the energy service provider. In many recently deregulated industries such as telecommunications, natural gas, financial services and others – all loosely described as having evolved into "commodity markets" – leading companies are prospering by providing highly integrated packages of services, most of which did not exist only 5 years ago. In these industries, pure price competition is giving way to sophisticated bundling or service attributes to respond to customer needs.

Some stakeholders see the future of the electric power industry as a reprise of "what happened to the airlines." In this view, the inevitable outcome is dramatically lower retail prices, huge write-downs of stranded costs, and extreme pressures for consolidation within the industry. In 1973, there were 77 US airline companies, all of which were profitable; by 1995, only 31 remained, two of which were profitable. Other members pointed to "the coming electric WalMart," as an equally threatening vision of the future. In the early stages of competition, many believe that the key to success lies in becoming the low price leader. From these perspectives, the utility's role as a provider of integrated packages of energy services, including community services, is destined to become a relic of the past. Commodity competition among power suppliers, it is argued, will collapse the competitive battle to a single metric: cents per kilowatt-hour.

An alternate vision suggests that the development of integrated energy service packages, adapted to the industry's newly emerging competitive structure, will become the centerpiece of the utility's strategy, since the companies that master these capabilities will ultimately command a dominant position in relation to the customer. For companies undertaking this approach, becoming a low cost supplier is a necessary but not sufficient condition for success.

These stakeholders argue that the experiences of other recently "deregulated" industries suggests the following hypotheses about the future of the US electricity industry:

- The initial phase of *dis*integration and commodity competition at the wholesale, and possibly retail, levels is likely to be followed by a period of *re*integration in which non-price service attributes become important sources of competitive advantage.
- New technologies for grid management, small-scale distributed generation, efficient end-use, and energy storage point toward the emergence of the "distributed utility." Delivering energy services in this environment will require "mass customization" of technology and service packages adapted to specific circumstances.

- The interplay of regulatory and judicial decisions which led to the development of competitive secondary markets in transmission rights in the railroad, natural gas, and telecommunications industries could pave the way for the emergence of 'virtual" utilities in the electric power industry. The first "Internet utilities" have already emerged. See http://www.utility.com
- The entrepreneurs who are at the cutting edge of developing new business structures during the utility industry's transition ahead will be able to influence the rules of the game according to which later entrants must compete.

Stakeholders who embrace this view of the electric industry – in which the traditional utility companies become the critical interface between the customers and wide array of new companies allied in creative ways to provide many new and unforeseen services – point to the experiences of the oil, natural gas and telecommunications industries. In each of these industries, reintegration began to emerge after a short period of market-driven disintegration and commodity competition.

Oil companies discovered that their crude oil and product trading operations, which were launched as defensive measures to counteract price volatility, became profit centers and began to provide risk management services to their customers. They found that operation of convenience stores in conjunction with their gasoline stations could substantially enhance their downstream profitability. Similarly, in the natural gas industry, the disintegration phase precipitated by the birth of gas spot markets in the early 1980s was followed by a period in which a handful of major supply aggregators escaped pure commodity competition by developing sophisticated capabilities to provide integrated financial risk management, transportation, storage, and other services. Long-distance telecommunications companies, who initially competed almost exclusively on price terms, now compete on the basis of highly customized service packages; special rates tied to customer's usage patterns, voice recognition, ease of international use, and other nonprice service characteristics. Price remains an important factor, but is not the only factor.

Taxes

Recent concerns over the relationship between taxes and electric power industry restructuring have emerged as a major issue in several states. Specifically, given existing state tax laws, restructuring could produce lower tax revenues and create an "unlevel playing field" that would disadvantage certain competitive groups. Such an outcome has both economic and political implications.

The general consensus in states where the tax implications of electric power industry restructuring have been discussed is that state laws need to be revised to preserve existing revenues while not granting competitive advantage to any group of electric energy providers. The goal of this approach is to create a regime in which taxes are competitively neutral, while having a minimal impact on the tax revenues currently collected by state and local governmental units.

A major objective of any revised state law would be to place small public utilities on the same standing with regard to taxes as investor-owned utilities (IOUs), independent generators and power marketers. One option is to replace the electric cooperative taxes with a sales tax imposed on all electricity suppliers. Another option for preventing losses in tax revenues and for maintaining competitive neutrality is to establish a consumption tax on a per-kWh basis in lieu of the electric cooperative tax. A uniform consumption tax would avoid any taxing inequities among competitors that would otherwise skew the market in favor of tax-advantaged competitors, but there are concerns that a consumption tax could have regressive impacts.

The interest in a consumption tax has grown in recent months. New legislation in Oklahoma requires the state's tax commission to study the feasibility of establishing a uniform consumption tax. A tax advisory group in Virginia has indicated its preference for a usage tax to replace the current gross-receipts tax. Ohio is currently considering a user or sales tax to replace existing taxes such as the state's high tangible personal-property tax on electric utilities.

Careful review of the correlative impacts of the Corporate Net Income Tax and property and sales taxes is also essential in order to ensure tax neutrality. Any significant modification of the taxing structure will require legislative action.

The issue of taxes is discussed in greater detail in Part 3 of this report.

Employment

Industry restructuring, specifically the removal of government rate regulations and restrictions on entry, has been one of the most significant economic policy changes of the last few decades. The effects of such policy changes are not limited to the product market, as stepped-up competition in an industry can easily place greater downward pressure on labor earnings. In an effort to assess the potential impacts on employment from restructuring the electric power industry, it may be helpful to review the experiences from the trucking, railroad, airline and telecommunications industry. These industries were all "deregulated" in the late 1970s and early 1980s -- government policies placed greater emphasis on allowing the market to set prices and determine successful entry.

The academic literature on the relationship between economic regulation and labor market impacts often focuses on the role of unions. Regulation that restricts entry of potential competitors allows for relative ease of unionization, because the per-worker cost of organizing employees is low in industries consisting of a few large firms. Rate regulation that allowed carriers in these industries to pass on costs to customers also contributed to their unions receiving high wages for their members.

Table 3.4 presents information on the size of the work force in trucking, railroads, airlines and telecommunications from the early 1970s to the 1990s, along with the weekly earnings of workers and percentage of workers in each industry belonging to a union. The sample years from 1978 to 1996 cover the post-deregulation period for trucking, railroads, and airlines. The years 1983 to 1996 encompass the post-deregulation period for telecommunications, following the break-up of AT&T in 1984. The summary results in the table show some similarities and differences across the industries.

The summary figures offer some evidence that the bargaining power of labor declined in all four of these industries following deregulation and that workers lost income. Taking the product of the earnings changes shown in Table 5.7 from the time before deregulation to 1996 indicates worker losses of $5.7 billion in trucking, $1.2 billion in railroads, $3.4 billion in airlines, and $5.1 billion in telecommunications. Of course, these quick calculations should be taken only as illustrating the order of magnitude of losses to labor. But to place these figures in context, the annual consumer welfare gains from deregulation have been roughly estimated at $50 billion for a not exactly comparable group of industries[1]. This indicates that worker surplus losses do represent a sizeable share of consumer welfare gains from deregulation.

This evidence is consistent with the observation that entry by non-union firms weakens unions' control over the industry labor supply, and that the shift from rate regulation toward competitive pricing makes it unprofitable for carriers to pass on higher union wages that are not justified by higher productivity.

A more detailed discussion of employment and possible labor market outcomes as the result of industry restructuring is provided in Section 10.

[1] Belzer, Michael, "Commentary on Railroad Deregulation and Union Labor Earnings." In James Peoples, ed. Regulatory Reform and Labor Markets. Boston, Massachusetts: Kluwer Academic Publishers, 1997.

Rural Utilities

The contrasts within the utility industry in Alaska are as dramatic as anywhere in the US. While the Railbelt is characterized by large centralized power plants and a bulk transmission network that takes advantage of the economies of scale available in the industry, the 200 small, isolated bush villages are powered by far less efficient generators. The utilities in these villages are consumer-owned, not interconnected, and usually powered by one diesel-fired internal-combustion generator. As a result of small size of generators and the great distances involved in the shipment of fuel, great disparities in rates exist both between rural and urban areas, and among village utilities. The small customer base also creates other potential problems. In many cases, the loss of a single large customer, such as the village school, could substantially increase the cost to the remaining customers.

A significant portion of the costs associated with increasing efficiency and lowering the operational costs of village utility systems is borne by the Alaska Division of Energy. The Division of Energy currently administers 4 loan programs, 6 rural energy programs, and 5 additional programs, all designed to provide benefits to village systems. Additional detail on these programs is provided in Table 3.6.

The population in the rural villages is projected to grow only marginally over the next 20 years. In contrast, the population of Anchorage is projected to grow by more than 75,000 people during the same period. The lack of significant population growth in areas outside Anchorage is a mixed blessing: no major capacity additions will be necessary, but the lack of growth also implies no growth to the revenue base that could help finance new, more efficient infrastructure improvements. Table 3.7 and Figure 3.1 provide projections of population growth in the regions of Alaska.

The differences in size between urban and rural utilities is also reflected in operational metrics. For instance, ML&P employs four times as many workers and has four times the revenues of AVEC members and therefore has substantially the same amount of revenues per employee. In sharp contrast, however, there are dramatic differences in revenues per kWh, largely a reflection of the differences in the number of customers per line mile of distribution lines. A comparison of employees, sales and customers per mile for selected utilities is shown in Table 3.8.

For the village utilities, what is missing is the critical mass of customers and revenues to justify greater infrastructure investment, increased staffing, and other services. The result is little opportunity to capture cost reductions from increased economies of scale and economies of scope. Some of the characteristics of the AVEC utilities are provided in Table 3.9 and Figures 3.2 through 3.5.

Power Cost Equalization

The Power Cost Equalization program has paid a portion of the electrical bills of rural customers since 1985. The fund for this program has disbursed an average $17.5 million each year since that time. Funds are distributed according to formulas set forth in rules adopted by the Alaska Public Utilities Commission. Though not so named, the PCE program is essentially a universal service fund. Its express purpose is to ensure access to affordable electric service in rural Alaska.

As the initial PCE fund appropriation has been drawn down, policy makers in Alaska recognized an impending problem. In anticipation of the current legislative session, the Governor of Alaska convened a Blue Ribbon Committee to evaluate and submit recommendations regarding the future of the PCE fund. The recommendations of that Committee were issued on February 1, 1999, and contain a comprehensive and well-reasoned assessment of the issues as well as a range of options for securing the future of PCE funding. Just as importantly, the Committee addressed both "sides" of the PCE issue – funding and need. The Committee recommended a number of measures aimed ensuring the fund targeted the most serious need, and addressed modifications to the current system that would fit seamlessly into any restructuring scenario.

The Committee's recommendations are summarized in its report as follows:

1. PCE or an alternative rate support program for high cost service areas should be extended into the future.
2. Such rate support should be available only for:
   A. A "lifeline" supply of electric power for residential customers. A lifeline supply is defined as one-half of the statewide average consumption per household each month. While this amount varies over the course of a year, the average monthly lifeline supply would be approximately 350 kWh.

   B. Electric power for community facilities that are directly related to public health and safety.
3. A stable source of funding for PCE or an alternative rate support program should be established with the following major components:

A. 60 percent of the annual debt service paid to the State by the Four Dam Pool – this would include the 40 percent now allocated to PCE plus the 20 percent now allocated to the Power Project Fund loan program.

B. $20 million appropriated by the 1993 legislature as a loan for the Swan/Tyee intertie, based on a proposal from Ketchikan Public Utilities to forego the loan in exchange for State bonding of Swan/Tyee intertie costs.

C. Proceeds of a universal service fund to be created from a surcharge on all electricity sold statewide by public utilities.

4. A statewide organization or agency should be designated to establish standards for rural electric utilities with respect to financial management, physical plant, and system operations. No rural electric utility should continue to receive rate support or capital project grants from the State unless it is in compliance with these standards, is making clear and continuing progress in attaining compliance, or has entered into an agreement with an existing utility or utility organization whose operation is consistent with the standards.

TABLE 3.1
Rate Impacts on Rural Areas from Recently Restructured Industries

Industry	Rates, general	Rates, small/rural markets	Rates, variability between large and small markets
Gas	$/mcf declined noticeably following deregulation, for all economic sectors	Residential gas prices declined 32.6 percent between 1984 and 1995. No information on rural vs. non-rural residents	N/A
Telecommunications	Long distance access charges declined from 16.6-6.7 cents/minute between 1985 and 1993 in real terms. Long distance revenues/minute fell from 30.4-7.5 cents/minute between 1985 and 1993	Overall, local rates roughly same in 1994 as in 1985 after slight increase in late '80s Removed cross-subsidies	Long-distance phone rates declined more than access charges collected by local phone companies from long-distance companies, i.e., cost shift from long-distance to local service.
Airlines	Revenue per passenger mile has declined from an average of 21.7 cents in 1977 to 13.8 cents in 1995, indicating that fares have decreased as well during that time period.	Following the general trend, revenue per passenger mile have decreased since deregulation in areas with single-carrier routes. For the shortest distance markets (0-250 miles) fares have increased slightly (43.5 to 45.7 cents/mile) from 1979-1995 as previous regulation held fares below cost.	Correcting for service differences between hub and non-hub flights (more airlines, shorter flight distances, larger percentage of full fare tickets, higher cost airlines, etc.), fares at concentrated hubs (dominated by one airline) are about 5 percent higher than fares at non-hubs, but still lower than fares before deregulation.
Trucking	Truck load (TL) and less than truckload (LTL) rates fell by 3 percent and 17 percent, respectively during the first five years of deregulation, through 1985. Real operating costs per line mile declined 2.1 percent per year b/t 1987 and 1993 and for TL carriers by 9 percent per year.	N/A	N/A

Source: Crandall and Ellig, 1997.

Industry	Participation, general	Participation, small/rural markets	Participation, variability between large and small markets
Gas	N/A	N/A	N/A
Telecommunications	Penetration up to 94 percent in 1995 from 91.6 percent in 1984	Universal service provisions ensure that small and rural communities have access to basic local and long distance services.	N/A
Airlines	50 percent of population in 1971 to 75 percent of population in 1995	Drastic decline in rates “democratized” air travel, allowing passengers to travel by air who previously would have traveled by bus or private auto.	N/A
Trucking	Number of carriers licensed by the Interstate Commerce Commission grew from 18,000 in 1980 to 33,000 in 1986		

Source: Crandall and Ellig, 1997.

TABLE 3.2
Quality of Service Impacts on Rural Areas from recently Restructured Industries

Industry	Quality of service, general	Quality of service, small/rural markets	Quality of service, variability between large & small markets
Gas	Interstate customers benefitted most from service quality improvements resulting from deregulation	N/A	N/A
Telecommunications	Have increased as a result of electronic revolution applied to telecommunications. Telephone equipment is more sophisticated, long-distance service increase use of fiber-optic cable and higher speed service (e.g. modems).	Universal service provided through subsidies built into current rate structures	Little if any variation. Local telephone companies, now offer services such as call waiting, call messaging, caller ID.
Airlines	Quality has improved through more frequent flights, more non-stop flights, more routes. Fourteen percent of passengers had to change airlines to reach destination in 1978. In 1995, only one percent needed to change airlines to reach destination. Fatalities per 100,000 departures and per million aircraft miles have decreased since 1978, and it is difficult to prove that safety would be greater today had regulation continued.	95 small communities lost air service between 1978 and 1993. However, it is inconclusive whether deregulation was the cause since air service in these communities was not federally regulated prior. A total of 114 communities lost air service during first 6 years of deregulation but study shows that regulation could have prevented loss to only four of those cities.	Slight reduction in non-stop flights for small and medium sized communities, coupled with a modest increase in one-stop destinations. Frequency of flights have both increased by about 50 percent for both small and large cities, between 1978 and 1995.
Trucking	Freight tracking and monitoring technologies help to increase efficiency and service responsiveness.		
Railroad	Efficiency increases due to lower freight rates. Rail box cars and trucks that used to be empty are now filled with items for shipment.		

Source: Crandall and Ellig, 1997.

TABLE 3.3
Quantity of Services Impacts on Rural Areas from Recently Restructured Industries

Industry	Quantity/variety of services, general	Quantity/variety of services, small/rural markets	Quantity/variety of services, variability between small and large market
Gas	Innovation includes market hubs and financial instruments for managing risk	N/A	N/A
Telecommunications	Increased tremendously as a result of advances in electronic technology, and competition-driven innovation.	Fewer options than more urban communities but in general have also increased following deregulation.	Small differences in variability. Most consumers buy more than one product (i.e. both local and long-distance)
Airlines	Deregulation facilitated development of lower-cost, hub-and-spoke system of service, the rise of “commuter” airlines, and the entrance of small low-cost airlines.	Small communities are generally served by one dominant carrier	Larger communities have greater number of airline carriers to choose from.

Source: Crandall and Ellig, 1997

TABLE 3.4
Unionization, Employment and Labor Earnings Patterns in Transportation and Telecommunications Industries

Industry	**1973**	**1978**	**1983**	**1988**	**1991**	**1996**
Trucking						
Union Membership Rate	49%	46%	38%	25%	25%	23%
Work Force Size (x1,000)	997	1,111	1,117	1,544	1,617	1,907
Weekly Earning (1983/84 dollars)	$499	$491	$404	$386	$405	$353
Railroad						
Union Membership Rate	83%	79%	83%	81%	78%	74%
Work Force Size (x1,000)	587	580	428	363	286	282
Weekly Earning (1983/84 dollars)	$475	$491	$507	$490	$494	$470
Airlines						
Union Membership Rate	46%	45%	43%	42%	37%	36%
Work Force Size (x1,000)	368	465	464	683	696	800
Weekly Earning (1983/84 dollars)	$499	$498	$455	$420	$443	$435
Telecommunications						
Union Membership Rate	59%	55%	55%	44%	42%	29%
Work Force Size (x1,000)	949	1,075	1,060	1,114	1,107	1,126
Weekly Earning (1983/84 dollars)	$399	$442	$457	$447	$458	$488
All other Industries						
Union Membership Rate	23%	22%	19%	16%	15%	14%
Work Force Size (x1,000)	72,619	81,737	85,220	97,704	99,080	107,844
Weekly Earning (1983/84 dollars)	$399	$363	$301	$310	$322	$334

Source: Information on union membership rates and industry work force sizes were provided by Barry Hirsch and David Macpherson. Information on labor earnings for the 1973-1991 sample period are taken from Current Population Survey Files and the 1996 earnings are taken from Hirsch and Macpherson's Union Membership and Earnings Data Book (1997a). The sample years from 1978 to 1996 cover the post-deregulation period for trucking, railroads, and airlines. The years 1983-1996 cover the post-divestiture period for telecommunications.

TABLE 3.5
Local Impacts

Category	Issue	Policy Options	Advantages	Disadvantages	Comment
Revenues	Depending on the course that state and federal policies take, and the corresponding actions of local governments, revenue streams could be enhanced or diminished.	Do nothing	Simple to state and implement	Assumes that the current tax/fee structure is appropriate in a restructured market.	Tax, franchise, or other fees received from utilities could decline due to alteration of the market value of the current utility's equipment and facilities.
		Establish a "revenue neutral" policy	Provides local governments an equal level of revenues after restructuring	Implies implementation of multiple changes, from slight adjustments to major policy changes.	Existing agreements for payment under leases, contracts, or other arrangements may be changed.
		Level playing field	Balance tax and fee burdens, property tax valuations, use taxes, federal and state taxes and incentives, depreciation methods, etc.	Major revisions in tax and fee policies. Creates winners and losers.	The accounting firm of Deloitte and Touche has estimated that $15 billion in annual state and local revenues are at risk.
Energy Budgets	Local governments are likely to face changes in their energy budgets. Funding for local programs and energy efficiency and renewable energy development could be eliminated.	Systems benefit charge	Places equal burden on all ESP to provide desired public policy benefits	Diminishes local control and discretion regarding implementation priorities	

Category	Issue	Policy Options	Advantages	Disadvantages	Comment
Planning Issues	Economic development efforts may be improved or diminished and long-term capability to influence planning and policies for other infrastructure industries, such as telecommunications, may also be affected by local actions on electric utility deregulation.	Integrate all infrastructure development efforts to take advantage of convergence benefits	Cost savings from common trenching, service coordination, etc. Opportunity to exploit new value added markets for products and services	Creates new challenges for cost allocation and regulatory oversight	This is particularly important in light of the trend for utilities and power suppliers to propose “bundled services” for consumers, or “smart metering” and other programs that require integration of services.
Local Powers and Authorities	Restructuring of electric utilities could raise some fundamental challenges to local power and authorities	Opt-in/opt-out provisions	Retains local control	May raise constitutional issues	Control over use and occupation of streets and right-of-ways for delivery of services Changes in the ability to adequately protect community and public interests
Duplication of retail delivery systems	Competitors to traditional utilities may seek to duplicate or bypass transmission and distribution systems to gain access to customers	Prohibition against local bypass	Retains customers and protects local utility loads and revenues	May prevent large customers from gaining access to lower cost power	
Metering and Billing	Removing the metering and billing functions from the distribution utility	Metering and billing remain regulated parts of the distribution franchise		Lost opportunities for cost savings from competition and innovation	

Category	Issue	Policy Options	Advantages	Disadvantages	Comment
Equitable treatment of all consumers	Rural customers may not receive the same level of service as their urban counterparts	Establish licensing requirements that includes minimum service standards and codes of conduct	Creates uniform standards of conduct and nondiscriminatory access to affordable electric service for all customers	Increased regulatory and oversight requirement	
Market Power	Rural consumers without much buying power could see unreasonable rate increases from the exercise of market power by dominant utility	Information disclosure for independent party to assess market power and utility submission of market power mitigation plan Commission authority to monitor market power Aggregation of customers or distribution systems to increase buying power	Legislatively established redress mechanism for complaints	Processing claim is costly and burdensome	
Employment	Jobs will be reduced/lost as power providers downsize, aggregate, pull out of smaller communities. If generation shifts towards sources such as natural gas and renewables, coal mining communities may be adversely affected.	Early retirement compensation, workforce retraining			

Category	Issue	Policy Options	Advantages	Disadvantages	Comment
Service Quality	Consumers worry that services such as local customer assistance centers will be significantly reduced and that the quality of residual services will deteriorate as power providers cut costs to remain competitive.	Municipal/community aggregation	Cooperatives/ communities within a state or region collectively address needs to serve chain account customers and aggregated loads, to bundle new and additional services that add revenues and enhance consumer relationship. Main advantage is not in short term sharing of costs but *long term* benefit of increasing size, financial strength, and diversity of resources, services, and markets.	Requires high level of commitment, organization, coordination, innovation, and long-term outlook.	Additional services include negotiating lower rates for customers, developing consumer information systems that keep detailed billing, accounting, etc. Additional services also include long-distance telephone, and electronic home security.
Safety and Reliability	Competitive cost pressures may compromise the proper maintenance of the transmission and distribution infrastructure	Maintain transmission and distribution functions as regulated functions	Maintains local control and accountability	Lost opportunities for cost savings from competition and innovation	

TABLE 3.6
Alaska Division of Energy Program Activities

Energy Loan Programs	
Bulk Fuel Revolving Loan Fund	This program assists small rural communities in purchasing annual bulk fuel supplies. The loan amount may not exceed 90% of the wholesale price of the fuel being purchased; maximum loan amount is $100,000. Loans may be made to an organized municipality or an unincorporated village with a population under 2,000, or to a private individual who has a written endorsement from the governing body of the community. The loan must be repaid within one year. There is no interest on the first BFRLF loan; the second BFRLF loan carries five percent interest; and an interest rate based on the average weekly bond rates applies to subsequent loans.
Power Project Revolving Loan Fund	Provides loans to local utilities, local governments or independent power producers for the development or upgrade of electric power facilities, including conservation, bulk fuel storage, and waste energy conservation, or potable water supply projects. Loan term is related to the life of the project. Interest rate is not less than zero and must be the lesser of the average weekly yield of municipal bonds for the 12 months preceding the date of loan, or a rate the Division determines will allow the project to be financially feasible.
Rural Electrification Revolving Loan Fund	Provides loans to local communities for extending electrical service into previously unserved areas of the state. Loans are made only to electrical utilities holding an Alaska Public Utilities Commission Certificate of Public Convenience and Necessity. Maximum loan amount is $500,000 or $250,000 if cash available in the fund is less than $3 million at the time of application. Interest is fixed at 2%. Borrowers must demonstrate that the loan is likely to be repaid in ten years from the date electrical service is provided to the new customers.

Source: (http://www.comregaf.state.ak.us/doe_loan.htm)

Rural Energy Programs	
Operational, Technical and Emergency Assistance	Rural Technical Assistance (RTA). Technical assistance to rural utilities in evaluating deficiencies and needs in respect to the collective energy systems and facilities within a community. Community support is a key element. Rural Utility Training (RUT). Formal technical training of rural utility operators. To meet this need, emphasis is placed on adapting and expanding existing programs such as those provided by the Seward Skills Center, the University of Alaska, and the Job Training Partnership Act. Meter Installation and Data Acquisition. Provides for adequate metering of rural utilities and trains operators to accurately read and record meter data. This program would also be used to install monitoring devices to record and transmit time-coded data necessary for planning purposes. Emergency Prevention. Provides funding to continue activities, procurement of materials, and equipment that would be used to prevent power plant-related emergencies and disasters statewide. This program is designed to prevent a potential emergency situation before disaster occurs.
Electric System Life, Health and Safety Improvements	Provides follow-on funding for correction of hazards that are existing or pose a possible threat to life, health and safety in rural communities. Wherever possible, funds will be used to leverage local matching funds.
Voluntary Rural Utility Business Management Development	Works towards the goal of creating self-supporting utilities in rural Alaska. This is to be achieved through (1) the development of partnerships between utilities, i.e., private ownership, a cooperative or an operations and maintenance agreement with a larger utility, (2) utilities joining a regional utility entity, and (3) the training of utility business manager and operators.
Rural Power Systems Upgrade	Provides funding for systems upgrades that have been identified through Rural Technical Assistance, Circuit Rider Maintenance, the local community or legislature. Upgrades might include efficiency improvements, line assessments, lines to new customers, demand side improvements, other repairs to generation and distribution systems.
Emergency Bulk Fuel Repairs, Spill Prevention and Bulk Fuel System Upgrades	Creates incentives and mechanisms to repair bulk fuel systems before a crisis develops. This includes emergency repairs to storage and handling systems. Priority is given to communities whose fuel vendors or regulating agencies have threatened to halt delivery of fuel, or where conditions have become a life, health and safety matter, or the environment is threatened. The upgrades programs assist private owners in recognizing the need to meet minimum standards.
Rural Electric Capitalization Fund	Provides for electric utility improvements matching grants (75%) to utilities eligible to participate in Power Cost Equalization. Grants can be made for small power projects that reduce costs to utility customers.

Source: http://www.comregaf.state.ak.us/doerural.htm

OTHER PROGRAMS	
Circuit Rider/Emergency Response Services	Preventive maintenance assessment and response service for emergency work needed on rural electrical systems. This program is intended to be an interim fix until long-term planning can address the problems.
Power Project Planning	Engineering, environmental, economic and financial assessment of power projects proposed for development by legislators, utilities and communities.
Alternative Energy Development	Evaluation and development of rural energy alternatives including small hydro, village interties, conservation, and energy supply based on wood, municipal solid waste, wind and coal.
Southeast Energy Fund	This is a grant fund established by the Legislature in 1993. Utilities participating in the power transmission intertie between Swan Lake and Tyee Lake hydroelectric projects are eligible for this grant fund.

Source: http://www.comregaf.state.ak.us/doeother.htm

Energy Savings Initiatives **The Division of Energy uses U.S. Department of Energy funds, along with state matching funds, to promote energy saving in Alaska through several initiatives:**	
Rebuild America Program	The Division of Energy received a three year Rebuild America Program grant in late 1996. This grant covers energy use assessments in large buildings like schools and public offices in communities participating in the Power Cost Equalization (PCE) Program. Rebuild America energy auditors do walk-through assessments and provide building owners/managers with recommendations for energy saving changes. Energy auditors also provide maintenance workers and building occupants with training on ways to save energy. These services are provided free of charge. This program does not cover the cost of high efficiency products or retrofits, but it does provide information on possible sources of financing. The Rebuild America Program is implemented in Alaska as the Rural Alaskans Conserve Energy (RACE) Program.

Source: http://www.comregaf.state.ak.us/doe_save.htm

TABLE 3.7
Population Estimates

	1998	2003	2008	2013	2018
Alaska - Statewide	621,400	656,150	6,934,018	733,852	776,488
Regions					
Anchorage/Matanuska-Susitna	313,308	333,042	353,770	376,779	401,631
Gulf Coast	73,028	76,771	80,553	84,737	88,837
Interior	98,647	102,931	106,963	110,915	114,459
Northern	23,649	25,627	28,098	31,027	34,236
Southeast	74,285	76,298	78,687	81,462	83,976
Southwest	38,483	41,481	44,947	48,932	53,349

Source: Alaska Department of Labor
http://www.labor.state.ak.us/research/pop/pop-proj.pdf

FIGURE 3.1 Alaska Population Projections, by Region (1998-2018)

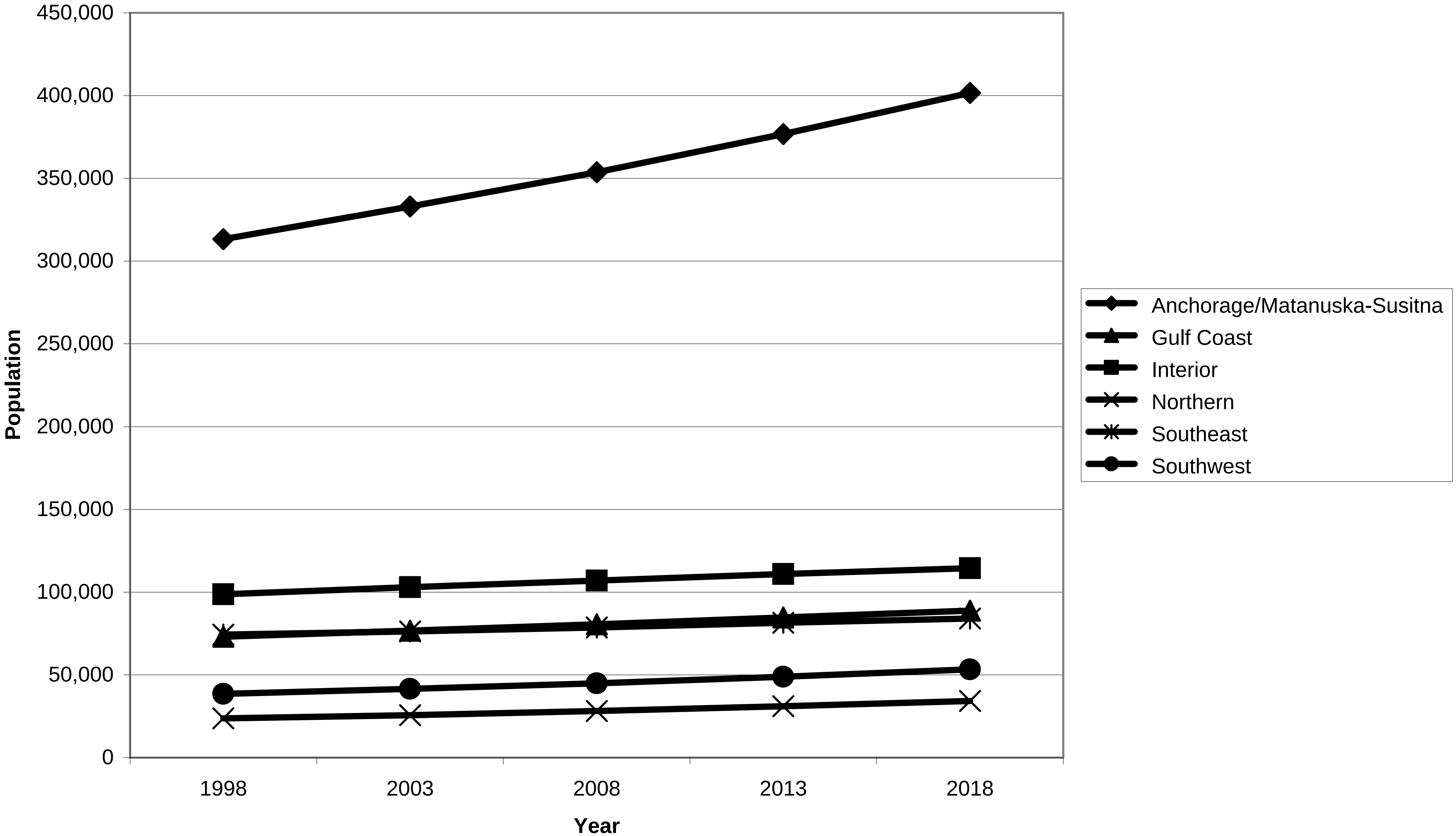


TABLE 3.8
Comparison of Employees, Revenues, Sales and Customers per Mile for Selected Utilities, 1998

	Employees	Annual Revenues	Revenues/Employee	Annual Sales	Sales/Employee	Revenue/kWh	Customers/Line Mile
MEA	125	$48,360,050	$386,880	474,701,264	1,227	$0.102	11.5
ML&P	225	$86,793,088	$385,747	905,820,399	2,348	$0.096	83.8
AVEC	59	$20,430,923	$346,287	51,045,159	147	$0.400	0.05

Source: Utility data.

TABLE 3.9

Summary Data for Railbelt and Non-Railbelt Utilities - 1997

	All Utilities	Railbelt Utilities	Non-Railbelt Utilities
Weighted Average Residential Rate	$0.114	$0.103	
Monthly Residential Consumption (kWh)	669	671	
Monthly Residential Revenues	$76	$69	
Annual Residential Consumption (kWh)	8,028	8,054	
Annual Residential Revenues	$918	$830	
Sales (kWh)	4,840,529,000	3,708,957,000	1,131,572,000
Revenues	$487,620,000	$325,752,000	$161,868,000
Value of 1 mill	$4,840,000	$3,710,000	

Source: EIA, Electricity Sales and Revenues

FIGURE 3.2 Sales at Railbelt and Non-Railbelt Utilities (1997)
Source: EIA, Electricity Sales and Revenues

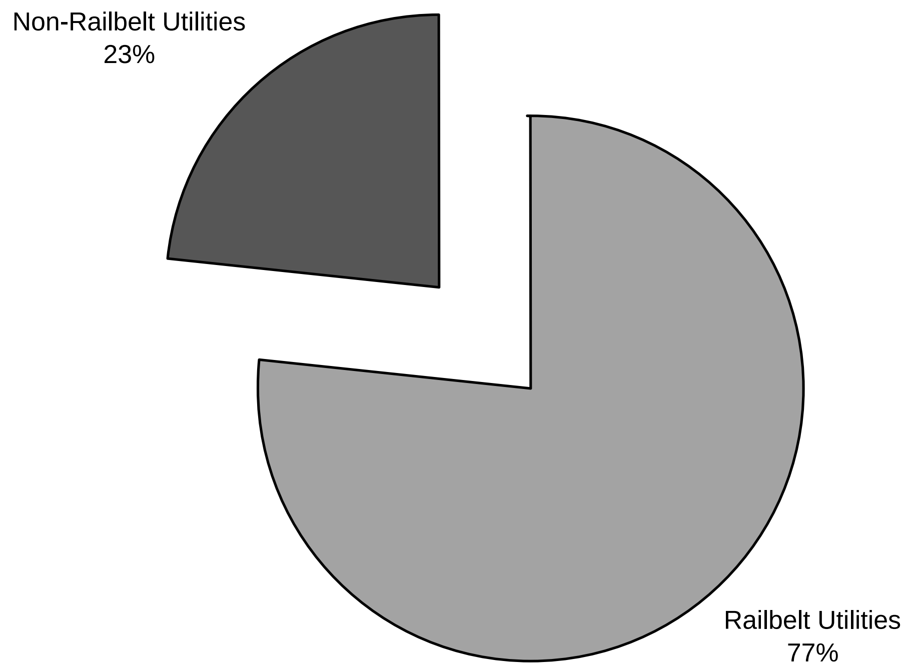


FIGURE 3.3 Revenues at Railbelt and Non-Railbelt Utilities (1997)
Source: EIA, Electricity Sales and Revenues

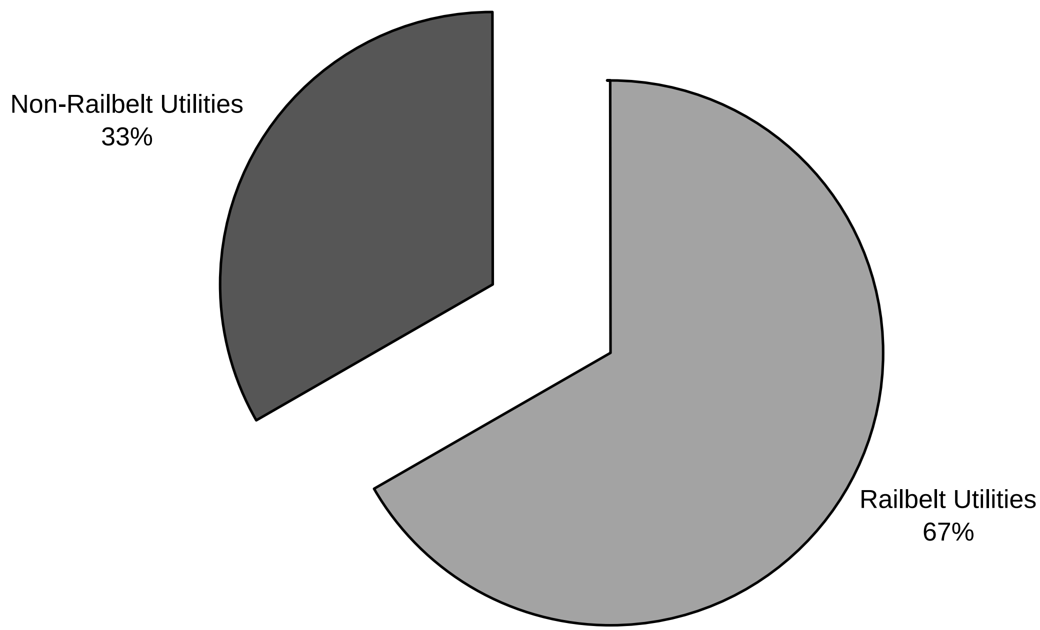


FIGURE 3.4 AVEC Sources of Electric Revenue, 1994
Source: ARECA/AVEC

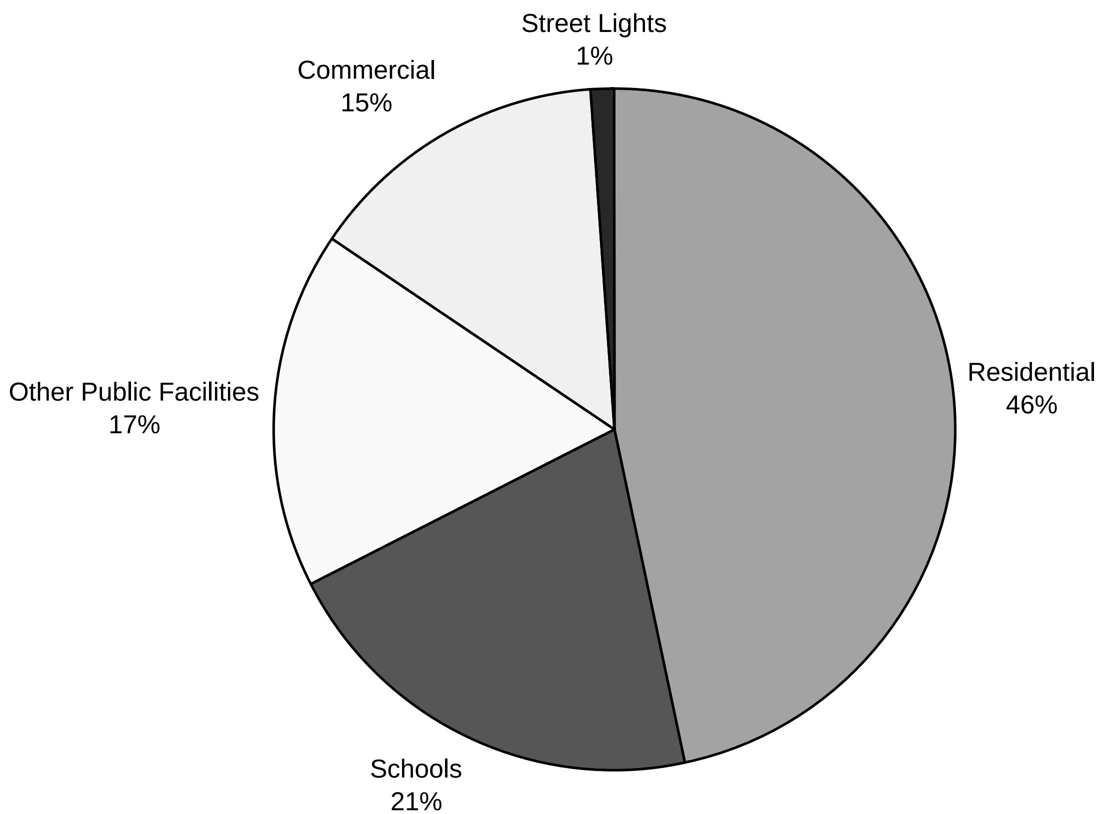
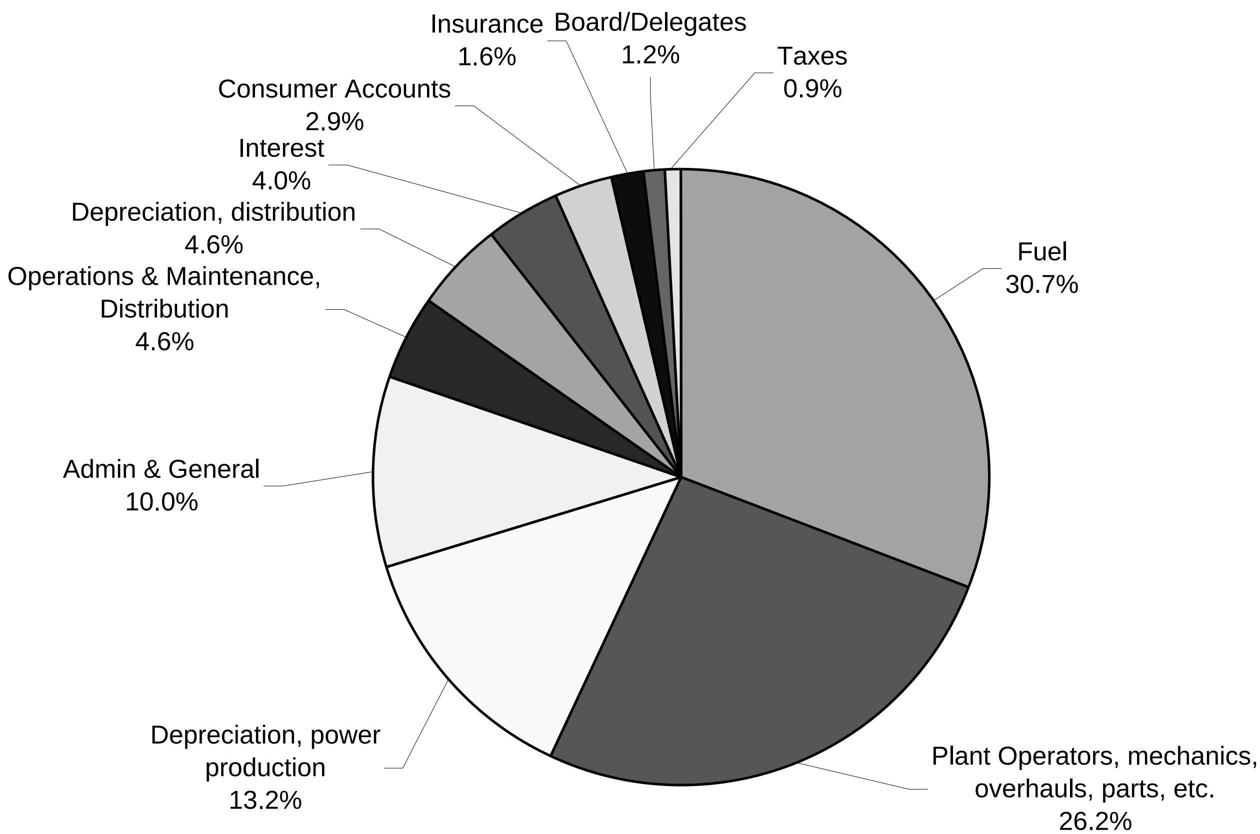


FIGURE 3.5 AVEC Total Cost of Electric Service by Item, 1994
Source: ARECA//AVEC



Local Choice

Issue

Many small utility stakeholders are concerned about the possible impacts of restructuring on their unique role in the community as suppliers of electricity. Publicly owned electric utilities are expected to aid their communities by promoting local economies, enhancing the environment, and improving the quality of life through appropriate provision of electricity. The principal concern for most stakeholders is the question of prescriptive jurisdiction – that is, who will be vested with the authority to make decisions about the rules and procedures to govern access to local electricity transmission and distribution facilities, and to retail customers.

Alaska Dynamic

The majority of stakeholders in Alaska believe that competition will provide lower electricity rates in the long-term, but oppose a federal mandate to implement retail access. Representatives from the small electric utilities feel very strongly that they should determine through their own political processes what policies best serve their communities. To that end, they support the Legislature's initiative to undertake this study of industry restructuring and retail access issues to determine whether customer choice would provide benefits to all consumers.

Implications

How public power systems carry out their tasks of procuring and delivering energy services for their customers is affected by their relationship to the larger context in which they operate – local economy, demography, work force, natural resources, legislation, regulation, technological innovation, politics, financing, and communications. It is against this general backdrop that the Legislature must consider the historical basis and the framework for Alaska's existing structure of local regulation and local control over cooperative and municipal utilities, and detail the possible impacts various legislative and regulatory restructuring options may have.

For representatives from small public utilities, adequate consumer protection holds the highest value and is an absolute prerequisite to any restructuring initiative that would allow retail access.

Utility representatives throughout the US also feel very strongly about protecting community-based programs funded by local power companies. These include lifeline rates, low income assistance, wildlife preservation, service cut off protections, energy efficiency, and community services such as lighting for playgrounds, athletic fields, and holiday lighting.

There is fairly broad consensus that universal service programs should not compete for funding with other public benefit programs. In addition, low-income assistance programs should be supported by dedicated funds. If the state chose not to provide for the most vulnerable, a mechanism would be needed to provide the poorest and highest cost-to-serve customers with access to electricity.

Municipal utility representatives in the lower-48 also stated that another condition of local choice participation is the continued right of annexation – seen as an important tool that allows local governments to meet their obligation to serve new residents and promote economic development on behalf of the community. Current APUC rules allow the Commission to address service territory disputes.

Assessment

Representatives from small cooperative and municipal utilities feel very strongly that their participation in competitive retail electricity markets should be predicated on a voluntary choice, and not mandated by federal authorities. Alaska's high concentration of public power providers, however, effectively means that "opt-in" local participation approaches are not likely to work well in this environment. One variation proposed for Alaska is to require retail competition for Anchorage while allowing other Railbelt utilities the "opt-in" option. To this end, some stakeholders have enumerated several conditions as a prerequisite for local participation. Other stakeholders feel that these conditions are too broad and expansive, are not warranted by the competitive risks, will inhibit fair competition, and serve to protect competitive advantages not afforded to other groups of competitors. They feel that if competition is deemed to be in the best interest of the State, all consumers should be given equal access to competitive supplies and energy services, and that consumer protection, universal service, and public benefits should be prescribed and administered on a uniform basis across the State, or at least across the Railbelt.

Key Decisions

- **Rates.** Should the state of Alaska proceed with electric industry restructuring if lower rates for residential and small business consumers cannot be guaranteed for both the short- and long-term?
- **Competitive Safeguards.** If policymakers choose to restructure, how should state regulators ensure that truly competitive generation markets will be created? Should robust wholesale markets exist before retail access is adopted? To prevent the creation of unregulated monopolies, should specific definitions of what constitutes effective competition be in place before restructuring takes place? Should state and federal agencies update and strictly enforce antitrust and other statutes to protect consumers?
- **Protection from Price Cross-Subsidization.** How should state regulators prevent the practice of cross subsidization between a company's regulated and non-regulated subsidiaries?
- **Access to Information.** To what extent should consumers be able to determine and compare the prices for transmission, distribution, and retail energy services and have access to information about the generation sources of the electricity they purchase?
- **Aggregation Protection.** To what extent should the ability of consumers to aggregate their electricity purchases be protected?
- **Consumer Protections.** What is the need for state agencies to update and strictly enforce consumer protection laws to ensure fair marketing, sales and service practices? Should all sellers of electricity be licensed and be subject to penalty for license violations? What is the state policy regarding other consumer protection issues such as privacy protection; "slamming" (unauthorized switching of providers); "pre-selling" (securing customers before a supplier has the technical ability or legal authorization to provide service); fair and understandable billing; and clearly written terms and conditions of service?

List of Accompanying Tables & Figures

Local Aggregation

Local governments have a substantial stake in the outcome of electric industry restructuring in terms of revenue streams, the ability to protect and advance the public interest and to protect the welfare of businesses and residents, and the ability to guide key infrastructure development.

Local government is a "natural aggregator." Local governments aggregate consumers for a range of essential services. Through aggregation for electric service, it is argued, consumers may gain greater benefits and terms of service. As an aggregator, local government is a non-profit, non-discriminatory service provider, subject to ethics and open-bidding laws, and to local control by consumer/voters. Furthermore, it is argued that local government aggregation offers transparent pricing and consumer oriented benchmarks for service – the institutional standing and statutory powers of local government helps to enforce contract compliance.

Partnerships of local-and-state governments are one way to adequately translate regulatory policies into market rules and to protect the public interest and provide balance to the interests of suppliers and service providers. The ability of consumers to grant, amend, or revoke franchises and contracts though their local government constitutes a fundamental consumer protection in many states. The features of local aggregation are provided in Table 4.1.

Local Franchise Authority Status

The power and authorities of local government for franchising electric service vary from state to state. In many states, the franchise power is seen as providing an effective tool for ensuring that tax, fee, and fee-in-lieu of taxes revenues are not adversely impacted by competition. Franchise oversight through terms and conditions is also seen as a mechanism for ensuring a measure of customer protection. Whether to create franchise powers for Alaska communities is a policy question that should be considered as part of the overall restructuring debate. Thirty states indicate local electric franchise contracts still in use. Another eleven states indicate local government with substantial franchising power for electric service even though contracts are not currently in use. Nine states, including Alaska, indicate that local franchising power have been removed to the state level. A summary of Local Franchise Authority states is provided in Table 4.2

Local Franchise Issues

There are four core powers of local government that function in an interactive manner for effective aggregation of consumers under a community franchise: certification, regulation, municipalization, and aggregation and contracting on behalf of consumers. A description of these four powers is provided in Table 4.3. To be successful, local government must be able to use its full range of power to represent consumers and to work with state government to establish a level playing field for terms of service among competing suppliers.

The primary obstacles to use of community franchise are lack of political support, lack of initial resources for establishment, clouded or absent local authority, opposition from entrenched utilities or power suppliers seeking market power, and opposition from others ideologically opposed to local government representing the interests of consumers for essential services.

Issues associated with local franchises and the implications of retention of local ownership and regulation in a restructured market are addressed in Table 4.4

Aggregation

Aggregation of consumers can function in the currently existing utility structure, in a transitional structure, and in competitive retail markets. Aggregation offers a stable, institutional option that provides access and protection for small consumers in what may be a stratified and very volatile marketplace. It provides an opportunity to combine loads. With larger combined (or aggregated) loads, consumers may be able to negotiate for better deals.

Combining many customers' loads into a buying pool provides an opportunity for a lower price of electricity. Aggregation can possibly achieve lower prices by using market power and diversity power. Market power is the power to negotiate for lower electricity prices by buying in bulk, comparable to buying in a club or discount membership store. Diversity power is the combining of customers with different electric use patterns into a more attractive pattern that does not change over the day. Relatively constant use over the day will be more attractive to an energy service provider than a pattern that has pronounced high use peaks and low use valleys because the energy service provider will be able to negotiate a better deal from generators.

Loads can be aggregated in two ways. A single business that has control over many individual accounts can offer all of those loads to a seller. An example of this "single-owner" method of aggregation is McDonald's packaging all of its restaurants into a single energy services offer. In contrast, the "multi-owner" aggregation method combines the loads of separate businesses. The California Electric Users Cooperative, which is combining the loads of individual agricultural cooperatives, is an example of multi-owner aggregation.

Aggregation raises public policy problems if it is not voluntary. This is an important issue for cooperative and municipal utilities. Policy maker must decide at which point individual customers of cooperative and municipal utilities will enjoy the right to "opt-out" of their aggregation pool.

The savings from aggregation need to be balanced against the costs of aggregation. One multi-owner aggregation group of almost 500 members in California expects gross annual savings of approximately $720,000. The average use for each member is 640,000 kilowatt-hours (kWh) or the equivalent of 100 residential customers. These savings are offset by start-up costs of approximately $150 per customer. The forms aggregation can take are shown in Table 4.5. Some examples of aggregation from California are provided in Table 4.6. A sample of position guidelines on electric industry restructuring from the Massachusetts Municipal Association is provided in Table 4.7.

TABLE 4.1
Features of Local Aggregation

Feature	Comment
Leverage of Existing Capabilities	Most local governments currently provide aggregation of many other services for consumers, and function in a manner that is non-discriminatory, subject to open-bidding laws, and subject to public disclosure and ethics requirements.
Home Rule	Local government possess statutory and "home rule" powers specifically related to electric service that can provide consumers with leverage in offering, negotiating, and maintaining aggregate contracts.
Opportunity for Lower Prices	Market Power – the power to negotiate for lower electricity prices by buying in bulk. Diversity Power – combining customers with different electric use patterns into a more attractive load pattern.
Costs	Start-Up Costs – establishing the aggregation pool Customer Switching Costs – switching a customer to an aggregation pool On-Going Costs – maintenance of the aggregation pool
Broker vs. Electric Service Provider	As a broker, local government acts as an agent, bringing together buyers and sellers. A broker does not take ownership of electricity and, consequently, is not paid directly by customers of electricity service. As an aggregator, the local government can become an energy services provider (ESP). As an ESP, it takes ownership of the commodity and is paid for the product and services by its customers.
Existing Mechanisms	Existing mechanisms, such as community energy authorities, joint power agreements, or joint power agencies, can become brokers or createESPs to take advantage of aggregation buying power.
Opt-In/Opt-Out	Opt-in requirement – where the local utility is the default provider – each customer is automatically excluded from the pool unless they make a specific request to participate. Opt-out model – where the local municipality/county is the default provider – each customer is automatically included in the aggregation pool unless the customer specifically takes steps to indicate that they choose not to participate. An opt-out model decreases recruitment costs and increases the aggregate loads under the negotiation power of the local government.

TABLE 4.2
Summary of Local Franchise Authority Status

The listing of states below is based on a survey of information contained in*Utility Regulatory Policy in the United States and Canada: Compilation 1994-1995*, (Washington, D.C.: National Association of Regulatory Utility Commissioners, 12995) and *The Electric Utility Franchise and Renewal Process*, (Washington, D.C. Urban Consortium Energy Task Force of PTI, September 1989). Neither of these sources provides comprehensive data.

1) Local franchise contracts with electric utilities reported active in 30 states:

Alabama	Illinois	Minnesota	Oklahoma
Arizona	Iowa	Mississippi	Oregon
Arkansas	Kansas	Missouri	South Carolina
California	Kentucky	Nevada	South. Dakota
Colorado	Louisiana	Nebraska	Texas
Florida	Michigan	New Mexico	Virginia
Georgia	Minnesota	New York	Washington
Idaho	Mississippi	Ohio	Wyoming

2) Significant local franchise power are indicated in 11 additional states that do not currently have active local franchise contracts:

Connecticut	Massachusetts	North Dakota
Hawaii	Montana	Rhode Island
Indiana	New Jersey	Tennessee
Maryland	North Carolina	

3) Lack of local franchise power is indicated in nine states:

Alaska	North Dakota	West Virginia
Delaware	Pennsylvania	Wisconsin
Maine	Utah	
New Hampshire	Vermont	

TABLE 4.3
Four Core Powers Related to Municipal Aggregation of Consumers

Powers	Description	Comment
Certification	Allows local government to continue to determine the terms and conditions for utilization of public streets and ways at the local level for delivery of services.	Far reaching implications over the ability of communities to guide infrastructure development and the traditional protection of public interest at the local level.
Regulation	Most states have statutes that allow local government some degree of regulatory control over electric utility service.	The extent of local authority is generally interpreted as complimentary to state jurisdiction. With alteration of state regulatory oversight, the specific interpretation of local power may change to ensure continued protection of consumers and the public interest.
Municipalization	The sovereignty of choice – for a local government to self-franchise – is a power given to local government in most states.	Specific state requirements for eminent domain takings of existing private utilities can make it a difficult and lengthy process.
Aggregation and Contracting	These are the traditional functions that municipalities carry out on behalf of citizens for a range of services. For electric service, it is an inherent part of the franchise grant.	Municipalities utilizing these functions do not buy and sell electricity, but set the terms and conditions for service. Effective use of municipal aggregation contracts will rely on the intermix of the three other powers – regulation, certification, and provisions for municipalization.

TABLE 4.4
Issues of Retention of Local Ownership and Regulation in a Restructured Market

Issue	Comment
Regulation to protect the public interest currently provides for mixed oversight by federal, state, and local government. As a central part of this mixed system, the historic building blocks of the electric industry and existing markets are local government franchise grants to utilize public streets and ways	Most private electric utilities operate today under rights derived from these local franchise grants and various statutes and rules reflect continuing local authority.
Locally-based competition is not new.	During the first decades of this century, municipal governments commonly aggregated consumers and offered franchises for electric service to competitive bidders.
More than one thousand cities and towns in 30 states still hold franchise contracts with an existing monopoly electric power supplier.	In eleven states, statutes and rules indicate local government possesses substantial franchising power, although electric franchise contracts are not currently in use. In nine states, statutes and rules indicate that state government has displaced local franchise authority.[1]
Franchise contracts for thousands of other cities and towns have lapsed or expired.	The APPA sees utility restructuring as an opportunity to revitalize franchise contracts and aggregate consumers. In many cases, this may be a matter of utilizing existing provisions in city charters, statutory, or constitutional powers that have remained dormant under the current system of monopoly electric service. In other cases, legislation, regulatory rule-making, or litigation may be required to clarify local authority to aggregate and contract for consumers where local power has become clouded or displaced.
More open and competitive power markets will lead to greater access to transmission facilities and new providers of energy and energy services	Franchises will offer communities renewed opportunities and substantial competitive leverage for pricing and other terms.
An initial review of the potential financial impact of utility restructuring undertaken by the firm of Deloitte and Touch has indicated $15 billion in state and local tax and revenue streams in jeopardy.[2]	The APPA sees restructuring as a way to reestablish and protect local tax and revenue streams.

[1] Survey information from *Utility Regulatory Policy in the United States and Canada: Compilation 1994-1995*, National Association of Regulatory Utility Commissioners, 1995; and City of Chicago Planning Department, *The Electric Utility Franchise Expiration and Renewal Process*, Urban Consortium Energy Task Force, September 1989.

[2] Deloitte & Touch, *Federal State and Local Tax Implications of Electric Industry Restructuring*, The National Council on Competition and the Electric Utility Industry, October 1996.

TABLE 4.5
Aggregation Forms

Franchise Form	Description	Advantages/Disadvantages
Firm Franchise – Municipal Utility	Automatically aggregates all consumers in a municipal service territory (existing franchises already possess this form)	Offers consumers control over policies Ability to grant, amend, or revoke contracts consistent with the community's interests
"Muni-Lite"	Local government claim that it owns enough of the local electricity distribution system to be granted the right to act like a municipal utility	Eliminates the protracted and costly legal and political process of full municipalization
Loose Franchise	Automatically aggregates all consumers in a municipal service territory, but allows individual consumers a choice to opt-out	Address specific state conditions and provides flexibility for consumers to "opt-out" of the franchise
Split Franchise	Allows for municipal consumption only, or some other form of service	Provides benefits only for municipal street lighting and buildings May pit the municipality against its own residents in a competitive market
Cooperative Franchises	Units of local government can band together – counties, cities, towns, school districts, sewer and water districts, municipal hospitals, etc.	Reduce transactions costs by procuring energy related needs on a cooperative basis. Reduce costs by increasing buying power
Preferred Provider Franchise	A municipality (or group of municipalities) or a county (or group of counties) can act as the purchasing agent for all, or a number of, its constituents	The supply contract resides between the end-users and the provider – the municipality remains free from financial risk and day-to-day operation
Licensed Power Marketer	The municipality buys and sells electricity on the wholesale market for its own account and the account of others	Requires high level of specialized skills May imply unacceptable level of financial risk for municipality

TABLE 4.6
Aggregation Examples

	Description	Savings	Electric Service Provider
City of San Jose	13 municipal sites	5% savings of the energy portion – 1.5% off the total bill	New Energy Ventures
California Manufacturers Association	An association of California manufacturing firms	6% savings off the energy portion on a one-year contract – about 2.4% off the total bill 8% savings off the energy portion on a two-year contract – about 3.2 percent off the total bill	Montana Power
San Diego Association of Governments	An association of San Diego county government agencies	1.5-3.5% savings off the total bill 1 year term	Commonwealth Energy
Sonoma County	Government loads	3.5 percent off total bill for selected accounts 3 year term	Commonwealth Energy
City of Concord	Government loads	2.75 percent off total bill 3 year term, with opt-out after year 2	New West Energy
California Electric Users Cooperative	10 agricultural cooperatives	About 3% off the total bill	New West Energy
City of Long Beach	Government loads	2.75 percent off total bill 4 year term	New West Energy
ABAG Power	A joint powers agency serving public agencies in PG&E's service area Operating as an energy service provider	About 2-3% off the total bill	
California Department of General Services	Offers electricity supply services to state agencies, public sector higher education, cities, counties, and school districts Operates as a broker	Savings ranging from 2.75% to 4.25% off the total bill	

TABLE 4.7
Sample Position Guidelines on Electric Industry Restructuring, The Massachusetts Municipal Association, February 1996

In order to provide cost containment for municipal and other electric consumers, and as a means to foster economic development in the Commonwealth of Massachusetts and it is municipalities, the Massachusetts Municipal Association supports the concept of electric industry restructuring. A restructuring plan must result in lower future electric rates with no diminution of services. The MMA does not support or oppose any specific form of restructuring. However, the MMA believes that any electric industry restructuring plan must, at a minimum, satisfactorily address the criteria listed below.

Equitable Benefits	Any restructuring program must result in all rate payers directly and equitably sharing in the benefits of a restructured environment.
Economic Impact	Any new industry structure should be based on a thorough economic analysis of the full short and long term costs and potential benefits of the alternatives under consideration.
Municipal Authority and Local Governance	Existing local powers authorized by the state Constitution, state law, municipal charters, and case law should not be abridged by any restructuring plan. Any restructuring program should maintain the concept of municipal utilities; must not abridge the existing authority of municipal utilities to operate; and should facilitate the ability cities and towns to form individual or regional municipal utilities, pools, and franchises in the future. Under any restructuring program, a local government should have the option to serve as an aggregator to negotiate the purchase of electricity with electric suppliers on behalf of its community.
Stranded Investments	The problem of stranded investments should be resolved in a way that keeps rate payers and municipalities financially whole.
Wheeling	Any restructuring plan should facilitate the fair and equitable transmission access of electricity between generators and whole and retail end users.
Alternative Sources	Any restructuring program should incorporate support of alternative energy in order to enhance the mix of energy sources available in Massachusetts, both for environmental and strategic energy security reasons and further to enhance competition.
Social and Environmental Impacts	Massachusetts should not abandon its energy programs that provide social and environmental benefits.

Competitive Advantage

Issue

Competition in electric power markets must be healthy and energetic for consumers to realize the benefits believed to flow from more open and competitive markets. A robust competitive market could be compromised if one group of competitors is advantaged by market structure, market rules, or financial incentives and subsidies.

Alaska Dynamic

The principal concern among stakeholders is the extent to which structural, legal and financial advantages currently enjoyed by different competitive groups in Alaska could translate into a cost advantage in a competitive market for retail customers. This is especially true in the large commercial and industrial sectors, where rates differ by more than $0.02/kWh. The concern among several utility representatives is that cost-based commodity competition could have a disproportionate impact on small utilities. For instance, the loss of several large customers for a large utility like CEA will have a much smaller impact on the company than for Homer or MEA.

Implications

The devil is in the details. The spirited debate among railbelt utilities regarding the relative competitive advantages each would enjoy in a competitive market has produced a very informative body of literature. In order to first define, and then create, a "level playing field" for all competitors, the policy makers must consider a broad range of legitimately complex technical, financial, and legal issues. These issues include: differing treatment under tax law, access to lower than market capital, disagreements over the rules and procedures that should govern access to transmission and distribution facilities; the division of regulatory authority between federal, state and local government agencies; protection of all customer classes; obligation to serve, open records and public meetings laws, new demands for more stringent environmental protection, and a number of questions related to cost allocation, cost recovery, and system reliability.

Assessment

There is unanimous agreement among stakeholders that the current structure of the industry and the differing benefits enjoyed by municipal, cooperative, and investor-owned utilities is a result of historical circumstances, and needs to be carefully reconsidered in the context of more open and competitive markets. The principal questions center on which of these relative benefits should be retained, or what new protections should be added, because of the special circumstances or needs of individual utilities or groups of utilities. Many stakeholders feel that the utilitarian benefits associated with insulating certain utilities by structural means and/or maintaining specific legal rights and financial benefits outweigh the pragmatic and ideological exigencies of a uniformly level playing field. Several others – on both sides of the debate – find this position troubling and advocate an "all or nothing" approach. Manipulation of the system on the margin to affect certain short-term outcomes, they argue, produces the least desirable results

Key Questions

- Are the benefits, incentives, advantages and subsidies inherent in current legal, regulatory and tax structure still appropriate today?
- To what extent they should they be modified to reflect new and emerging market conditions?
- To what extent is a "level playing field" (in which all competitors are subject to the same structural, legal, and financial rules) in the best interests of the State?
- Are there certain competitive protections and advantages that should be maintained to help guide and influence a desired outcome?
- How do you measure and allocate stranded investment?
- What are the public policy standards that should guide regulatory bodies in assessing horizontal 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?

List of Accompanying Tables & Figures

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 ("EPAct"), 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).

EPAct also granted the Federal Energy Regulatory Commission ("FERC") the express authority to order wholesale wheeling under certain conditions. Until EPAct, 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-EPAct 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 of control 10 percent of 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 form 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 independent power producer (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 ruled 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 that 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 Rural Utility Service (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.	EEI 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-mitigatible. 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-mitigatible, 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 no 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 "grand-fathered" 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.

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?

List of Accompanying Tables & Figures

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 many 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 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 units 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 (SO_2) and carbon dioxide (CO_2) 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?

List of Accompanying Tables & Figures

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 SO_2 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 are 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 SO_2 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 in 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 typical 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. In interconnected systems, departures from the nominal 60 Hz by even ±0.1 Hz are rare. If frequency departs by as much as ±1Hz, 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 bus 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 Flexible AC Transmission System (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 thosewho 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 (CO_2)	Sulfur Dioxide (SO_2)	Nitrogen Oxide (NOx)
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 state/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 30percent 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, Kusdodwin, 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

TABLE 6.13
Renewable Provisions in Federal Legislation
RPS=renewable portfolio standard; SBC=system benefits charge; MSW=municipal solid waste

Bill Sponsor	Provision	Basis	Technology Eligibility	Comments
Bumpers & Gorton (S 1401)	RPS – 5% 2003-2007 9% 2008-2012 12% 2009-2019	Retail electricity sales	Solar, wind, biomass, hydro, geothermal, waste/landfill gas	Sunset December 31, 2019. Requirement on retail suppliers. Submit credits to FERC based on percentage of retail sales from preceding year. ½ credit for large hydro (above 80 MW). 1 credit for existing renewables inc. small hydro. 2 credits for new renewables inc. small hydro.
Clinton Administration (S2287)	RPS – 7.5% 2010-2015 (DOE Secretary sets targets for 2000-2004 and 2005-2009) SBC – Public Benefits Fund Net metering (up to 20 kW) NOx cap and trade	Retail electricity sales	Wind, solar, biomass, and geothermal. (not specified whether or not MSW is eligible) SBC funding for low-income, energy efficiency, renewables, consumer education and R&D.	Sunset in 2015. Requirement on retail suppliers. Credit banking allowed. 1.5 c/kWh cost cap, adjusted for inflation. Administered by DOE. Administration costs must be less than 5% of credit value. RPS replaces PURPA “must buy” provision, but honors existing PURPA contracts. SBC matching funds to states, federal portion not to exceed 1 mill/kWh ($3 billion).
Jeffords (S 687)	RPS – 2.5% in 2000 rising 0.5%/yr 5% in 2005 rising 1%/yr 10% in 2010 20% in 2020 onwards SBC – Public Benefits Fund Emissions cap and trade for SO2, NOx, and CO2.	All electricity generated for sale except hydro (includes cogeneration sold to utilities and excludes self-gen.)	Solar, wind, biomass, geothermal, waste/landfill gas (excludes incinerated MSW)	Self-sunsetting. Requirement on generator. Submit credits to FERC by July 1 based on generation for sale from preceding year. SBC matching funds to states, federal portion not to exceed 2 mills per kWh.
Kucinich (HR4798)	RPS- Existing baseline plus: 3% by 2005 8% by 2010 increasing by 1% per year thereafter PB fund of 0.7¢ per kWh	Generation	Organic waste biomass (not including municipal solid waste), dedicated biomass energy crops, landfill gas, geothermal, solar, or wind resources	Sunsets when DOE certifies that the administrative costs are no longer justified by the market value or number of credits traded.

Bill Sponsor	Provision	Basis	Technology Eligibility	Comments
Markey (HR 1960)	RPS – 3% in 1998 10% in 2010 (DOE Secretary sets targets in intervening years.) Net metering	All electricity generated for sale (includes cogeneration sold to utilities and excludes self-gen.)	Solar, wind, geothermal, biomass (excludes MSW)	Self-sunsetting. Requirement on generator. Submit credits to DOE based on generation for sale from preceding year. DOE issues, monitors and administers
Schaefer, Palone & Largent (HR 655)	RPS – 2% 2000-2004 3% 2005-2009 4% 2010	All electricity generated for sale except hydro (includes cogeneration sold to utilities and excludes self-gen.)	Organic waste, biomass, dedicated energy crops, landfill gas, geothermal, solar, tidal, wind	Sunset in 2015. Requirement on generator. Submit credits to FERC based on generation for sale from preceding year. Utility purchasing renewables under existing PURPA contract considered generator.
DeFazio (HR 1359)	SBC – Public Benefits Fund			Matching funds to states, federal portion not to exceed 2 mills per kWh.
Pallone (HR 2909)	NOx cap 2 mm tons by 2005 SOx cap 4 mm tons by 2005			Caps for emissions, with higher credits for renewables.

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Timeline for Federal Renewable Portfolio Standard Bills

	Bill #	2000	2003	2005	2008	2010	2013	2015	2020	Applies to:
Bumpers	S1401		5%		9%		12%	12%	sunset	Retailer
Clinton	S2287	existing				5.5%		sunset		Retailer
Jeffords	S687	2.5%	4%	5%	8%	10%	13%	15%	20%	Generator
Kucinich	HR4798	baseline	+1.5%	+3%	+6%	+8%	+11%	+13%	+18%	Retailer
Markey	HR1960	3%				10%	10%	10%	10%	Generator
Schaefer	HR655	2%		3%		4%	4%	sunset		Generator

Notes: Hydro not eligible, except for Bumpers, where large hydro (above 80MW) gets 1/2 credit, existing small hydro (below 80MW) gets 1 credit and new small hydro gets 2 credits.

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TABLE 6.14
State Minimum Renewable Energy Requirements

State	Requirement*	Status	Eligibility	Comments
Arizona	0.2% of sales in 1999 rising to 1% in 2003	Regulation: Decision and Amended Rules On Electric Competition www.cc.state.az.us/rules/elec.htm	In-state solar PV and solar thermal electric	Solar Portfolio Standard: www.cc.state.az.us/rules/ELEC/APP_A/2-1609.HTM Penalty of 30 cents/kWh to solar electric fund
Connecticut	Class I or II technologies 5.5% in 2000; 6% in 2005 7% in 2009 Class I technologies 0.5% in 2000 +0.25%/yr. to 1% by 2002 +0.5%/yrr to 3% by 2006 +1%/yr to 6% in 2009	Law H. 5005 www.cga.state.ct.us/ps98/act/pa/pa%2D0028.htm	Class I: solar, wind, hydro, sustainable biomass, landfill gas, fuel cells. Class II: hydro, MSW, other biomass.	Law allows state (Connecticut Public Utilities Commission) to implement credit trading.
Iowa	105 average MW ~ 2.5% of sales	Law Alternate Energy Production Law (1983) revised (1991)	Solar, wind, methane recovery, biomass	Applies to IOUs only.
Maine	30% of sales in 2000 (start of competition)	Law LD1804 and Public Law Chapter 316 http://janus.state.me.us/legis/statutes/35A/title277.htm Draft regulations published Docket 97-584	Fuel cells, tidal power, solar, wind, geothermal, hydro, biomass, MSW and cogeneration (under 100 MW)	Renewables currently 46-51% of generation. PUC makes recommendations for changes to legislature no later than 5 years after beginning of retail competition. No credit trading (draft regulations).
Massachusetts	State to determine existing renewables by 12/31/99 (~7%) +1% from new renewables by 2003 +0.5%/yr. to 4% by 2009 +1% per year thereafter until date determined by Division of Energy Resources.	Law Chapter 164 of the Acts of 1997 www.magnet.state.ma.us/legis/laws/seslaw97/sl970164.htm Legal challenge	Solar, wind, ocean, clean biomass; hydro and MSW qualify as existing, but not as new renewables.	+1% new renewables requirement may start one year after any renewable within 10% of avg. spot market price. Language ambiguous as to whether requires preservation of existing level of renewables. Studies of tradable credits, penalties, state agency minimum purchase requirements. These mechanisms would require new legislative authorization.

State	Requirement*	Status	Eligibility	Comments
Minnesota	550 MW phased in, plus possible 400 MW more wind by 2002 ~4.3% of sales	Law Radioactive Waste Management Facility Authorization (1994)	Wind (425 MW) and biomass (125 MW)	NSP allowed to build temporary dry cask storage of nuclear waste at Prairie Island nuclear plant in exchange for renewable energy development. +400 more MW of wind by 2002 if least cost resource.
Nevada	0.2% in 2001, rising 0.2% biannually to 1% in 2009	Regulatory proceeding underway	50% from solar, 50% from wind, biomass, geothermal in state.	Applies to IOUs and IPPs, but not coops, munis or general improvement districts. Utilities with 9% or more of their electricity coming from renewables in 1997 are deemed to be in compliance until 2005.
Wisconsin	50 MW by 2000	Reliability Act		RPS proposed in SB517

State's considering RPS: Wisconsin (4% by 2009), Kansas (20% by 2020), Nebraska (10% by 2010), New Mexico (10% by 2015), Vermont (15% existing +4% new by 2007) and Delaware, Texas (3% by 2009)..

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TABLE 6.15
State Public Benefit Funding for Efficiency, Renewables, R&D

State	Efficiency	Renewables	R&D	Status	Renewables Uses and Eligibility	Comments
California	1.2 mills/kWh $185m/year for 4 years	0.8 mills/kWh $135 million/year for 4 years Existing renewables = 45% of funds New projects = 30% Emerging techs. = 10% Customer credits = 15%	0.4 mills/kWh $61.8 million/yr. for 4 years	Law A.B. 1890 www.leginfo.ca.gov/bilinfo.html www.energy.ca.gov	Production incentives, project financing and customer rebates. Separate renewables fund accounts for existing, new, emerging, customer incentives.	Renewables/R&D administered by Cal. Energy Commission Efficiency by utilities/collaborative
Connecticut	3 mills/kWh $63 million/year	0.5 mills/kWh in 2000 0.75 mills in 2002 1 mill in 2004 1 mill ~ $21 million per year		Law H 5005 www.cga.state.ct.us/ps98/act/pa/pa%2D0028.htm	Renewables and fuel cells. Economic development and renewables for customers.	Renewables admin. by Connecticut Innovations (econ. development) Efficiency by utilities/collaborative
Illinois	$3 million/year ~03 mills/kWh 10 years residential DSM	2.5¢/month customer charge ~0.04 mills/kWh matched w/gas co. funding = $5 million per year for 10 years	$5 million/year for “clean coal” R&D	Law HB 362, HB 1817, and SB 56 http://www.state.il.us/icc/Dereg/IEDB/	Grants, loans, and other incentives for wind, solar thermal, PV, dedicated biomass crops and organic waste biomass, existing or run-of-river hydropower	Administered by Department of Commerce and Community Affairs

State	Efficiency	Renewables	R&D	Status	Renewables Uses and Eligibility	Comments
Massachusetts	Declines from 3.3 mills/kWh to 2.5 Averages 2.9 mills =$135 million/ year, 5 years	Averages 0.95 mills/kWh first 5 years = $45 million per year 0.25 mills dedicated for MSW pollution controls or retirement 0.5 mills thereafter (no MSW) ~$20-$25 million/yr.		Law Chapter 164 of the Acts of 1997 www.magnet.state.ma.us/ legis/laws/seslaw97/sl970 164.htm Legal challenge	New solar, wind, ocean, advanced biomass, fuel cells, possibly DSM and distributed generation. Economic development, renewables for customers, education, R&D	Renewables administered by Mass. Tech. Park (Econ. Development). Efficiency by utilities/collaborative IOU customers only. Municipal aggregators can access.
Montana	2.4% of annual retail sales for 1995 (about $12 million per year)			Law www.psc.state.mt.us/gas elec/mcaelec.htm		
New Mexico		0.5% of revenues		Rate order for Public Service of New Mexico Regulation proposed statewide http://www.puc.state.nm.u s/proceed.htm	50% to solar 50% bidding process for other renewables	Proposed rulemaking on net metering and disclosure.
New York	0.6 – 1.0 mills/kWh per utility; avg. ~0.7 mills (~$78 million/yr.) Historically DSM = 74.4%; renewables/R&D = 15%; low-income = 10.6%			Case-by-case regulatory review. Order at http://www.dps.state.ny.u s/fileroom/doc4406.t		Administered by NYSERDA state agency
Rhode Island	2.3 mills/kWh about $15 million per year			Law	Renewables & DSM, including hydro under 100 MW	Administered by utility collaborative
Estimated Total	~$530 million/yr.	~$210 million/yr.	~$70 million/yr.			

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TABLE 6.16
Number of Customers and Retail Sales by Power Marketers in State Pilot Programs, 1997

	Residential		Commercial		Industrial	
State/Power Marketer	**Consumers**	**Sales (MWh)**	**Consumers**	**Sales (MWh)**	**Consumers**	**Sales (MWh)**
California						
National Gas & Electric LP			12	3887		
Idaho						
Cincinnati Gas & Electric Co.					4	8487
Energy Services, Inc.					1	1130350
IGI Resources, Inc.					1	11225
PSI Energy, Inc.					*	8487
Illinois						
Cincinnati Gas & Electric Co.			4	3830		
Enron Power Marketing, Inc.					4	78954
Illinova Energy Partners, Inc.					6	59665
National Gas & Electric LP					3	34443
PSI Energy, Inc.			*	3637		
QST Energy, Inc.	1329	18261	4	17027	9	288699
Rainbow Energy Marketing Corp.	6	98				
Massachusetts						
Working Assets Green Power, Inc.	730	3766				
XENERGY, Inc.				14	218745	
Missouri						
Cincinnati Gas & Electric Co.			1	17938		

	Residential		Commercial		Industrial	
State/Power Marketer	**Consumers**	**Sales (MWh)**	**Consumers**	**Sales (MWh)**	**Consumers**	**Sales (MWh)**
PSI Energy, Inc.			*	20868		
New Hampshire						
Central Maine Power Co.	12	269	3	2922	1	820
Central Vermont Public Service Co.	274	159	237	4586	71	19950
Enron Power Marketing, Inc.	778	7467	315	14729		
Plum Street Energy Marketing Co.	23	146	24	3409		
UNITIL Resources, Inc.	1105	12095	28	11083	4	2073
Working Assets Green Power, Inc.	116	648				
XENERGY, Inc.	33	284	12	4954	2	10345
New York						
National Fuel Resources, Inc.	40	101		65	570	
NEV LLC			300	3935		
Plum Street Marketing Co.	7	642	4	289	3	2135
Oregon						
Energy Services, Inc.					1	948912
Enron Power Marketing, Inc.			205	581		
Pennsylvania						
Bruin Energy, Inc.	35	31				
CNG Retail Services Corp.	**	10274	**	1813		
Dupont Power Marketing, Inc.			1	235	1	18
DTE-CoEnergy LLC			26	1960		
Energis Resources, Inc.	2	11	349	11779	26	18321

	Residential		Commercial		Industrial	
State/Power Marketer	**Consumers**	**Sales (MWh)**	**Consumers**	**Sales (MWh)**	**Consumers**	**Sales (MWh)**
Enron Power Marketing, Inc.	4400	1725	78	105		
GPU Advanced Resources, Inc.	3804	4740	360	9372	6	3709
Horizon Energy Co.	**	33560			**	80863
New Millennium Energy Corp.			1	39		
QST Energy, Inc.	19557	19231	10	541	19	2692
UGI Power Supply, Inc.			10	107		
Rhode Island						
Enron Power Marketing, Inc.					1	5882
NEV LLC			13	45365		
Washington						
Avista Energy, Inc.					2	208798
Cincinnati Gas & Electric Co.					1	1449
Duke Energy Trading & Marketing			3	17518	2	1006190
Dupont Power Marketing, Inc.					1	16256
Energy Services, Inc.					2	963820
Illinova Energy Partners, Inc.					1	271860
IGI Resources, Inc.					9	137583
Montana Power Trading & Marketing					1	697
PSI Energy, Inc.					*	1449
Totals	32251	113508	2000	192509	251	5543447

Source: http://www.eia.doe.gov/cneaf/electricity/esr/esr.pdf (Table B1)

TABLE 6.17

Impacts of Renewable Portfolio Standard on Alaska

RPS Set at 7.5% in 2010	UNIT	TOTAL 2000-2015	NPV 2000-2015	1997	2000	2005	2010	2015
Alaska Sales	**1,000 kWh**	84,263,852		4,840,529	4,957,633	5,159,137	5,368,831	5,587,048
RPS	**%**			0.00%	0.00%	3.75%	7.50%	7.50%
Renewables	**1,000 kWh**	4,224,890		0	0	193,468	402,662	419,029
Premium								
@ 0.5¢/kWh	**$**	2,112,445	665,442	0	0	96,734	201,331	209,514
@ 1.0¢/kWh	**$**	4,224,890	1,330,883	0	0	193,468	402,662	419,029
@ 1.5¢/kWh	**$**	6,337,336	1,996,325	0	0	290,201	603,993	628,543
@ 2.0¢/kWh	**$**	8,449,781	2,661,767	0	0	386,935	805,325	838,057
@ 2.5¢/kWh	**$**	10,562,226	3,327,209	0	0	483,669	1,006,656	1,047,572

Load Growth	0.8%
Discount Rate	12.0%

TABLE 6.18
Example Price Impacts of Public Purpose Program Options
(In Alaska in 1997, a charge of 1 mill on electricity sold in the Railbelt will collect approximately $3.7 million/yr. total funds, and cost the average residential customer $0.67/mo. A charge of 1 mill on electricity sold throughout Alaska will collect approximately $4.8 million/yr. total funds, and cost the average residential customer $0.69/mo.)

Program Option	Total Cost/Duration	Average kWh Cost	Cost Impact on Average Residential Customer	MW Impact
Renewable Energy				
Renewable Portfolio Standard – Clinton Administration Proposal	$2.1 to $10.6 million/yr. – 15 yr.	$0.005 to $0.025/kWh (range of premium costs)	$0.30 to $1.40/mo	121 MW added
Energy Efficiency				
Energy Efficiency – (Using Connecticut, Illinois laws)	$14.5 million/yr.	$0.003/kWh	$2.04/mo	N/A
Low Income				
Dedicated Fund for Low Income Energy Assistance (0.5% & 1.0% of revenues)	$2.44 million/yr. @ 0.5% rev. $4.88 million/yr. @ 1% rev.	$0.0005/kWh @ 0.5% $0.0010/kWh @ 1%	$0.35/mo @ 0.5% $0.70/mo @ 1.0%	N/A
Energy Research & Development				
Energy Research & Development – (Using California law - .4 mill/kWh)	$1.94 million/yr. – 3 yr.	$0.0004/kWh	$0.27/mo	N/A

TABLE 6.19

Green Pricing Program Summary

State	Utility Name	Program Name	Type	Size	Start Date	Premium
AZ	Arizona Public Service	Solar Partner Pilot Program	central PV	82 kW	1996	$3.00/ 100 watts
AZ	Salt River Project	Solar Choice	central PV	100kW	1998	$3.00/ 100 watts
CA	City of Alameda	New Renewables Program	various	n/a	1998	n/a
CA	Los Angelos Dept. of Water and Power	Green Plan	various	expect 20 MW	1998	$2-5/month
CA	Los Angelos Dept. of Water and Power	Pure Solar	rooftop PV	up to 2MW	1998	up to 20% premium
CA	Sacramento Municipal Utility District	Greenergy - Community Solar Program	rooftop PV	n/a	1997	1¢/kWh
CA	Sacramento Municipal Utility District	PV Pioneers	rooftop PV	1500 kW	1993	$4/month
CO	Public Service Company of Colorado	Renewable Energy Trust	various; off-grid PV and schools	40 kW	1993	Contribution
CO	Public Service Company of Colorado	WindSource	wind	13.3 MW	1997	2.5¢/kWh
CO	Colorado Springs Utilities	Green Power	wind from PSCO	0.5 MW	1997	3¢/kWh
CO	Holy Cross Electric Cooperative	Wind Power Program	wind from PSCO	2.75 MW	1997	2.5¢/kWh
CO	Fort Collins Light & Power	Wind Power Pilot Program	wind (2)	1.2 MW	1996	2¢/kWh
CO	Tri-State Generation & Transmission	Green Power Program	small hydro	n/a	1999	2.5¢/kWh
FL	Gainesville Regional Utilities	Green Pricing	utility PV	10 kW	1993	Contribution
FL	Florida Power & Light	Green Pricing	utility PV	10 kW	1997	Contribution
FL	Gulf Power Company	Solar for Schools	PV in schools	n/a	1996	Contribution
FL	City of Tallahassee	PV Green Pricing	PV for public bldgs.	10 kW	1997	$1.75/month
HI	Hawaiian Electric	Sun Power for Schools	PV in schools	20 kw	1996	Contribution
IN	Indianapolis Power & Light	Green Pricing	geothermal purchase		1997	0.9¢/kWh
MI	Detroit Edison	Solar Currents Solar School	central PV ; rooftop PV	54 kW	1996	$6.59/ 100 watts
MI	Traverse City Light and Power	Green Rate	wind	0.6 MW	1996	1.58¢/kWh
MN	Moorehead Public Service	Capture the Wind	wind	750 kW	1998	0.5¢/kWh
MN	Northern States Power	EnergyWise Solar Advantage	2 kW rooftop res PV	34 kW	1996	$2.50/ 100 watts
MN	United Power Association	Wind Power	wind purchase from NSP	n/a	Planning	n/a
MN	Cooperative Power Association	Renewable Energy Option	wind	2 MW	1997	2¢/kWh
MN	Dakota Electric Association	Renewable Energy Service Tariff	wind purchase from CPA	0.8 MW	1997	2¢/kWh
NE	Lincoln Electric System	Wind power program	wind	660 kW	1998	4.3¢/kWh
NM	Southwestern Public Service	Wind Power Program	wind	700 kW	1998	3¢/kWh
NV	Nevada Power Company	Green Pricing	central PV (2)	40 kW	1998	Contribution
OK	Western Resources	Wind Power	wind (2)	1.5 MW	1998	not developed
OR	Bonneville Power Administration	Wholesale Green Rates	wind/ geothermal	n/a	1995	1¢/kWh
TN	Tennesse Valley Authority	Green power RFP	various purchases	up to 300 MW	1998	n/a
TX	Austin Energy/(City of Austin)	PV Friendly Pricing	central PV	32 kW	1997	$3.50/ 50 watts
TX	West Texas Utilities	Clear Choice	small hydro	1.2 MW	1997	2¢/kWh
WI	Madison Gas & Electric	Green Pricing	wind	11.25 MW	1997	4-5¢/kWh
WI	Wisconsin Electric Power Company	Energy for Tomorrow	wind/wind, hydro	1.2 MW 5.0 MW	1998/1996	2.04¢/kWh
WI	Wisconsin Public Service	Solar Wise for Schools/Public Buildings	PV in schools/public areas	24 kW	1996/1998	Contribution

Revised 1/25/99 by Blair Swezey and Lori Bird, National Renewable Energy Laboratory, Golden, Colorado.

TABLE 6.20
Stakeholder Identified Impacts and Views Regarding Renewable Energy, Energy Efficiency and Environment

Description of Stakeholder	Impact of Retail Competition Identified	Views Concerning RE, EE & Environment
Independent Power Producer	Properly designed, retail competition will allow customers who want them to buy renewables at market prices. Restructuring should be designed to ensure that the electric industry continues to limit its adverse impacts on air quality.	Targets for RE in generation mix should be designed to hedge the risks of fuel price increases and environmental concerns and to achieve economies of scale continuing to bring down costs. SBC funding, for an appropriate period, of research, development, and demonstration of RE technologies should encourage rural economic development, job creation, and use of local technologies and services. Mechanisms designed to protect environment need to be structured so as not to provide competitive advantages to existing facilities, and might include appropriate and non-discriminatory siting rules for new power plants, as well as consideration of regional emission trading and cap systems.
Labor Representative	Environmental and conservation programs voluntarily implemented by electric power companies could be dropped in a deregulated industry. Emissions from power generation will be geographically redistributed, adversely affecting states and regions currently in compliance with clean air policies. The present balance of environmental concerns associated with electrical energy is threatened, and environmentally beneficial programs may ultimately be dropped. Effective energy-saving programs provide customers with direct financial incentives to invest in measures and equipment to promote energy efficiency. In an environment motivated solely by profits, the electric power supplier will have no reason to conduct these programs.	Environmental protections and conservation programs must not be abandoned for the sake of enhanced profits and competitiveness.
Municipal Utility	Restructuring should have minimal, if any, negative impact on air quality health-based standards. Restructuring could promote more effective use of resources through improved technologies, resulting in reduced emissions of regulated air pollutants.	In a competitive market, renewable resources must stand on their own merits in the marketplace. Whether a customer pays more for RE should be an option, rather than a mandate. Any legislation which opens distribution systems to retail access should provide equal market opportunities to both traditional and renewable resources. Existing environmental rules, regulations and standards should be enforced in a restructured market. Rules and regulations are emerging to address regional haze, global warming, and air quality related values.

Description of Stakeholder	Impact of Retail Competition Identified	Views Concerning RE, EE & Environment
Municipal Utility	If the competitive marketplace results in efficient allocation of resources, renewable energy should not be afforded mandated preferences. Paying more for RE should remain a consumer option.	RE should not be mandated so as to force higher costs on all customers.
Consumer Advocate	Restructuring could cause environmental quality to decline.	The costs of environmental protection should fall on the energy suppliers and consumers who seek to profit from new market opportunities.
Investor Owned Utility	Marketers in competitive markets will seek to provide renewable energy and energy efficiency products in accord with customer demand. Environmental regulations and statutes will provide protection of human health and the environment. Some mechanisms may be appropriate to support renewable energy generation development and energy efficiency market development for a limited period.	Markets should be structured to facilitate offer of "green" power products and energy efficiency services by providers who wish to do so. Mandated set asides or programs should be avoided. System benefits or other charges to support early markets should be applied in a non-discriminatory fashion, and carefully targeted.
Renewable Energy and Environment Advocate	Renewable energy and energy efficiency markets need support in order to be viable in a more competitive environment. Successful RE and EE markets will allow market forces to maintain and improve environmental quality. Environmental laws and regulations should be maintained and strengthened to ensure restructuring does not degrade environmental conditions. Some generation facilities may enjoy competitive advantage based on less stringent environmental regulation.	Many customers have strong preference for "green" power and energy efficiency programs, and any restructured market should provide meaningful opportunities for customer choice. Investments in renewable energy generation and energy efficiency resources, through portfolio standards and/or system benefit charges, are essential to launch these markets. Successful penetration of electric services markets by RE and EE will reduce long term costs and ensure that restructuring provides benefits to all customers. Such measure will also stimulate new business investment and job growth.

TABLE 6.21
Policy Options Relating to Renewables, Efficiency & Environment
RE=renewable energy, SBC=system benefits charge, EE=energy efficiency, ESCO=energy service company

Policy Option	Method of Implementation	Advantages	Disadvantages
Renewable Energy			
Portfolio Standard	Establish minimum renewable energy generation percentage requirements. Requires proof of kWh or tradable credits for RE kWh on annual basis. Install price cap for credits. Increase % requirements to target in future.	Spreads costs broadly. Allow generators to seek most efficient method for meeting standard. Creates incentive for least expensive resources.	Generators uncertain as to cost, except that it will not exceed cap. Favors lower cost over emergent technologies – may require sub-category standards. Perceived as "set aside." Creates separate market for RE. Benefits limited to RE generators.
Production Incentives	Collect funding through SBC and distribute on annual basis (through auction or application) for kWh generated and sold.	Cost certainty. Allows RE market participants to allocate incentive at point in generation/sales chain for maximum effect. Funding only needed for premium price component. No payment for capacity not sold into market – integrates RE into overall market structure.	No guarantee that funds will lead to sustainable amount of capacity. Requires administration mechanism. May require sub-category allocations to fund emergent technologies.
Customer Rebates	Collect funding through SBC and distribute to customers purchasing qualified RE.	Focuses on overcoming cost premium. Limits funding directly to level of customer demand.	May create inequities in collection/distribution – potentially complex administration. May have free-rider problems. May not, by itself, incent new capacity construction. Lack of customer awareness and counter-marketing by non-renewable marketers could limit effectiveness.
Emissions Taxes	Assess tax on generators based on emissions of pollutants and use fund to support RE through incentives or rebates.	Links RE funding to a major problem – internalizes externality costs. Tax is self-liquidating as emissions decrease.	Political opposition from emitters. Potentially complex administration. Correct setting of tax rate may be difficult.

Policy Option	Method of Implementation	Advantages	Disadvantages
Tax Incentives	Enact property tax reform for RE facilities, or production tax credits, or tax exemptions or credits for RE activities.	Creates incentives and benefits attractive to businesses engaged in RE. Remedies perceived tax inequities. Spreads costs broadly through general revenues.	Impact on state, county, local budgets. Potentially difficult to administer.
Green Markets	Rely on green marketing activities and success to set and meet goals.	No adverse impacts on market participants and customers who oppose RE.	Free rider problems. Presumes market liquidity and efficiency that is not likely to appear for several years. Imposes high customer education and acquisition costs on top of RE production costs.

Energy Efficiency (special provisions may be included in each for low income customers)			
Rebates	Collect funding through SBC and distribute as rebates to customers purchasing, installing or initiating EE activities.	Focuses on overcoming cost premium. Limits funding directly to level of customer demand.	May create inequities in collection/distribution – potentially complex administration. May have free-rider problems. May not, by itself, incent emergence of strong ESCO market. Lack of customer awareness and counter-marketing by anti-efficiency marketers could limit effectiveness.
Trust Fund	Collect funding through SBC and distribute through trust fund public agency or quasi-governmental agency to encourage EE.	Provides certainty on funding level. Allows expenditure of funds for installation and market transformation. Centralizes program focus to capture most cost-effective opportunities.	Potentially complex administration. If funds are not large enough, inequities in distribution may result.
Standard Offers	Require all distribution companies to establish "avoided costs" for efficiency and establish periodically updated standard offer to purchase efficiency measures as is cost-effective.	Focuses distribution company on reducing overall costs to customers. Requires no separate funding except for administrative review of standard offers. Incents development of ESCO industry.	Unless distribution company is functionally (and perhaps structurally) separate from generation, it will always have incentive to sell. Administration may be difficult given lack of market already developed in Alaska.
Emissions Taxes	Assess tax on generators based on emissions of pollutants and use fund to support EE through incentives or rebates.	Links EE funding to a major problem – internalizes externality costs. Tax is self-liquidating as emissions decrease.	Political opposition from emitters. Potentially complex administration. Correct setting of tax rate may be difficult.
ESCO Markets	Rely on energy services activities and success to set and meet goals.	No adverse impacts on market participants and customers who oppose EE.	Free rider problems. Presumes market liquidity and efficiency that is not likely to appear for several years. Imposes high customer education and acquisition costs on top of EE business costs.

Environment			
Emissions Taxes	Assess tax on generators based on emissions of pollutants and use fund to support general revenues.	Internalizes externality costs. Tax is self-liquidating as emissions decrease.	Political opposition from polluters. Potentially complex administration. Correct setting of tax rate may be difficult.
Cap and Trade	Establish maximum allowable level of emissions, allocate allowances on basis of historical emissions, allow trading, require emitter to hold sufficient allowances on annual compliance date.	Encourages market participants to seek most cost-effective means for emissions reductions. (Like S02 trading under US Clean Air Act.)	Administrative and enforcement expense. Historical baseline creates windfall benefits for historically high emitters. Setting appropriate cap may be politically difficult.
Cap and Trade with Comparability	Same as cap and trade, but allocates allowances according to a performance standard (pounds per unit of production).	Same as cap and trade, and creates incentives for new cleaner technologies.	Potential political opposition from historically high sources of emissions.
New Source Performance Standards	Require new market participants to meet NSPS, set timetable for incumbent generators to upgrade performance to NSPS.	Ensures that market participants do not use "grandfather" status or other dissimilar regulatory burden to gain competitive market advantage.	Costs for upgrades could be quite high. May stifle market entry, reducing levels of prices savings.

TABLE 6.22
Value Added Products and Services Innovations

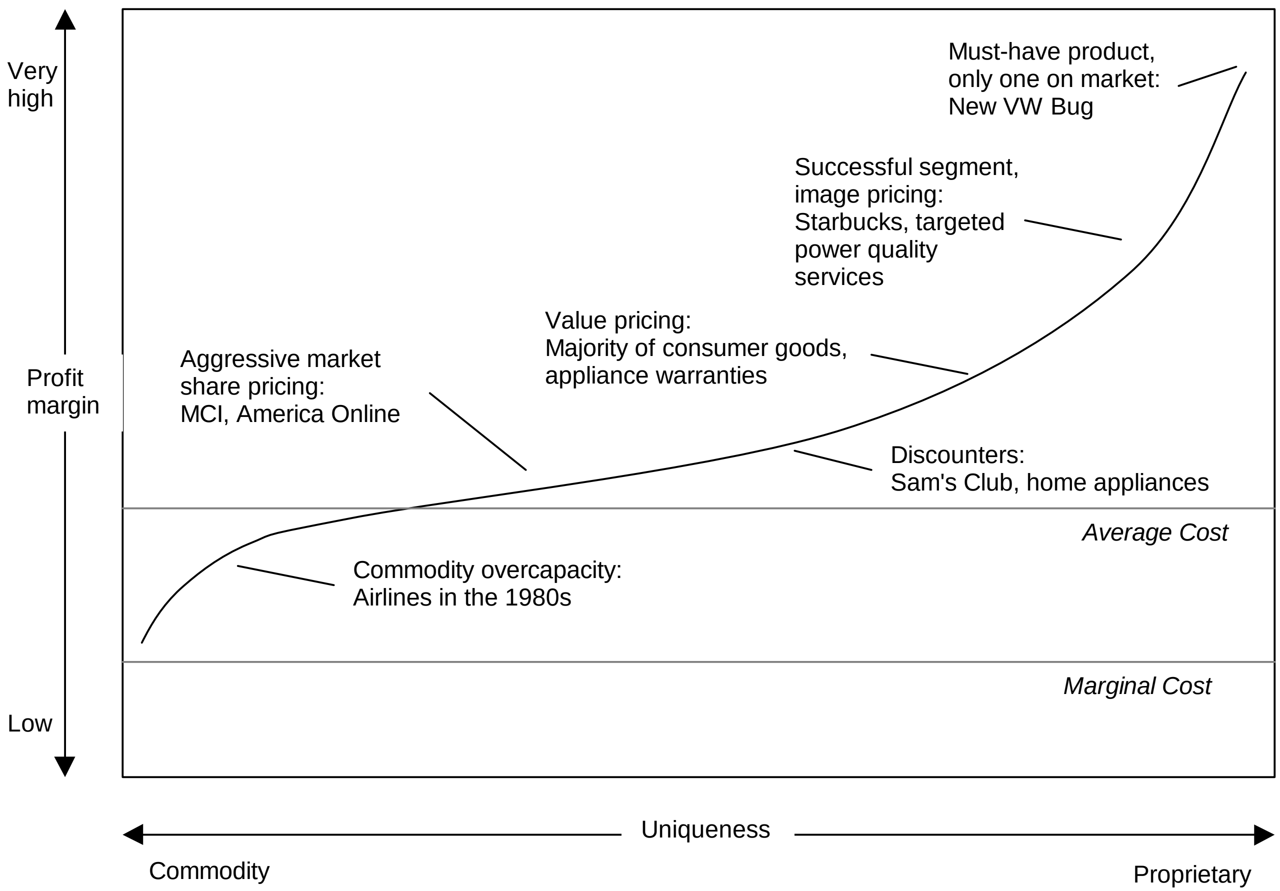
Product/Service	Description	Market Estimates	Advantages	Disadvantages
Real Time Pricing	Time-differentiated electricity pricing, with prices corresponding to actual hourly costs of generation and delivery.	No empirical data. Estimate 1-3% of eligible customers.	More closely aligns prices with cost of providing electric energy services. Allows customers opportunity to tailor consumption levels to price signals.	May impose higher costs on customers without discretion to alter consumption patterns. Requires new metering and information technology deployment.
Fixed-Bill Pricing	Pricing offered according to specified fixed terms, e.g. a fixed bill up to a certain level of consumption, or a rate frozen for a fixed period.	No empirical data. Estimate 1-5% of eligible customers.	Enhances electricity budget certainty. Creates incentive for service provider to manage cost of service.	Rates for exceeding consumption level may create financial hardship. May create incentive for wasteful consumption. Partially breaks consumption/bill relationship.
Green Power	Electricity supply products reflecting specified percentages of renewable energy supply	Depending on market structure, ranging from 1 – 15% of eligible market.	Allows customer demand to influence extent to which renewable energy capacity and services are added.	Because many benefits of renewable energy are "public," may create free-rider problems. May weaken case for public policy mandates. Relatively higher costs may exclude some customers from participation.
Energy Efficiency Services	Electricity distribution service providers offer energy efficiency services and equipment in conjunction with energy sales.	Potentially quite large in terms of revenues.	Offers customers opportunity to reduce energy bills. May create system-wide savings through deferral of infrastructure investments. Easy and quick to implement.	Because many benefits of energy efficiency are "public," may create free rider problems. May weaken case for public policy mandates. Up-front costs and small savings potential may exclude some customers from participation.
Electric Appliance and HVAC Sales, Maintenance and Repair	Electricity distribution service providers offer electric end-use equipment for sale, and/or with maintenance and repair warranties and services.	Many rural and cooperative utilities have offered residential appliance sales and services for many years.	Increases availability of products and services. Allows new/related profit centers in electricity distribution service companies. May help deploy of more efficient equipment and improve operating efficiency.	Potential for unfair competition leveraging off utility market power, i.e. cross subsidization. May help deploy less efficient equipment as mechanism for increasing electricity sales.

Product/Service	Description	Market Estimates	Advantages	Disadvantages
Other "Bundled" Services and Products	Electricity sold in conjunction with or by a vendor who also sells other services, e.g. internet, home security, long distance telephone, gas, cable, etc.	Wide range of potential services and local nature of markets makes estimation difficult.	May offer customers opportunities to obtain goods and services not otherwise widely available in the market. Allows new profit centers in utility.	May make it more difficult to accomplish cost and service regulation. Customers may find it more difficult to understand electricity use and costs.
Affiliation/Affinity Marketing	Electricity sold through or on behalf of an organization or association, e.g. nonprofit groups, employee benefits packages, credit cards, etc.	Wide range of potential approaches and local nature of markets makes estimation difficult.	A type of aggregation. Enhances bargaining power of customers. Offers opportunity to blend high and low margin businesses to expand availability.	May make it more difficult to accomplish cost and service regulation. Customers may find it more difficult to understand electricity use and costs.

TABLE 6.23
Policy Options Relating to Competition in Non-Electricity Service Markets

Policy Option	Advantages	Disadvantages	Remarks
Detailed Survey – APUC or other appropriate agency conducts detailed survey of current and planned competitive activities by electricity service providers, and the extent to which competitive markets for those services and products exists.	Allows objective assessment of the extent of the issue, likely areas of market entry, and affected markets prior to the formulation of oversight and/or remedial mechanisms.	Does not expressly create oversight and/or remedial mechanism. Creates regulatory burden, requires verification, collation and reporting.	Competitive market products and services offered by electric service providers, whether in regulated or deregulated environment, offer benefits to customers but may raise issues of competitive fairness. Assessment of the scope of the issue allows evaluation of the costs and benefits of oversight and/or remedial mechanisms.
Prohibition – Legislative prohibition of provision of enumerated competitive (non-utility) goods and services by any entity providing electricity distribution service, with mechanism for complaint, enforcement, and/or penalty.	Relatively simple to craft, oversee and enforce. Ensures that electricity distribution service providers cannot use their market position to obtain unfair competitive advantage in other markets.	May deny goods and services to customers not otherwise provided in the marketplace. Precludes fair competition for new products and services by electricity distribution service providers.	To the extent competitive goods and services are currently offered, electricity distribution entities could be allowed to decide whether to terminate activities or structurally separate their organizations.
Legal Complaint and Redress Mechanism – Develop and adopt standards for fair/unfair competition. Create/expand jurisdiction of state attorney general (or other appropriate executive branch agency) and courts to receive, investigate, initiate, and seek legal resolution of complaints of unfair competition.	Allows for uniform treatment of business practices oversight and enforcement. Provides for creation of clearly articulated standards. Clarifies jurisdiction and available mechanisms for oversight and/or remedial actions.	Increases regulation and potential for litigation. Standards must be continually updated for evolving market conditions, and must be tailored to prevent unintended effects (e.g. stifling market innovation).	Requires legal review of state/federal jurisdictional issues. Requires new legislation, regulation, appropriations or fee collection mechanisms.
APUC Oversight – Empower APUC to investigate, make rules, and appropriately regulate non-utility services offered by electricity distribution entities. Require APUC to adopt cost allocation, business practices, reporting and enforcement standards.	Allows APUC, which has experience in electricity regulation, to craft appropriate regulatory mechanisms to determine the existence of and regulate unfair business practices, including cross-subsidization issues.	Creates regulatory, administrative and cost burdens. Subjects otherwise unregulated entities to new regulatory requirements. May result in disclosure of legitimate competitive business strategies. Does not address unfair competition by entities other than electricity distribution service providers.	Could be seen as requiring incumbents to compete with "one hand tied behind their back."

FIGURE 6.1 Pricing for Profits: Where the Margins Are
Source: "E News," E Source, Inc., No. 31, Sept/Oct 1998.



In a "high-pricing IQ" market, products and services show a profit on the basis of their strategic positioning and value-based pricing. For example, Enron is moving aggressively into higher-margin energy service business to offset what are fast becoming razor-thin margins in the commodity market for electricity.

Universal Service

Issue

Coordinated national, state, and local economic and regulatory policy has resulted in near-universal connection of customers to electricity supply. The evolving nature of electricity services, however, and the introduction of market-based retail competition, suggests a need to reexamine the nature of universal service policy in Alaska. In more open and competitive markets, the obligation to serve may be replaced with an obligation to connect, and raises the issue of whether competition for customers will improve electric service for every customer, or whether some customers will be left behind. Some have argued that the introduction of competition must be accompanied by specific regulations addressing an expanded concept of universal service, including issues such as disconnection rules, customer service requirements, service quality standards, and access to information necessary to make purchase decisions. Others argue that competitive markets will address these issues without the need for statutory and/or regulatory intervention.

Alaska Dynamic

Alaska's more than 118 independent utilities serve just 600,000 citizens in an environment of enormous geographic and economic diversity. Alaska's electric utilities have established near universal connection to electricity for customers in the Railbelt. Village power systems provide the benefits of electrification for many more. While Alaska statutes articulate clear policies and mechanisms related to telecommunications services, no similar legislative policy exists regarding electric service. (See, for example, AS 42.05.145 which provides that regulation of telecommunications, utilities shall "seek to maintain and further the efficiency, availability, and affordability of universal basic telecommunications service.") In addition, while both the law and the APUC regulations address virtually every issue embodied in a broad definition of universal service, the APUC has not yet articulated a definition and policy with regard to electric universal service. Though not labeled as such, the State does have a strong policy tradition of universal service for rural Alaska. The Power Cost Equalization program, the numerous programs conducted by the Division of Energy, and other programs such as low income weatherization and the Energy Assistance Program, taken together, reflect a public policy recognition of the benefits of electrification and the essential service character of electricity today. Measured in dollars, the primary emphasis of these programs is lowering the cost of electricity. Other programs, specifically those conducted by the Division of Energy, also seek to increase the safety and reliability of rural power systems.

The Alaska Village Electric Cooperative, the single largest entity focusing on rural electric service, is no longer subject to APUC regulation. In that situation, the Cooperative addresses universal service issues as an individual entity, though its member village electric systems receive the benefits of the PCE and other state programs.

Most stakeholders agree that providers of last resort or default providers must be established under competition in order to ensure continued access to electric service. Most also agree that some regulatory oversight of marketing practices, service quality, and consumer complaints and relations may be appropriate if multiple service providers are introduced through competition. The APUC enjoys broad authority to regulate matters relating to electric service, but that authority is untested in a competitive regime. As a result, retail competition may require new legislation and regulation to preserve universal values by clarifying the authority of the APUC to reach the activities of, for example, electricity service providers that do not own facilities.

Implications

Any policy decision to ensure universal service values are maintained or enhanced in a more competitive environment flows from a determination that: (1) maintaining universal service benefits is essential, and (2) these benefits are at risk without explicit support. The mechanisms most commonly suggested to support universal service are financial and regulatory in nature. Financial mechanisms include system benefit charges, taxes, high-cost assistance funds, and other mechanisms. Regulatory mechanisms include service quality standards, consumer protection enforcement mechanisms, anti-discrimination rules, and other laws and regulations. In some jurisdictions, it has been suggested that the right to provide default service could be competitively auctioned, under contractual terms and conditions that would guarantee universal service. Because the concept of electricity universal service has not been rigorously defined or articulated in Alaska under a unified policy umbrella, the critical first step facing policy makers is the articulation of a policy definition and framework. The greatest single concern is that public funding mechanisms necessarily have the effect of reducing the overall level of savings made available by electricity restructuring, and that regulatory solutions risk creating impediments to efficient market functioning. Whether these impacts are significant will depend on two factors – the scope of the definition of universal service deemed to reflect the best interests of the State of Alaska.

Assessment

The majority of stakeholders believe that universal service benefits must be preserved in a market-based retail competition structure, and that some level of policy support is appropriate. Some feel very strongly that restructuring legislation should incorporate specific funding provisions. However, most also agree that any funding provisions must not operate in a manner that creates competitive advantages or disadvantages in the marketplace.

Any proposal to dramatically alter the utility regulatory environment must take into account the unique characteristics of the Alaska system. Simply stated, the Alaska electricity industry fits into three major categories. First, there is the highly urban area in Anchorage and a few other larger cities. Second are the smaller Railbelt cities and regions. Finally, there are non-interconnected villages in the Alaska bush. Any funding provisions to support universal service must account for the differences in impact, amount of available resources, and costs of program administration in each distinct category.

Key Decisions

- Is preserving or enhancing universal service benefits in the electricity sector an essential component of industry restructuring and the introduction of retail market competition?
- How will Universal Service be defined?
- What policy framework should be constructed for Universal Service in Alaska?
- Will restructured markets ensure that universal service benefits are retained in the absence of legislative, regulatory, or fiscal provisions?
- If such supports are deemed appropriate, what type and level of supports should be adopted?

List of Accompanying Tables & Figures

Universal Service Overview

Alaska enjoys a strong and successful history of electrification, in spite of the significant challenges inherent in the size, geography, weather, and population of the State. Today the vast majority of Alaskans enjoy the benefits of electricity that is relatively affordable, and service which is reliable. No longer a luxury service, electricity's benefits are, in our modern age, practically essential to everyday life. Many Alaskans have access to a range of other services, including low or no-cost energy audits, energy management advice, customer service facilities, and others. The most pervasive and flexible fuel in human history, electricity provides light, heat, computing, and many more benefits. Electricity makes life in modern society possible. As a result of concerted economic and regulatory policy, customers nearly everywhere in Alaska have access to electricity services from providers operating under an obligation to serve. In return for assuming this obligation to serve, utilities enjoy the exclusive right to serve all customers within certificated territories. Within these territories, customers also have access to averaged rates across customer classes, and generally uniform service quality and reliability. Because of the interconnected nature of the electricity system, facility improvements within even the smallest grid generally operate to the benefit of all customers alike. Without a doubt, the current system of utility operations provides substantial and broad benefits to electricity customers.

The introduction of market forces into the electric system in the Railbelt region has the potential to substantially change these relationships. Most observers share a common belief that competitive forces can be introduced into the generation and transmission sectors of the industry without significantly threatening universal service benefits to Alaska customers in that region. The federal Public Utility Regulatory Policy Act and the subsequent Energy Policy Act of 1992 each led to significant changes in the electric industry, all aimed at making generation and transmission more competitive. While not all aspects of the regulatory progeny of those laws are applicable in Alaska (notably the comparability provisions of the Federal Energy Regulatory Commission's Order 888), these policy changes have injected a measure of competition in the generation and wholesale power markets in the lower-48 states. These changes in turn are generating learning and experience that theoretically, at least, can be translated to the Railbelt region of Alaska.

PURPA created an opportunity for competitive independent power producers to sell electricity to utilities, diversifying the supply mix throughout the Nation, and spawning regulatory proceedings in Alaska, as well. The Energy Policy Act led directly to the Federal Energy Regulatory Agency's institution of open access provisions for the transmission system, aimed at ensuring that power transfers on the grid move efficiently and competitively. While much work remains to be done, including the resolution of disputes between large generators and transmission owners in the lower-48, experiences with the introduction of competitive market forces to the top tiers of the system have demonstrated the potential for benefits for all customers in a more competitive environment. The Black & Veatch study has already indicated that some steps down that path may hold promise of benefits for Alaska as well.

As Alaska and many other states consider the introduction of retail competition into the electricity sector, many more significant and potentially troubling issues arise. Retail access (a system of allowing customers to choose their electricity suppliers) means a fundamental dismantling of the exclusivity relationship between electric service providers and their customers. While advocates of retail competition envision a world in which savvy marketers aggressively seek to serve all customers with less expensive and more tailored products, there is a concern that in an industry driven by profitability, some customers will be disadvantaged. Moreover, as competitors "segment" the markets they believe they can serve profitably, there is real concern that less "attractive" customers will face rising costs and declining service as they are de-averaged from the larger pool in which they receive services today.

The experience of states dealing with retail electric competition is relatively scarce and highly specific. There is no example available for what would happen to universal service under a model where all aspects of the issue have been left solely to the market. That the states moving to retail competition have all addressed universal service issues in some manner is not surprising given the essential nature of electric service and the political implications of drastic changes in course. As Alaska policy makers address the issue of retail competition in the electricity industry, they will have an opportunity (and many would say, obligation) to address the universal service issue from Alaska's unique perspective.

A number of mechanisms are available to address the adverse impacts of competition on universal service, but they have costs – both economic and social. The key question facing policy makers is whether any adverse impacts can be avoided or mitigated, and whether the overall result of restructuring will be in the best interests of the people and state of Alaska.

It is important to note that there is another kind of restructuring for which there is no relevant extant experience. That is, there is no experience and very little academic discussion about introducing competition into a system characterized by numerous non-interconnected systems like those in rural Alaska. While a good deal of the discussion about distributed energy systems and regulatory reform for the residual distribution utility could be adapted to rural Alaska, the overwhelming majority of ideas and concepts have been developed under the model of the interconnected grid system. It may be possible in the not-to-distant future to conceive a means for bringing competition to the isolated village systems, or to articulate alternative approaches for introducing competitive concepts into those systems. This discussion of competition, however, is limited to the interconnected Railbelt region and utilities.

Preserving Access under Retail Competition

The concept of universal service derives from the telecommunications industry. The basic policy justification for supporting and subsidizing universal telephone connections is founded in the concept of network externalities – costs and benefits not typically reflected in the cost of providing a service. In telecommunications, the broader social value of connecting all businesses and households to a telecommunications network was seen as exceeding the costs associated with creating high cost assistance and other mechanisms. In fact, the historical precedent of the rural electric cooperatives reflects similar values. When competitive utility providers did not appear interested in extending electrification to rural America, Congress created, supported and funded the Rural Electrification Administration – now the Rural Utility Service. By pooling efforts on a national and regional level, electricity service was extended to today's situation of near total interconnection in the lower-48 and near universal service in Alaska – bringing the benefits of electrification to almost the entire country.

AVEC is a clear example of the approach of pooling effort to reduce costs and increase electrification penetration. A number of rural utilities in Alaska already cooperate to purchase diesel fuel, obtaining economies of scale in purchasing power. The Alaska Division of Energy is also exploring mechanisms for pooling of administrative functions – a kind of "virtual utility" approach to harvesting system efficiencies.

Just as the "regulatory compact" avoided wasteful economic investment by granting exclusive franchises to urban electric utilities, rural electrification harnessed economies of scale by promoting the development of consumer-owned cooperative associations. As the regulatory landscape has matured, electric utilities have used their exclusive franchises as a way of ensuring that all customers enjoy the price benefits of these scale economies. For regulated utilities, the process of rate setting, and more recently, performance based regulation, has made utilities financially accountable to render non-discriminatory and reliable electric service as rates determined to be in the public interest.

As policy makers contemplate the introduction of market forces into the retail electric industry, the issues of universal service are brought sharply into focus. On the one hand, competitive markets typically operate more efficiently than heavily regulated or monopoly industries. But competitive markets are also less effective in meeting non-economic public interest objectives. By definition, truly competitive markets are impersonal, volatile and tend to create clear winners and losers. As the Virginia public utility commission staff has reported,

> The concept of equitable sharing is not the focal point of a competitive market. Those with the most information and the greatest ability to interpret and react to that information tend to win. Those with less information and more limited response capabilities tend to lose. . . . For example, competitive markets experience both capacity excesses and shortages over time. During periods of capacity shortages, the product or service is rationed by increasing prices to what the market will bear. Those customers willing and able to pay the most would receive service. Since the most likely time of generation shortages would be on the coldest days in the winter or the hottest days in the summer, low income residential customers who heat or cool with electricity could face a dilemma.

Equipping all customers with the education and technological capacity to fully participate in markets characterized by changing hourly electricity costs could easily overwhelm any savings likely to result from the introduction of competition into the industry. Impacts of retail competition on universal service are discussed in Table 7.1.

In the face of such issues, several states and congressional bills have articulated a number of alternatives for ensuring that electric service remains both reliable and affordable under competition.

Though most observers believe Congress will be slow to act on electric utility restructuring, a number of bills have been introduced on the subject. A summary of the universal service provisions in proposed federal legislation is included in Table 7.2.

In the New England states and California, restructuring legislation has included provisions for low income benefits and services, including funding for rate discounts and for energy conservation measures. In Pennsylvania, Montana, Oklahoma and Nevada, the state legislatures have directed their respective public utilities commissions to address universal service issues. These directives are often broadly worded, and depend upon detailed implementation through utility-specific cases or generic implementation proceedings.

System Benefits Charges - The most common method of supporting universal service programs 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, which enjoys relatively low electric rates in the Railbelt area that may not be amenable to significant further 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, less profitable groups of customers or the costs associated with quasi-competitive sales and contract transactions. Disconnection rules are an example of the former. Load retention rates and economy sales transactions are examples of the latter. But under a competitive system, if a system benefit charge were collected as a fixed percentage of electricity sold at the distribution meter, large customers that take service at the transmission level may be exempted from the charge.

Rate Discounts - Though not specifically categorized as a universal service mechanism, several states have also implemented mandatory across-the-board rate reductions for residential customers. These reductions, often guaranteed for a set number of years, provide a level of assurance to customers that competition will not result in rate increases during the initial stages of the transition to a full competitive market.

While across the board rate discounts provide certain guarantees to customers, they may also have a chilling effect on competition. If the mandated discount is set too low, competitors may find it unprofitable to enter the market. In addition, if rate discounts are set below the cost to provide service, they may even generate "stranded costs" – costs that are unrecoverable through rates. Some states, like California, have established elaborate mechanisms to both provide customers with discounts and keep service providers economically whole. Many believe that these mechanisms have played a significant part in limiting the robustness of the restructured market in those states.

Standard Offer - An alternative mechanism used in conjunction with rate reductions is the institution of a "standard offer" rate. Under this approach, the regulatory authority, with guidance from the legislature, establishes a rate at which any customer may receive electric service. A standard offer is typically established through a process substantially similar to a rate case, and the offer itself greatly resembles a tariffed rate for electricity under the regulated model.

Standard offers pose similar problems as rate discounts. If the standard offer is set too low, it may stifle market entry by competitive providers and add to stranded costs.

Default provider/service - Finally, a number of states have also instituted a default provider or default service mechanism for customers who do not make an express choice of electricity service provider. Evidence from the long distance telephone market, and from the early experiences in retail electric competition suggests that a great many customers exercise their right to choose by doing nothing. In order to ensure that unaware customers are not adversely impacted by not choosing, a number of states assign non-switching customers to a default service rate and / or to a default service provider.

The default service mechanism raises the same issues as the standard offer or rate discount mechanism because it typically involves a rate set through a regulatory process. In addition, assigning non-switching customer to a default provider raises the issues of strengthening the relative market power of the default provider. In most cases, the default provider is the formerly monopoly utility. There have been some proposals for competitive auction of the right to provider default service, or for the institution of a mechanism that allocates customers among a number of qualified default service providers, but with the exception of the gas deregulation effort in Georgia, this approach has not been instituted anywhere in the United States to date.

Provider of last resort - Finally, a number of commentators have suggested the adoption of a provider of last resort mechanism for use in more mature retail electricity markets. Under this approach, customers would always have the guaranteed option of turning to an approved provider for service under specified "last resort" terms and conditions. The duty of serving as such a provider could be imposed upon the distribution entity or any other provider of electric service through regulation. Some advocates have suggested that a separate state agency should be established to create a kind of pool for last-resort service.

The institution and oversight of a provider of last resort will create regulatory and administrative burdens. If a provider of last resort mechanism includes a specified rate or service level, the provider may require economic support, which could be collected through a systems benefits charge. As with any such charge, the funding required will have the effect of reducing the overall benefits of competition in the industry. A summary of provider of last resort options is set out at Table 7.3.

Customer protection mechanisms – Regardless of the model chosen for maintaining and ensuring universal access to affordable electric service, most observers agree that some level of oversight of the market will still be required to ensure that marketers do not improperly discriminate in their provision of services. Some consumer advocates advocate particularly strong oversight to prevent a discriminatory practice known as "redlining." Redlining is the practice of refusing to provide service to customers located within the boundaries of a particular geographic region for improper reasons.

In addition, most customer advocates argue for the institution and administration of service standards relating to customer complaint resolution, billing and service dispute resolution, and other activities. Oversight of these issues requires some level of regulatory authority over market participants. If distribution, billing, meter reading or other services remain regulated monopoly functions, the APUC would be well positioned to assume this oversight responsibility. For new market entrants, requirements could be imposed as part of a licensing or registration process. In any event, regulatory oversight will require funding. The oversight agency must either be appropriately funded to perform its mission or be empowered to receive funding through fees collected from market participants.

The nature and extent of regulatory oversight of the business practices of market participants raises the issue of costs, and the question of the extent to which these costs reduce the benefits of competition. In addition, while the oversight role is similar to the current mission of the APUC, the environment in which this regulation will occur is substantially different from today's system. Staff additions and other funding requirements will likely arise, especially during the early stages of the transition to competition.

Cooperative and municipal utilities – The record of Alaska's utilities in providing safe, reliable, and affordable electric service is at least in part a result of broad reliance on local control mechanisms for utility management oversight. Retail competitive choice introduces a new dynamic to the current state of affairs, and raises important jurisdictional and management issues. The current model of local control for cooperatives and municipal utilities is based on geographical or political boundaries, and, as discussed above, delivers many benefits through scale economies associated with monopoly status. The most significant change that restructuring may introduce is the opportunity for these utilities to compete head to head with other market participants.

Many representatives of cooperative and municipal utilities in the lower-48 advocate an "opt-in" approach to retail competition where the management of these entities enjoys the complete discretion over whether to compete in the restructured markets. This approach is a direct result of a concern that, in the lower-48, most public utilities are far smaller and more vulnerable to competition than their investor-owned counterparts. Of concern to some potential competitors is whether all utilities will be subject to the same fees, charges and regulations as all other competitors if they decide to compete in the marketplace. Simply put, a competitor that does not have to contribute to a system benefits charge, for example, enjoys a competitive advantage over one that does. Resolution of these issues implies significant statutory issues in Alaska, especially regarding the degree to which municipal utility autonomy is reduced or effectively transferred to a statewide oversight agency.

For every potential approach to ensuring the continuation of universal service benefits, there are accompanying costs. Reconciling and balancing these costs and benefits is a significant challenge in designing a restructuring agenda for Alaska that will benefit the state and its citizens.

For example, the Blue Ribbon Committee that studied the Power Cost Equalization program considered a funding mechanism that would operate like a system benefits charge to provide PCE funding support. Collecting such a fund as a percentage of Railbelt electricity use raises issues of wealth transfer, but also recognizes the practical necessity to derive funding from sources outside the PCE-served utility base. Collecting the charge from electricity consumption more closely aligns the funding with the ultimate use. That is, an electric rate support charge is based on electricity consumption. However, this approach creates a risk that PCE funding will have to compete with other public purpose funding objectives integrated into electricity rates.

Conceptual models for universal service in Alaska are set out in Table 7.4. Table 7.5 summarizes selected state approaches to universal service.

Economic Benefits Associated with Universal Service

Electric service means heat, light, connectivity, productivity, safety, security and a host of other benefits now virtually essential to modern life. The electric utility system today, with its combination of regulatory oversight and local control, has made reliable service available at rates that both affordable and stable. In addition, a number of utilities offer a range of additional services to customers.

Affordable electricity is a key component of economic growth and well-being throughout the state. The extant obligation to serve guarantees that new citizens and businesses will have access to that service. The costs of public purpose programs in Alaska, including the costs of regulatory or management oversight are spread broadly over the customer base, and in many cases, over the entire state budget.

As discussed above, retail competition raises a concern that competitive markets will lead to even greater cost disparities among service providers and geographic regions of the state. If costs rise severely in some areas, they could exacerbate local economic problems and stifle economic growth. To the extent that competition increases market and price volatility to unacceptable levels, the impact on economic growth could be seen statewide. Finally, the pressures of competition may force public purpose charges on an ever-shrinking group of customers, as valuable customers are "cherry-picked" by competitors.

On the other hand, competitive markets offer an opportunity for overall reductions in costs for electric service. Innovative market participants, free of the burden of regulatory oversight, may create exciting new electricity products and services to attract new customers and support the State's economic growth. Competition may have the added benefit of stimulating the introduction of new technologies to provide new services and extract greater efficiency from the current system. Finally, new structural and regulatory mechanisms could offer the opportunity for more efficiently addressing public policy goals.

From an overall economic perspective, other states enacting restructuring have committed up to 5% of general electricity revenues to preserving and enhancing public purpose benefits, including universal service, energy efficiency, low income programs, and renewable energy. Funds for low income and universal service programs have averaged in the range of 0.5% to 3% of revenues. Whether these costs are affordable and sustainable depends on the level of savings that competition may bring to the electric system in the Railbelt region of Alaska, and on the level of public policy support.

The first step in determining the costs of universal service benefits is to establish a definition for the concept. Today's statutory and regulatory structure does not contain such a definition, though a number of statutory provisions and government programs establish a kind of outline for universal service policy for Alaska. Even without a commitment to retail competition in the electricity industry, there could be significant public policy benefits from adopting a uniform definition and policy framework for universal service.

One simple definition for universal service describes it as "access to a basic package of affordable and reliable electric services." The idea is that universal service is first about access – all customers should have the opportunity to buy affordable and reliable services. Second, the concept involves a basic package of services – including not just an affordably priced commodity supply, but also accompanying services, such as access to billing dispute resolution mechanisms, clear and understandable bills, low income energy assistance and weatherization programs, and a minimally satisfactory level of service quality. Universal service most importantly contemplates affordability. While this does not mean subsidized electricity for every customer in any amount, it does reflect the notion that electricity is too important a service to be denied or be made unavailable to certain segments of society. Mechanisms to address affordability are discussed below. Lastly, universal service contemplates minimal standards of reliability of service. Again, electricity must be available to customers to meet basic and essential needs.

Based upon such a definition, universal service provisions in any utility restructuring legislation should establish an obligation on some or all providers to make basic, reliable service available at affordable rates. As discussed above, ensuring such a level of service may well require a commitment of funds.

More broadly conceived, universal service policy can become a platform for continuously improving service quality, service options, and efficient use of electricity. With such a model, policy makers can ensure that the benefits emerging from retail competition are widely disseminated throughout the marketplace. For example, as technological improvements and volume of use make sophisticated metering technology more available and affordable, a model of universal service that contemplates continuous service improvement can be used as a basis for encouraging and facilitating the penetration of such technology throughout the electric system. Public policy abounds with examples of this approach. For example, while the automobile manufacturing and sales business is highly competitive, targeted regulatory policy has ensured that new safety options – like seatbelts, airbags, and high-level brake lights - are made universally available in new cars.

An expanding view of universal service standards has supported efforts to improve the data carrying capabilities of telephone lines and the penetration of tone dialing. This broader view of universal service policy implies a more comprehensive and regularized approach to government intervention without necessarily requiring comprehensive regulatory oversight. Table 7.6 sets out a comprehensive review of the consumer protection provisions addressed in nine states. That table addresses the range of issues that could be addressed in a broadly articulated universal service model.

At the other end of the spectrum is a model of universal service which leaves most issues up to the marketplace. This model assumes that economic self-interest on the part of market participants, in conjunction with choice and customer demand, will naturally lead the sector to meeting universal service policy objectives. While unfair discriminatory or other business practices would be subject to oversight, the market model does not involve the setting of standards or rates for electric service.

It is the choice of a working policy definition for universal service that most strongly dictates the nature and level of support or regulatory mechanisms that should be reflected in an electric utility restructuring agenda for Alaska. In addition, resolution of these issue informs the basic question about whether restructuring is in the best interests of the state of Alaska.

Stakeholder Views

Alaska stakeholders in the electric utility restructuring debate hold diverse views about the extent to which universal service policy should be protected in a competitive market.

Some stakeholders feel that universal service benefits will be irretrievably lost under restructuring, and that any mechanisms put in place will ultimately offer less protection and benefit to customers. Others argue that universal service policy is an issue of local control, and that state-wide laws and regulations are especially inappropriate for cooperative and municipal utilities. The majority of stakeholders who support a transition to competition agree that some mechanisms should be established to protect universal service benefits. These stakeholders also insist that to the extent funding support is required, it should be collected in a non-discriminatory fashion that does not give competitive advantage to one entity over another. A summary of stakeholder view regarding universal service is included in Table 7.7.

Legal and Regulatory Framework

A review of the statutory and regulatory provisions relating to electric utilities reveals a broad range of provisions and mechanisms for ensuring the benefits of universal service under regulation. For example, Alaska statutes today require regulated utilities to:

- Pay fees to defray regulatory costs,
- Charge only just and reasonable rates,
- Maintain adequate facilities,
- Provide notice of rate changes,
- Protect customers when offering competitive rates,
- Submit reports,
- Submit to rate investigations,
- Not subsidize competitive activities from regulated rates, and
- Obtain certificates prior to construction of new facilities.

Rules adopted by the APUC implement these statutes and establish the overall regulatory framework. However, as discussed above, neither statutes nor rules provide for a single definition or policy framework for universal service explicitly. The words "universal service" do not appear in the statutes and rules relating to regulated electric utilities.

As a result, a decision to formalize universal service policy in Alaska, either today or as part of restructuring legislation, must address these issues. That is, policy makers must decide whether a universal service policy definition should be expressly set out for Alaska. In addition, as part of the broader decisions about how non-utility competitors are to be impacted by restructuring, policy makers must decide whether any regulatory or fiscal mechanisms relating to universal service should be made applicable these entities. Table 7.8 sets out a legal and regulatory road map of provisions relating to universal service in Alaska.

Policy Options

Alaska policy makers enjoy a broad range of options in deciding whether and how to address universal service issues as part of electric utility restructuring in the Railbelt region. A number of these policy options may be considered alone or in conjunction with others. Each option presents its own set of advantages and disadvantages. The APUC has the authority to begin establishing a comprehensive universal service policy framework for regulated utilities today. Such an approach is limited to utilities falling under the agency's current regulatory jurisdiction. All other options entail the passage of legislation, as part of broader electric utility restructuring legislation. Such legislation could:

- Establish a state-wide definition of universal service to include access to an affordable block of basic, reliable and quality services for all customers.
- Create a universal service support fund through a non-discriminatory system benefits charge.
- Establish broadly worded obligations on market participants to "ensure universal service," without specific funding or program prescriptions.
- Order the APUC to establish performance based regulation for distribution utilities, with standards addressing universal service and service quality standards.
- Establish registration and service practice requirements for retails, standardize information requirements, and establish customer protection rules.
- Encourage cooperative activities between electric service providers and community service agencies.

The decision about the level and nature of universal service policy mechanism to be implemented requires a careful consideration of the costs – including economic and regulatory costs – associated with that mechanism. Against these costs must be balanced the benefits of ensuring continued universal service for Alaska electricity customers.

A summary of policy options available to Alaska decision makers is set out in Table 7.9.

Affordability of Distribution Service

Issue

Market-based retail competition may lead to lower electricity costs overall, but may fail to create incentives for competitors to offer low-priced electricity supply to residential and small commercial customers, especially low-income and rural customers. Because these customers have higher per-customer costs to serve and less individual market power as purchasers, full rate deregulation may lead to rate de-averaging and cost re-allocation that results in higher rates for these customers. Many national and state-level programs for providing energy assistance have seen declining funding in recent years. Choice-driven markets could be structured to ensure affordability of distribution service, but may require explicit subsidies or establishment of "standard offers" for residential distribution service.

Alaska Dynamic

Concerns over affordability of electric service have been mitigated in Alaska as a result of averaged, regulated rates, and relatively low electricity generation costs in the Railbelt. In rural Alaska, the Power Cost Equalization has been an important mechanism for offsetting the high costs of establishing and operating small village power systems. Much residential heating load is provided by natural gas. In addition, energy assistance programs have been supported by federal and state funds. Public funding is declining, however. Retail competition raises a concern that large, sophisticated customers may be "cherry-picked" by competitors, leaving former incumbent utilities with only high-cost residential customers to bear system costs. This concern is especially great in the Municipality of Anchorage, where commercial loads generate a significant percentage of revenues. In the Railbelt, Alaska does not have any legally mandated affordability programs in place for all electricity customers. The Alaska Housing Finance Corporation and the Alaska Division of Energy do operate programs for energy bill assistance, low income weatherization, rural electricity system support, and other purposes.

Implications

Any policy decision to ensure affordability of distribution service in a more competitive environment flows from a determination that: (1) maintaining affordability is a desirable feature of a restructured electricity industry, and (2) competitive markets will not ensure affordability in the absence of policy and/or structural support. The mechanisms most commonly suggested to support affordability are essentially financial in nature - establishing state-wide assistance funds (perhaps through a "system benefits charge" added to the per-kWh price) or mandating standard offer tariffs at an administratively determined level. Additional structural mechanisms, such as anti-discrimination rules or competitively allocated default provider "franchises" may help address the problem. Some assert that open markets will, by themselves, create incentives for supplies to find ways to ensure affordable electricity service. Others argue that restructuring the electricity industry is both complicated and confusing, and that price savings or the prohibition of price increases are essential to ensuring the political and economic viability of the effort. They assert that affordability is a "public good" and that competitive markets will not, by themselves, allocate a societally optimal level of resources to this "good." Public funding mechanisms to support affordability 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.

Special issues are raised in regard to small utilities in the Railbelt region. Even under an "opt-in" strategy, some cherry-picking or loss of load-growth opportunity could occur. Moreover, statewide funding mechanisms that draw revenues from more populated areas to support other areas have proven politically unpopular. Finally, the price of participating in statewide distribution mechanisms for system benefits charges could require a degree of regulatory oversight not acceptable to some utilities

Assessment

The majority of stakeholders believe that electricity must remain affordable after introduction of market-based retail competition, and that some level of policy support is appropriate. Most agree that any funding mechanism must be non-discriminatory. However, some feel that financial and other supports are inconsistent with market-based retail competition, or that utilities should be free to decide whether or not to provide affordability support to certain customers.

Key Decisions

- How should "affordability" be defined?
- Will retail competition pose a serious threat to short and long-term affordability of electric service?

- Is maintaining affordable electric service (however defined) an essential element of successful introduction of market forces into the electricity industry?
- What mechanisms should be instituted to ensure continued affordability of electric service in any restructuring legislation?
- How should affordability protection mechanisms be structured and funded to address needs in the most efficient manner?

List of Accompanying Tables & Figures

Current and Projected Affordability

Electricity service providers in Alaska have an excellent record of maintaining low rates for electricity, especially given the difficult conditions under which service must be provided. While overall electricity rates in Alaska are higher than in many parts of the country, Anchorage area customers buy electricity at rates that would be very competitive in many parts of the country. Other characteristics of Alaska energy consumption contribute to affordability, including the fact that many residential customers heat their homes with natural gas. Most observers agree that rates will remain affordable into the future in the Railbelt region, though there is some concern over the long-term viability of the PCE mechanism. A table showing the ranking of costs among major US cities is provided in Table 7.10.

There are differences buried in the averages, of course. Rates vary by as much as a factor of 10 in cents per kilowatt-hour across the state, and by as much as several cents in the Railbelt. In some regions customers depend on electricity for all their heating needs.

Alaska has a significant low income population, with 60,000 or 10 percent of the State's citizens estimated to be living in poverty. For these Alaskans, electricity bills represent twice the economic burden of families with median incomes. There are highly successful low income energy assistance program in Alaska, which have received funding for bill payment assistance, weatherization, and other services from a variety of sources. Some of these sources, such as federal funds through the LIHEAP program, however, have been declining significantly in recent years. Basic information regarding low income citizens of Alaska and poverty guidelines are included in Table 7.11 and Table 7.12.

In addition to providing affordable electricity, Alaska utilities deliver consistently reliable and high-quality electric service. In support of continued high-quality service, utilities must plan and make investments in infrastructure and customer services.

Costs Associated with Public Purpose Programs

Electric utility restructuring has the effect of making explicit that which was hidden. This is especially true as regards public purpose programs and uneconomic (or "stranded" costs). The costs of these programs must be considered in light of the anticipated savings and other benefits that competition will bring in order to reach a conclusion about whether the process of restructuring is in the best interests of the state and its people.

A number of differing approaches have been adopted and suggested for accomplishing public purpose programs such as low income assistance, energy efficiency, renewable energy, and energy research and development. The net impact on customers is a function of the level of public purpose program support instituted and the potential savings anticipated. In Alaska's Railbelt region, a charge of 1/10th of one cent (one mill) per kilowatt hour will generate approximately $3.7 million per year. This amount increases by just under $40,000 per year for each percent of sales growth in the region. The bill impact on the average residential customer in Alaska is approximately 67 cents per month per mill of charge.

Various program approaches offer differing benefits for the amount invested. A 1 percent charge to fund low income assistance programs would generate over $3 million in annual program funding for an average monthly charge to residential customers of approximately $0.69.

A summary of the expected price impacts of a wide range of public purpose program options is included in Table 7.13.

Operational Concepts of Affordability

Policy makers have a number of differing options for use in addressing affordability of electric services in Alaska under restructuring. As discussed above, one important issue is the level of public purpose program support to be pursued. A second issue relates to the competitive benefits sought from restructuring. The level of competitively induced savings benefits is directly related to the level of competition introduced into the industry. Restructuring experience from other jurisdiction demonstrates that limiting the scope of competition or protecting the market share of incumbent providers tends to reduce the amount of savings realized.

There are also available several different conceptual models of affordability that can be reflected in any restructuring plan. At one end of the spectrum is the choice of leaving affordability issues to the markets themselves. This idea is based on the concept that restructuring is supposed to be about allowing market forces to set the appropriate price of electricity, and that affirmative intervention with market prices creates market inefficiencies. This kind of approach offers simplicity of implementation, but may create hardships on some customers, especially low income customers, if market prices rise.

At the other end of the spectrum of policy options is a model that incorporates affordability into a generalized policy of universal service. This approach operates from the premise that all customers should have access to a basic package of affordable and reliable electric services. Under the universal service model, rates for an initial block of electric energy would be maintained at predetermined levels, and funding would be required to ensure additional services such as weatherization for low income customers was also available. While this approach offers greater protection against hardships for customers, it requires the development of regulatory standards and administrative implementation and oversight. Such regulatory costs will have the added effect of diminishing the savings potential from competition.

Table 7.14 provides a summary of the features of alternative conceptualizations of affordability.

Impacts of Restructuring on Affordability

Restructuring of the electric utility industry may support or frustrate the goal of affordable electric service. As discussed above, competitive market efficiencies should translate into overall cost savings. However, whether these savings will be allocated by the market to residential customers will be highly influenced by policy decisions made in the course of developing a restructuring plan.

The potential for price reductions is largely a function of the liquidity and openness of electricity markets. On the other side of the equation are a number of potential negative impacts of restructuring on affordability. Whether restructuring serves the best interests of all the people of Alaska's Railbelt will depend on a careful balance of market structure issues and the nature and extent of affordability mechanisms introduced.

The most commonly identified potential negative impact is the allocational issue – that the price savings resulting from competition will be cherry-picked by a few large customers. To a large extent, this is a problem inherent in the de-averaging and segmentation of previously homogenous classes of customers. While most observers would welcome the introduction of new services and products to meet customer demands, there is a concern that costs will shift toward customers with smaller discretionary budgets and fewer choices. Several mechanisms exist to counter this impact, though they may have the effect of artificially reducing prices for some customers. These options include default provider or service provisions, provider of last resort systems, or customer aggregation mechanisms.

Customer class segmentation may create another problem for affordability in areas served by smaller utilities. For these utilities, a relatively few customers make up a significant portion of the utilities' revenue base. If these customers are lost to competitive providers, fixed costs are spread over fewer remaining customers and could drive rates upward. In the lower-48, similarly situated utilities have proposed an opt-in approach to retail competition which would allow them to an opportunity to prepare for or avoid entirely the risks of competition. Many observers believe, however, that such opt-in approaches offer only temporary refuge from the threat of competition.

The potential negative impacts of retail competition on affordability are summarized in Table 7.15.

Stakeholder Views

A number of stakeholders, primarily representing cooperative and municipal utilities, expect significant adverse impacts on affordability as a result of restructuring. The vast majority of stakeholders in Alaska envision the adoption of some mechanisms to attempt to ensure affordability of electricity service in a competitive retail environment. While some stress the need for a clearly established affordability goal as part of restructuring, most stakeholders are most concerned with the manner and methods used to address the issue. These stakeholders are concerned that any funding mechanism, such as a system benefits charge, must be imposed in such a manner as to avoid competitive discrimination against certain market participants. Finally, some stakeholders argue for exit fees or other mechanisms for recovering the value of investments made to serve customers switching to new suppliers.

A summary of stakeholder views are contained in Table 7.16.

Policy Options

Policy makers in Alaska have several options for ensuring affordability under industry restructuring in the Railbelt. These options fit into a few broad categories. The first option is to let markets decide the appropriate price for electricity. This approach imposes no direct costs, but may create indirect costs associated with hardships on certain customers if prices for these customers rise or they lose their current benefits. Other mechanisms include funding rate discounts for certain low income customers. While discounts for low income customers target those for whom rising prices pose the greatest threat of hardship, they must be funded through some kind of system benefits fund. This funding has the effect of reducing overall savings from competition.

One option that has been discussed but not implemented to date involves establishing a competitive auction for the right to serve as default provider or provider of last resort. Under this approach, the regulatory authority would periodically conduct a competitive auction or solicitation for suppliers. In return for a commitment to provide service to customers at affordable rates, providers would be granted a right to provide service within designated geographic regions or market segments. This approach could require revenue supplements for high-cost customers, entailing the need for a funding mechanism such as a system benefits charge.

As with most policy options, the key issue is the balance between the benefits of meeting policy goals and the financial or administrative costs associated with implementing remedial mechanisms. Options involving a system benefits charge reduce overall competitive savings, and regulatory oversight mechanisms require agency funding and impose compliance costs on participants.

A range of policy options for addressing affordability issues and impacts is set forth in Table 7.17.

As has been noted by some consumer advocates, there are opportunities to impact affordability throughout the restructuring process. High transaction costs in providing services to small customers can be mitigated through aggregation mechanisms, and through regulatory oversight of distribution, metering and billing practices. Cost allocation processes have a significant potential to create price discrimination among classes of customers, to the detriment of residential and small commercial customers. Unmitigated market power that can be used to charge higher than marginal rates could directly impact affordability. Finally, calculation and allocation of uneconomic or stranded costs will directly impact affordability. It is important to note that, in the end, a number of structural actions or mechanisms instituted to preserve or enhance affordability also have a direct impact on making a restructured electric industry more competitive.

The policy recommendations of Consumers Union and the Consumer Federation of America regarding these issues are summarized in Table 7.18.

TABLE 7.1
Impacts of Retail Competition on Universal Service

Impact	Likely Effects	Remedial Actions	Statutory Changes Required
Pre-competitive investments by utilities may be "stranded" by customers leaving the utility, imposing rising costs on remaining customers.	Formerly incumbent utilities may face competitive disadvantage vis-à-vis new market entrants.	Determine the extent to which investments have not been recovered or depreciated. Establish exit fees or other lost-revenue mechanisms to hold utilities harmless.	Yes. As part of restructuring legislation, some entity must be empowered to review and adjudge unrecovered investments and to impose collection mechanisms.
Providers of last resort may be required to maintain excess capacity in order to serve returning customers.	Providers of last resort with obligation to serve will face greater fluctuation in numbers of customers served due to customers switching providers and returning.	Limit obligation to serve to either a universally established default service package, or to customers that never switch. Impose more limited obligation to connect for new and returning customers.	Yes. Creation of default service package for all utilities requires broader authority and potential state wide cost-sharing mechanism. Opt-in mechanism for some utilities reduces impact.
Competitive providers seeking profits may "cherry-pick" most attractive customers, imposing rising costs on remaining customers.	Provider of last resort utilities bear highest overall costs, limiting their ability to also profitably compete for customers. Benefits of competition not uniformly distributed.	Impose proportional burdens on all providers to serve all classes of customers (by allocation). Create universal service fund through system benefits charge to offset costs.	Yes. An entity must be empowered to assess and distribute burdens, to collect and distribute funds according to prescribed standards.
Relatively few customers will be in a position to successfully pursue alternative suppliers, due to lack of information, sophistication, or usage level.	Non-switching customers may not receive the benefits of new competitive offers, discounts, and incentives. Costs associated with increasing switching volume may reduce overall level of savings.	Conduct comprehensive customer education. Auction or assign customers to kick-start market churn. Encourage or facilitate aggregation of residential customers.	Yes and No. APUC enjoys broad authority to specify information provided to customers of regulated utilities. Allocation of customers on basis other than certified or franchised territories requires statutory amendment/ authority. Non-geographic aggregation is essentially retail access.

Impact	Likely Effects	Remedial Actions	Statutory Changes Required
Many customers will be customers simply because they never made any choice.	Absent opportunity for significant savings, or in the event of confusing terms and conditions, customers respond with inaction, and may not exercise choice. They may never be approached to switch.	Conduct comprehensive customer education. Auction or assign customers to kick-start market churn. Encourage or facilitate aggregation of residential customers.	Yes and No. APUC enjoys broad authority to specify information provided to customers of regulated utilities. Allocation of customers on basis other than certified or franchised territories requires statutory amendment/ authority. Non-geographic aggregation is essentially retail access.
Costs associated with ensuring universal service reduce the level of system-wide savings available through restructuring.	Lack of clear statutory or regulatory definition of universal service creates uncertainty about likely costs of ensuring universal service. Regulatory and oversight costs could be relatively significant.	Conduct regulatory proceeding to establish universal service definitions and requirements. Estimate costs under various competitive scenarios.	Yes and No. APUC enjoys authority to establish rules and gather information relating to regulated public utilities.
Competitive providers seeking to reduce costs may allow degradation of facility or service quality.	Lack of statutory or regulatory definition of universal service creates uncertainty about relationship with service quality standards.	Conduct regulatory proceeding to establish universal service definitions and requirements. Estimate costs under various competitive scenarios.	Yes and No. APUC enjoys authority to establish rules and gather information relating to regulated public utilities.

TABLE 7.2
Universal and Affordable Service Proposals: Congress 1997

Bill No.	**HR 655**	**HR 1230**	**HR 1359**	**HR 1960**	**S 237/1401**	**S 687**	**S 722**	**S 1276**
Sponsor	Rep. Schaefer, R/CO	Rep. Delay, R/TX	Rep. DeFazio, D/CA	Rep. Markey D/MA	Sen. Bumpers D/AR	Sen. Jeffords R/VT	Sen. Thomas R/WY	Sen. Bingamon, D/MN
Definition of Universal or Affordable Service	"adequate electric service is available to all customers served by the retail distribution system concerned"	"continuation of service to residential customers unable to afford electric energy service..."	Universal service program = any that promotes high quality and reliable electric service at just, reasonable and affordable rates for low income consumers and those in rural, insular or high cost areas.	Evolving level of electric services established periodically be states taking into account advances in technology and services.	S 1401: "ensures that all consumers have access to purchase retail electric energy from at least one retail electric energy supplier at a just and reasonable rate."	Lists universal service and affordable service as separate items in list of eligible public benefit programs.		Every consumer should have access to electric energy at reasonable and affordable rates, the Commission and states should ensure competition does not result in loss of service to rural, residential or low income customers.
Mandated?	No	No	No	No, but states must certify action on universal service to qualify for PUHCA exemption.	Program voluntary, but in states with no program suppliers obligated to sell to customers in areas without effective competition and customer has not chosen a supplier.	No	No	No

Bill No.	HR 655	HR 1230	HR 1359	HR 1960	S 237/1401	S 687	S 722	S 1276
Sponsor	Rep. Schaefer, R/CO	Rep. Delay, R/TX	Rep. DeFazio, D/CA	Rep. Markey D/MA	Sen. Bumpers D/AR	Sen. Jeffords R/VT	Sen. Thomas R/WY	Sen. Bingamon, D/MN
State Role	Each state and unregulated utility must consider provisions to ensure supply to all customers.	Retains authority over local distribution service, can provide Lifeline service for “continuation of service to residential customers unable to afford electric energy service.”	Propose public benefit programs, pay half the cost. May use federal matching funds only for eligible public benefit programs.	May adopt regulations to advance universal service, ensure universal service at rates that are fair, just, reasonable, consider recommenda-tions of joint board and complete proceeding re implementation within one year.	May establish programs, must enforce service obligations (see above)	Propose public benefit programs, pay half the cost. May use federal matching funds only for eligible public benefit programs.	States have jurisdiction over retail supply and local distribution service, may establish performance standards for reliability, health and safety, protect from unfair business practices.	States shall consider measures to ensure access at affordable rates and prevent loss of service to low income and rural customers, report any measures adopted to FERC.

Bill No.	**HR 655**	**HR 1230**	**HR 1359**	**HR 1960**	**S 237/1401**	**S 687**	**S 722**	**S 1276**
Sponsor	Rep. Schaefer, R/CO	Rep. Delay, R/TX	Rep. DeFazio, D/CA	Rep. Markey D/MA	Sen. Bumpers D/AR	Sen. Jeffords R/VT	Sen. Thomas R/WY	Sen. Bingamon, D/MN
Federal Role	None	FERC to provide for Nondiscrimina-tory prices, terms, conditions of transmission and distribution services.	Sec. Energy Oversees National Electric System Public Benefit Board, which recommends and oversees programs. Appoints non-federal fiscal agent to collect and distribute funds after approval by Sec.	FERC to establish federal-state joint board to institute proceeding to recommend universal service support mechanisms, act on state certifications of competition.		Sec. Energy oversees National Electric System Public Benefit Board which recommends eligibility criteria for programs, established fund, determines and reports to FERC amount needed for programs & admin.		Unbundled service must be provided on non-discriminatory basis. Any state law, regulation or order that results in unbundled service which is unjust, unreasonable or unduly discriminatory or preferential is preempted.

Bill No.	**HR 655**	**HR 1230**	**HR 1359**	**HR 1960**	**S 237/1401**	**S 687**	**S 722**	**S 1276**
Sponsor	Rep. Schaefer, R/CO	Rep. Delay, R/TX	Rep. DeFazio, D/CA	Rep. Markey D/MA	Sen. Bumpers D/AR	Sen. Jeffords R/VT	Sen. Thomas R/WY	Sen. Bingamon, D/MN
Funding Mechanism	State may “impose requirements” to ensure all can get service.	State has authority to establish non-discriminatory local distribution access charges on any power delivered sufficient to cover cost of lifeline program.	Owners of generation contribute to fund per kWh. Amount based on 1/2 the cost of eligible programs but cannot be more than 2 mills per kWh. Transmitting utility collects from generator and transfers money to fiscal agent.	Electric utilities providing interstate service shall contribute to specific, predictable and sufficient mechanisms established by states to preserve universal service.	State may impose non-bypassable. Universal Service Charge on all customers of every retail provider to fund all or part of programs.	FERC imposes non-bypassable, Competitively neutral wires charge paid into fund by operator of wires impacting interstate commerce, measured at exit of busbar at generation. Amount collected to be lesser of 2 mills/kWh or sufficient to fund programs.	State OR non-regulated utility may require payment of charge as condition of purchase of electricity for public purpose programs, including assistance to low income customers.	State may assess non-discriminatory charge on unbundled local distribution service, retail sale of electricity or generation for consumption by generator within state.
Who Pays?	Not discussed	Customers	Generation owners	Electric utilities in interstate commerce	Customers	Operators of wires Impacting interstate commerce	Customers	Customers
State Share/Match	N/A	100%	50%	0%	100%	50%	100%	100%

Bill No.	HR 655	HR 1230	HR 1359	HR 1960	S 237/1401	S 687	S 722	S 1276
Sponsor	Rep. Schaefer, R/CO	Rep. Delay, R/TX	Rep. DeFazio, D/CA	Rep. Markey D/MA	Sen. Bumpers D/AR	Sen. Jeffords R/VT	Sen. Thomas R/WY	Sen. Bingamon, D/MN
Low Income Share	Not discussed	None stated.	None stated. Must compete with conservation, renewable and R&D.	Universal service fund specific to low income and access in rural and high cost areas, no set shares stated.	In addition to Universal Service Fund, state can also assess charges on customers for efficiency and R&E programs.	None stated. Must compete with conservation, renewable and R&D.	None stated. Must compete with conservation, R&D, renewable energy, reliability, transition costs.	None stated.
Access Requirements	Must consider, and may require, steps so that all customers can get service.	Right to choose cannot be denied or limited.	None stated.	Universal service to include access to "advanced services."	S237: Utilities required to serve any customer that is not offered service from at least two suppliers/ S1401: In states with no universal service program each retail provider has service obligations where no effective competition and choice not exercised.		States can require providers of electricity to serve all classes of customers.	

Bill No.	HR 655	HR 1230	HR 1359	HR 1960	S 237/1401	S 687	S 722	S 1276
Sponsor	Rep. Schaefer, R/CO	Rep. Delay, R/TX	Rep. DeFazio, D/CA	Rep. Markey D/MA	Sen. Bumpers D/AR	Sen. Jeffords R/VT	Sen. Thomas R/WY	Sen. Bingamon, D/MN
Other		Ban on exit fees, penalties for switching	Intent of Congress that public benefits programs not replace existing programs	Customers must have reasonable opportunity to aggregate to get lower rates	S 1401: Any aggrieved person may bring action in federal district court to enforce act	Detailed provisions re: audits and Board process		

SOURCE: http://www.spratley.com/leap/stuff/1998.01.00.02.universal_and_affordable_service_proposals_congress_1997.pdf

Prepared by: Kay Guinane, Consulting Attorney, National Consumer Law Center 202/986-6060

Sources: Electric Power Alert Special Report, June 20, 1997, American Public Power Association Summary, June, 1997, http://thomas.loc.gov, National Environmental Trust Bill Summary and Status 105th Congress, Nov. 1997

TABLE 7.3
Provider of Last Resort Options

Policy Option	Method of Implementation	Advantages	Disadvantages
Assign responsibility to incumbent utility or local distribution company.	Maintain current system. Clarify obligations in legislation, including mechanisms to prevent competitive disadvantage.	Most like current system – less confusion to customers. Maximizes opportunity for utilities to recover past investments made on behalf of all customers.	May strengthen incumbency advantage in competitive market. May stifle incentive for efficiency improvements. May create competitive disadvantage for provider.
Require all suppliers in the market to reserve a percentage of revenues to serve last-resort customers.	Legislation – obligation created as a condition of opportunity to compete. Obligations overseen by APUC.	Spreads costs across all competitors. Maximizes potential for development of innovative solutions.	Requires extensive regulatory oversight. Administrative requirements on all suppliers could act as barrier to market entry.
Ensure all customers have a legal right to purchase service at power exchange prices for energy plus regulated rates for transmission, distribution and ancillary services.	Legislation – establish right and mechanism for any customer to obtain service on application. APUC implements creation of market to provide supply & rates for T&D, ancillary services.	Does not impose unwanted burdens on competitors. Provides uniformity across the market.	Requires regulatory setting of rates and oversight. Right must be protected with mechanism for enforcement; provisions made for service during dispute resolution.
Create a new state agency to provide service of last resort.	Legislation & appropriation of funds.	Does not Impose unwanted service burdens on competitors. Provides uniformity across the market; and efficient match of resources to need. Creates market benchmark without assigning competitive benefits to incumbents.	Administrative and regulatory burden. Places government directly in competition with private sector for residential service. May stifle innovation in service provision.
Competitively auction the right to serve as provider of last resort to a fixed number of qualified suppliers.	Legislation. APUC implements and oversees auction mechanism, tracks contract performance, imposes other appropriate conditions.	Applies market forces to default service provision. Encourages creation of new class of service provider with market objectives aligned to public purposes.	Requires extensive oversight. May create competitive advantage for selected providers in other markets.
Create a supplier pool or load aggregator.	Legislation. APUC or other agency must create supply pool or aggregator.	Allows for efficient aggregation of demand to reduce need for public benefit supports.	May require supplemental funding support in order to deliver price benefits. Concentrates expensive or difficult to serve customers into high-cost pool.

TABLE 7.4

Universal Service Policy Options Available in Alaska - Conceptual Models

Policy Option	Method of Implementation	Advantages	Disadvantages
Universal Service Facility*	Provider has the option of ceding the risk of customer's account to a universal service facility or retaining the customer in its own portfolio. A ceded customer's payments are collected by the service provider then paid to the service facility. The service provider provides the same service to the customer and offers the same rates. If a ceded customer's account incurs a claim, the costs of paying that claim is borne by the facility. Total costs to the facility are apportioned to all electric generation providers in the state, weighted according to the providers' facility use and market share.	Costs of last resort provider are shared among all providers in the state. Cost apportionment mechanism insures that *only* the riskiest customers (those who need a provider of last resort) are ceded to the facility, thus avoiding the possibility that the generation provider retains all but the most attractive customers, ceding the rest to the facility (cherry-picking). Transactions are transparent to the customer, and services are provided by generation provider. The utility has absolute right of ceding risk to facility, without regard to any objective criteria.	Difficulty in designing the optimal weighting of facility use and market share to minimize total facility use (excessive ceding of customers to facility).
Joint Provider's Association (JPA)*	All electric generators are required to participate in a joint provider's association who agrees to handle "involuntary" customers whom the competitive market ("voluntary market") does not wish to serve. Risks are borne by association as a whole.	All customers are guaranteed access to adequate electricity service. Customers retain their ability to choose an electricity provider. Costs of last resort provider services are shared among all providers in the state.	No incentive to keep "marginally" attractive customers out of the association. Utility may assign all but the most attractive customers as "involuntary", resulting in overpopulation of the JPA, and consequent rate distortions. Customers in the involuntary market end up paying higher rates than the voluntary market, exactly the opposit of the inteded result.
Assigned Last Resort Providers or a Single-Entity Provider of Last Resort*	State regulatory officials promulgate a standard set of rates and terms for customers in the high risk pool. Customers are randomly assigned to electric generation providers to be served with the standard package. In the case of the single provider, high risk customers are assigned to either the incumbent utility or transmission system owner or operator. The provider bears all costs and profits of serving the high risk customer.	All customers are guaranteed access to minimum electricity service.	Customers are not given the freedom to choose their generation service provider. There is a tendency for providers to offer only the bare minimum services to these high risk customers, such that they are often denied the full competitve service offerings.
Competitive Auction	State regulatory officials create mechanism to conduct periodic competitive auction of right to serve as provider of last resort. Rate of return is regulated either under cost of service methodology or performance based regulatory arrangements.	Serves aggregation function to create profitable customer set. Applies well-established regulatory experience and allows introduction of performance-based regulatory approaches. Auction can be structured to recognize value of investments made to serve "captive" customers prior to competition. Focuses funding on customers' needs.	No practical prior experience. Requires on-going regulatory oversight of provider. May require supplemental funding if customer base is too small or shrinks due to choice. Performance-based regulation must be carefully designed to avoid incenting inefficient operation.

*Source: Colton, Roger D. Provider of Last Resort: Lessons from the Insurance Industry. *The Electricity Journal.* December 1998. Pp. 77-84.

TABLE 7.5
Selected State Restructuring Provisions Regarding Universal Service

California	The California Electric Restructuring statute (AB 1890, eff. September 23, 1996) states: "It is the further intent of the Legislature to continue to fund low-income ratepayer assistance programs, ..." Section 1(d). The Legislation authorized the Commission to establish a non-bypassable charge to be collected through the distribution company rates on the basis of usage to fund low income energy efficiency and ratepayer assistance programs. Section 381. A minimum funding level equal to the 1996 authorized spending levels for each utility was established as well. Section 383. California utilities fund and implement both energy efficiency and rate assistance programs to low income customers through their rate structure. The California CARE program provides a 15 percent discount on volumetric gas, electric and monthly customer charges to households with income at or below 150 percent of federal poverty guidelines. For electric low income customers these discount costs were approximately $106.9 million in 1996. The energy management programs targeted to low income customers totaled approximately $50 million by investor owned utilities. These programs have a penetration ratio of approximately 56-58 percent of the eligible low income households.
Pennsylvania	The Consumer Choice Act (effective January 1, 1997) in Pennsylvania calls on the Public Utility Commission to address the need for a comprehensive Universal Service program for all electric utilities as a necessary element of the move to electric competition. The General Assembly has declared that, "Electric service is essential to the health and well being of residents...; and electric service should be available to all customers on reasonable terms and conditions." Sec. 2802(9). The Commission has determined that it cannot achieve this objective without a comprehensive program that meets the needs of Pennsylvania's most needy and potentially most vulnerable electric consumers. In the Restructuring Filings from all electric utilities, the Commission was obligated to "ensure that universal service and energy conservation policies, activities and services are appropriately funded and available in each electric distribution territory." Section 2804(9). As part of its Restructuring Plan, the utility must submit an "initial plan that sets forth how it shall meet its universal service and energy conservation obligations." Sec. 2804(15). At a minimum the Commission is required by the Consumer Choice Act to continue the "protections, policies and services that now assist customers who are low income." Section 2802(10). The Consumer Choice Act sets forth the major components of a Universal Service Program for low-income customers: (1) Electric Distribution companies should continue to be the provider of last resort in order to ensure that electric service is available unless another provider of last resort is approved by the Commission. Sec. 2802(16), and (2) Policies, protections and services that help low-income customers maintain electric service. The term includes customer assistance programs, termination of service protections and policies and services that help low-income customers to reduce or manage energy consumption in a cost-effective manner, such as the low-income usage reduction programs (LIURP), application of renewable resources and consumer education. Sec. 2803 The Act directs that these programs and services will be delivered and funded via the electric distribution companies. The Act also requires that the distribution utilities rely on community-based organizations for the delivery of these programs where that is appropriate. Section 2804(9). These programs must be funded by a "non-bypassable" cost recovery mechanism "...which is designed to fully recover the electric utility's universal service and energy conservation costs over the life of these programs." Sec. 2802(17); 2804(8).

Massachusetts	The Massachusetts DPU has required each electric and gas utility to fund low income discounts or rate reduction programs for low income customers for many years as part of their regular revenue requirement reviews. Electric restructuring legislation (Chapter 164, Acts of 1997, eff. November 25, 1997) requires that these programs be continued by the distribution companies "comparable to the low-income discount rate in effect prior to March 1, 1998." (Section 1F(4)) The cost of these programs must be included in the rates charged to all other customers of a distribution company. Further, "Each distribution company shall guarantee payment to the generation supplier for all power sold to low-income customers at said discounted rate." (Ibid.) Eligibility may extend to 175 percent of the federal poverty guidelines. The distribution companies are required to conduct substantial outreach to obtain a high penetration rate for these programs, including the establishment of an automated program to match customer accounts with lists of recipients of means-tested public benefit programs. Prior to the end of the 7-year transition period, the Department must analyze and make recommendations concerning the affordability of electricity and consider modifications for expansion of the program and specifically must consider whether to modify the discount to adopt a sliding scale discount program (thus providing a better match between usage and income). Low-income customers may obtain default service without additional charge at any time. The legislation also requires funding for energy conservation programs via distribution company rates for a five-year period at levels that are the highest in any state. Funding starts at 3.3 mills per kWh in 1998 and phases down to 2.5 mills in 2002, totaling about $500 million over this period. Included in this program is a permanent set-aside for low income DSM of .25 mills per kWh or 20 percent of each utility's residential conservation program. These programs must be coordinated with the local Weatherization Assistance Program agencies. These programs must conform to statewide standards that will be set by the Division of Energy Resources.
New Hampshire	The New Hampshire electric restructuring legislation calls for, "Programs and mechanisms that enable residential customers with low incomes to manage and afford essential electricity requirements should be included as part of industry restructuring." RSA 374--F:3(V). The New Hampshire PUC's Final Restructuring Order interprets this directive to create a new $13.2 million bill payment assistance and energy management program, modeled after a Percentage of Income Payment approach. The program will be funded by through usage-based rates charged by all distribution utilities. It is not clear whether this program must include low income energy management programs or whether these programs will be funded separately from the payment assistance program.
Rhode Island	Rhode Island's electric restructuring legislation declares that, "...in a restructured electrical industry the same protections currently afforded to low income customers shall continue." Section 39-1-1, Declaration of Policy. The current programs include special discount rates and Percentage of Income Payment programs. The costs of all these programs must be "...included in the distribution rates charged to all customers." Section 39-2.1.2(b).
Maine	The Maine restructuring legislation states, "In order to meet legitimate needs of electricity consumers who are unable to pay their electricity bills in full and who satisfy eligibility criteria for assistance, and recognizing that electricity is a basic necessity to which all residents of the State should have access, it is the policy of the State to ensure adequate provision of financial assistance." Section 3214. Existing ratepayer assistance programs must continue as a minimum at current expenditure levels, approximately .5 percent of jurisdictional electric utility revenues. The program costs will be included in distribution rates charged to all customers. Future funding will be set based on "aggregate customer need." Section 3214(2)(B). The Legislation also provides for the possible future funding of these programs by the General Fund (i.e., taxes), at which time the PUC must reduce the funding provided through distribution company rates.

Vermont	The Vermont Public Service Board has recommended all-fuels energy assistance program to be funded by a broad-based tax or energy fee. The Board recommends that if the Legislature does not enact the all-fuels tax or fee approach, electric utilities should provide programs to low income customers funded by a non-bypassable charge. In either case, the minimum program should be based on need, as a reflection of the household electric bill in relation to the household's income, and administered statewide by an independent entity separate from the utilities themselves. The assistance program should include energy management services targeted to low income customers as well.
Montana	The Montana electric restructuring legislation mandates a universal service policy, "The public interest requires the continued protection of consumers through: *** (d) continued funding for public purpose programs for: (i) cost-effective local energy conservation; (ii) low-income customer weatherization; (iii) renewable resource projects and applications; (iv) research and development programs related to energy conservation and renewables; (v) market transformation; and (vi) low income energy assistance." Section 2. These mandates will be funded by revenues equal to 2.4percent of each utility's annual retail sales revenue, of which 17percent of the fund must be allocated to energy assistance and weatherization. A Transition Advisory Committee will make recommendations for the implementation of a statewide universal service system benefits charge and energy assistance funds prior to 1/99. By 11/98 the Committee must submit recommendations concerning the provision of low income assistance by all energy providers, thus potentially expanding the program from just electric companies to all energy providers in the state.
Oklahoma	The Oklahoma electric restructuring legislation is far less detailed that other state legislation adopted to date and all the future Commission restructuring decisions must be approved by the Legislature. However, the Commission is directed to incorporate key principles in its creation of a framework to achieve retail electric competition: "Minimum residential consumer service safeguards and protections shall be ensured including programs and mechanisms that enable residential consumers with limited incomes to obtain affordable essential electric service, and the establishment of a default provider or providers for any distribution customer who has not chosen an alternative retail electric energy supplier." Section 4(9). The legislation authorizes a distribution access fee to cover the normal costs associated with providing distribution services, and to include social costs. The Commission's final report and recommendations to the Legislature must include an identification of public policy benefits and their funding by 12/98, to be followed by recommendations concerning consumer protection and low-income programs by 12/99.
Nevada	The Nevada PUC is directed to adopt regulations to implement electric restructuring and must, "Provide effective protection of persons who depend upon electric service." Section 2. The legislation does not specifically require or discuss universal service or low income programs. However, the Commission is required to designate an existing utility to provide electric service to customers who are unable to obtain electric service from an alternative provider or who fail to select an alternative provider. This service must operate with a rate cap for at least two years. The Commission may also consider alternative methods of providing this service, including direct assignment of customers to alternative providers or the use of competitive bidding for the generation portion of this service.
New York	The New York Public Service Commission has issued generic policy decisions concerning electric competition and is trying to move forward to implement those policy decisions in individual electric restructuring cases without specific legislative authorization or guidance. The Commission has stated its support for universal service and low income programs, but has deferred to the individual utility cases to determine the program design and funding level. The Commission has stated that such programs must remain the responsibility of the distribution companies as part of their overall obligation to provide "last resort" services to all customers. The first restructuring case to reach the Commission, a negotiated settlement with Consolidated Edison and numerous parties, contains a provision that creates a non-bypassable charge to fund low income assistance and energy management programs. The Commission approved this settlement on September 23, 1997 (Case 96-E-0897).

Illinois	The Electric Service Customer Choice and Rate Relief Law of 1997 (HB0362, eff. December 16, 1997) does not offer residential customers the right to choose an alternative supplier until 2002, but rate reductions (15percent for the larger utilities) for all residential customers will take effect beginning in August, 1998. The legislation mandates a per customer monthly charge of $.40/month for residential gas and electric customers which will be included in the monthly customer charge billed by distribution utilities. Other flat monthly fees are also specified for all other non-residential customers. This Supplemental Energy Assistance Fund is estimated to raise $76 million annually for energy assistance funding for low-income customers and 10 percent of this fund is mandated for energy efficiency measures. The funding will be directed to the State's Energy Assistance Program which currently delivers the LIHEAP and federally-funded Weatherization Assistance Programs. In the short term, the funds will be used to primarily supplement the LIHEAP grants, but the long term plan for this funding includes design and implementation of new programs, particularly those targeted to energy efficiency. This funding source is permanent and marks the first significant state funding for low income energy assistance in Illinois.

Source: SUMMARY OF STATE ELECTRIC RESTRUCTURING LEGISLATION: UNIVERSAL SERVICE PROVISIONS. Barbara R. Alexander
http://www.spratley.com/leap/stuff/1998.05.00.01.summary-of-state-electric-restructuring-legislation-universal-service-provisions.html

TABLE 7.6

Comparison of Consumer Protection Provisions in Selected States, Part 1.

Public Policy Issues	New Hampshire	Massachusetts	Maine	Rhode Island	Pennsylvania
Retail Access Date	1/1/98 (Delayed due to court appeal by largest utility)	3/1/98	3/1/00	3/1/98	Pilots start 9/97; retail access phased in for 1/3 all customers during the 1/1999-1/2001 period.
Standard Offer/Default Service	Default Power Service administered by D&T utility; can use owned generation, but only at market price; must issue competitive bids or use spot market to get additional power; choose minimum of 5 suppliers.	Standard Service: Provided by D&T utility for 7 years; combination of the total bill must reflect 10% rate reduction 3/1/98 and 15% reduction by 9/1/99; must use competitive bid if necessary; available to current customers only or low income customers at any time. Default Service: available to any customer who has entered competitive market; safety net service; competitive bid; priced at market rates with 6-mo. rate stability; no fee or minimum contract period for residential customers who switch at meter read.	Standard Offer service provided to any customer who does not choose or who cannot obtain power in market on reasonable terms; competitive bid process administered by D&T utility; but PUC determination of terms and conditions of standard offer service; affiliates of "large" D&T utilities can bid for no more than 20% of load; small utilities and munis can bid for entire load; rates for this service must reflect rate design of current rates for each customer class; rates must be stable for 2-year period (reflected in bid specifications).	Standard Offer: provided by D&T utility pursuant to its wholesale power supplier; applicable to those who have not chosen competitive supplier; price must not exceed rates in effect in 1996, adjusted by a price cap index; once customers select alternative supplier, D&T utility no longer responsible to supply. Last Resort Power Supply: for customers no longer eligible for Standard Offer and unable to get power at reasonable price in market; D&T utility obtains power by bid from competitive providers.	D&T utilities must provide service to customers who do not choose and who seek to return to regulated service from the competitive market; total generation and D&T rates capped for time periods (up to 9 years) that reflect recovery of stranded costs. After transition period the PUC determines how this service is priced and can consider competitive bids from other than D&T utilities.

Public Policy Issues	New Hampshire	Massachusetts	Maine	Rhode Island	Pennsylvania
Form of Regulation of Distribution Company	Traditional regulation based on 1996 embedded cost of service studies; unbundling by function; PBR possible, but postponed until analysis of studies.	Performance Based Regulation favored, but not mandated; any plan must include comprehensive service quality and reliability provisions with penalty up to 2% of revenues at risk for degradation of service quality. Code of Conduct (regulate transactions between D&T utility and affiliates) mandated with specific legislative directives.	Price cap regulation currently in place until 2000 for 2 of 3 large investor-owned utilities; PUC has discretion to change or continue based on statutory criteria in place prior to this Legislation; current PBR plans have individual service quality index with penalties for degradation from baseline standards. Code of Conduct required with detailed legislative guidance.	Price Cap plan established in Legislation; utilities filed for automatic 2% rate increase in 12/96.	D&T utilities subject to rate caps (with specific exceptions) during transition period. PBR authorized, but not mandated. Code of Conduct authorized by PUC rule.

Public Policy Issues	New Hampshire	Massachusetts	Maine	Rhode Island	Pennsylvania
Definition of Distribution utility obligation; competition for billing and metering services	Must divest of all generation facilities except QF contracts; D&T utilities shall remain responsible for reading meters and transferring data to suppliers; must offer to supply billing services to suppliers; defer unbundling of metering and customer services for small customers (those with less than 100 kW demand), but energy billing services must be unbundled, i.e., suppliers can issue own bills.	Obligation to provide open access; D&T utilities must continue to offer billing and metering services; study of possible competition of these services deferred until 1/1/2000, with report to Legislature by 1/2001. Must address possible impacts on utility employees.	Distribution regulated as monopoly; obligation to connect; exclusive service territories; reliable and safe service obligation; billing and metering must be competitive in 2002 (or earlier) pursuant to PUC rules.	D&T utilities regulated as monopoly with price caps; exclusive service territories; no metering and billing competition provisions	Distribution company obligated to provide same level of customer services and quality of service with retail choice; customer can choose whether to receive one bill from D&T utility or two bills; no legislative mandate for billing and metering competition, but PUC has ruled that statute does not prohibit competition. Go slow approach to be explored in rulemaking.
Licensing of Generation Suppliers	Registration requirements minimal.	Licensing required by DTE; technical ability; financial capability; company form of ownership; fees set by rule; bond authorized.	Licensing by PUC; financial and technical resources to carry out business obligations and customer commitments; disclosure of all pending legal actions and customer complaints at other regulatory bodies; disclosure all affiliates; consider bond.	Registration by PUC; registration requirements to be proposed to Legislature by 1/1/97. PUC rules intended to ensure that suppliers meet the operating and reliability standards of NEPOOL; rely on D&T utility contracts for nondiscriminatory billing, metering and settlement procedures.	Licensing by PUC; standards set by rule; extensive licensing requirements and disclosures; bond; affidavit re compliance with customer service and billing and collection rules.

Public Policy Issues	New Hampshire	Massachusetts	Maine	Rhode Island	Pennsylvania
Application of current consumer protection rules to generation suppliers	No automatic application of current D&T rules to suppliers; minimal consumer protections to protect against abuse in competitive market to be defined by rule: slamming; monitor for redlining; cancel contract on notice	Legislation mandates that current consumer protection rules must be applied to suppliers; DTE to specify by rule which must "retain or make increasingly protective..."	PUC has obligation to adopted new minimum standards for suppliers' conduct: minimum notice provision for change in rates or other terms; conditions for service termination; requirements for change in provider; minimum information and marketing material requirements	PUC granted authority to adopt consumer protection rules applicable to competitive power suppliers.	Legislation requires all suppliers to comply with existing consumer protection, credit, billing and collection regulations. Legislation prohibits any decrease in consumer protection or service quality due to competition. PUC will consider case-by-case request for waiver from rules.
Disclosures	Mandatory price and price components information on bills; fuel mix and environmental characteristics of supplier fuel mix to be developed.	Disclosures required at time of initiation of service (Terms of Service booklet), in advertising, and on customer bills; price; key contract terms; fuel mix and environmental air emissions authorized.	Broad grant of authority to PUC to require "information that enhances consumers' ability to effectively make choices in a competitive electricity market."	No specific discussion.	Legislation authorizes PUC to adopt rules that stimulate consumers' ability to shop and compare in a competitive market. Pending rulemaking proposes uniform price and fuel mix disclosures.
Disconnection for Failure to Pay Supplier/Nonregulated Charges	No disconnection by T&D utility for failure to pay supplier bill except for Default Power Service; D&T utility cannot attempt to collect bill owed to another supplier as condition of providing service.	Only distribution utilities can disconnect from electric grid pursuant to DTE rules.	Disconnection for nonpayment of charges and disputes with power suppliers not allowed; power suppliers may discontinue service to nonpaying customers with minimal notice, but must use same methods to collect their unpaid debts as other competitive businesses.	No specific discussion, but Legislation specifically adds reference to "distribution utility" in the disconnection and winter rule provisions of law, suggesting suppliers cannot use disconnection tool.	Although legislation silent, PUC has ruled that suppliers cannot use threat of disconnection to collect; must use minimum notice of contract cancellation.

Public Policy Issues	New Hampshire	Massachusetts	Maine	Rhode Island	Pennsylvania
Unfair Marketing/Slamming	PUC to develop rules; slamming specifically mentioned; more deference to jurisdiction of state A.G.	Detailed legislative guidance to prevent slamming: customer authorization must be in writing or oral verification by independent third party; no negative option or combination with prizes or checks allowed; DTE and state AG authorized to adopt further rules.	PUC granted specific authority to adopt consumer protection standards to prevent fraud and unfair practices by suppliers, including slamming. Customers can prevent telemarketing to their homes with list maintained by PUC.	PUC required to propose consumer protection rules to Legislature by 1/1/97.	PUC jurisdiction to adopt unfair practice rules, including slamming. Legislation requires D&T utility to obtain proof of customer authorization of selection of supplier prior to switch.
Regulation of Supplier Contract Terms	Minimal regulation; reasonable notice prior to cancellation of contract by supplier; bill disclosures.	DTE and state AG authority to adopt rules; a 3-day right of rescission mandated after customer receives Terms of Service booklet.	PUC has authority to require suppliers to file their prices and standard form contracts with the Commission, but emphasis on disclosure and standard bill format; consumers have 5-day right of rescission within reasonable time after agree to contract.	PUC required to propose consumer protection rules to Legislature by 1/1/97.	Supplier terms must comply with minimum billing and collection requirements, including late fees, in existing PUC rules.
Credit/Discrimination	No discussion.	Legislation requires suppliers to comply with existing consumer protection rules; interpreted to prohibit suppliers from charging late fees or requiring deposits from residential customers.	No specific discussion. PUC has authority to adopt consumer protections rules.	No specific discussion.	Suppliers must comply with PUC credit rules that require service without deposit if customer has good payment/utility history; denial/deposit only based on PUC credit rules adopted for utilities.

Public Policy Issues	New Hampshire	Massachusetts	Maine	Rhode Island	Pennsylvania
Consumer Education	Strong endorsement of consumer outreach and education; PUC considering statewide plan developed by consultant with assistance of working group. To be funded via T&D utility rates.	Division of Energy Resources authorized, in consultation with local and state-wide consumer groups, to undertake consumer education activities; funded via appropriation; toll-free hotline; plan to be submitted to DTE for approval; plan must recommend services "only to the extent that the private market cannot or doesn't adequately meet the information needs of retail customers..."	Unbundled bills beginning in 1999. Commission to appoint a Consumer Education Advisory Board to recommend specific education program, funding sources and roles, followed by PUC rules for program by 2/1/98.	No specific discussion; reliance on D&T utility to communicate options available to customers at least 90 days prior to retail access.	Legislative directive requires distribution companies to assume responsibility, "in conjunction with the Commission" for consumer education. Commission has issued recent order to require all D&T utilities to fund a statewide education program under supervision of PUC and Consumer Education Advisory Board.
Dispute Resolution	Commission will retain jurisdiction over disputes; widespread marketing abuse will be referred to A.G.	All suppliers must disclose DTE complaint number to customers; DTE will assume authority to resolve disputes; alternative dispute resolution process mandated for all damage claims by customers for less than $100.	Commission granted jurisdiction to resolve disputes between customers and competitive providers concerning the consumer protection and licensing rules adopted by the PUC.	PUC has authority to resolve complaints between customers and competitive providers.	PUC has jurisdiction to resolve informal disputes; suppliers must refer customers to PUC if not satisfied; PUC will monitor for licensing criteria and unfair trade practices.

Public Policy Issues	New Hampshire	Massachusetts	Maine	Rhode Island	Pennsylvania
Privacy	No discussion.	Distribution company cannot release customer billing information without permission from customer.	Legislative directive to protect consumer privacy; PUC jurisdiction re rules.	No specific discussion, except that D&T utilities cannot use information that is not available to other competitive providers; D&T utilities must provide customer list to competitive providers, but not customer-specific information.	PUC has mandated that distribution companies provide customer name, address and telephone # with customer written consent for pilot programs; customers can have access to usage data without charge.
Enforcement by commission	Commission will use graduated series of fines, probation, to revocation of registration in response to supplier misconduct.	DTE authority to seek civil penalty up to $25,000 for each violation per day and up to $1 million for related violations; license revocation; order customer refunds; AG authorized to obtain restitution, civil penalties, injunctive relief.	PUC authority significantly expanded: license revocation; fines; cease and desist orders; authority to order restitution to customers.	PUC given specific authority for license revocation.	PUC can revoke license; civil and criminal penalties.
Consumer aggregation; cooperatives	No discussion, but clearly an option.	Extensive legislative guidance for municipal and private aggregation; municipal aggregation may occur with approved energy plans; public outreach; minimum bid procedures and contract provisions; residential customers must opt-out to choose alternative supplier, but can do so without penalty.	Consumers may aggregate their purchases of generation service in any manner they choose. A public entity can act as aggregator, but cannot require consumer to purchase from that entity.	Legislation specifically authorizes "purchasing cooperatives", not required to be legal entities and prohibited from re-sale.	No specific discussion.

TABLE 7.6 continued

Comparison of Consumer Protection Provisions in Selected States, Part 2.

Public Policy Issues	California	Montana	Nevada	Illinois
Retail Access Date	1/1/98 [Delayed until 3/31/98]	Pilots start 7/98; retail access phased in beginning with larger customers (over 1,000kW); all customers by 7/2002.	Phase-in and different dates by geographic areas authorized; full retail access no later than 12/31/99 unless PUC determines different date necessary to protect the public interest.	Phase-in beginning with largest non-residential customers on 10/1/99 and including all residential customers by 5/1/2002.
Standard Offer/Default Service	Distribution companies must provide generation service to customers based on market price (set by Power Exchange); service provided automatically to customers who do not choose and upon request, with notice, to those customers who want to return to default supply.	Distribution companies required to propose a method for assigning customers to an electricity supplier in their transition plans; must provide cost-based prices for supply service for those customers who do not choose during transition period.	PUC must designate an electric utility to provide service to customers who are unable to obtain electric service from an alternative seller or who fail to select an alternative seller. Utility authorized to recover costs for this service. Alternative methods authorized if PUC finds in public interest: direct assignment of customers to alternative sellers or process of competitive bidding. Rate cap in effect for 2 years.	Utility has obligation to provide tariffed service to customers who do not choose or who seek to return; market-based price that reflects competitive bid or neutral determination of market value; utility may impose conditions, including reasonable fee and minimum 24-month contract period for those returning to utility service.

Public Policy Issues	California	Montana	Nevada	Illinois
Regulation of Distribution Company	PBR preferred form of regulation; investor-owned utilities will continue current price cap regulation for their distribution function; divestiture preferred, but not mandated; 10% overall rate decrease.	Rate moratorium during transition period except that rates can increase for universal system benefit programs or costs necessary to implement full customer choice, including metering, billing and technology (latter costs assessed on customers for whom costs incurred);PBR authorized.	Residential rates capped at 7/1/97 levels for 2 years; alternative regulation authorized if alternative [compared with traditional regulation] "...improves the performance of the service or lowers the cost of the service to the customer, or both."	15% rate decreases begin 8/98 for most customers, but 5% for one utility's customers.
	Structural separation mandated: affiliate transaction standards mandated.		Structural separation for conduct of competitive business required: affiliate transaction standards mandated.	Functional separation only required (not structural); ICC retains authority over cost allocation and establish standards of conduct.
				PBR authorized; ICC to establish regulations to ensure reliability of delivery services re outages, construction and maintenance expenditures, cust. satis. surveys.

Public Policy Issues	**California**	**Montana**	**Nevada**	**Illinois**
Distribution Co. Obligation; billing and metering services	Distribution company has obligation to provide access and connection, but metering, billing and customer service functions subject to competition for large customers in 1998 and for customers below 20 kW beginning in 1999; working group to report on metering architecture, accuracy and data transmission standards later in 1997; by 1/98 all utilities must offer three billing options: single bill from supplier, single bill from D&T utility, dual bills; utilities must unbundle these charges from current distribution rates.	Distribution company authorized to recover costs for metering, billing and technology for transition to retail access; utilities must maintain "existing customer service requirements"; no reference to possible competition in these areas in Legislation.	PUC authorized to determine which services are competitive. Distribution utilities required to continue to provide all noncompetitive services formerly provided by vertically-integrated utilities.	Delivery service defined to include "standard metering and billing services." Competition in these services may be declared by ICC no earlier than 3 years after retail competition for generation services. Billing experiments, including real-time pricing options offered to non-res.customers first, and then res.cust. beg. 10/1/2000. Utilities must offer a single billing option that allows suppliers to bill for delivery services.

Public Policy Issues	California	Montana	Nevada	Illinois
Licensing of Generation Suppliers	AB 1280 established minimal registration requirements; SB 477 establishes more extensive registration requirements, including financial criteria "...to ensures that residential and small commercial customers have adequate recourse in the event of fraud or nonperformance." Disclosure of civil, criminal or regulatory sanctions or penalties imposed within the past 10 years against co. or officer or director.	PUC granted licensing authority; supplier must identify affiliates and degree of reciprocity in access to distribution facilities of supplier's affiliate; rulemaking to establish standards and may include a requirement that supplier provide standard service offer to small customers.	PUC must establish licensing standards for alternative sellers which must include: safety and reliability of service; financial and operational fitness; and billing practices and customer service, including the initiation and termination of service.	Certification of alternative retail electric suppliers must be obtained from the ICC; sufficient technical, financial and managerial resources and abilities; applicant must comply with informational or reporting requirements; stricter review of access and comparability of pricing for delivery services for affiliates of T&D utilities. Hearings authorized for suppliers who seek to service residential customers; streamlined procedures for suppliers who serve non-res.customers.

Public Policy Issues	California	Montana	Nevada	Illinois
Application of Consumer Protection rules to Generation Suppliers	Current PUC rules do not apply, but PUC must adopt rules to implement minimum standards re privacy, disconnection or discontinuance of service; change in providers; written notices; billing; meter integrity; customer deposits; and additional protections.	PUC has authority to adopt rules, but no requirement that current utility rules apply to suppliers; distribution companies must continue to apply current consumer protection rules.	No requirement that current consumer protection rules apply to alternative sellers.	Suppliers must comply with current statutory requirements imposed on public utilities to the extent applicable.

Public Policy Issues	California	Montana	Nevada	Illinois
Disclosures	All providers must provide written notices of price, terms and conditions of service prior to its commencement of service; notice shall include price expressed in a "...format which makes it possible for residential and small commercial customers to compare and select among similar products and services on a standard basis"; PUC must require disclosure of total price of electricity on cents per kWh basis; itemization of all services and charges; separate disclosure of all recurring and nonrecurring charges; description of right to rescind within 3 days. Bills must conform to a standardized bill format to be established by the PUC.	All bills must include distribution and trans. charges; supply charges; competitive transition charges; universal system benefit charges and such other disclosures as required by PSC rule.	PUC authorized to adopt minimum standards for the form and content of all disclosures, explanations or sales information disseminated by alternative sellers, "...to ensure that the person provides adequate, accurate and understandable information about the service which enables a customers to make an informed decision relating to the source and type of electric service purchased."	Marketing information must "contain information that adequately discloses the prices, terms and conditions of the products or services" offered by the supplier. ICC authorized to adopt a uniform disclosure form. Written information must be provided to customers prior to switch.

Public Policy Issues	California	Montana	Nevada	Illinois
	S.B. 1304 requires suppliers to disclose fuel mix to customers; CA Energy Comm. to develop rules.			Suppliers must substantiate claims to ICC and customers upon request re technologies or fuel types. Suppliers must disclose fuel mix and air emissions quarterly to customers and ICC will post infor. on their website. Supplier bills must itemize products and services and their prices; annual statement that discloses the average monthly price and terms and conditions.
Disconnection for Failure to Pay Supplier/Nonregulated Charges	Utilities prohibited from disconnecting customer for failure to pay competitive charges owed to providers; notice of discontinuance by provider authorized.	PSC must by rule establish the procedures "relating to how and when an electricity supplier may discontinue service to a customer because of the customer's nonpayment and the procedures relating to reconnection..." (Sec. 26(2)).	No discussion.	No specific discussion, but if supplier issues a single bill that includes delivery services, the utility retains the right to disconnect the customers "if it does not receive payment for its tariffed services."

Public Policy Issues	California	Montana	Nevada	Illinois
Unfair Marketing Practices/Slamming	Legislation adopts specific anti-slamming requirements for small commercial and residential customers: residential switch orders must be confirmed by an independent third-party verification company unless customer calls current supplier directly.	Customers must provide written authorization for change in electricity supplier; the Transition Advisory Committee must report by 2000 on need, if any, for additional consumer protection, including protection from abusive or anti-competitive practices.	PUC regulations to ensure that there is a "reliable confirmation of the customer's intent" to switch suppliers.	Suppliers must obtain "verifiable authorization from a customer" prior to a switch. Reference to state Consumer Fraud and Deceptive Business Practices Act which is amended to require written authorization on letter of agency.
	Violators liable to previous provider in an amount equal to all charges paid by the customer after the violation.			Both utilities and suppliers must maintain customer call centers and notify customers how to reach such centers; ICC can establish reporting requirements for such centers.
	PUC must maintain a "do-not-call list of res.and sm.commercial customers.			Amendments to Consumer Fraud Act to define "electric service fraud" and est. max. penalty of $50,000 and regulate billing and collection practices of suppliers.

Public Policy Issues	California	Montana	Nevada	Illinois
Regulation of Supplier Contract Terms	PUC authorized to adopt specific consumer protection regulations specified above and additional protection standards "...which are in the public interest."	See above.	No specific discussion.	No specific discussion.
Credit/Discrimination	If a provider denies an application to serve a residential customer, must provide a written notice of explanation of denial within 30 days of request. Must disclose right to request such notice at time service is denied.	See above.	No specific discussion.	As part of licensing application, suppliers must declare their service area and type of customers served. Suppliers may limit the overall size or availability of service offering with notice to the ICC. Suppliers specifically prohibited from denying service based on race, gender or income or to deny service based on locality or to establish unreasonable difference re prices, terms based on locality.

Public Policy Issues	California	Montana	Nevada	Illinois
Consumer Education	Electric utilities, "in conjunction with the commission," must devise and implement a customer education program which provides customers with information necessary to help them make appropriate choices as to their electric service. PUC must approve program. Extensive program subsequently approved with budget of approximately $80 m.	Distribution companies required to educate customers about customer choice so that customers may make an informed choice.	Prior to commencement of direct access, PUC must conduct a educational program for customers; up to $500,000 authorized. Purposes of program: inform customers of changes and availability of alternative sellers; inform customers of disclosure requirements; provide assistance to customers in understanding and using the information to make reasonably informed choices.	ICC to implement and maintain a consumer education program; working group to develop package of printed materials subject to ICC approval; recommendations re variety of communication methods, including mass media; list of key topics for materials; utilities must mail the materials; suppliers must provide same to new customers; special appropriation for funding.
Dispute Resolution	PUC must accept, compile and attempt to informally resolve customer complaints with providers; investigations authorized based on complaint patterns; PUC may award reparations to customers; providers cannot discontinue service to customers for disputed amounts if complaint pending and amt. deposited in escrow account.	Legislation calls for continuation of "provision of a process for investigating and resolving complaints."	A division of consumer complaint resolution established within the PUC; authorized to receive and investigate complaints against alternative sellers and conduct investigations of service practices of utilities and alternative sellers.	ICC has complaint jurisdiction over suppliers re violation of statutory minimums, terms of contract with customer or delivery tariff.

Public Policy Issues	California	Montana	Nevada	Illinois
Privacy	Existing California privacy legislation applicable to suppliers; all release of data by D&T utilities to suppliers and marketers prohibited unless customer gives written consent; D&T utilities required to offer customers usage information 2X per year without fee; suppliers can get name, address, telephone #, account# and metered usage infor. with consent.	No specific provision.	No discussion.	Utilities must supply to customer or its authorized agent (supplier) the customer's billing and usage data at request of customer or with verifiable authorization. Fee may be required. Utility may provide generic information for a fee as well.
Commission Enforcement	PUC may deny applications for registration; PUC provided with enforcement tools that exist for utilities for use against providers; license suspension or revocation; access to books and records for investigations; PUC can prosecute under existing authority for civil and criminal penalties. AG jurisdiction and	PUC can revoke license for false information, slamming, failure to provide adequate electricity supply for MT customers or commits fraud or deceptive practice; assess fines (not less than $100 or more than $1,000) for violation of rules and slamming.	PUC authorized to revoke license; seek penalties; enforcement by Attorney General. New bureau of consumer protection in office of AG created as public advocate.	ICC can issue cease and desist order, penalties, seek revocation of certificate. Legislation creates the Consumer Utilities Unit in the AG's office to represent the public in all ICC proceedings re electric service.

Public Policy Issues	California	Montana	Nevada	Illinois
	enforcement authority preserved. Consumers specifically authorized to recover actual damages, attorney’s fees and court costs, and exemplary damages; equitable relief in court.			
Consumer Aggregation; Cooperatives	Customers entitled to aggregate their electric loads on a voluntary basis; customers must provide positive written declaration to leave current utility and select an aggregator; both private and public (municipal) aggregation authorized.	No specific discussion.	No discussion.	Utilities required to allow aggregation for any voluntary grouping of customers for both energy and delivery services.

Source: "Comparison of Consumer Protection Provisions in State Legislation on Retail Electric Competition," Barbara R. Alexander
http://www.spratley.com/leap/stuff/1998.05.00.00.comparison-of-consumer-protection-provisions-in-state-legislation-on-retail-electric-competition.html

TABLE 7.7
Stakeholder Identified Impacts and Views Regarding Universal Service

Description of Stakeholder	Impact of Retail Competition Identified	Views Concerning Universal Service
Municipal Utility	Re: obligation to serve: Utility may already have obliged capacity used by the departing customer	Restructuring legislation should include language to clarify that a utility is under no obligation to provide tariffed sales to retail wheeling customers who discontinue sales and then return. Customers should have to make an affirmative choice to switch electric providers rather than unknowingly or forcibly being transferred to another provider.
Rural Electric Cooperative	Customers who are the least profitable to serve may be disadvantaged if energy marketers are allowed to “cherry pick” the most profitable customers.	A restructured electric utility industry should provide adequate safeguards to assure affordable electric service to residential customers and that the utility providing the service can stay in business.
Rural Electric Cooperative	Affordable service will be affected for mostconsumers as only a few will be in a position to take advantage of choice suppliers.	The incumbent utility should be given the first opportunity to be the provider of last resort—perhaps a universal service fund to support high service cost areas. All customers should be accommodated.
Investor Owned Utility	A portion of a utility's customer may not, for various reasons, choose any marketer.	[Customers who do not choose] should have the option of being placed on a default service that would be provided either by the utility's non-regulated marketing affiliate, or by some other third party selected by the APUC.
Independent Power Producer	Programs such as low-income energy assistance, consumer education and information programs, today funded by electric utilities, may require new funding mechanism.	Non-bypassable System Benefit Charge could be used to retain pre-existing programs at current funding levels. If a consensus can be reached on funding levels, the SBC could used to increase funding. One step would be to mandate either no rate increase about current levels or a predetermined and guaranteed minimum price savings for all residential and small commercial customers – via the SBC or allowed to take effect on or before choice date for larger customers. The local monopoly will ensure universal service through "Standard Offer" service provided by one or moreESPs selected through competitive bid process or by default provider.

Description of Stakeholder	Impact of Retail Competition Identified	Views Concerning Universal Service
Labor Representative	Deregulated electric power companies may not be obligated or motivated to serve customers needing electricity in remote areas or in regions suffering economic trouble.	Electricity is a necessity, and methods will have to be found to assure that these customers still have electric power companies to serve them at reasonable prices. Universal access must be preserved, because electricity is a necessary service. Electrical service must remain reliable, safe and efficient. There must be assurances that there will be sufficient operating reserves for crisis situations.
Consumer Advocate	Electricity is almost universally available in our society because costs have been shared by all utility customer classes. Restructuring undermines that arrangement by forcing customers to shop for their own power.	Specific programs must be created to ensure services to all people, with particular attention to preventing service cut-offs, discounts for households in need, and low-income weatherization.

TABLE 7.8
Legal and Regulatory Roadmap of Universal Service Provisions in Alaska

Source	Relevant Language	Economic Costs	Economic Benefits	Remarks
		STATUTES		
AS 42.05.141	APUC "may do all things necessary and proper" including regulation, investigation, ratemaking, regulation of service, require reports.	Cost of regulation.	Provides customers with assurances of oversight, accountability.	General grant of authority.
AS 42.05.221	Requires utilities to hold certificates.	Cost of regulation, compliance.	Provides customers with assurances of oversight, accountability. Allows review of competence to serve.	Policy question about whether similar precondition should apply to marketers.
AS 42.05.241	Certificate holders must be fit, willing and able. APUC may attach conditions to certificate.	Cost of compliance, regulation.	Reduces costs by ensuring economic viability of provider.	Policy question about whether similar precondition should apply to marketers.
AS 42.05.254	Provides for regulatory cost charge.	Not to exceed .8 percent of gross revenues.	Ensures adequately funded oversight agency. Spreads costs uniformly.	Similar to a systems benefit charge for the purpose of regulation.
AS 42.05.271	Authorizes modification, suspension or revocation of certificates.	Cost of regulation.	Protects customers from inadequate providers.	Policy question about whether similar precondition should apply to marketers.
AS 42.05.291	Requires utilities to maintain adequate, efficient, safe services & facilities. Commission may modify.	Cost of compliance, regulatory oversight.	Ensures uniform service quality.	Policy question about whether similar precondition should apply to marketers.
AS 42.05.301	Prohibits unreasonable discrimination in service.	Cost of maintaining uniform services, compliance, oversight.	Protects customers, universality of service.	Competition is about "fair discrimination." Standard may be too strict in competitive markets.

Source	Relevant Language	Economic Costs	Economic Benefits	Remarks
AS 42.05.330, 340, 350	Commission may prescribe standards for measurement, testing.	Cost of compliance, maintaining equipment, oversight.	Helps ensure fairness in service, adherence to service quality standards.	Policy question about whether similar precondition should apply to marketers.
AS 42.05.361, 371	Requires tariffs for services, adherence to tariffs.	Cost of approval, compliance, oversight.	Ensures fair, public terms of service.	Principal must be adapted under competition to enable customers to understand terms and conditions.
AS 42.05.381	Requires just and reasonable rates.	Largest source of regulatory costs.	Provides regulatory oversight and public interest review of rates.	Competition contemplates market-based rates. Potential for unfair discrimination.
AS 42.05.391	Prohibits unreasonable discrimination in rates.	Cost of maintaining uniform services, compliance, oversight.	Provides benefits of averaged and uniform rates.	Competition is about "fair discrimination." Standard may be too strict in competitive markets.
AS 42.05.411	Requires notice of rate changes.	Cost of delay, compliance, oversight.	Provides public notice of price changes.	Competitive markets require transparent prices. Must be adapted to competitive environment.
AS 42.05.511	Authorizes APUC to investigate and act upon management practices, including staffing patterns and pay scales for practices that adversely affect cost or quality of service.	Cost of oversight, compliance. Imposes limits on management discretion.	Ensures utilities maintain adequate staff and capability.	In competitive markets, bad management is rewarded with lost profits and/or market share. Essential nature of electric service may justify some adaptation to competitive markets.
RULES				
3 AAC 50.300	Establishes requirements for information to be provided to customers.	Cost of compliance.	Provides customers with information about prices and terms of service.	Competitive markets require transparent prices. Must be adapted to competitive environment.

Source	Relevant Language	Economic Costs	Economic Benefits	Remarks
3 AAC 52.400-500	Rules applicable to electric utility service, including service connection, deposit requirements, meter reading, bill information, deferred payment agreements, disconnection, line extension, quality of service, safety standards, maintenance standards, etc.	Costs of compliance.	Broad range of obligations on utilities ensure universal service, customer protections.	Policy decisions about which, if any, provisions will be applicable to competitive market participants.

TABLE 7.9
Universal Service Policy Options Available in Alaska

Policy Option	Method of Implementation	Advantages	Disadvantages
APUC initiates regulatory process to define universal service concepts and institute appropriate programs for regulated public utilities.	APUC investigation and rulemaking.	Can be initiated in advance of legislation for regulated public utilities.	Does not automatically transfer to restructured environment.
Establish state-wide definition of universal service to include access to an affordable block of basic, reliable and quality services for all customers.	Legislation. Requires differential treatment for Railbelt and rural Alaska.	Ensures comprehensive approach to universal service issues. Provides flexible baseline. Establishes services and service quality platform for future improvement.	Broadly defined universal service obligations could impose additional costs that are significant, especially for smaller utilities and service providers.
Create state or market-wide universal service support fund through non-discriminatory system benefits charge.	Legislation authorizing collection of charge and providing for program design and fund disbursement.	Ensures funding is in place to meet obligations. Market impacts are non-discriminatory. Charge can be structured as a condition of competitive entry for opt-in entities.	Funding requirements may offset savings potential, and may not be distributed uniformly.
Establish broadly worded obligations on competitive market participants to "ensure universal service," without specific funding or program prescriptions.	Legislation.	Provides maximum flexibility to market participants to meet customer needs. Avoids additional system-wide costs. Allows markets to decide level of services and protections.	Limits policy response to post-hoc remedies. May lead to gap in levels of services and service quality among and within customer classes.
Performance-based regulation (PBR) for distribution utilities incorporating universal service and service quality standards.	Legislation to establish applicability to all competing entities. Regulation by APUC to establish standards and revenue mechanisms.	Focuses regulation on distribution entity likely to remain regulated. Uses incentive-based approach to minimize costs and create competitive "postage stamp" cost for use of distribution system.	PBR mechanisms subject to gaming (especially as relates to 'Z' factors). Lack of regulatory experience and precedent.

Policy Option	Method of Implementation	Advantages	Disadvantages
Establish registration and service practice requirements for all market retailers; including requirements to ensure financial solvency, technical reliability. Standardize information requirements (e.g. billing). Establish customer protection rules.	Legislation to establish applicability to all competitors. Regulation by APUC to establish standards.	Establishes level playing field of business qualifications and practices.	Regulatory requirements will impose costs on market participants, may have the effect of creating barriers to entry and enhancing market power of incumbents.
Encourage cooperative activities and programs between electricity service providers and community service providers to maximize efficiency of program execution and administration.	Legislation to establish standards and assign lead jurisdictional responsibilities. Regulation and Memoranda of Understanding between agencies to guide activities and programs.	Builds on extant agency expertise. Avoids inefficient duplication of functions and programs.	May create conflicts over program priorities at agencies with multiple missions.
Allow locally controlled utilities to continue to use existing governance mechanisms to establish terms and conditions of universal service provisions.	Create "opt-in" mechanism for municipal and cooperative electric utilities in any legislation.	Reduces customer confusion, retains existing mechanisms, allows form of democratic representation for policy decisions.	Exception could swallow the rule. Local policy dictated by local majority. Leads to inconsistency across state. May create inconsistent burdens on competitors.

TABLE 7.10
Ranking of Major Alaska Cities for Consumer Prices
(Number indicates rank among all US cities, lower ranking number indicates higher costs in category – 3rd Quarter 1997)

		Ranking – Compared to All Major US Cities						
City	Total Monthly Energy Cost	Utilities	All Items Index	Grocery Items	Housing	Transportation	Health Care	Misc. Goods & Services
Anchorage	$92	233	8	5	19	28	2	5
Fairbanks	$183	7	7	6	16	14	3	8
Juneau	$174	4	4	3	5	11	4	4
Kodiak	$190	2	2	1	8	8	6	1

Source: http://www.labor.state.ak.us/trends/jun98.pdf

TABLE 7.11
Affordability Indicators

Region	Weighted Average Electricity Revenue/kWh	Cost to Average Customer
Railbelt Utilities	$0.103/kWh	$830/yr $69/mo 1.55% of weighted average median household income ($53,439) 3.98+% of low income household income ($20,880)
All Alaska Utilities	$0.123//kWh	$987/yr $82/mo 2.34% of median household income ($42,255) 4.72+% of low income household income ($20,880)
US Average	$0.084/kWh	$844/yr $70/mo 2.41% of median household income ($35,082) 5.1+% of low income household income ($16,700)

TABLE 7.12
1999 US Department of Health & Human Services Poverty Guidelines

Size of Family Unit	48 Contiguous States & D.C.	Alaska	Hawaii
1	$ 8,240	**$10,320**	$ 9,490
2	11,060	**13,840**	12,730
3	13,880	**17,360**	15,970
4	16,700	**20,880**	19,210
5	19,520	**24,400**	22,450
6	22,340	**27,920**	25,690
7	25,160	**31,440**	28,930
8	27,980	**34,960**	32,170
For each additional person, add	2,820	**3,520**	3,240

SOURCE: *Federal Register*, Vol. 64, No. 52, March 18, 1999, pp. 13428-13430.

TABLE 7.13
Example Price Impacts of Public Purpose Program Options
(In Alaska in 1997, a charge of 1 mill on electricity sold in the Railbelt will collect approximately $3.7 million/yr. total funds, and cost the average residential customer $0.67/mo. A charge of 1 mill on electricity sold throughout Alaska will collect approximately $4.8 million/yr. total funds, and cost the average residential customer $0.69/mo.)

Program Option	Total Cost/Duration	Average kWh Cost	Cost Impact on Average Residential Customer	MW Impact
Renewable Energy				
Renewable Portfolio Standard – Clinton Administration Proposal	$2.1 to $10.6 million/yr. – 15 yr.	$0.005 to $0.025/kWh (range of premium costs)	$0.30 to $1.40/mo	121 MW added
Energy Efficiency				
Energy Efficiency – (Using Connecticut, Illinois laws)	$14.5 million/yr.	$0.003/kWh	$2.04/mo	N/A
Low Income				
Dedicated Fund for Low Income Energy Assistance (0.5% & 1.0% of revenues)	$2.44 million/yr. @ 0.5% rev. $4.88 million/yr. @ 1% rev.	$0.0005/kWh @ 0.5% $0.0010/kWh @ 1%	$0.35/mo @ 0.5% $0.70/mo @ 1.0%	N/A
Energy Research & Development				
Energy Research & Development – (Using California law - .4 mill/kWh)	$1.94 million/yr. – 3 yr.	$0.0004/kWh	$0.27/mo	N/A

TABLE 7.14
Alternative Conceptualizations of Affordability

Concept	Relation to kWh Consumption or Funding	Costs	Advantages	Disadvantages
Pure market approach – prices set by competition, demand responds to prices with high coefficient of elasticity.	Consumption determined by market.	No direct implementation cost. Indirect costs associated with higher uncollectables and inability of some customers to obtain sufficient services.	Requires no direct funding or implementation mechanism.	Likely to create severe hardships for many customers. Inconsistent with concept of electricity as an essential service.
Voluntary contribution approach – customers and charitable institutions may contribute funds to a program or pool for distribution to needy customers.	Amount of energy subsidized directly tied to amount of available funding.	Management and disbursement costs. No other direct costs. Indirect costs associated with higher uncollectables, as this method will significantly reduce current budgets.	Does not impose affordability support costs directly on electricity markets.	Significantly reduces available budget. May increase uncollectable expenses. Decreased budgets may cause significant hardships.
Energy assistance and supporting agency funding for bill assistance. May include bill payment programs.	Not tied to kWh cost, but to bill levels, ability to pay, poverty level, and household demographics.	Funding collected from SBC, from general revenue appropriations, or other sources. Administrative and oversight costs.	Makes use of broad menu of approaches to address affordability problems. Does not directly subsidize electricity costs.	Current funding sources are declining, and may require supplementation. Requires administrative coordination.
Cost of service-based rate setting for intra-class rates.	Rate set for statistically determined first block of consumption, e.g. first 200 kWh/month.	Regulatory and compliance cost of detailed cost of service study.	Detailed study may reveal economic justification for reduced rates under cost-causation principles. May reveal competitive opportunity to serve low use customers.	Administrative and regulatory costs. Policy judgments necessary to create appropriate categories.

Concept	Relation to kWh Consumption or Funding	Costs	Advantages	Disadvantages
Benefit charge-funded rate discounts.	Rate discounts for certain customers, may be limited to certain consumption levels. E.g. 20% discount from basic residential rate for customers at or below 150% federal poverty level.	Requires System Benefit Charge funded from electricity usage.	Creates stable funding source. Simplifies administration – suppliers would collect from the fund based on sales. Properly structured, SBC is non-discriminatory.	Strong incentive to avoid charges. Administrative system required. Once set, funding level may be difficult to adjust. Reduces overall magnitude of savings. Not specifically targeted to extent of need.
Affordable block of basic services based on consumption requirements (universal service model).	Discounts applied to first block of consumption, sized to be sufficient to address basic electricity needs. Includes services such as weatherization, credit counseling, etc.	Requires System Benefit Charge or other mechanism to fund discounts.	Focuses discounts on most important needs. Avoids incentive to consume excess through price signals. Integrates subsidy and non-subsidy mechanisms.	Requires calculation of needs and administration. May need regular updating. Administration costs.

TABLE 7.15
Potential Negative Impacts of Retail Access on Affordability

Impact	Likely Effects	Remedial Action	Statutory Changes Required
Legislated rate reductions for residential customers reduce opportunity for competitive market entry.	Artificially low rates set by legislative decree may reduce incentive for competitors to enter market. Legislated reductions may be the only benefits available to residential customers.	Ensure that market structure creates fair opportunity for new suppliers and marketers to enter. Allocate joint and common costs in a manner to encourage competitive entry.	Regulatory authority exists to conduct cost allocation proceeding. For market wide actions, legislation required.
Competitively induced price reductions fail to extend to residential sector.	Small size and relative cost to serve residential customers may make them unattractive in competitive markets.	Create default provider or last resort options. Create policy and mechanisms to facilitate aggregation. Ensure market structure creates incentive for market entry. Encourage customer aggregation. (Note: To the extent preexisting aggregation inherent in current system is preserved, it may act as a barrier to competitive entry.)	Backstop & aggregation provisions, funding mechanisms requires legislation.
Energy savings, weatherization and emergency assistance programs decline or disappear.	Extra costs associated with funding and conducting such programs may be unacceptable to profit-seeking marketers. Large customers use political power to avoid supporting programs through rates. Programs and funding reduced or eliminated.	Establish mechanisms to ensure continued viability of programs. Establish non-discriminatory funding mechanism to continue programs (e.g. SBC), that draws on broadest possible base of consumption. Consider public purpose exit fees.	Legislation required to create administration and collection mechanisms.
Reduced regulation results in unfair marketing practices, customer confusion, and lost savings opportunities.	Residential and small commercial customers, unaccustomed to shopping for electric service, fall victim to unscrupulous market practices, purchasing unneeded services and options.	Establish customer protection rules and assign or create agency responsibility for oversight and enforcement. Create standardized information format requirements.	Legislation and appropriation required to establish oversight and rulemaking authority, and to apply rules to all participating marketers.
Market results in cost shifting to residential customers.	Relatively weaker market power in residential and small commercial customers may result in disproportionate share of costs being shifted to small customer rates.	Conduct comprehensive cost allocation proceeding. Establish rate caps or other mechanisms to prevent cost shifting.	Legislation required to extend regulatory or cost-cap requirements beyond regulated utilities.

Impact	Likely Effects	Remedial Action	Statutory Changes Required
Rate de-averaging results in long-term price increases for expensive-to-serve customers.	Increasing segmentation of customer classes negates historical benefits of system-wide cost averaging.	If market fails to deliver savings over the long term, institute affirmative cost shifting mechanism, such as SBC or taxes to fund price supports.	Legislation required to create funding & distribution mechanism. (Note: Essentially, this amounts to a return to regulation.)

TABLE 7.16
Stakeholder Identified Impacts and Views Relating to Affordability of Distribution Service

Description of Stakeholder	Impact of Retail Competition Identified	Views Concerning Affordability
Labor Representative	Valuable community-based programs currently funded by local power companies are likely to disappear. Electric prices may increase due to profiteering, temporary shortages and the shifting of costs from large industrial users to small commercial and residential energy users.	Most educated observers claim that customer choice will be of little or no value to residential consumers or small businesses in terms of the price of electricity. The price of electricity in a competitive market must remain stable for all classes of customers, and the quality of power must remain high. Societal and community programs should not be abandoned as local government revenues decline due to utilities paying less tax.
Municipal Utility	Residential consumers, low income consumers, fixed income consumers and small agricultural consumers are the likely losers if the present system of regulation is thrown out.	The basic notion of equity and fairness will wither away under restructuring for those consumers least likely to "wheel and deal" in the new environment. Local choice and control must not be jeopardized by restructuring, in order to assure that utility decisions best reflect the desires of customers.
Municipal Utility	Restructuring is not deregulation; more regulation will be required in a restructured environment.	There must be strong measures to protect consumers from fraudulent advertising and fraudulent practices.
Consumer Advocate	For the average consumer to benefit from deregulation of electricity, policy makers must have a clear set of goals and be guided by specific principles.	A clear public policy to ensure affordability must be put in place; policies must also ensure that people with low incomes or who live in high-cost areas be able to afford service. Specific programs must be created to ensure services to all people, with particular attention to preventing service cut-offs, discounts for households in need, and low-income weatherization.
Consumer Advocate	Retail prices may rise due to the potential of creating an unregulated monopoly.	Current pricing to consumers should be capped until true competition is fully established.
Several Utilities	Regulatory or other mechanisms and obligations relating to default or universal service, or to control prices to residential customers may create competitive discrimination against providers of these benefits.	Any obligations established in lieu of traditional obligation to serve must be non-discriminatory in effect. E.g. SBC must apply uniformly across the market and providers. Exit fees or charges may be necessary to compensate for investments made on behalf of default service customers.

Description of Stakeholder	Impact of Retail Competition Identified	Views Concerning Affordability
IPPs, Marketers, Some Utilities	Retail competition will stimulate cost-saving market innovations and incent increasing reliance on low cost resources and technologies. In a properly structured market, these benefits will flow naturally to all customers.	Current regulatory system constrains innovation and investment in lower-cost systems and services. Marketers' pursuit of profitability will lead to savings, creative service offerings, and rapid transformation of generation stock to most efficient generators. Any mechanism to correct for short-term affordability problems must be non-discriminatory in impact and carefully shaped and targeted.

TABLE 7.17
Options to Ensure Affordability of Distribution Service in Alaska

Policy Option	Method of Implementation	Advantages	Disadvantages
Every utility or retail electric provider must provide a discounted rate (20%) to any household whose members receive food stamps or medical assistance and any customer with an income at or below 125% of the federal poverty guideline.	System benefits charge	Focuses funding effort on most-needy customers.	A direct subsidy could encourage wasteful consumption of electricity. Amount of subsidy undefined.
Discounted rates (as above) but limited to a fixed first block of consumption or a block sufficient to provide lighting, refrigeration, heating, and cooling as determined based on 10-yr. average in service area.	System benefits charge. PUC determines minimum block.	Focuses efforts on most needy customers. Avoid incentive for excess consumption.	Requires ongoing regulation. Amount of subsidy undefined.
Market approach	Allow market prices to determine consumption based on individual customer benefits.	Transitions full system to market-based pricing. More rapidly reveals market inefficiencies so that they can be addressed by competitors.	If implemented too rapidly, could cause severe dislocation and hardship. Some market imperfections may never be addressed. Incumbent advantage/market power-related advantages may create insurmountable barriers to aggregation, entry, or other theoretical solutions.

Policy Option	Method of Implementation	Advantages	Disadvantages
Competitive auction for default service provider.	APUC or other agency established periodic solicitation and award of right to provide default service to one or more providers, according to specified terms and conditions. Oversight may include performance based structures, such as "revenue per customer" based profit mechanisms. Service provider may be eligible for revenue supplements from high cost assistance pool funded by SBC or other mechanism.	Creates competitive market incentive for provider to meet default service requirements. May reduce subsidy requirements. Can be adapted to reflect competitive value of incumbency. Orients providers to specific performance objectives aligned with policy goals.	Requires administrative oversight. Revenue supplement mechanisms require collection and disbursement features. To date, no entities other than incumbents are established to compete to provide service. Pool of served customers may to be enlarged to create economic market size. Grant of right to serve may have act as a barrier to competitive entry by alternate providers. System could devolve into today's status quo.

TABLE 7.18
Policy Recommendations to Protect Residential Customers – Consumers Union & Consumer Federation of America
"The Residential Ratepayer Economics of Electric Utility Restructuring: Balancing All the Costs and Benefits," Consumers Union and Consumer Federation of America, July 1998

Minimize Transaction Costs	Minimize or Reduce Price Discrimination	Minimize Potential Impacts of Market Power	Minimize the Impact of Recovery of Uneconomic Costs
1. Facilitate the aggregation of small customers, especially municipal aggregation, which will reduce overhead.	5. Prohibit shifting costs from high volume to low volume customers.	10. Require vertical divestiture – separate ownership of generation from ownership of transmission and distribution facilities. "Functional unbundling" is insufficient to control market power.	17. Require shareholders to bear their share of stranded costs.
2. Allow the integration function to be performed by the system operator with benefits credited to the customers who do not elect suppliers.	6. Prohibit cherry picking; require service providers to serve all customers in their chosen service territory.	11. If vertical divestiture is not required, provide extensive authority to prevent abuse of affiliate transactions including imposition of affiliate transaction rules and an affiliate code of conduct.	18. Ensure that any stranded costs that are recovered are paid for equitably by all customer classes, allocated by usage of stranded assets.
3. Ensure that costs associated with transactions, including additional facility and management costs are borne by the parties engaging in the transactions.	7. Ensure that residential customers bear no more than a reasonable share of network facilities and other joint and common costs incurred to serve all customers.	12. Regulators must have the authority to ensure non-discriminatory access to the transmission and distribution system. Non-discriminatory access must include the imposition of "just and reasonable" rates for access.	19. Prohibit securitization of stranded costs because it locks in recover of costs without an opportunity to "true-up" for over-recovery.
4. Retain regulatory oversight over the metering and billing process.	8. Allocate uneconomic costs based on electricity usage (kWh consumed), not other formulae that shift excess costs onto residential customers.	13. Regulators must have the authority to monitor and investigate market conditions. The regulatory authority must include the ability to gather evidence, hold a hearing and order corrective action, including penalties and restitution.	20. Prohibit the shifting of costs from generation assets to the transmission and distribution system as a method of stranded cost recovery. This method shifts costs on to residential and small commercial customers and away from large industrial customers and shareholders.

Minimize Transaction Costs	Minimize or Reduce Price Discrimination	Minimize Potential Impacts of Market Power	Minimize the Impact of Recovery of Uneconomic Costs
	9. Prohibit the transfer of costs from generation assets to transmission and distribution assets as a way to collect stranded costs because such transfers allow large industrial customers to further avoid stranded costs, since they do not use the distribution system.	14. In a highly concentrated generation market, regulators must have the option of imposing price ceilings, conditions or limitations on sales and/or the ordering of divestiture.	
		15. Regulators must have the authority to apply any condition or limitation on a merger or acquisition within its jurisdiction, to the extent that the regulator finds it necessary to protect ratepayers, promote competition, or prevent anti-competitive actions.	
		16. Prohibit electric service providers from coercing or inducing their customers toward the purchase of non-regulated goods and services from affiliated companies.	

Stranded Investment

Issue

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.

Implications

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.

Stranded Generating and Transmission Assets Stranded generating assets are capital investments that were put in the ratebase with the expectation of cost recovery over a regulatory determined amortization period. These investment decisions were made, and approved, based on a portfolio theory that assumes that the average cost of alternative power supply sources is the most effective way to mitigate fuel price risk and keep rates reasonable and stable over time. It implies, however, that the savings from lower incremental cost generating plants are used to offset higher cost generators. In a competitive market, the value of higher marginal cost plants will be determined in the market, not in relation to the value it has as part of a diversified portfolio.

The problem of high capital costs on the books and low prices for power in the market is most serious for newer, capital intensive plants. Faced with competition, many utilities may have to write down the book value of capital-intensive plants and forego recovery of some portion of the fixed costs in order to continue operating the plant. In certain cases, the market price of power may not be high enough to even recover the variable costs of certain plants and management may be faced with the decision of closing such plants. This would expose the entire undepreciated book value of the plant to loss.

Stranded Regulatory Assets In the regulated world, the timing of cost recovery is a policy decision. Utilities sometimes create large deferred accounts, such as previously flowed-through tax benefits and fuel cost balancing accounts, with the regulatory promise that they will be amortized and the costs recovered at a future date. Deferred accounts, which appear on the balance sheet, play a key role in managing the time profile of cost recovery for the purposes of rate stabilization. This gives rise to the notion of “regulatory assets” on the books -- agreed amounts for incurred costs that will be carried on the books and recovered in future rate cases. As cost pressures rise, however, it will become increasingly difficult to recover these costs through rates and, as a result, the book value of these regulatory assets could potentially become stranded.

Stranded Power Purchase Contracts One aspect of the transition to more open and competitive markets for electric power not widely noted is the pivotal role of power purchase arrangements. More than 40 percent of electric power generation in the US is sold in the bulk power markets before it is resold to end-users in the retail markets. The portion above market prices, or the “uneconomic” portion of these purchases, could be “stranded” in the transition to more competitive markets.

Power purchases are an increasingly important part of electric utilities’ supply portfolio. As cost concerns in the industry mount, power suppliers to the utility industry will come under growing and intense pressure to renegotiate lucrative power purchase contracts, and could face the loss of significant potential revenue. The amount of markdown constitutes a transition cost, or “stranded liability,” for those who will have to absorb responsibility for the loss. A growing body of evidence suggests that this trend is already well underway.

Stranded Fuel Supply Contracts Although fuel supply expense is generally regarded as a variable production cost, there are a number of reasons to question the conventional wisdom. Over 80% of fuel purchases by utilities are purchased under long-term contracts.

The regulatory movement toward increased competition in the electric power industry will favor electricity generators with the lowest, short-term marginal costs. If the bottom line is competitively-priced power, only utilities with competitively priced fuel contracts will be able to compete effectively.

Utilities with long term fuel contracts above prevailing market prices will be under strong economic pressure to either buy-down or write-down the uneconomic portion of those contracts. Fuel suppliers holding contracts above prevailing market prices will be under growing and intense pressure from utilities to renegotiate the terms and conditions. The amount of markdown constitutes a transition cost, or "stranded investment," for those who will have to absorb responsibility for the loss.

The experience of the North American natural gas industry over the past decade should serve as a sober warning to anyone who believes that contractual obligations to purchase fuel at prices in excess of competitive market prices are inviolable. Indeed, the "take-or-pay" contract losses in the gas industry resulted in writedowns of approximately $20 billion, of which producers absorbed roughly one-half, end-users a bit over one-quarter, and pipelines and local distribution companies the rest.

Classification Framework For Different Valuation Approaches

The classification of methodologies for calculating stranded costs is from Baxter and Hirst, 1995. It consists of three categories, each with two elements: administrative versus market valuation; ex ante versus ex post valuation; and bottom-up versus top-down valuation. Administrative valuation methods use forecasting, modeling, or other analytical techniques to determine the market and regulated value of utility assets and obligations. Market valuation uses auctions, sales, or asset spin-offs to determine the market value of assets (analysis may then be needed to compare market and regulated values). Ex ante methods are used before industry restructuring proposals are implemented. Ex post methods are used after these proposals are implemented. Bottom-up methods value assets individually while top-down methods value asset portfolios.

The classification framework defines eight general valuation approaches. Eight options are described in Table 8.1 that present the strengths and weaknesses of each. A shared strength of administrative approaches is that they include all relevant categories of assets and liabilities, although valuation of regulatory assets is done independently of other assets. Use of administrative approaches, however, may also require additional regulatory action to encourage utility mitigation of transition costs. Many regulators will not wish to allow utilities to continue to operate as if full recovery of all embedded costs is guaranteed.

Market valuation approaches that use asset auctions or sales provide a clear indicator of value at the time of the sale.[1] The timing of the sale will affect the market value; ex ante market valuation will yield different results than ex post market valuation. Time is also an important consideration for market valuation approaches that rely on asset spin-offs to affiliated companies. In these cases, the stock price is one indicator of market value, but determining the appropriate time(s) to observe stock price may be difficult and contentious. Market valuation approaches also have the added benefit of addressing the market power concerns tied to several restructuring proposals.

Unfortunately, not all assets potentially contributing to transition costs have market value. Regulatory assets are a prime example. Other assets, such hydropower facilities, have productive value, but concerns with future liability or transfer of ownership or operating licenses may inhibit market interest.

The distinction between ex ante and ex post options is time. All four general ex ante approaches could also be implemented ex post with appropriate changes to assumptions or procedures. The key strength of ex ante approaches is that they provide an early estimate of transition costs. As a result, suppliers and consumers can plan for the industry transition with these costs clearly established. The cost of acquiring this early certainty is the risk of being wrong. Ex ante administrative approaches that rely on a single estimate or single forecast of market price create potentially large risks for shareholders and ratepayers. Such approaches are untenable and suffer from the misuse of analysis and models as substitutes for, rather than guides to, decision making that contributed to many utilities' currently high embedded costs. Whether administrative or market valuation approaches are used, the difficult problem of anticipating the market response to a still undetermined industry and regulatory structure must be faced with ex ante methods. The important advantage of ex post options is that they resolve the uncertainty problem by delaying valuation until after industry restructuring is underway and a mature electricity market develops. Delaying valuation to this extent is unreasonable, however. Standard accounting practices and the financial markets may compel utilities to

[1]The financial management field makes two important distinctions in the definition of asset value (see, for example, Weston and Brigham 1978). The amount realized from an asset sold separately from the organization that has been using it is known as the liquidity value. If an asset is sold as an operating business, the amount paid is called the going-concem value of the asset. Asset value as determined through sale or auction will thus be affected by whether the asset alone or the accompanying organization is included as part of the sale.

write off or mark down certain assets well before a competitive market matures.

Bottom-up options result in market values being assigned to individual assets. This feature addresses important accounting concerns; standard accounting practice requires that changes to book values be made for specific assets. In contrast, top-down approaches value overall changes to a portfolio of assets. Administrative bottom-up options also provide a wealth of information about the profitability of different assets or insights about the behavior of future markets. This detail and insight comes at the price of data intensiveness, computational complexity, and the attendant administrative difficulties associated with litigating numerous assumptions. Administrative top-down approaches are easier to understand and implement. The opposite may be true for market approaches. Individual asset sales may be simpler to administer than asset portfolios or packages. Yet asset portfolios may make less desirable assets more marketable.

No single type of valuation approach is without a substantial weakness when the objective is to provide transition cost estimates that regulators authorize utilities to recover. For this important objective, combinations of these general approaches will be needed or solutions must be developed to address the substantial weaknesses of any preferred approach.

Alaska

Estimates of stranded costs from the modeling are presented in Section 11.

TABLE 8.1
Assessing Different General Approaches to Estimating Transition Costs (TC)

Approach	Strengths	Weaknesses
Administrative valuation, ex ante, top down	Provides "up-front" estimate of TC Includes all categories of assets and liabilities in estimates (regulatory assets require separate treatment) Detailed analysis linking TC to specific assets (which reduces accounting concerns by linking TC to changes in book values of specific assets) May provide endogenous price forecast (utility and market) through market simulation May capture dynamic response of suppliers and customers to changing market conditions	Data and computationally intensive Careful data preparation essential (e.g., danger of double-counting costs) May be difficult to understand (many assumptions and complex relationships) Agreeing on appropriate assumptions will be difficult Response of market to restructuring may be difficult to predict Reliance on forecast creates risks for utilities and ratepayers
Administrative valuation, ex ante, bottom up	Provides "up-front" estimate of TC Includes all categories of assets and liabilities in estimates (regulatory assets require separate treatment) Requires little data and simple calculations (few assumptions and simple relationships) Fewer assumptions to litigate	Aggregate analysis does not link TC to specific assets (but TC can be linked to categories of assets) Relies on exogenous price forecast (utility and market) Does not capture dynamic response of suppliers and customers to changing market conditions Reliance on forecast creates risks for utilities and ratepayers

Approach	Strengths	Weaknesses
Administrative valuation, ex post, bottom up	Initial conditions known (restructuring proposal approved) Market response observed Includes all categories of assets and liabilities in estimates (regulatory assets require separate treatment) Detailed analysis linking TC to specific assets (which reduces accounting concerns by linking TC to changes in book values of specific assets)	Does not provide “up-front” estimate of TC Delays valuation until market maturity achieved (probable conflict with accounting practice) Developing market price indices may be difficult
Administrative valuation, ex post, top down	Initial conditions known (restructuring proposal approved) Market response observed Includes all categories of assets and liabilities in estimates (regulatory assets require separate treatment) Requires little data and simple calculations (simple relationships)	Does not provide "up-front" estimate of TC Delays valuation until market maturity achieved Aggregate analysis does not link TC to specific assets (but TC can be linked to categories of assets)
Market valuation, ex ante, bottom up	Provides "up-front" estimate of TC Provides clear indicator of market price at time of sale Clear changes in value of specific assets May resolve market power concerns	Regulatory and market uncertainty will affect market value Does not address power-purchase contracts and regulatory assets Assets contributing to TC are less marketable Ownership of certain assets (hydro, nuclear) may be difficult to transfer

Approach	Strengths	Weaknesses
Market valuation, ex ante, top down	Provides "up-front" estimate of TC Provides clear indicator of market price at time of sale Possible to package less desirable assets with more desirable assets May resolve market power concerns	Regulatory and market uncertainty will affect market value Does not address Power-purchase contracts an regulatory assets Assets contributing to TC are less marketable Ownership of certain assets (hydro, nuclear) may be difficult to transfer May not provide clear changes in value of specific assets
Market valuation, ex post, bottom up	Regulatory and market uncertainty reduced Provides clear indicator of market price at time of sale Clear changes in value of specific assets May resolve market power concerns	Does not provide "up-front" estimate of TC Delays valuation until market maturity achieved (probable conflict with accounting practice) Does not address power-purchase contracts and regulatory assets Assets contributing to TC are less marketable Ownership of certain assets (hydro, nuclear) may be difficult to transfer
Market valuation, ex post, top down	Regulatory and market uncertainty reduced Provides clear indicator of market price at time of sale Possible to package less desirable assets with more desirable assets May resolve market power concerns	Does not provide "up-front" estimate of TC Does not address power-purchase contracts and regulatory assets Assets contributing to TC are less marketable Ownership of certain assets (hydro, nuclear) may be difficult to transfer May not provide clear changes in value of specific assets

Source: Baxter & Hirst, 1995

Taxes

Issue

As one of the largest industries in the State, the electric utility industry can have a significant impact on the tax base of state and local governments. The current structure of taxes, fees, payments in lieu of taxes, and other revenue items related to the sale of electricity is based on a long history of a regulated marketplace. Any significant change in the structure of the industry, and/or in the number and character of companies and entities engaged in the supply of electricity products and services could have a significant impact on the tax base of the state and municipal authorities. Restructuring will likely bring about a shift in the amount and the distribution of tax and fee revenues. There is a broad range of options that might be considered in response to these changes. Some argue that no changes should be made, others say that only slight modifications will be needed, and others would argue that this is an opportunity to significantly alter the tax and fee system to accomplish certain public policy goals.

Alaska Dynamic

The electric utility industry in Alaska is composed of several different types of entities including investor owned utilities, cooperative utilities, municipal utilities, federal agencies, non-utility generators, Native Americans, and state agencies. Each of these groups has different histories, finances, tax obligations, regulation and governing structure that may require varied treatment within restructuring legislation. Public power, in the form of municipal and cooperative utilities, dominates the Alaska electricity landscape.

Taxing policy is complicated. Tax policy is especially impacted by electric utility restructuring because of the potential to affect the functioning of competitive markets. Because investor-owned, cooperative and municipal utilities have different tax burdens, they face different tax rates per unit of product sold. These differences could translate into differences in costs. In competitive markets characterized by slim profit margins, these differences could become important. The difference in taxation of financing is also often cited as a factor impacting the potential competitiveness of markets. Finally, public power representatives point to the impact on the Treasury of deferred taxes, investment tax credits, tax-free pollution control bonds, and lost corporate and individual taxes on these amounts as evidence that investor-owned utilities receive even larger taxpayer subsidies.

In addition, restructuring could fundamentally change the tax base. For example, to the extent an out-of-city electricity provider wins market share from an incumbent provider, the allocation of shared tax revenues could significantly affect municipal budgets.

Implications

Studies over the years suggest that retail demand for electricity within a single market area is relatively inelastic and therefore does not reflect changes in industry structure. However, because of the sheer size of the electricity industry, even small changes in the business could have dramatic impacts in local areas. For example, if competition were to lead to the closure of a power plant prior to the end of its useful life, a local community that collects property tax based on the value of the facility could be severely impacted. If Alaska were to implement an across-the-board rate reduction, as some other states have done, total taxable revenues would not be as seriously impacted as in those states because of the absence of an income tax in Alaska.

Another potentially significant differentiation could arise relating to for-profit marketers. These entities would not be subject to the electric cooperative tax on kilowatt-hours sold, nor would they necessarily own physical plant. However, these businesses would likely be subject to federal income tax and the Alaska Corporate Net Income Tax. As a result, it may be difficult to determine whether they would enjoy a tax advantage over electric cooperatives in some cases.

Solutions proposed or adopted in other states can have both advantages and disadvantages. For example, addressing municipal revenue shortfalls caused by reduced generation-based taxes with wires charges on retail distribution can shift tax impacts to residential and small business customers and away from larger customers that take power at the transmission level. In addition, stranded cost recovery schemes can also have a significant impact on the ad valorem value of utility assets.

Policy makers may consider a range of options and tools in attempting to address the tax implications of restructuring. These include:

- sales and use taxes
- exemptions
- franchise fees
- income taxes
- property taxes
- property valuation methodologies

- assessment ratios
- other incentives

These policy decisions could all have a direct impact on equity, market efficiency, and administrative costs, and may raise legal and statutory issues. Other issues include a shift in tax revenues from local governments to the state, a shift in tax revenues among communities, or an overall decline in local sales and tax revenues.

Assessment

The majority of stakeholders are unclear about the tax implications of restructuring but share a deep concern that any tax revenue impacts on state and local governments must be well understood and adequately addressed in any restructuring legislation. The effect of the revenue loss or shifting will vary depending on taxing structure.

Key Questions

- What is the most effective means to create a revenue neutral position amongst government entities (state and local jurisdictions, among communities, etc.) in a restructured electric industry?
- What tax laws or rules must be changed to establish a level playing field for all electricity providers in a competitive marketplace?
- What role should the state play in attempting to mitigate the tax revenue impacts on local governments?
- To what extent should tax laws and tax incentives be used to encourage or support a specific industry, economic sector, or regions in the state?
- As a matter of public policy, there are also a number of other questions. These include: what is the most desirable type of tax or fee; who pays the tax; how does it impacts economic activity; what is the revenue potential; what is the nexus; what is the true "incidence" of the tax (who actually pays); and how does it effect Alaska's economic development potential?

List of Accompanying Tables & Figures

Overview of Issues

In Alaska the main categories of taxes and fees related to the generation, distribution, and transmission of electricity include corporate net income tax, property taxes, sales taxes, and the electric cooperative tax.

According to the Alaska Department of Revenue, the Corporation Net Income Tax (AS 43.20) is levied on net income of corporations that have nexus and derive income from sources within Alaska. Corporations compute their tax liability based on federal taxable income with Alaska adjustments. Corporate tax rates are graduated from 1 percent to 9.4 percent in $10,000 increments of Alaska taxable income. The maximum rate of 9.4 percent applies to income over $90,000.

The Alaska Division of Trade and Development describes other taxes affecting general business as follows:

Corporation Franchise Tax: Biennial tax of $100 for domestic corporations and $200 for foreign corporations, in addition to a $50 biennial business license fee.

Sales and Use Tax: Several boroughs and cities impose a sales and use tax of up to 6 percent on retail sales and certain locally-provided personal services; neither Anchorage nor Fairbanks levies a retail sales tax. There are no state sales, income, gross receipts, or inventory taxes.

Property Tax: Real and personal property is taxed by nearly all home-rule and first-class boroughs and cities. The tax is levied primarily on real estate but in some communities, personal property represents a substantial portion of the tax base; property is assessed at an average of 82 percent valuation with rates ranging from 0 to 21.71 mills. The State does not have a property tax except on oil and gas properties.

Resource Tax: Specific resource taxes are levied on fishing and fish processing industries, ranging from one to five percent of the resource's value. Specific resource taxes also apply to oil and gas production. Specific consumer taxes are levied on motor fuel, tobacco, alcoholic beverages, insurance gross premiums, coin-operated devices, and electrical and telephone cooperatives.

Other types of taxes and fees include federal income taxes (for-profit entities) and regulatory fees (paid to offset the cost of regulation). Current Alaska tax, fee, and other revenue collection mechanisms are summarized in Table 9.1.

These fees and taxes occur at various levels of government (federal, state, county, municipal, other taxing districts), and not every level of government imposes the same set of taxes and fees nor the same rate of taxation.

The legal authority for taxes and fees derives from the US Constitution, the State constitution, statutory provisions, and rules of agencies such as the Public Utilities Commission and the Department of Revenue.

Under the US Constitution, the Due Process clause of the 14^{th} Amendment provides that a state cannot deprive anyone of life, liberty, or property without the due process of law. This has been interpreted to mean that there must be nexus, or some minimum link between the state and the entity being taxed. Typically, it has been held that there must be some level of physical presence in the taxing state before a tax can be justified. However, defining ‘physical presence’ continues to be a contentious issue. The Alaska Corporate Net Income Tax applies to businesses with a nexus to the state.

The 14^{th} Amendment also provides that no state shall deny persons equal protection under the law. It prohibits discrimination among taxpayers within the same class, but it does not prohibit states from treating one class differently than another. Discriminatory taxation is permitted if the discrimination is reasonably related to a state purpose. Notwithstanding this language, states enjoy broad discretion to tax persons and activities within their boundaries.

Alaska statutes provide for the Corporate Net Income Tax and the Electrical Cooperative Tax, described above.

Articles IX and X of the Alaska Constitution and Title 29 of the Alaska Statutes establish the legal framework for municipal taxation in Alaska.

- The Alaska Constitution permits delegation of the state's taxation power to local governments, but limits delegation of that power to only cities and boroughs. (Article X, Section 2)
- The constitution limitation that "no tax shall be levied... except for a public purpose..." applies to both state and municipal taxation. (Article IX, Section 6)
- Home rule municipalities are granted broad governmental powers by the Alaska Constitution, but the constitution also provides that

"...standards for appraisal of all property assessed by the State or its political subdivisions shall be prescribed by law..." (Article IX, Section 3)

- General law municipalities are granted the right by state statute to levy a tax or special assessment and impose a lien for its enforcement. (AS 29.35.010)
- Both home rule and general law municipalities are subject to limitations on their taxing powers found in Chapter 29.45 of the Alaska Statutes. Section 29.45.010 authorizes cities, boroughs and unified municipalities to levy a property tax. If a tax is levied on real or personal property, it must be assessed, levied and collected as provided in Chapter 29.45. This chapter also authorizes the implementation of sales and use taxes.
- Based on Article X, Section I of the Alaska Constitution which provides that "...a liberal construction shall be given to the powers of local government...", it is assumed, although not expressly stated in statute, that all real and personal property is taxable unless it is specifically exempted from property taxation.

It is also assumed that a municipality may impose severance taxes, as has been done by the Denali and Kodiak Island Boroughs.

Revenue Impacts

Data on electric utility industry specific taxes reveal that some $1.557 million in revenue was generated through shared taxes on electricity sales by electric cooperatives. One third of those revenues relate to sales within the Municipality of Anchorage. Another third is paid for sales in the 8 boroughs, and the balance in other smaller cities. Of this total, all but $60,000 was returned to the municipalities in which the cooperatives operated. Because these taxes are based on sales, they are not expected to change significantly under restructuring, except to the extent that entities not taxed win significant market share. This may justify legislative changes to ensure that the shared tax base is not adversely impacted.

The Alaska Corporate Net Income Tax generated $253 million in 1998. Of this amount, $55 million was collected from non-oil and gas businesses. The corporate net income tax is the single largest source of revenues of Alaska general revenue. Due to the high percentage of electric utilities that do not pay federal income tax, this tax does not impact the cost of electricity significantly, except to the extent that oil and gas taxes flow through the cost of fuel. Since many new competitors in a retail competition market are likely to be for-profit entities, this tax will impact their cost of doing business in Alaska.

Local governments also collected $423 million in non-oil and gas property taxes in 1998. An additional $234 million was collected from oil and gas properties, of which some proportion is reflected in the price of natural gas and diesel fuel. Because disaggregated data are not available, it cannot be determined how much of this revenue derives from electric utility plant. Under retail competition changes in the value of generating plants could be especially significant for local governments that impose property taxes. Because of the size of these facilities, impacts on individual taxing authorities could be significant. And in situations where the power plant output is transmitted long distances, property tax decreases would not be offset directly by reduced rates.

Some 78 boroughs and cities have exercised their authority to impose sales taxes. These taxes produced some $112 million in revenues in 1998. Complete disaggregated data were not available with which to determine the electric utility share. Tables 9.2 and 9.3 list available data on tax and fee payments from EIA form 412 and RUS files.

Table 9.4 summarizes potential impacts of retail competition on taxes, fees, and other revenue mechanisms.

Policy Options

The range of policy options to address the many different possible impacts of retail competition is broad and diverse, but generally fall into three categories:

- Do nothing. This is the simplest to state and the simplest to implement. However, this assumes that the current tax/fee scheme (developed in a regulated environment) is also the most appropriate in a restructured marketplace. In a competitive marketplace, there will be different winners and losers. It will be difficult for policy makers to ignore the fiscal impacts and the people, businesses, and organizations impacted by the new marketplace structure.

- Establish a "revenue neutral" policy. The goal is to provide local governments an equal level of revenues from the electric utility industry – in essence to make local and state government entities indifferent in terms of revenues to the effects of restructuring. Depending on the degree of retail competition, this implies options ranging from a slight adjustment in tax or fee rates to major policy changes to counter the loss of local revenue.

- Establish a fair competitive environment. The goal is to create a level playing field for all electricity providers. This is a complex task as policy makers attempt to balance tax and fee burdens, property tax valuations, use taxes, the contributing role of federal and state tax incentives, depreciation methods, renewable energy issues, and so on. It also implies major revisions in tax and fee policies.

Options available for levying alternative taxes under retail competition are summarized in Table 9.5. Policy options available in Alaska are contained in Table 9.6.

Redefining the Public Power Bond Market

On January 16, 1997, the US Treasury Department issued final tax rules covering the definition of private activity bonds for the electric utility industry. However, it reserved for future determination issues concerning the ability of public power systems to acquire privately held electric assets. This action underscores the complexity of the problems facing public power today. The practical implications of these rules could raise questions about whether public power will be able to compete effectively in the competitive electric power marketplace.

In the tax bill, Congress established significant new restrictions on how public power systems could use their tax-exempt financing authority. Some members of Congress were concerned that some projects financed by state and local agencies – for example, the use of tax exempt industrial development bonds to finance construction of fast food restaurants, golf courses, and industrial complexes – in effect allowed taxable entities to benefit from their tax exempt status. Public power systems were grouped together with all other tax exempt issuers.

The current tax code limits the maximum amount of "private use' activity that can be funded using tax exempt bonds to no more than 10 percent of the proceeds of a bond issue. But there is also an absolute cap of not more than $15 million in private use activity "per project." A public power system that exceeds the limits could face draconian penalties requiring investors to pay taxes on tax exempt bonds.

In some cases the rules are more flexible than those they replace. For example, they allow remedial action to overcome any private use impact even if a change in conditions occurs within five years after the bonds are issued. They allow the use of disposition proceeds to require an equivalent amount of nonqualified bonds on the next call date, and eliminate the need for a tender offer, which appeared to be required in several IRS private rulings. The rules also add some limitations. Most significantly they limit the use of defeasance as a remedy for bond issues that become private activity bonds to those bonds that are callable within 10.5 years from the issue date. That restriction might have the effect of discouraging future bond sales of noncallable securities and thus raise overall issuance costs to compensate for the uncertainty.

Public power systems are discovering that tax exempt project financing, long considered a substantial competitive advantage, may now begin to impose substantial limitations on their ability to effectively compete in a restructured electric generation segment. The tax laws restrict the "private use" of such tax exempt-funded generation assets. Public power utilities may find this financing tool a disadvantage if:

- changes in Treasury regulation place additional limitations on the ability of a public power system to sell temporarily excess generating capacity of energy except to another tax exempt entity,
- these limits restrict the ability of public power to create or participate in strategic alliances with other taxable utilities or businesses, or
- participation by public power in larger regional or national markets risks the tax exempt status of its underlying debt structure.

This problem would strike hardest those public power systems and their joint-action project finance agencies with investments in electric generation projects. Changes in the tax status of this tax exempt project financing would dramatically raise the cost of capital, erode credit rating, and subject the public power systems to lawsuits from bondholders with unexpected tax liabilities and lower-valued bonds.

Public power must fight this battle in a political environment in which the Edison Electric Institute, the trade and lobbying organization for the investor-owned utilities, will almost certainly object to any change in statutes or regulations that don't simultaneously address some of their own tax dilemmas.

TABLE 9.1
Current Tax, Fee, and Other Revenue Collection Mechanisms

Provision	Type of Collection	Assessing Jurisdiction	Value of Revenues
Electric Cooperative Tax	The utility collects from the consumer and remits to taxing authority. Tax revenues are shared with municipalities and other local government.	State, but nearly all funds are shared with local jurisdictions.	$1.557 million collected in 1998, $1.492 million shared with local government.
Corporate Net Income Tax	Collected by the state, deposited in general revenues. The largest source of general revenue funds – over 80 percent derived from oil & gas industries.	State.	$253 collected in 1998. $55 million from non-oil & gas.
Sales & Use Taxes	No state sales tax. Some local authorities impose taxes up to 6 percent.	78 boroughs, cities. None in Anchorage or Fairbanks. No state sales tax.	$112 million statewide.
Property taxes	Remitted by owner of the property. (Municipally owned utilities do not pay.)	12 boroughs, 13 cities. No state property tax.	$423 million in 1998 (non-oil & gas – all taxed property)
Federal income tax	Paid by IOU's, IPP's, and marketers to IRS. Cooperative and municipal utilities do not pay.	Federal	Not available

TABLE 9.2
State of Alaska
EIA-412 Tax Data

Note: "0" means no tax/fee paid or no data available.

Item	ALASKA ENERGY AUTHORITY	ALASKA POWER ADMINISTRATION	ANCHORAGE MUNICIPAL LIGHT & POWER	FAIRBANKS MUNICIPAL UTILITIES SYSTEM	KETCHIKAN PUBLIC UTILITIES
Taxes Other Than Inc Taxes-Utility Operating Inc	0	0	3472531	0	290844
Income Taxes-Utility Operating Inc	0	0	0	0	0
Taxes and Tax Equivalents	0	0	3472531	0	290844
Taxes Other Than Inc Taxes-Other Inc and Deduction	0	0	0	0	0
Income Taxes-Other Inc and Deductions	0	0	0	0	0
Taxes Applicable to Other Income and Deductions	0	0	0	0	0
Transfers from Retained Earnings-State or Local	0	0	0	0	0
Other Transfers from Retained Earnings	0	0	0	0	0
Total Taxes and Transfers	0	0	3472531	0	290844
Cont To:Free/Below Cost Electric Service	0	0	0	0	0
Cont To:Use of Electric Dept Employees	0	0	0	0	0
Cont To:Use of Electric Dept Vehicles & Oth Equip	0	0	0	0	0
Cont To:Materials and Supplies	0	0	0	0	0
Total Contributions To State & Local Government	0	0	0	0	0
Cont By:Free/Below Cost Services	0	0	0	0	0
Cont By:Use of State or Local Employees	0	0	0	0	0
Cont By:Use of Vehicles & Oth Equip	0	0	0	0	0
Cont By:Materials and Supplies	0	0	0	0	0
Total Contributions From State & Local Government	0	0	0	0	0
Net Contributions & Services by Elec Utility	0	0	0	0	0

TABLE 9.3

State of Alaska

RUS Tax Data

NOTE: Utilities that do not use RUS financing services do not report data. In some cases, an entry of "0" may mean no data is available.

Company	State	Region	Id No	Tax Expense- Property and Gross Receipts	Tax Expense- Other
ALASKA ELECTRIC G & T COOP INC	AK	PAC	00288	0	0
ALASKA VILLAGE ELECTRIC COOP INC	AK	PAC	00221	23733	135693
CHUGACH ELECTRIC ASSOCIATION INC	AK	PAC	03522	0	0
COPPER VALLEY ELECTRIC ASSOC INC	AK	PAC	04329	37376	0
CORDOVA ELECTRIC COOP INC	AK	PAC	40215	11117	0
GOLDEN VALLEY ELECTRIC ASSOCIATION INC	AK	PAC	07353	420910	1043672
HOMER ELECTRIC ASSOCIATION INC	AK	PAC	19558	208659	0
KODIAK ELECTRIC ASSOCIATION INC	AK	PAC	10433	58842	193883
KOTZEBUE ELECTRIC ASSOCIATION INC	AK	PAC	10451	0	5178
MATANUSKA ELECTRIC ASSOCIATION INC	AK	PAC	11824	0	0
METLAKATLA POWER & LIGHT	AK	PAC	12385	0	0
NAKNEK ELECTRIC ASSOC INC	AK	PAC	13201	10155	0
NUSHAGAK ELECTRIC COOP INC	AK	PAC	13870	0	8243
TLINGIT-HAIDA REGIONAL ELECTRIC AUTHORITY	AK	PAC	18963	0	0

TABLE 9.4
Potential Impacts of Retail Access on Taxes, Fees, and Other Revenue Sources

Impact	Likely Effects	Remedial Action	Statutory Changes Required
Tax/fee revenue streams could decline. (Refer to more specific scenarios listed below)	Greatest impact at local level; less so at state level. (Refer to specific scenarios listed below)	Strategies include: 1) do nothing, 2) reconfigure tax/fee scheme at local level, and/or 3) devise state schemes to mitigate some impacts.	Depends on specific strategy employed. (Refer to specific scenarios below.)
Tax/fee revenues could increase in certain areas.	Efficient, low-cost power plants could increase in value.	None required.	None.
High cost power plants may lose value or be shut down.	Significant revenue loss to local jurisdictions; may impair ability to maintain level of general obligation funding (bonds).	1) Revise tax scheme at local level, 2) seek remedial action at state level, 3) do nothing	Depends on specific strategy employed.
Lower electricity prices result in lower sales tax, franchise fee collections, etc.	Impacts local and state government budgets through lower revenues (but also some savings in lower electricity costs.)	Ranges from none to revise tax/fee scheme to mitigate some or all of impacts.	Depends on specific strategy employed.
“Unbundling” of generation, transmission and distribution businesses may occur.	Generation business will become more competitive while transmission and distribution businesses may remain regulated. Cost allocation, transfer pricing, and affiliate rules become important.	State may want to address rules to ensure fair and competitive marketplace for market participants.	Depends on specific issues addressed.
Restructuring may jeopardize tax exempt financing status.	A municipally-owned utility may have to allow third-parties to use distribution system but this could endanger tax exempt financing status	Legal and statutory changes required.	Yes.
Uneven tax/fee burdens may favor one type of electricity provider over others.	In regulated environment this has little impact, but under retail competition, relative tax burden may favor one class of competitors over others.	If goal is level playing field, then changes to tax/fee and legal structure may be required.	Yes.

Impact	Likely Effects	Remedial Action	Statutory Changes Required
Locating new plants will partly depend on relative tax/fee structure.	Companies considering building new generating plants will consider relative tax/fee burdens in making location decision.	Depends on state and local governments economic development, environmental stances.	Depends on goals and what is needed to implement them.
New players, such as Power Marketers enter market.	These players may not have much physical presence in Alaska which has impacts on state/local revenue streams.	None may be required, but nexus issues may be considered if policy goal is to capture revenue potential.	No action may be taken, but if goal is to capture revenue potential then nexus, interstate commerce, and constitutional issues have to be considered.

TABLE 9.5
Options Available for Levying Alternative Taxes under Retail Access

Option	Key Elements	Point of Taxation	Remarks
Gross receipts tax	Applied to gross revenues of utility and paid by utility directly (but typically passed to consumer through higher rates).	Utility	Local.
Consumption tax	Tax on consumption of an item by the consumer. May be based on unit of the commodity or purchase price.	Consumer	May be regressive.
Commodity tax	Tax on the delivery of a commodity (kWh) to end consumer.	Typically on company making final delivery to consumer (i.e., the utility).	
Property tax	Tax on value of real/personal property	Owner of property	Currently used in Alaska but its role and use may be modified under retail competition.
Franchise fees	Based on service agreement between local government and utility for specific service territory; paid in lieu of business licenses/ permits; fee based on revenues	Utility	Must be adapted for use under retail competition to account for multiple, and non-resident, service providers.
Sales tax	Based on retail sales price of item purchased or used.	Consumer (collected and remitted by utility) and utility (for own purchased items).	Currently used in Alaska at the local level. Its use may be modified under retail competition.

Option	Key Elements	Point of Taxation	Remarks
Use tax	Counterpart to sales tax except levied on items purchased out of state and not subjected to local sales tax	Consumer of good/service.	May require adaptation to retail competition environment.
Payments in lieu of tax	Payment to local jurisdiction by municipally-owned utility.	Municipally-owned utility.	Payment may be calculated by formula, by contract, or on annual basis. Use may be modified under retail competition.
Regulatory fee	Fee paid by regulated utilities to fund portion of utility commission's budget. Based on revenue.	Utility	Use may be modified under retail competition.
Income Tax	Paid on income.	On individuals and for-profit entities.	Limited to corporations in Alaska. Electric cooperatives treated separately.

TABLE 9.6
Options to Address Tax, Fee, and Other Revenue Issues in Alaska

Policy Option	Method of Implementation	Advantages	Disadvantages
Do Nothing	None required.	No regulatory or statutory changes needed.	The current tax/fee schemes are based on decades-old regulatory environment. A shift to retail competition creates different winners and losers, and the effected stakeholders will seek mitigation through public policy action and other means.
Establish “revenue neutral” tax/fee scheme.	Requires action at local and state levels.	Local and state entities maintain current revenue levels.	May negate potential economic benefit of lower prices, more efficient marketplace, etc.
Adopt plan that results in even playing field for all electricity providers	Requires action at local and state levels.	All providers in comparable competitive positions vis-a-vis taxes/fees.	Will require significant changes in tax/fee structure. Different classes of consumers may suffer relative to current position.
Institute plan where out-of-state sellers of electricity have comparable tax/fee burden as in-state providers.	May require shift to energy consumption tax, wires/distribution fees, etc.	Out-of-state entities (which may relatively little physical presence in Alaska) could not have competitive advantage over in-state providers.	Constitutional, interstate commerce, and other legal issues would have to be resolved.
Under retail competition there may be relative shift of revenues from local government to state government. Adopt plan to mitigate impact.	Adopt changes in local tax/fee schemes, such as, electric consumption fee or broad-based energy consumption fee, and/or seek state-level tax/fee that is apportioned to local governments.	Redresses “imbalance” between local governments and state government revenues.	Cumbersome to implement (at local level). Will not provide net benefit to buyers of electricity.
As a public policy goal, implement policies that favor one or more sectors.	Establish policies at state level.	Meets public policy goal of encouraging or assisting such sectors as renewable energy, not-for-profit community organizations, lower income residents, etc.	Inherently favors one group over others. Politically sensitive issue.

Policy Option	Method of Implementation	Advantages	Disadvantages
Under “unbundling” scenario (generation, transmission, distribution separate into different businesses), one or more functions may no longer be regulated. Establish policies to ensure assets are valued on same basis for assessment purposes.	Establish policies at state level; valuation and assessment may occur centrally or locally following state guidelines.	Ensures that regulated and unregulated utility assets are treated the same for valuation and assessment purposes.	Requires coordination between state and local assessment authorities.

Utility Employees

Issue

Market-based retail competition, as envisioned by its proponents, will create incentives for increased operational efficiency and reduced operational costs in the electrical utility industry. This suggests a potential for decline in employment in some businesses such as electric utilities and mining. A critical issue is whether adverse employment impacts will be regionally concentrated, or exaggerated by multiplier effects in certain regions and communities. Some businesses could actually see growth in employment as a result of restructuring if it creates a competitive environment sufficiently attractive to support business expansion. Finally, some express concern that the historical national shift from full-time to contract employment at utilities could lead to a long-term shortage of trained employees and a resultant risk to system-wide reliability and safety.

Alaska Dynamic

Statistics suggest that industry-wide utility employment levels have remained fairly constant over the past several years in Alaska. Unionization has certainly been a major factor in this trend. In fact, employment in the broader "Electricity, Gas & Sanitary Services" segment has exhibited a trend that is essentially consistent with state economic robustness and counter-cyclical to unemployment. Automation and mechanization have generally improved productivity while failing to increase employment in the face of steadily rising generation and demand.

Because the electric utility industry is characterized by economies of scale, additional efficiencies may be available through mergers and consolidations, outsourcing, or aggregation in Alaska, though this would be seen as a net loss to labor representatives. Some studies suggest that on a state-wide basis, employment growth could offset or slightly exceed declines if restructuring encourages business expansion through competitive opportunities. Labor union representatives around the nation are very concerned that a reduction in apprenticeship programs is leading to a pending shortage of qualified linemen and other technically trained workers.

Utilities and labor have engaged in some rather well publicized disputes in Alaska in recent years. IBEW workers at Matanuska Electric were on strike for more than three months during the winter of 1999. Although the causative factors underlying labor disputes are often difficult to parse, it is at least plausible that utility attempts to prepare for competition play a contributory role. One issue of special concern for Alaska is whether increasing competitive pressure brought on by electric utility restructuring will lead to more frequent and difficult conflict between utility management and employees.

The APUC enjoys broad authority under AS 42.05.511 to investigate the management of a public utility, including staffing patterns, wage and salary scales and agreements or other acts that adversely affect the cost or quality of service. The Commission may order corrective action on the finding of unreasonable practices. Whether this power should continue and be expanded to include all participants in a competitive market is an important question of public policy.

Implications

One key concern in Alaska is whether potential negative employment impacts are sufficiently large or regionally focused to create significant economic problems. Some argue that competitive markets are themselves a driver for job-creating investment in the state. They suggest that the introduction of market-based competition could result in more jobs gained than lost, so long as market entry is facilitated or encouraged. Low income services, energy efficiency and renewable energy advocates argue that these service options are more job-intensive than coal or natural gas-fired electricity generation, and therefore measures to encourage these sectors could result in job growth as well.

Both financial and structural mechanisms are available to encourage the maintenance or enhancement of a skilled and adequate workforce. For example, a systems benefits charge could be created to fund employee retraining or relocation. 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 the magnitude of benefits obtained.

As utilities and new market entrants seek to minimize labor costs by reducing full-time employment, a concern is raised over whether Alaska will continue to enjoy the reliability and safety benefits of a well-trained, experienced electricity infrastructure workforce. However, some argue that reductions in highly-skilled workers at utilities in the lower-48 are more a function of pre-competitive cost-cutting strategies in the face of uncertain market conditions and will stabilize. Restructuring could improve business certainty within functional areas likely to remain regulated (i.e., transmission and distribution), and safety and reliability standards imposed through regulation could create incentives for maintaining a highly trained and skilled infrastructure workforce. Performance based regulatory mechanisms could be imposed for market participants, especially the distribution and transmission providers. These mechanisms could create indirect pressure to maintain adequate staffing levels by rewarding safe, reliable service and penalizing failures. Though these mechanisms could properly incent adequate staffing, they could have the effect of increasing costs for distribution and transmission service, dampening the cost reduction benefits of competition.

Assessment

Most stakeholders believe that some employment changes are inevitable in the electricity industry as a result of the introduction of market forces. Few stakeholders express strong concern that the potential negative impacts are a critical issue, and many argue that the best incentive to employment growth is robust competition in the industry. However, some are concerned about erosion in the numbers of skilled workers responsible for infrastructure maintenance and repair, at least during the period of transition to competition.

Key Decisions

- Are unacceptable employment changes occurring in the electric utility industry today?
- To what extent can those changes be addressed under the current system of regulation and operations?
- What measures or mechanisms should be instituted today to address these adverse trends?
- Will restructuring (or the continued "preparation for restructuring" activities) cause unacceptable employment changes in the electric industry in Alaska?
- To what extent are those changes within the control of Alaska policy makers, and to what extent are they part of broader industry or nation-wide market forces and trends?
- Why are those changes unacceptable? Which adverse results are most likely to develop?
- What structural or economic mechanisms should be instituted to prevent unacceptable employment changes during the transition to and in a more competitive industry environment?
- How should those mechanisms be incorporated in current regulatory agendas and/or in restructuring legislation

List of Accompanying Tables & Figures

Historical trends

Electric utilities employ a broad range of staff to provide service to customers. Utilities hire manager, accountants, lawyers, engineers, clerical workers, customer service representatives, and many others. Related industries, such as the natural gas industry employ many additional personnel. Relatively stable employment levels have characterized the electric utility industry in Alaska over recent years. During the same time, utilities in Alaska have kept pace with increased demand.

Information on employment trends in the utility industry are provided in Table 10.1 and Figures 10.1 and 10.2.

Projections

The pressure to increase output and revenues while holding the line on additional staff will continue in the electric utility industry, even without retail competition. The introduction of market forces to the industry, however, introduces a new dynamic.

Analysis of the data from other industries that have gone through deregulation reveals certain trends. Data from the trucking, railroad, airlines, and telecommunication industries reveals consistent decline in union membership. Labor representatives are concerned that this trend could have adverse consequences on quality of service and safety if repeated in the electric industry. Further, while work force size in those industries has grown, average weekly earnings have declined. Table

10.2 sets out the industry data. Figure 10.3 graphs weighed average weekly earnings in those industries from 1973 to 1996.

As investor-owned utilities are shifted away from cost-of-service regulation for generation and marketing of electricity, competition will place increasing pressure on utilities to reduce costs. For unregulated, for-profit affiliates of utilities, an emphasis on profitability will strengthen these pressures. The experience and views of one senior labor representative in California are set out in Table 10.3. Utilities are capital intensive industries and have relatively high fixed costs associated with plant and facilities. Because the opportunities to reduce fixed costs are limited, utilities continue to look to staffing and other variable expenses as a means of reducing costs and increasing profitability.

Cooperative and municipal utilities are not immune from these pressures, though investor-owned utilities may feel the pressure more acutely. The process of business benchmarking and the ability of the customer/owners of these utilities to track changes in the electricity industry translates into cost management and competitiveness pressure in those organizations as well.

The electric utility industry is also characterized by pervasive economies of scale. As competitive pressures continue to permeate the industry, utilities will continue to look to mergers and acquisitions as a vehicle for achieving these economies and improving overall performance. Mergers continue to be a primary driver for staffing reductions, as merged entities eliminate redundant positions and organize around functional areas.

"Merger fever" translates to publicly owned utilities, too. In many parts of the country, municipal utility managers are pressured to consider mergers and privatizations, and cooperative utilities are forced to examine mergers and consolidations as ways to increase size and manage costs.

While policy makers will generally welcome cost reductions resulting from retail competition in the electricity industry, a number of stakeholders are concerned that further significant cuts in staff may ultimately threaten the excellent record of safety, reliability and emergency response that has typified electric utility performance in the past. Stakeholder views related to restructuring and utility employees is provided in Table 10.4.

Impacts of restructuring

The impacts of restructuring on electric utilities are being faced well in advance of the passage of actual legislation throughout much of the country. Utilities attempting to prepare for competition have engaged in broad cost-cutting and staff reduction programs. Staff reductions at utilities typically take two forms. Utilities rely on attrition through retirements and early retirement inducements to shrink the workforce without having to resort to layoffs. When layoffs are required in order to meet targets, they typically operate at the opposite end of the staff pool – on recent hires and younger employees. Labor advocates and utility consultants have recognized a resulting aging of the utility employee workforce, and express concern that utilities are no longer providing enough on the job training for the next generation of workers. Moreover, because the training period for newly hired staff can take years, there may be a significant lag in the time it takes to materially change – or restore – the quality of the workforce.

As competition enters the electric utility industry, one might also expect increased competition for trained and qualified staff. Electric utilities providing distribution service may face continuing erosion in trained and skilled staff as new market entrants attract employees from incumbent businesses in the industry. Electric utilities already increasingly rely upon contract workers and firms to obtain necessary skilled staff services without the financial cost of making permanent hires in the lower-48, and may be increasingly pressured to rely on these substitutes for full-time employees. There is potential for the same situation to develop in Alaska.

Another significant consequence of increasing competitive pressure is the automation of customer service functions. In this regard customers may see the greatest impacts, as local service offices are closed and replaced with telephone or mail-based customer service functions. As service agents are replaced by these systems, there is a risk that customers will have increasing difficulty resolving disputes, registering complaints or obtaining assistance dealing with a service account. Finally, as competition stimulates the introduction of new technologies into the industry, a broad range of staffing functions may be displaced. Automated meter reading technologies replacing human meter readers is a well-known example.

A summary of potential impacts on utility employees from restructuring appears in Table 10.5.

Restructuring may also act as stabilizing force. The current period between monopoly and competition is most characterized by uncertainty. This uncertainty contributes to utility unwillingness to hire additional staff unless absolutely necessary. A clear policy decision about whether and how to restructure the industry could provide the stability necessary for utilities to feel comfortable about permanently hiring full time staff.

Impacts on universal service and affordability

Reduced staffing levels or increased pressure to increase staff productivity may lead to several negative impacts on universal service and affordability. Utilities may take longer to respond to and repair emergency outages in widespread emergency situations, as smaller crews are expected to address more problems. In some cases of widespread weather-related outages in the recent past, community leaders have questioned their utility's restoration priorities and expressed concern that poor and minority neighborhoods are the last to be returned to service. While the affected utilities in these situations uniformly offer sound technical explanations and refutations for such charges, these allegations created at least a public relations problem. This adverse impact may be mitigated by technological advances that can substitute effectively for the act of sending an employee to the outage site until that action is most effective.

As customer service staff are reduced and consolidated at call centers, customers may face delays in obtaining information and resolving problems. The solution to this potential issue lies in ensuring that any automation or centralization of customers service functions meet high standards of responsiveness and effectiveness in addressing customer inquiries and problems.

Cost cutting strategies under restructuring may also lead to deferrals of scheduled maintenance and decisions to delay new investments in performance enhancing measures and programs. Such deferrals and delay may leave the utility system more vulnerable to multiple failure scenarios. Again, if staffing levels have been significantly reduced, customers may face more frequent and longer problems with service quality.

Finally, there may be adverse impacts on affordability as a result of cost shifting to the distribution system. Under most restructuring approaches taken in the United States, the transmission and distribution of electricity remain monopoly functions operating under cost of service regulation. As utilities reorganize themselves to operate in this world, there may be increasing incentive to shift employees, and therefore costs, to these sectors. As a result of this de-averaging of costs associated with the electricity system, residential and small commercial customers may be forced to bear a higher percentage of system costs. Even if such cost shifting is economically justified, the net effect may be sufficient to substantially offset the savings benefits of the move to competition. Potential impacts of changes in employment trends on universal service and reliability are summarized in Table 10.6.

Policy options

At one extreme of policy options is the option to do nothing. Policy makers can decide that staffing changes are an inevitable market response to increasing competition. This option has the effect of not only assigning the question of staffing levels to the market, but also the concomitant decision to allow the market to assign appropriate value to reliability, service quality, and emergency response. One significant disadvantage to this approach is the time lag associated with any policy change. Rebuilding a trained and capable staff, and restoring service quality conditions could take years.

Policy makers in Alaska have at their disposal a range of options for addressing potential adverse impacts on utility employees resulting from the introduction of competition. As indicated above, the most important step policy makers can take is to resolve the uncertainty about when and how the restructuring process will occur. In a more stable environment, utility services providers can address staffing levels and future needs with more certainty, and may be more willing to make investments in their workforce.

A more direct option is to mandate staffing levels for certain key utility functions. Staffing levels could be established by a competent agency to ensure safety, reliability and adequate response to emergency situations. The key disadvantage of this approach is that it requires extensive regulatory processes to determine appropriate staffing levels. Staffing standards may also reduce the utility's flexibility to respond to competitive pressures and to adjust staffing policies in the most cost-effective manner possible. The costs of developing and complying with such standards will be passed on to customers, and may diminish the overall level of savings benefits obtained through competition. Finally, staffing standards imposed under regulation may have the effect of eliminating market-driven incentives to increase productivity. Of course, these concerns are also often raised in response to efforts by labor organizations to maintain or expand minimum crew sizes. The essential question under such an approach is whether safety, reliability and emergency response rates can be maintained without unduly interfering with an appropriate level of utility management discretion.

An alternative to setting specific standards is the adoption of performance standards. Rather than attempting to determine "correct" staffing levels, a performance standard approach allows the utility to exercise its discretion in taking the appropriate action to meet the standard. Under a model of restructuring that allows some utilities to "opt-in" to restructured markets, the exercise of the option might be conditioned on an acceptance of limited jurisdiction.

At the most extreme, policy makers could create incentives for adequate staffing and service quality through legal liability mechanisms. That is, rather than dictating standards and overseeing them, policy makers could create and enhance legal mechanisms for imposing liability on service providers whose failure to maintain an adequate staffing resource causes or increases personal injury or property losses. While this approach has the benefit of allowing service providers discretion in ensuring continued safety, reliability and emergency response, establishing clear standards for liability may be difficult. Since most electrical system failures are related to forces beyond the control of the service provider, determining the degree to which inadequate staffing caused additional damages may be a complex task.

A summary of policy options relating to utility employees is contained in Table 10.7.

TABLE 10.1
1996 County (Borough) Business Patterns for Alaska

SIC	Industry	Number of Employees	Annual Payroll ($1,000)	Total Establish ments	Establishments by Employment-size class			
					1-19	20-99	100-499	> 499
	TOTAL	**183,484**	**6,093,911**	**17,645**	**15,992**	**1,391**	**241**	**21**
1200	Coal mining	(C)	(D)	2	1	0	1	0
1220	Bituminous coal and lignite mining	(C)	(D)	1	0	0	1	0
1221	Bituminous coal and lignite surface	(C)	(D)	1	0	0	1	0
1240	Coal mining services	(A)	(D)	1	1	0	0	0
4900	Electric, gas, and sanitary services	1,969	112,634	133	112	18	3	0
4910	Electric services	1,309	77,823	54	41	10	3	0
4920	Gas production and distribution	(C)	(D)	8	6	2	0	0
4930	Combination utility services	(B)	(D)	2	0	2	0	0
4939	Combination utilities, n.e.c.	(B)	(D)	2	0	2	0	0

Source: http://www.census.gov/cgi-bin/datamap/state?02
Abbreviations and symbols:
SIC -- Standard Industrial Classification.
n.e.c. -- Not elsewhere classified.
(D) -- Withheld to avoid disclosing data for individual companies; data are included in broader industry totals.
(A)-(C), (E)-(M) -- Employment-size classes are indicated as follows:

A--0 to 19	H--2,500 to 4,999
B--20 to 99	I--5,000 to 9,999
C--100 to 249	J--10,000 to 24,999
E--250 to 499	K--25,000 to 49,999
F--500 to 999	L--50,000 to 99,999
G--1,000 to 2,499	M--100,000 or more

FIGURE10.1 Average Employment in Electric, Gas & Sanitary Services Category and Average Unemployment Rates - Alaska (1990-1998)

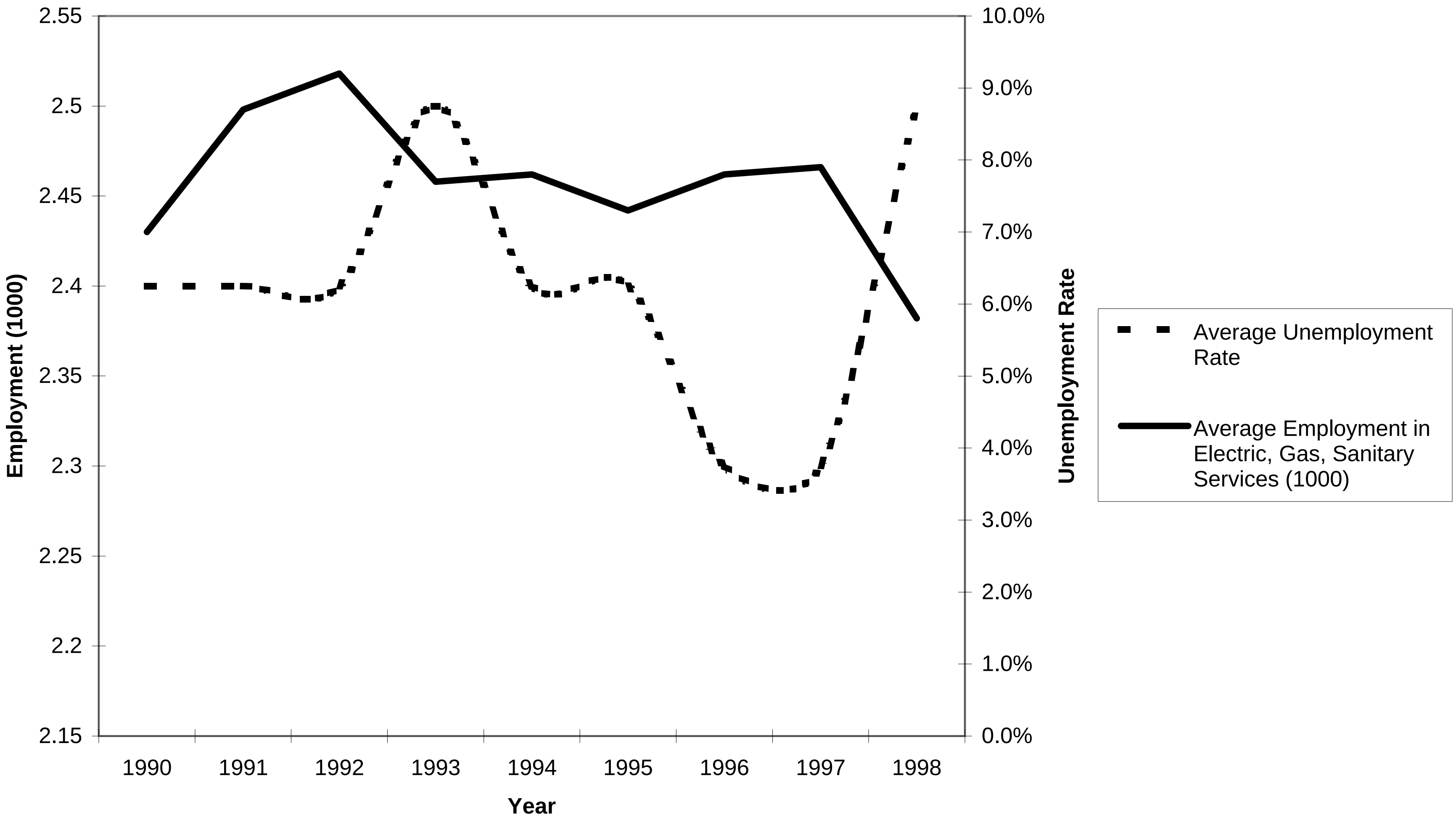
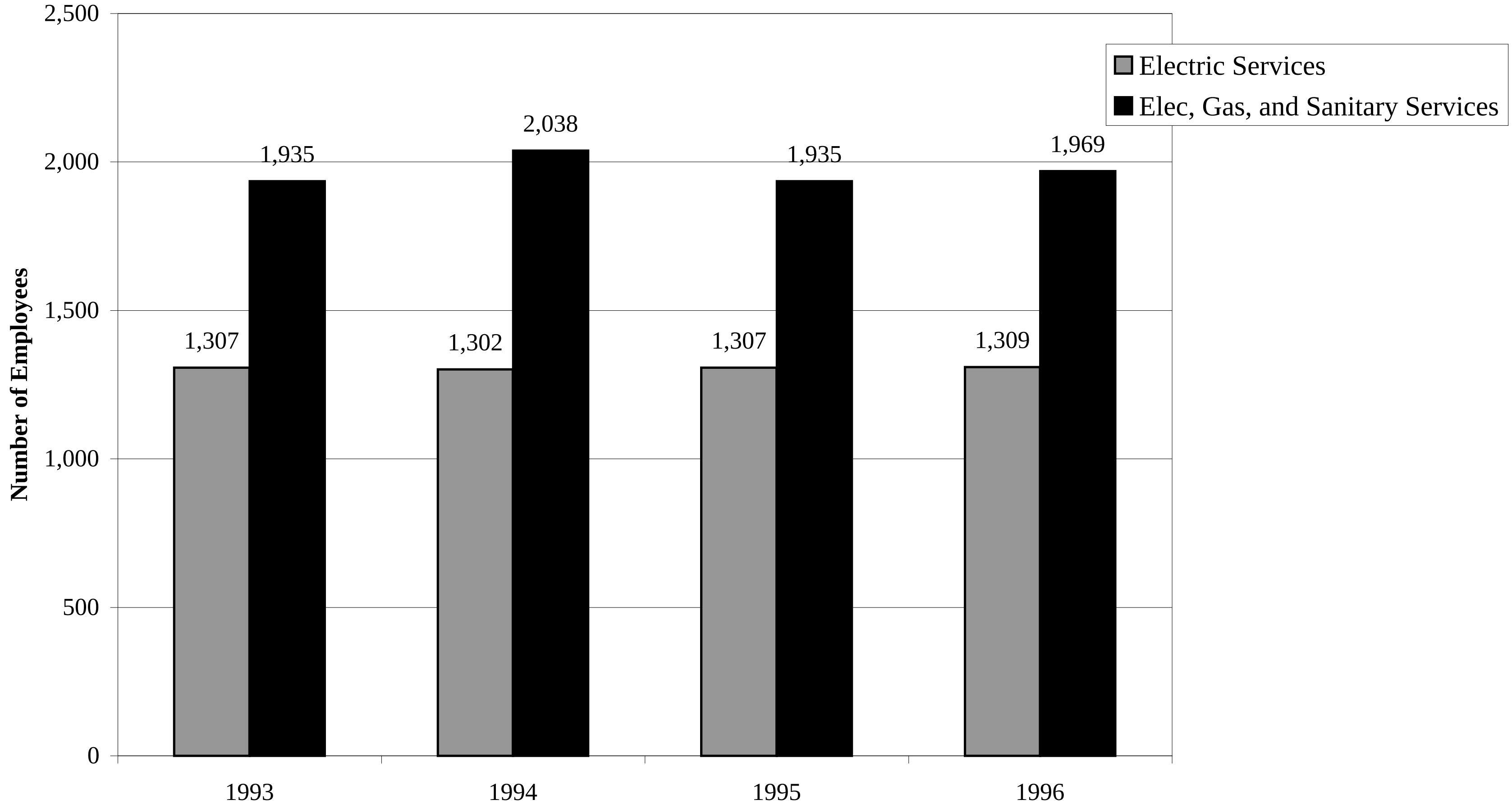


FIGURE 10.2 Utility Employment, Alaska 1993-1996



Source: US Census Bureau

TABLE 10.2
Unionization, Employment and Labor Earnings Patterns in Transportation and Telecommunications Industries

Industry	**1973**	**1978**	**1983**	**1988**	**1991**	**1996**
Trucking						
Union Membership Rate	49%	46%	38%	25%	25%	23%
Work Force Size (x1,000)	997	1,111	1,117	1,544	1,617	1,907
Weekly Earning (1983/84 dollars)	$499	$491	$404	$386	$405	$353
Railroad						
Union Membership Rate	83%	79%	83%	81%	78%	74%
Work Force Size (x1,000)	587	580	428	363	286	282
Weekly Earning (1983/84 dollars)	$475	$491	$507	$490	$494	$470
Airlines						
Union Membership Rate	46%	45%	43%	42%	37%	36%
Work Force Size (x1,000)	368	465	464	683	696	800
Weekly Earning (1983/84 dollars)	$499	$498	$455	$420	$443	$435
Telecommunications						
Union Membership Rate	59%	55%	55%	44%	42%	29%
Work Force Size (x1,000)	949	1,075	1,060	1,114	1,107	1,126
Weekly Earning (1983/84 dollars)	$399	$442	$457	$447	$458	$488
All other Industries						
Union Membership Rate	23%	22%	19%	16%	15%	14%
Work Force Size (x1,000)	72,619	81,737	85,220	97,704	99,080	107,844
Weekly Earning (1983/84 dollars)	$399	$363	$301	$310	$322	$334

Source: Information on union membership rates and industry work force sizes were provided by Barry Hirsch and David Macpherson. Information on labor earnings for the 1973-1991 sample period are taken from Current Population Survey Files and the 1996 earnings are taken from Hirsch and Macpherson's Union Membership and Earnings Data Book (1997a). The sample years from 1978 to 1996 cover the post-deregulation period for trucking, railroads, and airlines. The years 1983-1996 cover the post-divestiture period for telecommunications.

FIGURE 10.3 Weighted Average Weekly Earnings 1973 - 1996
Trucking, Railroad, Airlines, Telecommunications Industries
($1983-84)

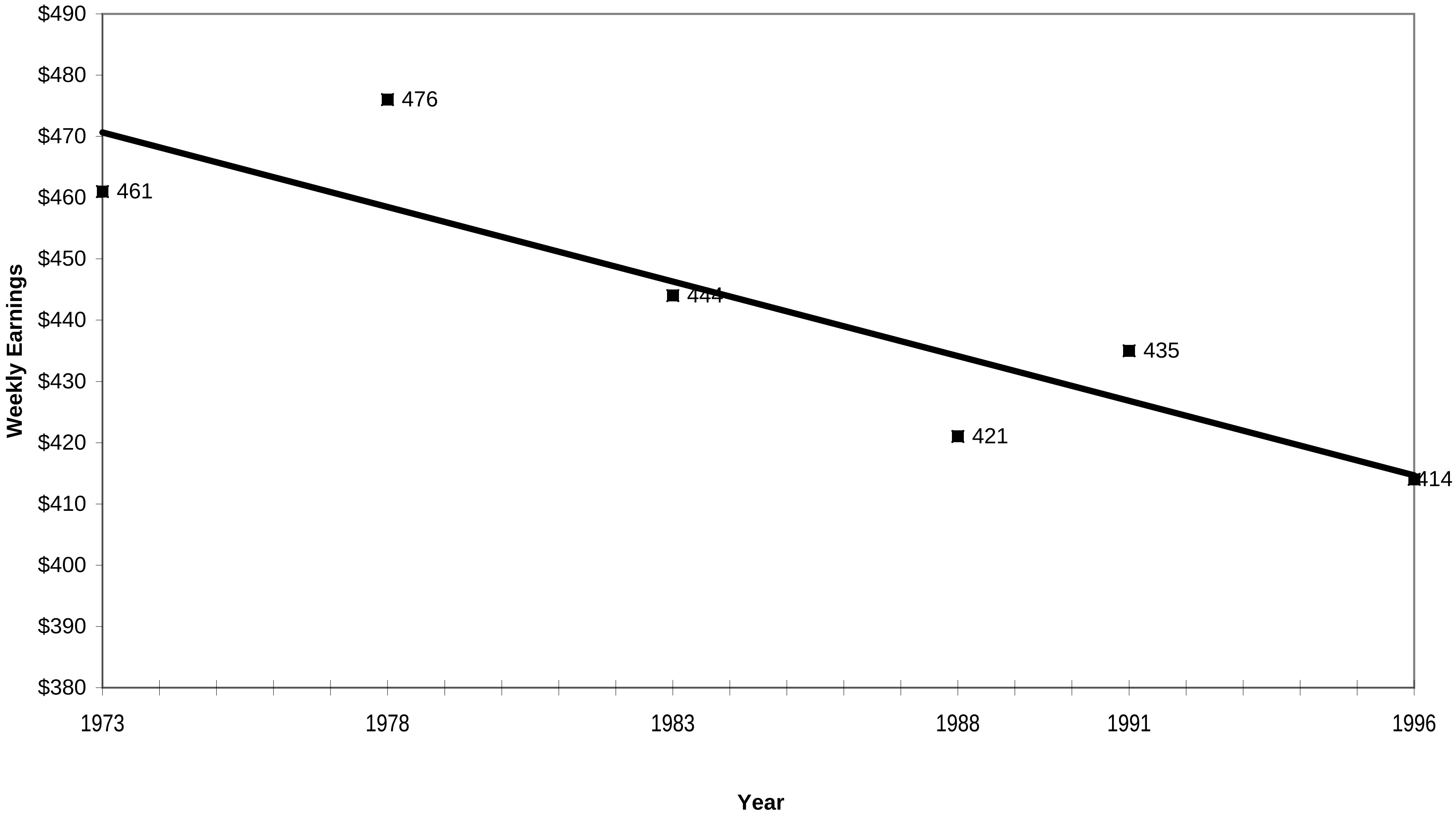


TABLE 10.3
Labor Representative's Experiences and Views on California Restructuring

Summary of Utility Employee Issues and Experiences – Labor Representative, California

TESTIMONY OF RAE E. SANBORN, BUSINESS MANAGER/FINANCIAL SECRETARY, IBEW LOCAL47 BEFORE THE CALIFORNIA ASSEMBLY UTILITIES AND COMMERCE COMMITTEE (January 25, 1999).

Chairman Wright and committee members; it is an honor to be afforded this opportunity to be here with you today and share my observations concerning changes in the California electric utility industry during the five years since the issue of utility deregulation came on the scene.

My comments will focus primarily on the impacts deregulation has had or is having on jobs and system reliability. As many of you know, I served as chairman of the CUE (California Utility Employees) coalition from its formation in May of 1994 through June of last year. While my testimony is based on my first-hand knowledge and experience on the Southern California Edison property, much of what I've addressed is applicable to the other utility properties in the state.

Loss of Good Full Time Jobs.

In March of 1994, Local 47 represented nearly 5,000 full-time workers on the Southern California Edison property. Three years later, that number had been cut by approximately 35 percent during the 95/96 time frame to slightly more than 3,200. This was done by laying off the younger up-and-coming workers followed by early retirements of the older, more skilled employees. As of December 1998, the number of full-time workers had climbed back to approximately 3,970 full-time workers. Thus, the number of California workers now receiving full- time employment and benefits in our segment of the industry is down approximately 20 percent. It would be one thing if deregulation had caused the utilities to examine their operations and determine that they actually had excess positions and had simply reduced the work force to the needed number of employees. However, this is not the case.

Cutbacks have left the Edison Company severely short-handed in skilled positions needed to lead and train the work force as well as in qualified younger employees to promote into vacancies. As a result of the understaffing, the remaining work forces in critical positions are being taxed to the maximum. For instance, in the manned substation switching centers, there is an ongoing shortage of qualified System Operators, thus requiring the remaining crew members to fill vacant shifts by working weeks and even months without a day off. Routine preventive maintenance is going undone due to the shortage of qualified test and maintenance personnel. Line crew personnel in many areas work virtually around the clock, with some employees tripling their base salaries due to overtime demands.

The voids in the work force are being filled with contractors (mostly non- union), and part-time and temporary employees. In many cases this is a temporary stop-gap measure which delays the inevitable. The adverse impact of the loss of the traditional supply of highly qualified personnel, coupled with the deterioration of the system infrastructure, will become more and more evident as time goes by. Edison is relying on expensive systems automation and modifications to substitute for the needed workers, but I believe this program has and will continue to result in decreases in true system reliability in the future. One thing is certain, several thousand good-paying middle-class California jobs have been lost and have been replaced by a transient, part-time work force which provides far less opportunity for California families.

System Reliability.

During the drafting of AB 1890, as residents and workers, we at Local 47 worked hard in helping to develop various performance standards to ensure a high level of system reliability and customer satisfaction. It seemed to be a perfect marriage: if meaningful system-reliability standards could be established, the public's interests would be protected and there would be a natural linkage to retaining good middle-class family jobs. Obviously, the number of jobs has been substantially reduced, yet you see no immediate correlation in reductions in service. This is a product of time and of recording and accounting procedures, rather than actual system reliability.

For example, in the case of a line outage, 92 percent of customers are considered to have had service restored when the substation circuit breaker is re-closed, regardless of the number of customers on the line who actually remain out of service. Therefore, the installation of a few thousand sets of line- sectionalizing disconnects or branch line fuses has drastically lowered the reported average customer minutes of interruption (ACMI) without regard for the duration of outages or the number of customers who remained out of service.

Similarly, Meter Readers are instructed to "punch the button" on their hand- held meter reading devices when they have a pleasant encounter with a customer, but not to record their unpleasant customer contacts. Thus, when the "encountered" customers are surveyed, the customer satisfaction index is artificially high.

Growth of Non-Union Utility Affiliates.

Not only are we experiencing a serious decline in the number of qualified personnel and good paying jobs in the utility industry, but we are also seeing the monies being recovered by the utilities through their CTC charges being utilized to spawn non-union utility company subsidiaries. Here again, we stood with the utilities in defending their billions of dollars in "stranded assets." We helped them gain the rights to go into non-traditional business ventures, and the right to utilize their established corporate identities (names and logos). We did this with a handshake agreement that success for them would translate into union job opportunities in the new affiliates for our members. Supposedly, the new jobs would help replace those lost to competition and down-sizing in the deregulated utilities. In spite of the strides made in protecting stranded assets through CTC and in opening up opportunities for a host of new business ventures, union workers on the Southern California Edison property have yet to see their first hour of work in any of Edison's new affiliates. (A few business ventures have been purchased where the workers were and are represented by a union.).

Workers Pensions Under Assault.

I'm sure you are aware of the move in recent years by big corporations across the United States to tap into the pension funds of their workers. I believe that any attempts to tap into, or reconfigure, workers' earned pension benefits in an effort to increase corporate profits is one of the lowest and most severe forms of attacks on our citizenry. Throughout our working years, a portion of the fruits of our labor is set aside for our use in our "golden years" when we can no longer provide for ourselves. These monies were earned by the workers, they belong to the workers, and no legitimate corporation should attempt to convert these funds into corporate "profit centers" at their workers' expense. (Although not considered a pro-labor publication, much has been written about this problem by the Wall Street Journal in recent months.) After 18 months of bargaining, we are deadlocked with the Edison Company over their attempt to adversely modify our membership's pensions.

While Edison has not indicated that they intend to attempt to "impasse" (force) our members into their newly developed "cash-balance" pension plan, they do intend to force all non-represented employees into their new plan this year. This plan could result in greatly reduced pensions (and greatly reduced company funding) for younger and future employees.

Conclusion: I believe it is far from certain that real bottom-line energy cost savings will trickle down to residential and small business consumers in the state of California as deregulation unfolds, but that's a subject I am not going to address here. I can tell you that deregulation, to date, has significantly reduced the number of good paying full-time jobs in the California utility industry. These were jobs by which California residents could support, raise and educate their families. The replacement jobs within the utilities are significantly downgraded in quality from what Californians enjoyed a short while ago. Fortunately, or unfortunately (depending on our point of view), stockholder interests, executive compensation, bonuses and stock options seem to be holding up well in the deregulated marketplace. It is possible that residential and small business consumers and the workers in the electric utility industry may benefit when/if actual competition for electric services comes to California. However, we must all remain vigilant to see to it that these promises develop as deregulation and competition unfold. If we do not remain vigilant, the quality of electric service and the jobs within the electric utility industry will further erode while consumer prices climb. If this should be allowed to happen, all Californians will be losers! Thank you very much for this opportunity to share these thoughts with you. I look forward to working with you in any way I can to help make California a better place.

Addendum To Testimony Of Rae E. Sanborn Before the California Assembly Utilities And Commerce Committee

The promise of electric utility deregulation in California was to save consumers money by creating competition in pricing and by better use of fuels, customer choices of service levels, etc. It absolutely was not intended that cost savings would be obtained by reducing the quality of workers, the quality of jobs, the safety of workers, or by jeopardizing the reliability of electrical service. Near the end of the written remarks I submitted to you earlier, I stated that we must be vigilant if the promise of deregulation is to be achieved. I want to offer you a few examples of what I feel we must watch for and protect against.

TRAINING AND QUALIFICATIONS OF WORKERS.

There are a number of involves potential dangers to workers, the public and system reliability. Some of these are:

Meter Installers (Metering work has recently been "unbundled" by the PUC.) Meters are basically sealed package units which are installed on homes and buildings to measure a customer's use of electricity for the providers. These "cash registers" of the electric utility industry are usually installed or removed uneventfully. However, when a new meter socket has been improperly installed, or if the meter has been tampered with, corroded or otherwise damaged, this task can be very hazardous and result in a very serious electrical shock and/or flash burns to workers or customers. (A number of workshops have been held to develop minimum training standards for employees who will do this work.) Steam Plant Maintenance Workers Recently, Edison proposed a 1-year (vs. the existing 3-year) apprenticeship for training new steam plant Electricians and Instrumentation Technicians! In the past, when utilities had a long-term view of their business and a very specific obligation to serve their customers, such a proposal would never have come up. This proposal has not been implemented because we refused to allow the company to trivialize the training for these positions.

However, in the unregulated and unrepresented plants of the future, this type of get-by-quick-and-cheap mentality is likely to prevail. If so, it will definitely threaten system reliability, worker safety, and job quality.

Test Technicians, Maintenance Electricians and Power Station Operators.

Edison is now significantly understaffed in these critical positions. A hodgepodge of retired and contract workers, and employees prematurely promoted or transplanted from related classifications, are being used to supplement these positions. An electric utility system is intricately integrated, and its components must "fit" perfectly together to work properly. Faults in electric utility system protection schemes can result in major system failures. An analogy may be drawn to computer systems: there are many different kinds and most of them are good, but they cannot all be modified or repaired in the same way. Software or hardware that works well in one system may cause another to "crash." Since utilities have cut their full-time Operating, Maintenance and Test crews, outsiders are being utilized in ever greater numbers to do this work. Some may be less than qualified. Few are fully familiar with the intricacies of the local protection schemes they are being asked to work on.

Line Crew Personnel and Work Methods.

Edison now also has a significant shortage of Linemen and related classifications. They are attempting to address this problem by refilling positions and with the use of contractors and new work methods. Recently, Edison proposed to use helicopters to lift line workers on and off steel transmission towers and aerial conductors. Under the Company's proposal, the linemen would climb into a large basket suspended by rope a few hundred feet below a helicopter. The "chopper" would fly them to the work area and hang them and their basket on the top of a tower or on the mid-span of a de-energized high-voltage conductor. After the workers performed their work, the chopper would move them to another location or return them to the ground. In addition to the obvious concerns about this proposal, Edison insisted that the helicopter pilots they wanted to use, to do this portion of our work and transport our union members, must remain non-union. As such, we would have no say in their selection, qualifications, training, adherence to safety rules and procedures, etc. Obviously, we have not agreed to the Company's proposal. We are willing to work with Edison to develop new work methods. However, it is not necessary for work to be done non-union, nor for management to have unfettered control over the lives and safety of its workers, for new work methods to be feasible.

Oversight Needed.

The electric utility industry is changing under deregulation. As utility deregulation unfolds, we are beginning to see a dangerous lowering of standards in construction, maintenance and operation of our high-voltage electric systems. As we have recently seen, mistakes on high voltage systems can cause horrendous explosions and can blackout multi-state areas.

We license lawyers, real estate salespeople, hairdressers and even barbers, but we have no license or minimal training requirements for utility workers in the critical positions. Setting reasonable standards for attracting, training and retaining highly qualified utility workers should be seriously considered.

I hope that my presentation has helped to shed some light on “the California experience” to date. I also hope that you will share some of my concerns for the adverse impacts on California’s citizens and workers because, in the bottom line, our assessment of how California is doing is really all about how our citizens and workers are doing.

Rae E. Sanborn, Business Manager/Financial Secretary, IBEW Local 47

TABLE 10.4
Stakeholder Identified Impacts and Views Relating to Utility Employees

Description of Stakeholder	Impact of Retail Competition Identified	Views Concerning Employees
Labor Representative	Cost-cutting measures and work force reductions are being implemented throughout the electric power industry. As a result, the existing work force and the electric systems are stressed to a point that threatens worker safety and public safety.	Public safety and worker safety must be maintained, as electric power companies cut staffing levels to enhance profitability.
Utility Consultant	As the energy utility industry becomes more competitive it is likely that the established players are going to get leaner. The work force will be reduced likely without much consideration for skill retention. Those with highly competitive skills will leave. Others will be forced out. This has been the ongoing experience in the telecommunications companies.	Part of the problem is knowing which skills the company requires and how it will communicate this to and reward those who stick with the company, as well a show to attract new talent.
Utility Consultant	The average age for most organizations in the electric utility industry is actually decreasing due to the downsizing efforts and early retirement packages being offered. This is leaving the existing workforce with a drain in technical expertise to be able to handle most situations. Since the downsizing is still fairly new, the impact on the industry has yet to be felt fully.	There are two strategies that companies facing this issue can pursue. The first is to utilize contract personnel for a short term where there is a lack of critical skills and experience. If this option is used, then it is suggested that they have plans in place for technology transfer as part of the contract. The second option to overcome the loss of experience is to establish well-structured and understood processes and procedures.
Labor Representative	Our organizations (NECA & IBEW) have anticipated workforce shortages in the industry with or without electric deregulation. Deregulation has and will continue to cause large shifts of workers from the regulated sector to the private sector. Are the private sector entities prepared to respond to the re-training needs of the older workforce and attract and train new people? Deregulation may also cause an increased demand for skilled workers, thus compounding the problem. This demand could come from the increased number of firms entering the market, the increase in energy services that will be offered to the consumer, and the overall expansion of the electrical industry.	Our apprenticeship programs are increasing their efforts to recruit more qualified applicants. We are also continually updating the training program with the latest teaching methods and industry technologies.

Description of Stakeholder	Impact of Retail Competition Identified	Views Concerning Employees
Utility Consultant	ENERGY SUPPLIERS WORKFORCE: We are seeing a lot of downsizing by utilities as they try to prepare for competition. Early retirement packages are becoming common place for all levels of the workforce. These retirement packages are being expensed and can become part of the rate base, which provides additional benefits for utilities that have been making too much money. These cost reduction measures, while reducing operating costs, are not causing a corresponding reduction in energy rates to existing customers; but will enhance cost competitiveness in the future. A lot of expertise is being shuffled out the door, leaving a younger, less costly employee base. However, this younger group, while certainly intelligent and eager, do not possess the experiential knowledge and understanding of the utilities systems of the older workforce and we have seen that customer service suffers as a result.	
Utility Consultant	CUSTOMER'S WORKFORCE: On the customers' side we are seeing large ESCOs coming to energy intensive clients with programs and offers to take over and manage the customers HVAC, lighting and other utilities. This can displace the existing workforce, although in some cases the ESCO will hire the facilities personnel to continue running the systems. There are similar issues to the utilities; a lot of site and systems specific experience is lost in the transition. Chauffage - the offering of energies and related services on a cost per square foot basis - is being considered as an option to replace on-site personnel.	The concerns are that an aging but qualified and experienced workforce is being displaced with the intent of cost reduction. It has been our experience that in most cases this workforce has the best understanding of the energy systems whether it be the utility or the customer's facility and in many cases with their experience, they are an IRREPLACEABLE source when analyzing systems for cost reduction strategies. It is our concern that cutting this experience by removing an experienced workforce that typically has 10 to 15 productive years left, in order to realize immediate savings is short sighted. Especially when this experience can be instrumental in the effective transition to a deregulated environment. We realize that there are situations where individuals may not be contributing but in our building analysis and dealings with utilities we have found the experienced and qualified workers to be an asset to developing cost reduction strategies for our clients.

Description of Stakeholder	Impact of Retail Competition Identified	Views Concerning Employees
Utility Consultant	At one of the utilities I represent, it is safe to say that the average age of linemen and substation repairmen is in the late forties. In the line dept., 56 percent of the linemen are over the age 45. In the substation repair dept., 60 percent of the people are over the age 45. At the present time there are no plans in place to replace the aging workforce. I know that some people are hoping to be able to go to the trades and be able to hire qualified journeymen, but we also see their numbers decreasing in the state.	Even if you are able to hire a qualified journeyman, it still takes time for them to become familiar with the specific utility's working practices. It has been stated that it takes 6-8 years to make a good qualified journeyman in the line and substation dept.; 4 years in apprenticeship and 2-4 years to learn the system and ojt. Taking the above into consideration, it appears we could be running into a shortage of qualified people in the next 5-10 years. In my opinion, the concentration has been on reducing numbers, not retraining and improving the skills of the workforce.
Utility Services/Consulting (General Physics Corp.)	Recent statistics state that approximately 42 percent of the technical utility workforce has been lost over the last five years. Those who left were typically the most senior (and most experienced) workers within those organizations. GP works at approximately 100 power plants each year. Our experience is that most utilities have stopped "downsizing" and are now implementing programs to attract and retain new employees with a "grow your own" philosophy. This philosophy involves providing "top quality" training and opportunities for advancement that entice the employees to remain. The more progressive companies are including "technology-based" training (e.g. CBT, Distance Learning, etc.) to meet these training needs. Finally, most (over 90 percent) of utilities are implementing cross-training or multi-skilling programs to create highly-skilled workers that can perform multiple tasks. This allows the utility to do more with less.	It is also important that utilities be proactive in preparing for the turnover of the aging workforce. Many utilities are capturing the knowledge of the aging workforce now, before they walk out the door. By proactively planning and preparing their training programs, the utilities are in a position to train new personnel quickly with high efficiency and effectiveness.
IPP – Coastal Power Corp.	We have experienced difficulty in identifying skilled professionals with experience in the domestic energy market. As the market continues to deregulate, individuals with experience in power development and marketing will be harder and harder to find.	The likely result will be a migration from other energy-related fields such as natural gas marketing, as well as unrelated fields such as finance, business development, and industrial marketing. During this phase, employers will be challenged to train and keep a skilled workforce.

TABLE 10.5
Potential Impacts of Retail Access on Utility Employees

Impact	Likely Effects	Remedial Action	Statutory Changes Required
Staffing Reductions due to cost cutting.	Reduced levels of skilled employees. Could increase productivity and reduce pressure to increase rates. Increased profits/reduced rates. If reductions reduce workforce below levels necessary to adequately maintain plant & services, increased reliance on contractor and outsource labor.	No action necessary if reliability, efficiency and emergency response not adversely impacted. Performance based standards or cost of service review could be applied to create financial incentives/penalties.	None required for jurisdictional utilities. Restructuring legislation may retain some form of regulation for distribution and transmission functions.
Staffing reductions due to mergers and acquisitions.	Staff reductions may not be geographically uniform. Efficiency and productivity benefits may be realized based on economies of scale.	Regulatory and merger approval authority should specifically include consideration of workforce impacts, and authority to impose conditions if impacts are adverse. Mergers could be used as opportunity to impose financial incentives/penalties for reliability, efficiency and emergency response performance.	Legislation may be required to strengthen authority.
Staffing reductions due to technological improvements.	Productivity, profitability and performance should increase. Risk that some players may seek to install expensive, performance enhancing technologies under regulation to prepare for competition, enhancing competitive position at ratepayer expense.	Regulatory review of jurisdictional utilities. Administrative review of stranded cost claims. Oversight through regulatory proceedings.	None required. Restructuring legislation may retain some form of regulation for distribution and transmission functions.
Staffing growth due to new services and offerings.	Creates new demand for broad range of staffing capabilities. Increased demand could lead to wage increases and worker shortages in the near term.	Enhanced cooperation between market participants and educational/training institutions. Improved in-house training and development programs.	None.

Impact	Likely Effects	Remedial Action	Statutory Changes Required
Staffing growth due to strengthened regulation of monopoly functions.	Regulation of non-competitive functions, such as transmission, distribution and metering, may result in partial reversal of any trends of staffing reduction. In turn, these could raise the costs associated with these functions, and reduce net savings associated with restructuring.	Comprehensive regulation of remaining monopoly functions can ensure efficient system operation and safety. Performance based incentives and penalties may offer opportunities for cost savings.	Regulatory responsibilities and authority must be detailed in any restructuring legislation.

TABLE 10.6
Potential Impacts of Changes in Employment Trends on Universal Service & Reliability

Impact of Workforce and Expense Reductions at Utilities	Likely Effects	Remedial Action	Statutory Changes Required
Increased emergency response and repair time.	Increase in costs associated with emergency interruptions. Delay in service restoration. Potential for allegations of discriminatory service restoration schedules.	Retain/enhance regulatory authority over T&D sectors. Establish and enforce comprehensive emergency response service quality standards. Consider performance based regulatory systems to apply incentives and penalties.	Regulatory responsibilities and authority must be detailed in any restructuring legislation.
Increased customer inquiry and complaint resolution time.	Reduced customer service personnel staffing could increase response and resolution time, while decreasing opportunities for "human" resolution of problems. Automated systems could improve response time and information, and more efficiently direct complaints and inquiries.	Establish and enforce minimum service quality standards for customer response and resolution. Consider performance based regulatory systems to apply incentives and penalties.	Regulatory responsibilities and authority must be detailed in any restructuring legislation.
Diminished service quality.	Absent clear regulatory standards or direct profitability feedback mechanisms, service providers may face an incentive to allow service quality degradation in order to enhance short-term profitability.	Establish and enforce minimum service quality standards. Consider performance based regulatory systems to apply incentives and penalties. Collect and disseminate service quality performance data to customers.	Regulatory responsibilities and authority must be detailed in any restructuring legislation.
Increased outage and incident rates.	Maintenance deferral and staffing reductions, as well as enhanced complexity associated with retail competition could lead to short and/or long-term degradation in reliability and increased incidence of service disruptions.	Establish and enforce minimum service quality standards. Consider performance based regulatory systems to apply incentives and penalties. Collect and disseminate service quality performance data to customers.	Regulatory responsibilities and authority must be detailed in any restructuring legislation.

Impact of Workforce and Expense Reductions at Utilities	Likely Effects	Remedial Action	Statutory Changes Required
Cost shifting to distribution entities could increase rates.	Absent comprehensive cost allocation process, utilities may have incentive to shift costs related to overall system reliability to distribution sector, where regulation is anticipated to remain. As a result, costs normally shared among a broad base of customers may be shifted off customers that take at transmission level.	Initiate and complete comprehensive cost allocation process to fairly assign costs prior to opening of retail access markets. Adopt and enforce affiliate transaction rules to prevent future cost shifting or unfair cross-subsidization.	Regulatory responsibilities and authority should be detailed in any restructuring legislation, with directive to complete cost allocation process and adopt affiliate rules prior to opening of markets.

TABLE 10.7
Policy Options Relating to Utility Employees

Policy Option	Method of Implementation	Advantages	Disadvantages
Resolve Market Uncertainty	Adopt clear timetable for restructuring activities, with date certain. Ensure early resolution of issues impacting employment levels.	Addresses the uncertainty about competition that has motivated labor cost cutting practices.	Has no effect on industry wide trends aimed at reducing labor costs.
Impose Staffing Requirements	Establish regulatory and/or good practice standards establishing minimal staffing levels for regulated entities (Today, regulated utilities. Under competition, regulated distribution and transmission utilities.)	Sets staff levels to ensure safety, reliability, and emergency response. Provides assurance of cost recovery for labor expenses. Removes incentive to cut labor costs to improve profitability.	Minimizes flexibility in staffing decisions. Requires administrative oversight. May remove incentives for productivity improvements. Imposes costs that are passed onto customers.
Impose Performance Standards	Establish performance mechanisms for application to regulated entities today and under retail competition.	Allows businesses maximum flexibility in retaining labor force best suited for reduced costs as well as safety, reliability, and emergency recovery.	Requires monitoring & oversight. Potential for gaming if standards not set properly.
Create Legal Liability for Losses Relating to Inadequate Staffing	Create and enhance legal mechanisms for imposing legal liability on utility service providers whose failure to maintain an adequate work force gives rise to unnecessary or unavoidable property losses or personal injury.	Allows businesses to manage risk of liability directly through staffing decisions. Creates judicial mechanism for adjudging responsibility.	Because so many system failures are related to forces beyond the control of the service provider, establishing fair rules for liability may be difficult. May encourage excessive litigation.
Market Response	Allow competitive market forces and customer response to ultimately determine staffing levels.	Allows markets to assign appropriate value to system reliability, safety, and emergency recovery. Avoids regulatory oversight.	Because electric service is deemed an essential service, discriminatory practices could result. Due to time lag in hiring and training qualified personnel, service quality and safety declines could take years to restore.

Analysis of Generation Competition in Alaska

To assist policy makers in the State of Alaska in understanding the potential impacts of electric market competition, this study was undertaken to estimate the impact on the Alaska interconnected utilities of wholesale competition. The underlying question being answered is: If Alaska establishes a competitive power market, how will it impact electric power prices and the profitability of the Alaska utilities?

Modeling competitive markets is highly dependent upon the assumptions that underlie the analysis. Projections of fuel costs, plant operating characteristics, the timing of new entrants, and load growth, as well as many other input variables, can have significant impacts on modeling outputs. To accommodate this source of uncertainty, this study utilized scenario analysis to characterize the impacts attributed to several key market and generator input variables.

This study was conducted on the heels of a central dispatch planning study completed by Black & Veatch International for the APUC in October 1998. In order to provide consistent and useful results to the APUC, this study has relied on input assumptions data, and projections developed for the Black & Veatch effort to the maximum extent possible.

Overview of Methodology

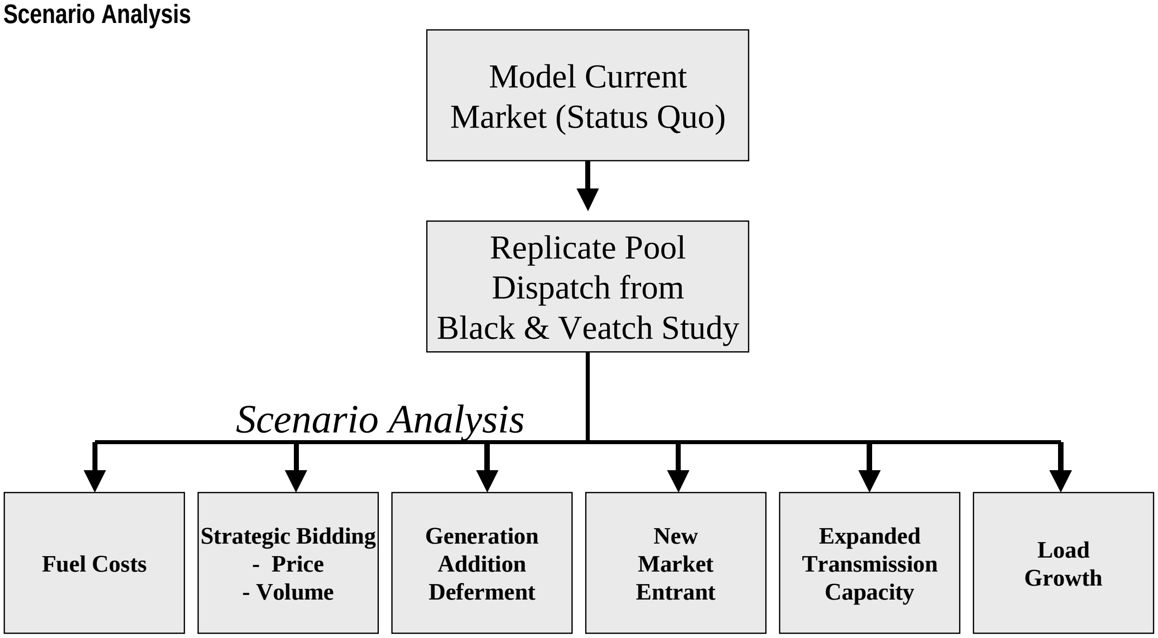
The impact of wholesale competition can be analyzed by the modeling of utility costs, generation, and sales revenues under a market environment. In this study, a market simulation model was used to simulate generation dispatch in a pool environment. The stacking model dispatches generation to meet load based on generator cost, and calculates the market prices that result when the last generator is dispatched to meet the last increment of load. A detailed description of the stacking model is included in Appendix 4, and the input assumptions used in the model are included in Appendix 5.

The stacking model is simple to use and easy to understand. It adequately captures the essence of a competitive market for the purposes of planning and scenario comparisons. It is not a daily operation model for real time dispatch and trading. For the purposes of estimating future market behavior, more complex optimization models that account for demand and supply uncertainties do not necessarily yield more accurate results. The accuracy afforded by more detailed production cost simulation models is irrelevant in the face of the large range of outcomes that result from input value assumptions and future uncertainties. The simplicity of the stacking model allows it to be used for scenario analysis and estimation of market outcomes under a range of assumptions for input values and market conditions. In addition, strategic bidding behavior of market participants can be modeled through selective alteration of plant parameters and market behavior of competitors.

The development of market simulations was conducted in several steps (see Figure 1). First, the model was run to simulate current conditions of the interconnected utilities. This is the Status Quo case. Then, the model was used to simulate coordinated dispatch between the utilities. This scenario is intended to simulate the Black & Veatch analysis, and was conducted to validate that the two modeling approaches produced consistent results. Based in this scenario, the model was used to investigate the impact on utility costs, sales and total revenues of various market and input assumptions. Six different areas were addressed in the scenario analysis:

1. Fuel cost differences between the utilities;
2. Strategic bidding behavior, including increasing generation bid prices above marginal costs, and decreasing supply volume;
3. Deferring planned generation additions;
4. Allowing new market entrants;
5. Reassigning and expanding transmission capacity; and
6. Varying load growth forecasts.

FIGURE 1
Scenario Analysis



In addition, the development of stranded cost estimates from the results provided in this analysis is straightforward. A commonly used methodology for the estimation of stranded costs is the lost net revenues method. Stranded costs are estimated by calculating the net present value of the difference between the utility revenues under regulation and under competition.

For each scenario, the model simulated wholesale market competition through the year 2017.

Major Structural Issues

In the design of competitive power markets, there are a number of structural components that can have significant impacts on the resulting market prices. In addition, the behavior of market participants can also impact market outcomes. For the purposes of this study, several assumptions were made regarding the pricing and availability of transmission capacity, the pricing rules used in the power pool, participant bidding behavior, the exercise of market power, and consumer behavior.

Transmission: The market simulation in this analysis included the interconnected utilities in Alaska's rail belt. There are significant transmission constraints in this area, particularly running south to north from the Anchorage area to Fairbanks. This study assumed that dispatch in the competitive market would be based on generation cost, and that only transmission limitations and system reliability issues would alter dispatch order. Given the limits on transmission capacity, this dispatch rule results in the formation of three zonal market prices within the railbelt system.

There are a variety of transmission pricing regimes in use in the lower-48 and internationally. The most well accepted and standard transmission pricing scheme in use in the US is the postage stamp tariff form adopted by FERC in the *Pro Forma* tariff. In this analysis, we assume that an open access, postage stamp tariff is in use by the participating utilities, and that no transmission owner is able to capture differences in regional market prices through transmission pricing. In addition, the study assumed that there would be no pancaking of transmission rates. Transactions using the transmission systems of several utilities pay only once for such usage.

Determination of Market Price and Bidding Behavior: This analysis assumes that the competitive market will consist of a centrally dispatched power pool, in which the pool determines dispatch order based on generator bid prices. Except in the scenarios in which generators are assumed to exhibit strategic pricing behavior, all generators are assumed to bid their variable operating costs, which consist of fuel costs, and fixed and variable operations and maintenance costs. The market clearing price is the bid price of the last unit dispatched to meet load.

Market Power: Beginning with the introduction of electric competition in the United Kingdom, the exercise of generation market power has proven to be a substantial problem for market restructuring efforts. This modeling exercise assumes that generators will not bid strategically, that is, that they will always bid their variable costs. In order to assess whether any generators could exercise market power, several scenarios were run to assess the impact of strategic bidding behavior. However, this study has not examined all possible sources of market power abuse.

Consumer Behavior: The model does not consider demand responsiveness to price. The analysis used the same customer load forecast in most of the scenarios. A few scenarios are included that show the impact of changes in load forecasts, but again, these scenarios do not include any strategic behavior of customers in response to market prices. Customer behavior can have an impact on market prices. For example, in the pool structure operating in California, schedule coordinators submit load forecasts that include incremental and decremental loads depending on the market price in each hour.

Estimating Market Clearing Prices

The stacking model produces market clearing prices that reflect the bid price of the last generator dispatched for that hour. For the base case, the bids match the total variable cost of fuel and operation and maintenance costs. All generators that are dispatched for that hour receive the market clearing price for their output.

Figure 2 depicts the zonal market clearing price, by hour, for base case pool dispatch in 1996. This scenario assumes coordinated dispatch among the railbelt utilities, and the imposition of existing transmission constraints. The price differentials between regions represent the varying costs of generation in the three regions, less economic energy exports and imports given existing transmission capabilities. The oscillation in market clearing prices shown in the top 1000 hours of the load duration curves are due to different units being able to send power North to GVEA because of variations in the native demand requirements in CEA and MLP service territories.

FIGURE 2
Zonal Market Clearing Prices for Pooled Dispatch in 1996

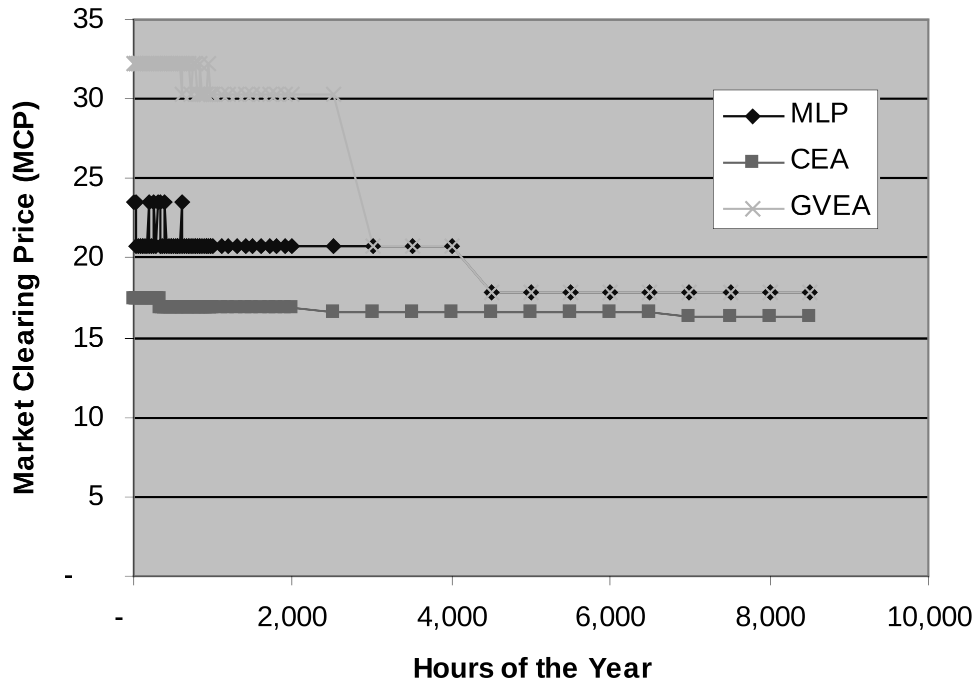


FIGURE 3
Zonal Market Prices for Study Period, Pool Dispatch

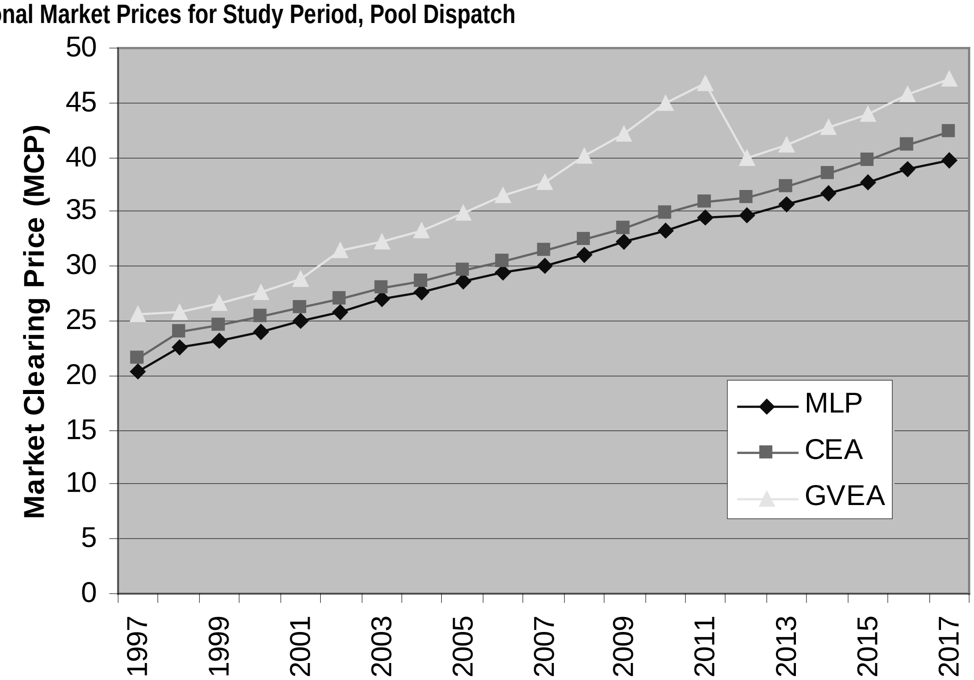


Figure 3 illustrates the difference in zonal market clearing prices over the study period. The drop in prices for GVEA corresponds to the planned addition of significant new capacity in that year.

Scenario Analyses

The following section summarizes the results of each market competition scenario. Analysis results are provided in the form of total sales (MWh) by utility and net present values of revenues, costs and profit by utility, over the study period. Scenarios are compared to a common case (Pool Dispatch Scenario) in order to compare the relative impacts of each market restructuring scenario.

Status Quo Case

The Status Quo scenario duplicates current conditions for the rail belt utilities in which each utility dispatches generation on an individual basis to serve its own loads, with only limited economy energy purchases and sales. The purpose of the case was to generate sales, revenue and cost totals for the three generating utilities before any cost savings due to market mechanisms are modeled. This case allows the quantification of the benefits of wholesale markets.

Table 1 below summarizes the major modeling assumptions for the Status Quo scenario. Unless noted otherwise, these assumptions were carried through all of the scenarios presented in this report.

TABLE 1
Modeling Assumptions

Major Modeling Assumptions
All current generation plants in the area are dispatched
New plants built in the GVEA service territory , per BVI Table 6-1
All plants bid their variable cost (fuel and variable O&M)
Total costs reflect both variable and fixed O&M costs. The costs do not include return of or on capital.
Plant heat rates based on 100% output at summer plant capacities
Multi-area transmission limits as follows:
1. Plants in the MLP service territory could dispatch up to the hourly load in the MLP service territory, plus an operating reserve margin. Max Dispatch = Load[MLP, LDC hour] * (1+OperatingReserve)
2. Plants in the CEA service territory can exceed area needs to reflect economy energy sales of 92 MWh to MLP (BVI, section 3.2) and (637,637-406,265 MWh) to GVEA (BVI, section 4.3). This is implemented in the model through a transmission capacity of 26.42 MW Max Dispatch = Load[CEA, LDC hour] * (1 + Operating Reserve) + 26.42 MW
3. Plants in the GVEA service territory could dispatch up to the hourly load in the GVEA service territory, plus an operating reserve margin. Max Dispatch = Load[GVEA, LDC hour] * (1+OperatingReserve)
Operating reserve is 6%. The 6% operating reserve criteria is based on reported load and generation in 1996.
Real discount rate is 8% for all utilities.
CEA includes AGENT, HA, MEA, and SEES.
Fuel costs by company and plant from BVI table 3-3.

Table 2 summarizes the results of the Status Quo scenario. Total sales are split between the three major utilities, and costs and revenues are indicated. Note that the revenues represent what each utility would receive under competitive market prices, and do not reflect current regulated revenue requirements.

TABLE 2
Total Sales, NPV Costs and Revenues for Study Period, Status Quo Case

Utility	Sales (MWh)	Total Costs ($Millions)	Generator Revenues ($ Millions)
MLP	26,946,946	276	302
CEA	71,492,787.2	782	911
GVEA	14,537,990	301	255
Total	112,977,724	1,359	1,468

Pooled Dispatch Case

The model was used to estimate the cost savings from employing a pool dispatch in the Railbelt area. The pool dispatch case is identical to the Status Quo case with the exception that the transmission limits were increased to allow more efficient dispatching. MLP was assigned 20MW of capacity, CEA 50MW of capacity and GVEA 70 MW (reverse flow). This scenario duplicates the coordinated dispatch analysis completed by the BVI study. Table 3 summarizes total sales by utility and the net present value of utility costs and revenues.

TABLE 3
Total Sales, NPV Costs and Revenues for Study Period, Pooled Dispatch Scenario

Utility	Sales (MWh)	Total Costs ($Millions)	Generator Revenues ($ Millions)
MLP	30,741,791	320	377
CEA	75,729,252	835	964
GVEA	6,506,680	163	90
Total	112,977,724	1,318	1,431

Table 4 compares the Pool Dispatch Scenario to the Status Quo scenario. As shown below, increasing the transmission allowances reduces overall system costs by $41 million. This is largely due to the fact that GVEA expensive generation can be displaced by MLP and CEA plants.

TABLE 4
Change from Status Quo Scenario

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)	
	MWh	%	$Millions	%
MLP	3,794,845	14%	$ 44.26	16%
CEA	4,236,465	6%	$ 53.17	7%
GVEA	(8,031,310)	-55%	$(138.36)	-46%
Total	0		$ (40.94)	

The costs savings estimate is higher than the BVI estimate, but still only represents a 3% savings in total variable costs. Moreover, given the strategic emphasis of the stacking model, the difference between a 2% (BVI study) and 3% stacking model savings is not significant.

TABLE 5
Comparison of BVI and E3 Study Results (Net Present Value $000's)

	BVI Costs (BVI Table ES-1)	Costs w/o Capital	Costs w/ Capital for New GVEA Plants
Individual	1,433	1,359	1,421
Pooled	1,403	1,318	1,380
Savings from Pooled Dispatch	30	41	41
Percentage Savings	2.09%		2.89%

All of the remaining scenarios are variations on this Pool Dispatch Scenario.

Equalization of Fuel Costs

The purpose of the Fuel Cost Equalization scenarios was to isolate the impact of differences in natural gas fuel contracts on the wholesale market. In this scenario, fuel costs for all natural gas plants were set equal to the cost for the CEA Beluga 1-8 plants. This scenario examined the impact of fuel cost differentials on the operations of the plants in the Railbelt. Under the Status Quo transmission limits, there is little impact from changing the fuel costs. Utility costs decrease by $41.7 million, but revenues also decrease by $49.2 million, leaving a decrease in net utility revenues (decrease in profit) of 7.5 million when compared to the Pool Dispatch scenario.

TABLE 6
Fuel Cost Equalization Base Case

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	59,555	0.2%	-32.1	-11.2%	-37.8	-11.2%	-5.7
CEA	-42,983	-0.1%	-9.4	-1.1%	-11.3	-1.2%	-1.8
GVEA	-16,572	-0.3%	-0.2	-0.1%	-0.2	-0.2%	0.0
Total	0		-41.7		-49.2		-7.5

Changing the transmission rights for MLP from 20MW to 35MW increases the impact of the fuel cost equalization dramatically. The change results in an over 2,900 GWh exchange between MLP and CEA over the 22 year period. The change in operating costs and total generator revenue between the two cases is less than $5 million. This small cost impact is due to the fact that once the fuel price differentials are eliminated, the MLP and CEA generators have essentially the same cost. Thus the replacement of CEA output with MLP output would lead to only very small cost savings. This suggests that the benefits of competition might largely come from fuel cost differentials, rather than generator stock differences.

TABLE 7
Fuel Cost Equalization with Increased MLP Transmission

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	2,950,355	8.8%	-0.9	-0.3%	14.7	3.8%	15.6
CEA	-2,926,103	-4.0%	-45.6	-5.8%	-59.6	-6.6%	-14.0
GVEA	-24,252	-0.4%	-0.2	-0.1%	-0.2	-0.3%	0.0
Total	0		-46.7		-45.1		1.6

Market Power

To assess the ability of generators to exercise market power and influence market clearing prices, several scenarios were run to test the impacts of increased bid prices and reduced bid quantities on market price. The scenarios are:

1. CEA's bid price is 20% over its marginal costs
2. CEA's bid price is 20% over its marginal costs, and MLP is assigned 35 MW of transmission capacity
3. CEA's bid price is 20% over its marginal costs, and MLP is assigned all 70 MW of transmission capacity
4. CEA's bid price is 40% over its marginal costs
5. CEA's bid price is 40% over its marginal costs, and MLP is assigned 35 MW of transmission capacity
6. CEA's bid price is 40% over its marginal costs, and MLP is assigned all 70 MW of transmission capacity.
7. CEA withholds Beluga 3 capacity
8. CEA withholds Beluga 6-8 capacity

The two Beluga units were chosen to examine the effect of withdrawing a mid-merit unit (Beluga 3) versus more efficient large units (Beluga 6-8). A more comprehensive analysis could evaluate the impact of each generating unit in the Railbelt.

The following tables summarize the results.

As shown in Table 8 through Table 13, CEA is able to significantly increase its profits by increasing its bid price. With no reallocation of transmission, CEA is able to increase its profits by $157 million and $315 million if it raises prices 20 percent and 40 percent, respectively. By increasing CEA's bid price, dispatch of GVEA's units is increased and the dispatch of CEA's generator is decreased, resulting in an increase in market prices. This increase represents the higher costs of GVEA's units.

Increasing the transmission capacity allocated to MLP dilutes CEA's ability to exercise such market power and reduces the increase in overall costs imposed on the system by CEA's high bid prices. Nevertheless, the higher bid prices increase overall profit and costs in all of the cases.

TABLE 8
CEA Bids 20% Over Marginal Cost, Contract Transmission Capacity

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	51,759	0.2%	0.9	0.3%	5.2	1.4%	4.4
CEA	-4,788,948	-6.8%	-47.6	-6.0%	109.4	10.2%	157.0
GVEA	4,737,189	42.1%	53.2	24.7%	57.6	38.9%	4.3
Total	0		6.4		172.2		165.8

TABLE 9
CEA Bids 20% Over Marginal Costs, 35 MW Transmission Capacity for MLP

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	2,922,646	8.7%	36.2	10.2%	62.5	14.2%	26.3
CEA	-7,252,587	-10.6%	-80.2	-10.6%	60.8	5.9%	141.0
GVEA	4,329,941	40.0%	48.9	23.1%	53.0	36.9%	4.2
Total	0		4.9		176.3		171.4

TABLE 10
CEA Bids 20% Over Marginal Costs, 70 MW Transmission Capacity for MLP

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	14,823,013	32.5%	190.6	37.3%	245.4	39.5%	54.9
CEA	-16,268,111	-27.4%	-197.2	-30.9%	-125.3	-14.9%	71.8
GVEA	1,445,098	18.2%	8.8	5.1%	-1.5	-1.7%	-10.4
Total	0		2.2		118.6		116.3

TABLE 11
CEA Fossil Fleet bids 40% over Marginal Cost

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	59,555	0.2%	1.0	0.3%	12.0	3.1%	11.0
CEA	-6,719,276	-9.7%	-64.0	-8.3%	251.3	20.7%	315.2
GVEA	6,659,721	50.6%	73.1	31.0%	80.7	47.1%	7.5
Total	0		10.1		343.9		333.8

TABLE 12
CEA Fleet bids 40% above Marginal Cost, and MLP Transmission Capacity increases to 35MW

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	2,950,355	8.8%	36.7	10.3%	74.1	16.5%	37.4
CEA	-9,454,754	-14.3%	-98.8	-13.4%	193.7	16.7%	292.5
GVEA	6,504,399	50.0%	71.2	30.4%	78.3	46.4%	7.1
Total	0		9.1		346.1		337.0

TABLE 13
CEA Fleet bids 40% above Marginal Cost, and MLP owns 70MW Transmission Capacity

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	9,653,370	23.9%	123.6	27.9%	209.6	35.8%	86.0
CEA	-14,255,834	-23.2%	-165.7	-24.7%	83.3	8.0%	249.0
GVEA	4,602,464	41.4%	51.6	24.1%	55.9	38.2%	4.3
Total	0		9.5		348.8		339.3

The three tables below, Tables 14, 15, and 16, summarize the results of scenarios in which a utility withholds generation from the pool. Table 13 shows that the withholding of Beluga 3 can result in a relatively small increase in costs and a substantial increase in profits for CEA. In comparison, as shown in Table 14 and 15, withholding Beluga 7-8 or 6-8 from the pool has a negative impact on profits for CEA.

TABLE 14
Withholding of Beluga 3 by CEA

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	0	0.0%	0.0	0.0%	0.2	0.0%	0.2
CEA	-269,975	-0.4%	-1.3	-0.2%	24.3	2.5%	25.5
GVEA	269,975	4.0%	2.6	1.6%	2.6	2.8%	0.1
Total	0		1.3		27.1		25.8

TABLE 15
Withholding of Beluga 7-8 by CEA

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	304	0.0%	0.0	0.0%	0.3	0.1%	0.3
CEA	-541,484	-0.7%	43.8	5.0%	39.0	3.9%	-4.9
GVEA	541,180	7.7%	5.2	3.1%	5.5	5.8%	0.3
Total	0		49.0		44.8		-4.3

TABLE 16
Withholding of Beluga 6-8

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	304	0.0%	0.0	0.0%	0.3	0.1%	0.3
CEA	-541,484	-0.7%	47.3	5.4%	39.0	3.9%	-8.4
GVEA	541,180	7.7%	5.2	3.1%	5.5	5.8%	0.3
Total	0		52.6		44.8		-7.8

This empirically supports the theory that removal of mid-merit plant like Beluga 3 can artificially increase market prices and inflate generator profits. These examples also demonstrate that not all plants are able to inflate market prices (e.g. Beluga 6-8 and 7-8.) Even with compensating transmission policies, some units, if allowed to bid strategically, can have a significant impact on the level of market prices.

Canceling Generation Additions

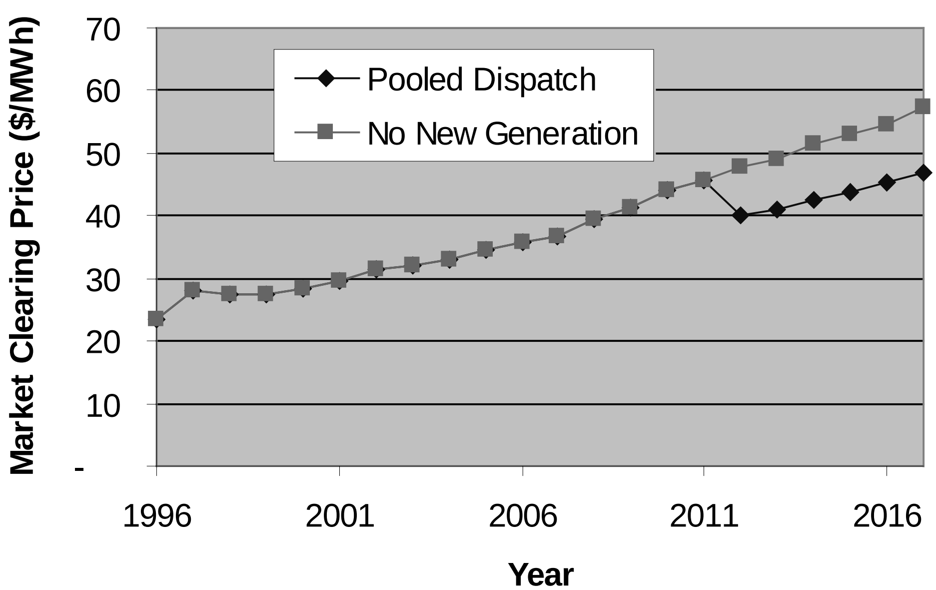
Table 16 summarizes the results of a scenario analysis in which GVEA's planned generation additions are not built. The GVEA planned additions are the only new plants included in the base case analysis, and are from BVI Table 6-1. Note that the elimination of the planned GVEA generation has some impact on the total dispatch costs, but a larger impact on the utility profit. Costs decline because GVEA avoids both the variable costs of the new generators, and also the fixed O&M costs associated with the units. Generator revenues increase because market clearing prices remain higher with no new assets in the area.

Figure 4 illustrates this impact on market prices.

TABLE 17
No New Generation Capacity Added

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	0	0.0%	0.0	0.0%	1.9	0.5%	1.9
CEA	28,914	0.0%	0.3	0.0%	6.0	0.6%	5.7
GVEA	-28,914	-0.4%	-42.6	-35.5%	5.3	5.5%	47.8
Total	0		-42.3		13.2		55.5

FIGURE 4
Impact on Market Prices of Canceling Generation Additions



Impact of New Market Entrants

This scenario examined the impact of a new market entrant on the costs and revenues that could be collected by the three major generating utilities. The scenario added a 100MW of new generation in the GVEA service territory in the year 2002, based on the cost characteristics of the GE 7EA combined cycle unit. The unit was assumed to obtain natural gas at the same cost as the CEA Beluga units.

In the Status Quo case, the efficient new unit displaced the majority of the existing GVEA generation.

TABLE 18
New Entrant in the Status Quo Case

	Sales by Company (MWh)_			Total NPV Costs ($M's)			Total NPV Revenues ($M's)		
	Base Case Resources	Add GE 7EA CC in 2002	Difference	Base Case Resources	Add GE 7EA CC in 2002	Difference	Base Case Resources	Add GE 7EA CC in 2002	Difference
MLP	26,946,946	30,793,550	3,846,604	275.5	320.6	45.1	301.7	378.0	76.3
CEA	71,492,787	60,770,096	(10,722,691)	782.1	672.0	(110.1)	911.4	904.0	(7.3)
GVEA	14,537,990	7,398,078	(7,139,913)	300.9	171.3	(129.6)	254.6	98.8	(155.9)
IPP	-	14,016,000	14,016,000	-	120.6	120.6	-	159.8	159.8
Total	112,977,724	112,977,724	(0)	1,358.6	1,284.5	(74.0)	1,467.7	1,540.7	72.9

In the pooled dispatch case, the largest impact of the Independent Power Producer (IPP) is to displace CEA power. While this benefits consumers in the GVEA territory, it is unlikely that this scenario would be realized. The costs of operating the IPP (which include fixed costs) are higher than the market revenues. The IPP would not be able to cover operating expenses, not to mention return of and on capital. On the other hand, if the IPP were to drive the market price in the GVEA territory higher through strategic bidding in order to cover return of an on capital, then consumers in the area would pay significantly higher rates.

TABLE 19
New Entrant in the Pooled Dispatch Base Case

	Sales by Company (MWh)_			Total NPV Costs ($000's)			Total NPV Revenues ($000's)		
	Base Case Resources	Add GE 7EA CC in 2002	Difference	Base Case Resources	Add GE 7EA CC in 2002	Difference	Base Case Resources	Add GE 7EA CC in 2002	Difference
MLP	30,741,791	29,475,134	(996,658)	319.8	308.9	(10.9)	376.5	350.3	(26.2)
CEA	75,729,252	66,200,801	(9,528,452)	835.3	730.5	(104.8)	964.0	826.8	(137.2)
GVEA	6,506,680	3,015,790	(3,490,891)	162.6	120.0	(42.6)	90.5	36.7	(53.8)
IPP	-	14,016,000	14,016,000	-	120.6	120.6	-	111.8	111.8
Total	112,977,724	112,977,724	-	1,317.6	1,280.0	(37.6)	1,431.1	1,325.7	(105.4)

Table 20 shows the impact of the IPP on CEA's market power. The IPP's introduction does reduce the revenues that CEA can collect from the market.

TABLE 20
New Entrant when the CEA Fleet Bids 40% above Dispatch Cost

	Sales by Company (MWh)_			Total NPV Costs ($000's)			Total NPV Revenues ($000's)		
	Base Case Resources	Add GE 7EA CC in 2002	Difference	Base Case Resources	Add GE 7EA CC in 2002	Difference	Base Case Resources	Add GE 7EA CC in 2002	Difference
MLP	30,801,346	30,801,346	-	320.8	320.8	-	388.5	386.2	(2.3)
CEA	69,009,976	59,225,746	(9,784,231)	771.3	658.9	(112.4)	1,215.3	1,030.5	(184.8)
GVEA	13,166,401	8,934,632	(4,231,769)	235.7	187.6	(48.1)	171.2	124.2	(47.0)
IPP	-	14,016,000	14,016,000	-	120.6	120.6	-	168.9	168.9
Total	112,977,724	112,977,724	0	1,327.8	1,287.9	(39.9)	1,775.0	1,709.7	(65.3)

The reduction, however, is far from sufficient to avoid the exercise of market power. Table 21 shows that even with the IPP in place, CEA could increase profits by $275 million (relative to the status quo with the IPP in 2002) through strategic bidding. The IPP is already running at full capacity in the base case with IPP scenario, so the IPP cannot increase sales in response to CEA's strategic behavior.

TABLE 21
Impact of CEA Bidding 40% above Dispatch Cost (with IPP in 2002)

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	1,056,213	3.4%	11.9	3.7%	35.9	9.3%	24.0
CEA	-6,975,055	-11.8%	-71.6	-10.9%	203.6	19.8%	275.3
GVEA	5,918,842	66.2%	67.6	36.0%	87.5	70.5%	19.9
IPP	0	0.0%	0.0	0.0%	57.0	0.0%	57.0
Total	0		7.8		384.1		376.2

Like the 40% bidding strategy case above, the introduction of an IPP in 2002 reduces CEA's profit from withdrawing Beluga 3 from service. CEA's profit increase drops from $25 million to $18 million, but the reward for strategic bidding behavior remains.

TABLE 22
Impact of IPP on CEA's Withdrawal of Beluga Unit 3

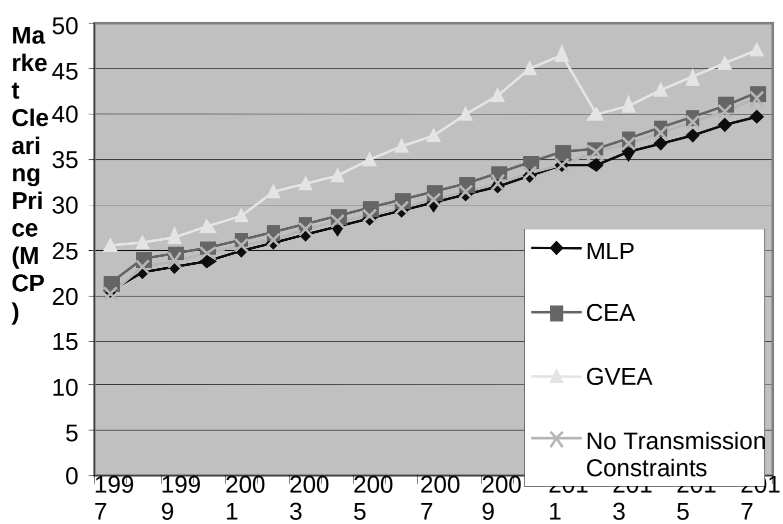
	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	458,812	1.5%	4.8	1.5%	9.5	2.7%	4.7
CEA	-992,736	-1.5%	-11.1	-1.5%	6.9	0.8%	18.0
GVEA	533,925	15.0%	4.9	3.9%	5.8	13.6%	0.9
IPP	0	0.0%	0.0	0.0%	0.0	0.0%	0.0
Total	0		-1.3		22.2		23.6

Impact of Additional Transmission Capacity

The Market Power section of this report explored some of the ways that transmission transfer capability can attempt to discipline the generation market. These scenarios examine the value of increased transmission, even if generation owners do not attempt to capitalize on market power.

Increased transmission capacity would remove the differences between zonal market prices. The new total region market price with no transmission capacity constraint is shown below in Figure 5. As illustrated, the market prices are generally higher than the MLP market prices, but lower than the prices for CEA and GVEA.

FIGURE 5
MCP with no Transmission Constraints



As shown in Table 23, the impact of removing the transmission capacity constraint is a decrease in total dispatch costs of only $10 million over the

22 year period. The impact on market clearing prices, however, results in an almost $72 million decrease in customer bills. Partial relief of the transmission constraint, modeled by assigning 35 MW of transmission capacity to MLP, has a similar impact on costs and revenues, but to a smaller degree. Cost savings are only $1 million, and utility revenues (consumer costs) decrease by $5.8 million.

TABLE 23
No Transmission Capacity Constraint

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	4,561,801	12.9%	45.9	12.6%	38.5	9.3%	-7.4
CEA	-898,542	-1.2%	-5.8	-0.7%	-32.4	-3.5%	-26.5
GVEA	-3,663,260	-128.8%	-50.6	-45.2%	-77.7	-606.4%	-27.1
Total	0		-10.5		-71.6		-61.1

TABLE 24
MLP Receives 35 MW of Transmission Capacity

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	2,868,609	8.5%	35.3	9.9%	53.9	12.5%	18.6
CEA	-2,870,399	-3.9%	-36.5	-4.6%	-48.3	-5.3%	-11.8
GVEA	1,790	0.0%	0.2	0.1%	0.2	0.2%	0.0
Total	0		-1.0		5.8		6.8

Load Growth

The load growth scenarios illustrate the impact that varying load growth forecasts have on utility costs and revenues. The market clearing prices for several load growth forecasts are illustrated in Figure 6. Table 25 below summarizes the impact of increasing the load forecast by 2% each year.

TABLE 25
Load Growth Forecast Increased by 2%

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	7,542,987	19.7%	79.8	20.0%	118.5	23.9%	38.7
CEA	16,710,445	18.1%	188.9	18.4%	290.6	23.2%	101.7
GVEA	7,542,842	53.7%	97.1	37.4%	120.2	57.0%	23.1
Total	31,796,274		365.7		529.3		163.5

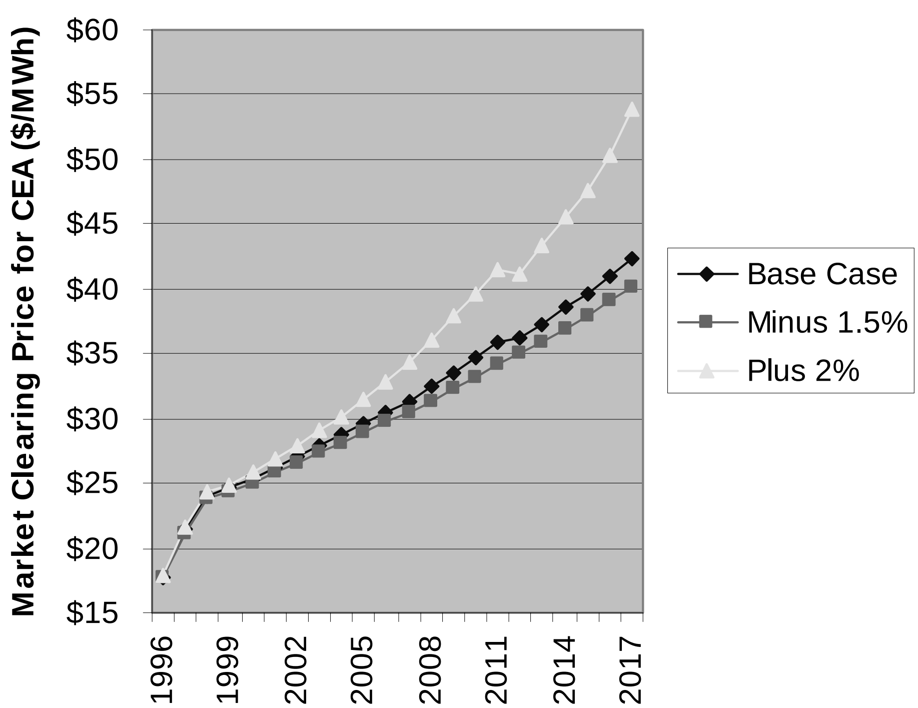
Note that under this high growth scenario, the increase in generator revenues is far greater than the increase in utility costs. This occurs because market clearing prices increase due to more expensive units being dispatched increases revenues for all generators.

TABLE 26
Load Growth Forecast Decreased by 1.5%

	Increase in Sales between 1996 and 2017		Increase in Costs ($M)		Increase in Generator Revenue		Increase in Profit
	MWh	%	$Millions	%	$ Millions	%	$ Millions
MLP	-4,448,137	-16.9%	-44.1	-16.0%	-66.8	-21.6%	-22.7
CEA	-11,416,719	-17.8%	-121.9	-17.1%	-146.4	-17.9%	-24.5
GVEA	-2,751,412	-73.3%	-33.7	-26.2%	-44.0	-94.4%	-10.2
Total	-18,616,268		-199.7		-257.1		-57.5

Table 26 reports the impacts of reducing the load growth forecast by 1.5% each year. Similar to the high growth scenario, the change in generator revenues outpaces the decrease in utility costs.

FIGURE 6
Annual MCP for CEA under Alternate Growth Forecasts



Plant Capacity Adequacy

This report analysis did not independently analyze the need for capacity under the individual or joint dispatch case. The base case used the GVEA generation plant scheduled additions from the BVI study.

Stranded Costs

Stranded costs are the reduction in generator revenues due to the introduction of competition into the Railbelt. E3 has estimated stranded costs as the difference between 1) the net generation revenues the utility would have received under rate of return regulation and 2) the net generation revenue the utility would receive under competition.

[1] Stranded Cost = NPV (Net Generation Revenue[R,y]) – NPV (Net Generation Revenue[C,y])

where *R is the regulated environment, and C is the competitive environment, y is the year*

Net generator revenue is the total revenue from customers for generation services less 1) variable fuel costs, 2) variable O&M costs , and 3) fixed O&M costs.

[2] Net Generation Revenue[x,y] = Revenue[x,y] – Cost[x,y]

where *Cost[x,y] is the sum of variable fuel, variable O&M, and fixed O&M costs,*
Revenue[x,y] is the generation revenue collected from customers
x is either R or C

Combining Equations 1 and 2 and rearranging terms results in the following simplified stranded cost formula:

[3] Stranded Cost = - NPV(Revenue[C,y] – Revenue[R,y]) + NPV(Cost[C,y] – Cost[R,y])

where NPV(Cost[C,y] – Cost[R,y]) is the increase in costs shown in Table 4 through Table 26 above.

The potential stranded costs are calculated for the period from 1996 to 2017. The 1996 starting point was chosen for consistency with the BVI study. The estimates of stranded costs vary between $34 million and almost $500 million. These estimates are provided as an indication of the potential magnitude of these costs. As is discusses in the following section, the generation revenue requirement (Revenue[R,y]) has been extrapolated from a single year of data, and merits further work and input from the respective utilities.

TABLE 27
Stranded Costs by Scenario ($Millions)

Scenario		Increase in NPV Revenue	Increase in NPV Costs	Stranded Cost
Table 5	Base Case	($414)	($41)	$373
Table 6	Fuel Cost Equalization	($463)	($83)	$380
Table 7	Fuel Cost Equalization with Increases MLP Transmission	($459)	($88)	$371
Table 8	CEA Bids 20% over Marginal Cost, Contract Transmission Capacity	($242)	($35)	$207
Table 9	CEA Bids 20% Over Marginal Costs, 35 MW Transmission Capacity for MLP	($238)	($36)	$202
Table 10	CEA Bids 20% Over Marginal Costs, 70 MW Transmission Capacity for MLP	($295)	($39)	$257
Table 11	CEA Fossil Fleet bids 40% over Marginal Cost	($70)	($31)	$39
Table 12	CEA Fleet bids 40% above Marginal Cost, and MLP T Capacity 35MW	($68)	($32)	$36
Table 13	CEA Fleet bids 40% above Marginal Cost, and MLP owns 70MW T Capacity	($65)	($31)	$34
Table 14	Withholding of Beluga 3 by CEA	($387)	($40)	$347
Table 15	Withholding of Beluga 7-8 by CEA	($369)	$8	$377
Table 16	Withholding of Beluga 6-8	($369)	$12	$381
Table 17	No New Generation Capacity Added	($401)	($83)	$317
Table 23	No Transmission Capacity Constraint	($485)	($51)	$434
Table 24	MLP Receives 35 MW of Transmission Capacity	($408)	($42)	$366
Table 25	Load Growth Forecast Increased by 2%	$115	$325	$209
Table 26	Load Growth Forecast Decreased by 1.5%	($671)	($241)	$430
Table 18	New Entrant in the Status Quo Case	($501)	($195)	$306
Table 19	New Entrant in the Pooled Dispatch Base Case	($631)	($158)	$473
Table 20	New Entrant when the CEA Fleet Bids 40% above Dispatch Cost	($648)	($161)	$488
Table 21	Impact of CEA Bidding 40% above Dispatch Cost (with IPP in 2002)	($304)	($158)	$146
Table 22	Impact of IPP on CEA's Withdrawal of Beluga Unit 3	($609)	($158)	$451

Generation Revenue

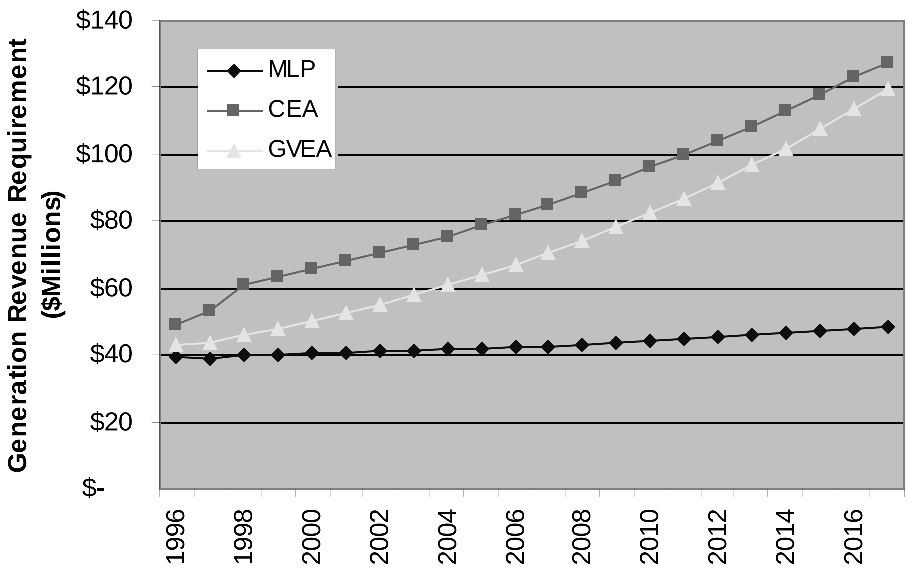
Generation revenue requirements under regulation are estimated for each utility. The generation revenue requirement excludes transmission and distribution, so those costs are separated out from the total utility revenues. The separation is based on 1997 FERC Form 1 information filed with FERC and the Alaska PUC. The 1997 revenues are extrapolated out to 2017 using the following simple assumptions:

1. Generation plant depreciation remains constant and reduces the annual generation return on investment
2. Generation operating costs increase in proportion to load growth
3. Generation operating costs increase in proportion to fuel cost increases

4. All other generation costs remain constant

These assumptions result in generation revenues that are projected to increase annually, as shown in Figure 7.

FIGURE 7
Generation Revenue Requirements



These generation revenue requirements are based on the assumption that the utilities remain under cost of service regulation. The streams also do not reflect the impact of GVEA adding generation capacity. These generation revenue requirements provide a reasonable estimate of stranded cost magnitudes, but are not intended to be the "final word" on the matter.

The net present values of these streams (1996 to 2017) are shown below for each of the three utilities.

TABLE 28
NPV Generation Revenues Under Regulation

Company	NPV Revenue under Regulation ($Millions)
MLP	$427
CEA	$775
GVEA	$642
Total	$1,845

Effect on Power Cost Equalization

Sufficient data was not available to single out the stranded investment exposure of the Four Dam Pool. However, it is important to note that the Blue Ribbon Panel study on the Power Cost Equalization program recommended that the funding level for PCE coming from the annual debt service from the Pool be increased from its current level of 40 percent to 60 percent in the future – from $4.4 million to $6.0 million. The implication is that if the value of the Pool is significantly reduced as a result of restructuring, and the debt service paid to the State is correspondingly reduced, the revenues to the PCE could be negatively impacted.

Conclusions

- The efficiency gains reported in the BVI study from coordinated dispatch are supported by the results of this analysis.
- Due to existing transmission capabilities, there will be regionally market price differences between the major railbelt utilities.
- Equalizing the differences in fuel costs between the railbelt utilities can result in over $40 million in cost savings, but this savings is met by decreases in utility revenue, resulting in a net loss to the utilities. Expanding MLPs access to transmission capacity practically removes the net loss to the utilities from fuel price equalization.
- Certain generation units may have the ability to exercise market power through strategic bidding behavior, including bidding above marginal cost and withholding generation from the market.
- Canceling GVEA's planned generation additions results in an increase in long-term market prices, and results in higher overall profits for the utilities.
- The introduction of new generation into the Railbelt can reduce utility gains from strategic behavior, but additional analysis would be required to determine the amount and location of that generation to fully mitigate market power issues.
- Removing transmission constraints results in the elimination of zonal market price differences. However, the reduction in transmission constraints must be large for the price differential to be completely eroded.
- Higher load growth forecasts increase utility revenues to a greater degree than utility costs, resulting in increased profits for the utilities. Likewise, lower load growth forecasts decrease utility revenues to a greater extent than utility costs, resulting in a decrease in utility profit.
- Competition in the Railbelt would likely result in stranded costs. The magnitude of the stranded cost problem could be in the range of $34 million to almost $500 million.