Reliability

Emerging Competition in the Electric Industry

Docket No. NOI-95-1

A Staff Analysis

March 1999

IOWA UTILITIES BOARD
IOWA DEPARTMENT OF COMMERCE

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LIST OF ACRONYMS

AARP - American Association of Retired Persons

ALT - Alliant Utilities (IES & IPC)

ANSI - American National Standards Institute

CESP - Competitive Electric Service Provider

CIAO - Critical Infrastructure Assurance Office

DNR - Department of Natural Resources

EPRI - Electric Power Research Institute

FERC - Federal Energy Regulatory Commission

FPA - Federal Power Act

G&T - Generation and Transmission Cooperative

IAC - Iowa Administrative Code

IAEC - Iowa Association of Electric Cooperatives

I&M - Inspection and Maintenance

IAMU - Iowa Association of Municipal Utilities

IESC - Iowa Electrical Safety Code

IOU - Investor-Owned Utility

ISO - Independent System Operator

IES - IES Utilities Inc.

IPC - Interstate Power Company

IUA - Iowa Utility Association

LOLP - Loss of Load Probability

MAIN - Mid-American Interconnected Network

MEC - MidAmerican Energy Company

MAPP - Mid-Continent Area Power Pool

NERC - North American Electric Reliability Council

NAERO - North American Electric Reliability Organization

NESC - National Electrical Safety Code

NIPCO - Northwest Iowa Power Cooperative

OCA - Office of Consumer Advocate, Iowa Department of Justice

OMS - Outage Management System

OSHA - Occupational Safety and Health Administration

PBR - Performance-Based Regulation

PUC - Public Utilities Commission

REC - Rural Electric Cooperative

GLOSSARY OF TERMS

Aggregator – A person that combines End-Use Consumers into a group and arranges for the acquisition of Competitive Electric Services without taking title to those services.

Alternative Energy Producer (AEP) – An AEP is an electric facility that derives 75 percent or more of its energy input from solar energy, wind, hydro, waste management, resource recovery, refuse-derived fuel, agricultural crops or residues, or wood.

Ancillary Services – Services that must be purchased in conjunction with Transmission Service to maintain reliability of the Grid. These services include, at a minimum:

a. Scheduling, system control, and dispatch
b. Reactive power supply and voltage control from generation sources
c. Regulation and frequency response
d. Energy imbalance
e. Operating reserve – spinning
f. Operating reserve - supplemental

Broker – An entity that acts as an agent or intermediary in the sale and purchase of electricity but does not take title to electricity. A broker would be considered an aggregator under the definition used in this report and be subject to aggregator certification requirements.

Bulk Power Market – Power transactions among utilities, or from a Wholesale Power Supply Provider to a Delivery Service Provider, power marketer or broker, or other wholesale entity.

Bulk Power System – The electrical system consisting of generation and the interconnected transmission system that moves bulk power to distribution or delivery systems.

Bulk Power System Reliability – There are two aspects of bulk power system reliability: adequacy and security. Adequacy is the ability of the electric system to supply the demand and energy requirements of the End-Use Consumers at all times, taking into account all outages of system elements. Security is the ability of the system to withstand sudden disturbances.

Competitive Electric Services – Competitive Power Supply Services and all other electric energy services sold at retail in Iowa on a competitive basis.

Competitive Electric Service Provider – A person that provides Competitive Electric Services in Iowa.

Competitive Power Supply Services – Electric demand/capacity, energy and Ancillary Services sold at retail in Iowa.

Control Area – A Control Area is an electrical system bounded by interconnection (tie line) metering and telemetry. It controls its generation directly to maintain its interchange schedule with other control areas and contributes to frequency regulation of the interconnection.

Control Area Operator – The person that performs the scheduling, dispatching, system support, balancing and financial settlement functions related to the effective operation of the Control Area.

Delivery Service – The transportation of electricity from one point on a Delivery Service Provider's grid to another point on the grid.

Delivery Service Provider – A person that provides delivery service in Iowa.

Dispatchability – The ability to “dispatch” or generate electricity from a plant on an as-needed basis.

Distribution Service – Electricity service provided over low-voltage lines to retail consumers.

Economic Dispatch – Distribution of total generation requirements among alternative generator sources for optimum system economy taking into account both incremental generating costs and incremental transmission costs.

End-Use Consumer – A person that consumes or uses Delivery Service at retail or competitive electric services in Iowa.

FERC – The Federal Energy Regulatory Commission (FERC) regulates wholesale power and transmission services.

Firm Power – Power which is intended to have assured availability to the End – Use Consumer to meet all or any agreed-upon portion of his load requirements.

Generation and Transmission Electric Cooperative (G&T) – A non-profit corporation, owned and controlled by Rural Electric Cooperatives (RECs) providing distribution service, that supplies wholesale power and transmission services to its members.

Independent System Operator (ISO) – An ISO is an independent entity that polices, monitors, and has overall decision-making authority over electric transmission operations. The purpose of an ISO is to provide reasonable and equitable access to the transmission system, to operate the transmission system safely and reliably, and to prevent the transmission system from becoming a factor in enhancing market power in an electricity market.

Load Factor – The average load of a customer, a group of customers, or the system divided by the maximum load. For example, assuming 48 kWh of usage for the day, the average load is 48/24 or 2 KW. If the maximum load is 4 KW, the load factor is 2/4 = 50 percent.

Marketer – An entity that as an intermediary purchases electricity and takes title to electricity for sale to retail customers. A marketer would be considered a supplier under the definition used in this report and be subject to supplier certification requirements.

Redlining – The possible practice of a supplier choosing not to serve a customer or groups of customers because of poor location and/or low profit margins.

Spinning Reserve – The reserve generating capacity connected to the grid and ready to take load and can respond immediately to correct for generation/load imbalances due to generation and/or transmission outages. Spinning reserve is fully available in ten minutes.

Supplemental Reserve – Generators and curtailable load that can be used to correct for generation/load imbalances due to generation and/or transmission outages within ten minutes. Unlike spinning reserve, supplemental reserve is not required to respond immediately.

Transmission Congestion Contracts – A point-to-point transmission contract that provides payments to holders of transmission rights in the event of constrained transmission in the grid.

Transmission Congestion Rental – The price paid under transmission congestion contracts to compensate transmission holders for transmission constraints.

Transmission Grid (System) – An interconnected group of electric transmission lines and associated equipment for the movement or transfer of electric energy in bulk between points of supply and points for delivery.

Transmission-Line Capacity – The maximum continuous rating of a transmission line. The rating may be limited by thermal considerations, capacity of associated equipment, voltage regulation, system stability, or other factors.

Transmission-Line Congestion – Use of the transmission grid which, in the short run, constrains long-distance movement of power and, thereby, imposes a higher marginal cost in certain locations due to transmission-line constraints.

Transmission-Line Constraint – Limits on the transmission line because of physical or system requirements.

Transmission-Line Loss – The power lost in transmission between one point and another. It is measured as the difference between the net power passing the first point and the net power passing the second.

Unbundling – Disaggregating electric utility service into its basic components of generation, transmission, and distribution and offering each discrete component separately for sale with separate rates for each component.

Wheeling – An electric operation wherein transmission facilities of one system are utilized to transmit power of another system.

EXECUTIVE SUMMARY

Introduction

The Iowa Utilities Board (Board) Action Plan to Develop a Competitive Model for the Electric Industry in Iowa (Action Plan)[1] stated that the Board will establish a Board staff team to:

- Assess the need for new service/safety/quality/reliability standards; and
- Draft minimum service/safety/quality/reliability standards if deemed necessary.

This Board staff[2] report explores the reliability, safety, and quality of service standards of an operational electric system and addresses the changes needed as the industry restructures and Iowa considers retail competition. However, nothing in this report actually argues that retail competition is or is not in the best interest of Iowa ratepayers.

This report addresses four main categories relating to the reliable operation of an electric system: (1) the bulk power system, (2) certification of Competitive Electric Service Providers (CESPs) and aggregators, (3) reliability standards, and (4) customer service quality and monitoring. Most of these four categories also have further breakdowns. For each of these issues, staff summarizes current Iowa statute and rules, provides staff analysis, and presents some policy considerations.[3]

The draft version of this report was distributed to the Advisory Group members for comment on September 15, 1998. Appendix D summarizes the comments received concerning that draft version.

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[1] Iowa Utilities Board, "Order Adopting Action Plan," Inquiry Into Emerging Competition in the Electric Industry, September 10, 1997.

[2] The Board staff Reliability Team included: Parveen Baig, Chancy Bittner (Team Leader), Dan Fritz, Tara Ganpat-Puffett, Dennis Hockmuth, Guy Johnson, Dale Pierantoni, and Don Stursma.

[3] Appendix B also contains a brief summary of what some other states are doing in these areas.

Bulk Power Systems

Bulk power system reliability is important and is defined as the ability of the system to provide adequate power to all customers at all times. National policies on reliability are currently being revised; therefore, it seems reasonable to consider in any Iowa restructuring law provisions that require compliance with all regional reliability standards emerging from this national debate. Reliability is a regional concern requiring both federal and state solutions.

Certification of CESPs/Aggregators

In developing restructuring legislation, policy makers should consider full certification of all CESPs. (See page 29 for certification requirements.) This could include Rural Electric Cooperatives (RECs) or municipal utilities that elect to serve customers outside their service territories. Aggregators might also be certified.

Reliability Standards

Monitoring Reliability

Assessing and assuring reliability of the distribution and transmission system in Iowa should be addressed in any electric restructuring statute. This could include the authority to impose significant penalties for unacceptable degradation of reliability. Rules requiring better recording and reporting standards should also be considered.

In addition, fair and open access to the transmission and distribution system and nondiscriminatory reliability should be objectives guiding any legislation introducing competition in electric supply.

Power Quality

System reliability also encompasses the issue of power quality which is defined as the delivery to customers of electricity in the form of a perfect 60-Hz sine wave at standard voltage levels. Current Iowa rules provide for acceptable levels of voltage delivery to customers. Any restructuring legislation should take into consideration similar power quality requirements for the new CESPs in the market.

Inspection and Maintenance

Restructuring of the electric industry may produce electric line owners and/or operators who are not subject to safety regulation under existing Iowa statute. Legislation may be needed to ensure that all entities who own or operate electric transmission and/or distribution facilities will be subject to the Iowa Electrical Safety Code (IESC) and IOWA ADMIN. CODE (IAC) 199-25, which provide standards for inspection and maintenance.

Safety

The existing safety rules and programs are adequate but may need periodic updating as national standards evolve. Consideration should be given to retaining current authority to review and assure safety compliance. In addition, restructuring legislation may include a requirement that all entities who own or operate transmission and/or distribution facilities must comply with the safety standards.

Customer Service Quality and Monitoring

Minimum Customer Service Standards

There are currently no rules on standards for installation or repair of electric service, or missed commitments. Nor are there standards regarding customer access and utility response. Policy makers may want to consider service quality rules similar to those adopted by the Board for telecommunications.

Dispute Resolution

IOWA CODE § 476.3 gives the Board the authority to investigate complaints filed against a utility. If the industry is restructured, the Board's authority may need to be expanded to meet the likely increase in number and complexity of complaints and disputes. In a competitive environment, disputes will extend beyond the current utilities operating in Iowa. Consideration should be given to extending the Board's jurisdiction over all CESPs. Jurisdiction should include, at a minimum, service, safety, and reliability related issues.

Policy makers might also consider imposing fines and/or sanctions upon CESPs or aggregators where violations of Board rules are discovered. Legislation should also address the right and/or responsibility to revoke or suspend the CESP or aggregator's certificate.

Customer Privacy Rights

Policy makers may want to consider granting the Board authority to determine what customer information should be held confidential and what information should be considered public. Currently, most states are requiring customer consent before releasing information.

The Federal Trade Commission's Telemarketing and Consumer Abuse Protection Act allows customers who do not wish to be bothered by telemarketers to file a request not to be called. The distribution companies could be required to maintain this list and keep it current.

The Universal Service Team is recommending that a working group be established to address additional customer protection issues. Customer privacy issues could be included in this working group's activities.

Appendices

Appendix A includes definitions of outage indices. Appendix B provides, by issue, brief summaries of staff's research of the restructuring activity in other jurisdictions. Appendix C summarizes the responses to two separate sets of questions used in investigating some issues early in the inquiry. Appendix D includes a brief summary of comments made to the draft version of this report.[4]

[4] The comments to the September 1998 Draft Reliability Report are not to be confused with written comments tendered in response to data queries sent out in March 1998. Appendix C summarizes those earlier comments which were already reflected in the draft of this report. Appendix D sumarizes respondent's comments to the draft of this report.

REPORT OF THE RELIABILITY TEAM

INTRODUCTION

The first principle adopted by the Board in its May 14, 1996, order is: "Safe and reliable electric service must be maintained."[5] Reliable electric energy is crucial to the safety, health, and welfare of Iowa citizens. The service and product is a crucial part of this economy's infrastructure and our citizens' life-style. However, its reliability is by no means easily assured, especially as the industry undergoes change.

Certain characteristics[6] of an electric system have significant implications for ensuring reliability in a restructured environment. That is to say, much about the interconnected electric system has a public good aspect and argues for cooperation rather than competition. To make these two mechanisms (cooperation and competition) work seamlessly together will require a lot of effort and careful, on-going guidance by governmental and other decision-makers.

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[5] Iowa Utilities Board, " Order Adopting Principles," Docket No. NOI-95-1, p. 2

[6] A typical list of the more important characteristics of our electric system follows:

- electricity must usually be generated at the same time that it is consumed since storing electricity 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; and
- a reliable supply of electricity is vital to certain essential human needs.

Source: Draft Working Model for Restructuring the Electric Utility Industry in Virginia, "Chapter 2: Reliability," November 1997, found at http://dit1.state.va.us/scc/news/streprt2.htm. July 24, 1998.

What is obvious is an almost universal agreement that reliability is a major and primary objective. Existing and proposed restructuring statutes around the nation all appear to articulate the objective that reliability must not decline with a move toward competition and there are some that demand improved reliability. Most charge the public utility commissions (PUCs) with specific duties in this regard. Some statutes also give specific guidance on how the PUC should perform these duties. This report's concern is: How does Iowa assure reliability at or better than traditional levels?

One germane dimension of our interconnected electric system is the diversity of stakeholders--vertically integrated investor-owned utilities (IOUs), municipal utilities, distribution RECs, generation and transmission cooperatives (G&Ts), and potential new competitive players. Up to now, each company has had its own exclusive service territory and from that secure position has reached out cooperatively to work with other entities to assure the overall reliability of the interconnected system and to share reserves. Introducing competition has the potential for changing all that, forcing a review of the public purpose and regulation of each of these entities. Some degree of this review is particularly important if Iowa is to assure reliability at or better than traditional levels. It is important to keep in mind that reliability depends upon generation plants to produce power and transmission and distribution lines to deliver power.

Interconnections between utilities' transmission systems were designed and built mainly to share generation reserves in emergencies. The transmission system was not built for massive transfer of power between utilities and/or regions. However, that is exactly what will be demanded by a move to a more competitive industry, with serious reliability implications throughout the region. For example, according to a recent Public Power Weekly, the Midwest came perilously close in the summer of 1997--within a few megawatts and a few minutes--to a cascading blackout. "The culprit wasn't untrimmed trees or a hot summer peak, but . . .the transfer of large amounts (historical levels) of power."[7] Whether Iowa chooses to allow retail competition or not, the evolving restructuring in the Midwest will have implications for how Iowa assures reliability of its electrical system. That means policy makers need to actively address evolving reliability concerns even if Iowa maintains traditional rate regulation.

To reiterate, this report is organized into four main categories: (1) the bulk power market, (2) certification of Competitive Electric Service Providers and aggregators, (3) reliability standards, and (4) customer service quality and monitoring. The latter two categories also have specific sub-categories. For each of these issues, staff summarizes current Iowa statute and rules, provides staff analysis, and presents some policy considerations.

1. BULK POWER SYSTEMS

"Bulk power system" refers to the flow of large amounts of electric power at high voltage as distinct from the local delivery to homes and businesses at a lower voltage. A bulk power system consists of generators, transmission lines, and control centers.

The first major component of the bulk power system is generation. Generating units are the sources of electricity. The effect of generation on system reliability depends on the number and size of generators and their operating characteristics. The generation technology mix also, generally, depends upon non-generation factors such as the availability of fuels, system load shapes, transmission interconnections, and excess generation of other interconnected systems.

[7] Public Power Weekly, "A Few More Minutes, a Few More Megawatts--and Midwest goes Dark?" May 25, 1998, p. 1.

The second major component of the bulk power system is transmission. The transmission system provides a path for electricity from generation sources to major distribution points. Sufficient transmission interconnections that provide alternative routes for flow of electricity are essential to operate the transmission system reliably.

An electrical system is fundamentally different from other large infrastructure systems due to its unique needs. First, the system needs to continuously and almost instantaneously balance generation and load consistent with generation and transmission constraints. Second, electricity cannot be stored, it must be produced at the moment it is needed. Third, electricity cannot be directed down a special path, it flows through any interconnected path of least resistance. A high amount of coordination among all interconnected electric systems is needed to ensure that power flows remain in balance to meet customer needs. Control area operators provide this coordination.

Current Statute and Rules

IOWA CODE does not specifically require electricity suppliers to maintain specific amounts of generating capacity to maintain a reliable electric system. IOWA CODE § 476.53, however, disallows a return on common equity on that portion of a public utility's electric generation capacity which is determined to be excess generating capacity. The IOWA CODE further defines excess generating capacity as the portion of generating capacity that exceeds the amount reasonably necessary to provide adequate and reliable service as determined by the Board. IAC 199-20.1 currently defines *operating reserve* as generating capacity required to ensure reliability of generation resources. Furthermore, IAC 199-20.5(3) requires that a utility's generating capacity, supplemented by the electric power regularly available from other sources, must be sufficiently large to meet all normal demands for service and provide a reasonable reserve for emergencies. In appraising adequacy of supply, utilities are divided into two classes--viz., those having high capacity transmission interconnections with other electrical utilities and those which are completely dependent upon the firm generating capacity of the utility's own generating facilities. In the case of interconnected utilities, adequate supply must take into account any widespread service interruptions and any capacity shortages along with the consideration of the supply regularly available from other sources, the normal demands, and the required reserve for emergencies. In the case of noninterconnected utilities, adequate supply includes the maximum total coincident customer demand that could be satisfied without the use of the single element of plant equipment, the normal demands for service, and reasonable reserve for emergencies.

IAC 199-24.11(2)“a”(3) provides, in issuing a generation certificate, the facility siting criteria shall include economic advantages and disadvantages, and risks to the public of the replacement of or the placing on reserve of existing generation units.

IOWA CODE § 476.2(4) gives the Board authority to inquire into the management of the business of all public utilities, the manner in which the business is conducted, and to obtain information necessary to perform its duties. IOWA CODE § 476.6(16), entitled “Annual electric energy supply and cost review,” requires the Board to conduct an annual review of the reasonableness and prudence of a rate-regulated public utility’s procurement of and contracting for generation fuel. IOWA CODE § 476.6(20), entitled “Filing of forecasts,” gives the Board authority to periodically require each rate-regulated utility to file a forecast of electric generating needs and requires the Board to evaluate the forecast. The forecast is to include, but is not limited to, a forecast of the requirements of its customers, its anticipated sources of supply, and its anticipated means of addressing the forecasted generating needs. Additionally, IAC 199-35.9 requires rate-regulated utilities’ energy efficiency plans include load forecasts (including reserve margins for summer and winter peak demand and for annual energy requirements), class load data, existing capacity and firm commitments, capacity purchases and shortfalls, capacity outside the utility's system, future supply options and costs, and avoided capacity and energy costs.

Staff Analysis

The following analysis first provides background information relating to bulk power system reliability by discussing (1) how reliability of an electric system is defined by the North American Reliability Council (NERC), (2) how these NERC defined reliability criteria are enforced by the regional reliability council serving Iowa (the Mid-Continent Area Power Pool (MAPP)), and (3) how independent system operators (ISOs) affect reliability. It also summarizes reliability discussion in Clinton Administration's "Comprehensive Electricity Competition Plan," the future role of NERC as a result of this plan, and FERC's views regarding reliability. The last section of this analysis draws conclusions based on these observations and reviews current Iowa statute and rules relating to bulk power reliability.

<u>NERC Definition of Reliability</u>

Since 1968, NERC has been the national organization that has the primary responsibility for reliability of the bulk power system. NERC defines reliability as "the degree to which the performance of the elements of [an electrical] system results in power being delivered to consumers within accepted standards and in the amount desired." NERC's definition of reliability encompasses two aspects: adequacy and security. Adequacy is defined as "the ability of the system to supply the aggregate electric power and energy requirements of the consumers at all times." Security is defined as "the ability of the system to withstand sudden disturbances." In simple words, adequacy relates to long-term planning which requires sufficient generation and transmission resources to meet projected load plus reserves for contingencies. Security implies that the system will continue to operate even after outages or other equipment failures occur. In addition to adequacy and security, power quality is an important component of reliable service. Issues relating to power quality are discussed in a later section of this report.

MAPP Reserve Capacity Obligations

MAPP, the reliability council serving Iowa, has provided benefits to electric consumers in the region, in terms of both enhanced system reliability and substantial economic savings. MAPP enforces reliability by requiring its member utilities to do reserve planning. Each utility's generating capacity, adjusted for power purchases and sales, for each month, must be more than its peak demand plus a 15 percent reserve margin. Each utility is also required to provide sufficient transmission capacity to serve its load without relying on or without imposing an undue burden on other systems. Transmission design and construction are required to consider transfers of capacity and energy between and within systems to ensure that system reliability will not be degraded. All utility transactions require adequate transfer capabilities. Security of the MAPP system is intended to be maintained such that the system can be operated at all load levels to meet certain defined unscheduled contingencies without instability, cascading, voltage instability, undamped oscillations, violating transient voltage limits, or service interruptions to a major portion of the MAPP system. Stability of the MAPP system is maintained without interruption of load during and after severe disturbances to the system. To minimize the effects of the sudden loss of a generating unit or the sudden dropping of a large load, all utilities are required to maintain operating reserves. The operating reserve for the MAPP system is the amount of generation sufficient to cover the loss of capacity equal to 150 percent of the largest generating unit in service. Operating reserves are allocated to each utility based on its peak load. Operating reserve includes spinning reserve and supplemental (non-spinning) reserve. MAPP defines spinning reserve as the amount of unloaded generating capacity that is interconnected and synchronized to the system that will respond immediately to the loss of MAPP generation. Non-spinning reserve is defined as the unloaded generating capacity, not qualified as spinning reserve, or other resources that can be made available in ten minutes or less. Because there is diversity in the timing of MAPP utilities' system peaks, the interconnections between utilities allows them to meet required reserves with lower reserve levels than if each utility had to meet this requirement individually. MAPP penalizes its members when they fail to meet reserve obligations. Under a competitive environment, entities with the responsibility for serving loads could be held individually responsible for meeting reserve criteria. Failure to secure generation to meet load would be handled by interruption or penalties. Currently the infrastructure to identify, meter, and enforce failures to provide reserves through interruptions does not exist.

Independent System Operator (ISO)

The Board's Action Plan reached the following conclusions regarding the operation of the state's transmission system:

- One system operator (perhaps in the form of an independent system operator) should coordinate the use of the state's transmission system, whether the system is used for retail or wholesale transactions.
- The transmission system operator's first responsibility must be to operate the system safely and reliably.
- A single transmission system operator will only be effective in facilitating a retail market in generation if it is truly independent of market participants.

On July 27, 1998, the Board adopted ISO principles. The principles state the purpose of an ISO is to prevent the transmission system from exercising market power in an electricity market, to provide reasonable and equitable access to the transmission system, and to operate the transmission system safely and reliably. These principles would apply to all transmission operators in Iowa. Alliant Utilities (ALT) and MidAmerican Energy Company (MEC) own most of the transmission lines in Iowa and have interconnections with utilities in neighboring states. Both utilities are considering joining an ISO. ALT has announced it plans to join the Midwest ISO[8], which was filed with FERC in January 1998. Both utilities were also involved in discussions to establish an ISO at MAPP.[9] After more than a year of discussions, the MAPP ISO proposal was rejected by its members on November 4, 1998.

Clinton Administration's Comprehensive Electricity Competition Plan

On March 25, 1998, the Clinton Administration released its "Comprehensive Electricity Competition Plan."[10] Regarding reliability, the plan proposes that the Federal Power Act (FPA) be amended to require FERC to approve the formation of and oversee a private self-regulatory organization that prescribes and enforces "mandatory" reliability standards. Federal oversight is required to provide legal support for a private self-regulatory structure. FERC would review all reliability standards developed by the self-regulating organization to ensure that they are in the public interest and reflect an appropriate level of reliability.

North American Electric Reliability Organization

NERC has reorganized by creating a new organization called the North American Electric Reliability Organization (NAERO) with an independent Board of directors. NAERO has the authority to enforce reliability standards and require mandatory participation by system operator organizations, including control areas, ISOs, and security coordinators.[11] NAERO will maintain short-term reliability (security) and assess and encourage long-term adequacy and will be the only organization overseeing the reliability of the interconnected electric

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[8] The Midwest ISO proposal covers portions of thirteen states from Maryland to Iowa and from Michigan to Kentucky

[9] MAPP covers portions of eight states from Montana to Illinois and Canadian provinces of Saskatchewan and Manitoba.

[10] The Critical Infrastructure Assurance Office (CIAO) was also recently created by the President to protect the nation's critical infrastructures from physical and computer threats. Critical infrastructures are defined as those systems whose incapacity or destruction would have a debilitating impact on the defense or economic security of the nation. Critical infrastructures include telecommunications, electrical power systems, gas and oil, banking and finance, transportation, water supply systems, government services, and emergency services.

[11] See www.nerc.com.

grids. NERC by-laws will be amended to allow independent Board members. The new Board is expected to be elected in January 1999. NAERO will have three standing committees--security, adequacy, and market interface. An interim market interface committee will be formed to determine impacts of reliability standards and policies on commercial markets. The regional councils will continue to fund NERC until an end-state mechanism is achieved.

FERC Reliability Rules

Historically, reliability councils have maintained the security of the grid through voluntary standards. FERC is looking at processes that may be used to move forward on reliability issues. On February 20, 1998, FERC held a round-table conference to discuss the preferred process for FERC approval of new reliability rules for use by jurisdictional transmission providers. FERC has received a number of comments on this issue.[12]

On October 1, 1998, the Secretary of Energy delegated authority to FERC to establish boundaries for ISOs or other appropriate transmission entities because providing this authority could aid in the orderly formation of properly-sized transmission institutions and in addressing reliability-related issues, thereby increasing the reliability of the transmission system. The Department of Energy has concluded that FERC is the most appropriate agency to exercise authority under section 202(a) of the Federal Power Act.

Conclusions

NAERO (the reorganized NERC) will be the private self-regulating organization envisioned in the Clinton Administration's plan. This organization will prescribe and enforce mandatory reliability standards which will be approved by FERC. However, several federal bills are also examining reliability issues. The bills range from requiring utilities to be members of self-regulating reliability councils

[12] FERC Docket No. PL98-3-000, "Process for Assuring Nondiscriminatory Transmission Services as New Reliability Rules are Developed for Using the Transmission System," Reliability Roundtable Before the Commissioners.

with FERC oversight to bills that give states the authority to prescribe rules to ensure service reliability.[13]

Generation Diversity

The effects of system load variations on generation technology and fuel choices are less clear today than they have been in the past. Traditionally, fossil-fuel base load units have burned coal while intermediate and peaking units have relied more on gas and oil. Now, base load units may be fueled by gas and combined cycle units may compare favorably with coal-fired units, especially if gas is relatively cheap.

A traditional "diversified generation portfolio" smoothes out any variations in load profiles, fuel prices (as long as these fuel prices are not directly correlated), and available capacity of transmission interconnections. Power pooling decreases the demand for peaking units and increases the loading of existing units in the long term. The portfolio approach also reduces the potential for loss of load and sales. Need for reserve margins increases with the size of unit and decreases with the number of units. The economies of scale greatly favor bigger units. Planning diversified generation is not new in electric industry; most utilities made efforts in the 1960s and 1970s to decrease oil and natural gas generation and to increase the coal and nuclear generation. But there is a recent trend in the industry to install peaking capacity because of its almost standardized design and low planning and construction time. The average age of existing units is increasing and assuming that unit condition is related to its age, this could mean reduced unit capacity factors and availability. In a competitive environment, it may not be possible to ensure diversity of generation. It is difficult, if not impossible, to track the source of supply for every CESP.

Policy Considerations

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[13] Electric Restructuring Legislative Reference, NARUC website, restructuring matrix, July 20, 1998.

In developing any restructuring legislation, policy makers may want to consider adding new requirements for the Competitive Electric Service Providers serving Iowans to fully comply with the operating policies, criteria, requirements, and standards of NAERO and the appropriate regional reliability councils or their successors.

2. CERTIFICATION OF CESPS/ AGGREGATORS

Current Statute and Rules

Current Iowa law does not require providers of electric service to be certified to sell power. IOWA CODE § 476A does, however, require that certificates be issued for generation plants. In addition, IOWA CODE chapter 478 and IAC 199-11 require electric lines to be franchised.

Staff Analysis

In a competitive environment, the viability and credibility of service providers becomes critical to maintaining continuity of service. Providers who prove unable to meet their obligations could not only cause their customers to lose service, but could disrupt the entire electrical grid. To date, all states that have enacted statutes or issued restructuring papers have concluded some type of certification is necessary. Currently, generation suppliers are not required to be certified in Iowa. While Iowa does require transmission line franchises and generation siting certificates, these statutes do not include language, which would provide a means to address restructuring concerns. Since electric utilities in Iowa have been operating as regulated monopolies with exclusive service territories, with their operations subject to Board scrutiny, strict certification requirements for service providers have not been warranted. But with nontraditional entrants into the markets, and with traditional utilities assuming new roles, regulatory oversight to ensure the ability of all players to deliver promised services appears desirable.

Certification raises the following questions:

1) Who should be certified?
2) How should the certification process be structured and how stringent should it be?
3) What should be the certification requirements?
4) What penalties should be imposed if a certified CESP violates the agreed upon service standards?
5) How can redlining by CESPs be prevented?

Who should be certified?

The authority to approve certification for all CESPs would allow the Board to investigate all possible entrants into the Iowa market to determine technical, managerial, and financial ability. In addition, with certification the Board could require that certain policies and standards be met and included in a standard of service statement. The findings of other states have shown that certification can provide support in ensuring a reliable electric system. (See Appendix B, page 56.) For example, California initially used a simple registration process for all applicants and required no PUC approval. That resulted in many cases of abuse and fraud among suppliers. California has subsequently strengthened its certification requirements.

Aggregators who do not actually take title to power for resale and only arrange the transaction on behalf of customers should also be certified, albeit with less stringent requirements. Although aggregators only arrange transactions on behalf of customers, credibility must be assured. Aggregator certification would allow the Board to require proof of technical, managerial, and financial ability and to require compliance with Board's policies and procedures. If the aggregator actually takes title to the power and then sells it to the aggregated customer group, that aggregator would be considered a CESP and would be subject to more stringent certification requirements.

If certification requirements for aggregators are too stringent, they may provide a barrier to those groups of customers wishing to pool together to buy power. Although it is not necessary to require full certification, as for CESPs, some certification of all aggregators appears to be warranted. (See registration requirements in the Certification Requirements Section 2 below.)

Policy makers may want to exempt from any certification requirement any REC or municipal utility electing to limit itself to customers in its service territory. An opt-out provision would allow for this. Such an exemption might also apply to a REC that requires all customers outside its exclusive service territory to become a member of the REC. If a new customer residing outside the REC service territory is required to become a member of the REC, that customer would presumably have voting rights and be required to follow the by-laws of that REC. Except for these possible exemptions, the same certification requirements would be applicable to RECs as to other CESPs. If a municipal chooses to serve customers outside its service territory, it may also need to be certified. Any opt-out provision would presumably apply to municipals as well as RECs.

How should the certification process be structured and how stringent should it be?

A Michigan PUC staff report discusses three levels of certification currently being implemented or discussed in other states.[14] Each level has obvious positives and negatives.

The lowest level requires certain basic information to be filed with the PUC and does not require any PUC approval. This is the simplest form of certification and amounts to little more than registration. Although this method is clearly the simplest form of certification, it may also lead to the biggest risk of abuse by allowing anyone to offer service after paying the fee and filing basic information.

[14] Michigan PUC, "Customer Focus Issues and Recommendations," Staff Report, Case No. U-11290 on Electric Restructuring, October 13, 1997.

California discovered first hand this method is probably too relaxed when numerous fraudulent companies entered the California market.

The middle level, which requires the filing of more specific information, still does not require approval and automatically becomes effective within a certain time period. This method is relatively easy to administer, however, the PUC does not actually certify the applicant.

The highest level includes a detailed filing that the PUC must approve before issuing a certificate. This method is the most stringent from the supplier's side and is the most time-consuming for regulators. However, it provides the most information, gives the PUC the most authority, and allows for the least amount of customer risk with the highest level of reliability.

What should be the certification requirements?

For CESPs, policy makers should consider requiring the filing of a formal certification application. The IOWA CODE currently includes certification language that was added when the long distance telephone market was opened to competition. This is detailed in the "Policy Considerations" section below.

In addition, consideration should be given to requiring aggregator certification on a lesser scale. The "Policy Considerations" section details possible requirements for aggregators.

Policy makers should also consider requiring a standards of service statement which includes standards similar to those outlined in the Michigan staff report. This approach is detailed in the Michigan summary--included in Appendix B.

An additional question is whether an application fee should be charged and, if so, at what level? A fee, if imposed, should cover the administrative costs of certification but should not be so high as to preclude competitive entry. If a fee is tied to an application which must be approved by the Board, Board approval would in itself lessen the possibility of fraudulent CESPs entering the market. However, if the Board chooses, or is directed by the legislature, to use the low or medium level certification approach, a higher application fee and bonding requirement may be warranted in order to keep the credibility of the applicants at the highest possible level.

What penalties should be imposed if a certified CESP/aggregator violates the agreed upon service standards?

The Board would be the most logical authority to consider violations of certification requirements. Policy makers should consider broadening current Board's authority to deal with these issues, ranging from issuing fines and/or sanctions to total certificate revocation.

How can redlining by CESPs be prevented?

Policy makers should consider giving the Board authority to establish rules to prevent unfair business practices including redlining. Redlining may occur if a CESP is unwilling to offer service to a particular customer group or geographic area.

Policy Considerations

In developing any restructuring legislation, policy makers may want to consider the following:

1) Adding new authority requiring CESPs be certified before providing service in Iowa. This could include aggregators who actually take title to power being purchased, along with RECs and municipals choosing to serve customers outside their exclusive service territories.
2) Adding new authority requiring aggregators who do not generate power or take title to purchased power to also be certified.
3) Adding new authority to determine what should be included in all certification filings. Legislation might allow 90 days to analyze the filing for approval with an additional 90 days if cause is shown. (This would be consistent with the timeframe in the telephone statute. IOWA CODE §§ 476.29 and 476.101 specifically addresses the telephone certification process.)

The following certification requirements should be considered for CESPs:[15]

1) Reasonably demonstrate it has the managerial, technical, and financial capability to obtain and deliver the services it proposes to offer;
2) Reasonably demonstrate the truth of any advertising claims made pursuant to fuel sources;
3) Agree to comply with all applicable Board rules; and
4) Disclose the names and corporate addresses of all affiliates of the CESP.

In addition, any restructuring legislation should consider granting authority to the Board to adopt rules relating to reliability and safety issues that would apply to all CESPs. CESPs providing competitive power supply services would need to show evidence of reliability as part of its certification application. If it is determined that billing and meter service should be offered competitively, policy makers should consider granting the Board authority to adopt rules to identify the certification requirements for these services. The authority should be broad enough to allow the Board to add requirements to the certificate application process as needed.

Any restructuring legislation should consider language which gives the Board broad authority to assess fees to cover administrative costs. In addition, this broad authority might include the right to assess fines and/or sanctions or revoke a certificate if just cause is shown. These fees, fines, and sanctions would be applicable to both CESPs and aggregators.

3. RELIABILITY STANDARDS

This section focuses on the security aspect of reliability (the ability of the system to operate in spite of unanticipated loss of system elements) and the tools to assure that ability. This encompasses a wide range of concerns including: (1)

[15] Suppliers are distinct from aggregators in that they actually generate or take title to power being purchased.

reliability of service; (2) power quality; (3) inspection and maintenance; and (4) safety. While these four areas are all salient dimensions of the reliability question, they are not necessarily exhaustive. That is, other policy decisions may also have reliability implications but are not explicitly addressed in this report.[16]

A staff report[17] of October 1997 found there is movement away from traditional reliance on voluntary standards for reliability and toward increased governmental imposition of mandatory standards, including some or all of the following:

1) Mandates that the PUC assure reliability.
2) Adoption of uniform methods for ensuring reliability and quality of service.
3) Use of reliability indices.
4) Establishment of benchmarks.
5) Improvement of definitions.
6) Articulation of data requirements and record keeping.
7) Improvement of report filing.
8) Inspection and maintenance standards.
9) Use of incentives in performance based ratemaking to assure reliability and consumer satisfaction.

One difficulty of addressing reliability standards is the fact that reliability is a system concern which extends beyond any state border. What with rapid changes in the industry and evolving federal authority, it becomes less than obvious what the precise future role for the state should or will be. However, there is little doubt as to the strong public interest aspect in assuring reliability, and that alone argues for state involvement.

[16] For example, a decision to require divestiture of generation to promote effective competition might have reliability ramifications if the synergy of the vertically integrated utility is lost.

[17] Bittner, Chancy, "State Initiatives to Assure Reliability," Iowa Utilities Board, October 1997.

In order to more fully understand what practices and mechanisms currently exist to assure reliability, the team mailed out technical data queries to the utilities. In addition, more general data queries focusing on policy concerns were sent to all members of the Advisory Group.[18] These responses are used to support staff analysis and understanding of the many issues, but especially for the following rather technical ones. (See Appendix C for the questions asked and a summary of the responses.)

3.1 MONITORING RELIABILITY

Industry indices exist to help assess the unavailability of electric power due to unanticipated loss of transmission or distribution elements of the system. About 90 percent of outages are considered distribution related.

Current Statute and Rules

IOWA CODE § 476.1A gives the Board authority over safety and engineering standards for equipment, operations, and procedures for the regulation of IOUs and RECs. It appears this specific authority allows the Board to regulate reliability concerns. However, in this regard, IOWA CODE § 476.1B appears to deny the Board this authority over municipal utilities except for safety concerns.

IAC 199-20.2(5)"c" requires utilities to file a written report of any unscheduled outage of one hour or more affecting 2 percent or more, or 1000 customers, whichever is less in number. This report shall contain, at minimum, "identification of the affected area, outage starting date and time, service restoration date and time, cause, number of affected customers and identification of estimates when actual data is unknown." In addition, a report shall be made by telegraph or telephone if customers affected are greater than 10 percent, or 5000 customers, whichever is less.

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[18] The Advisory Group was named by the Board in February 1996 to provide comment and analysis to the Board as it evaluates issues associated with the emergence of competition in the electric utility industry. The group includes representatives of utilities, Iowa businesses, as well as environmental and customer interests.

Staff Analysis

What, if any, additional authority does the Board need to assure reliability?

General statutory authority exists currently for application of reliability standards to IOUs and probably to RECs, although apparently not for municipal utilities. Policy makers should consider maintaining, and perhaps expanding, this authority. Reliability is important enough that any legislation allowing retail competition should at least articulate objectives supporting Board's authority in this regard.

Should the electric industry in Iowa move from voluntary efforts to mandatory requirements to assure reliability?

Nationwide, there is strong movement away from the traditional reliance on voluntary standards for reliability. Under traditional regulation, utilities have, for the most part, worked together and within their own companies to assure reliability. This is not surprising given that cost-based regulation has made recovery of relevant investments and maintenance fairly routine. However, as the industry changes to competition and performance-based rates, the concern is that reliability may suffer as utilities seek to aggressively minimize costs. In the words of one industry commentator: "the current voluntary structure for ensuring reliability is no longer viable in this new era of competition, and it must be replaced with a mandatory and enforceable system . . .."[19]

Both ALT and MEC argue against mandatory requirements while the Iowa Association of Electric Cooperatives (IAEC), Iowa Association of Municipal Utilities (IAMU), Office of Consumer Advocate (OCA), and the American Association of Retired Persons (AARP) appear favorably inclined.[20]

[19] Inside F.E.R.C., "Cry for Reliability Pierces Din of Debate," Dec. 9, 1996, p. 9.

[20] Also see Appendix C, page 70.

Should uniform standardized indices of system reliability be required?

A number of state PUCs[21] are seeking to adopt more uniform methods of monitoring the reliability of electric service within their states by adopting definitions and requirements for data maintenance and retention, and report filing. This allows the PUCs to better track a company's reliability over time to identify trends of improving or declining reliability, and perhaps even allow cautious comparisons between companies. Policy makers may want to consider a similar approach for the state of Iowa, especially for IOUs and probably for most RECs. (See discussion on page 38 regarding municipal utilities.) Of course, application would need to be sensitive to the specific ability to perform, which might reflect size of operations and degree of automation. For example, policy makers may want to have lesser standards for the smaller RECs and may even exempt those that choose to not participate in retail competition.

While MEC says mandatory standards should not be imposed unless a showing of need is made, it nevertheless argues "it is fundamental that the same standards be applied to all utilities,"[22] including RECs and municipal utilities. IAMU proposes that municipal utilities be exempt. IAEC proposes that a task force be assigned to determine a reasonable standard.

ALT is generally opposed to uniform standardized indices. It argues that comparison of these indices among utilities is inappropriate due to innate differences among utilities, their infrastructure, technology, and procedures. Staff agrees that the most appropriate comparisons are between years for a given utility and that comparisons between utilities may require additional knowledge above and beyond just the indices. Presumably, the utilities would be able to provide that additional information.

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[21] For example, Louisiana, Illinois, New York, Pennsylvania, Wisconsin, and Ohio. See Appendix B.

[22] MEC March 26, 1998, response to staff's policy questions (I.1c and I.4). See Appendix C.

Are the current outage reports adequate for tracking reliability?

The current outage reports are useful mainly for notification purposes. However, for tracking reliability it would be better to use industry indices. The industry indices have the advantage of reflecting the frequency and duration of all outages, including those that may not trigger a report under our current filing rules.

IAEC argues that current outage rules requiring reporting of an outage affecting 2 percent or more of REC customers result in reports of outages too small for Board concern.[23] It suggests annual reporting instead. However, these reports serve to alert the Board to outages; annual reports would be inadequate for this purpose.

What reliability data are currently collected by utilities?

Currently, it appears that the IOUs track reliability using at least some of the main industry reliability indices. These indices track frequency and duration of outages, sometimes down to the individual circuit level.[24] See Appendix A for a list of the main indices and their definitions. RECs, on the other hand, observe Rural Utility Service guidelines, although apparently could meet more rigorous recording and reporting standards if necessary. Most municipal utilities apparently do not measure data necessary for reliability indices.

Any reliance upon these indices for assessing reliability should require that all data be fully explained within the context of the utility's operations and reliability plans. The data should then be subject to further analysis and questioning--perhaps within the context of a proceeding if needed.

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[23] IAEC April 6, 1998, response to staff's technical question (I.1.k) , p. 9. See Appendix C.

[24] The ability to produce detail measurements--e.g. for individual circuits, not just on a system-wide basis--appears to hinge on how automated the outage management system is. The larger utilities are rapidly becoming computerized. Both ALT and MEC are undergoing efforts to fully automate outage management programs, providing better and quicker information to operations.

What recording and reporting should be adopted?

Unplanned Outages

ALT recommends each utility continue to track its own indices and provide information only on request. MEC recommends that a utility should not have to extensively modify its entire recording system to support new indices, but notes it already records many indices. IAMU argues for exemption. IAEC and the OCA support recording and reporting.[25]

Policy makers should seriously consider requiring the recording and reporting of service performance indices which measure the frequency and duration of sustained customer interruptions, calculated both including and excluding major events.[26] This could be required for IOUs and any entities, including RECs and municipals, who provide transmission and/or distribution service to CESPs. In addition, frequency indices from momentary interruptions could also be required.

Where possible, this recording and reporting could be required utility-wide, by state, by district, and down to distribution circuit level. Some sensitivity would need to be given to those cases where manual systems make accurate recording difficult. Policy makers could require reports be filed on an annual basis and impose fines for failure to maintain data and generate reports.

Plans

Policy makers may want to require annual reporting on plans for future investment and reliability improvements as well as reporting on the implementation of the prior year's plan. The annual reports would be useful to the Board in the determination of performance.

Other Reporting

[25] See Appendix C for summary of responses to staff's policy question I-2. .

[26] Some utilities routinely exclude major events like storms while others exclude nothing.

As the market evolves, policy makers may want to consider other reporting as needed. For each jurisdictional entity, this may include some or all of the following:

1) Outages that are due solely to the actions or inactions of a CESP.
2) Reports on request of the reliability record of specific customers where this is possible.
3) Reports of the reliability record of every customer (using an identifier other than name) whose reliability record falls short of some standard.
4) A detailed report of the age, current condition, reliability, and performance of existing transmission and distribution facilities.
5) Annual reports on emergency plans, including policy and procedures for identifying outage areas, providing outage response and restoration of service, and for seeking outside assistance in worst case weather scenarios.

Should reporting include worst-performing circuits?

Many states, including Illinois and Wisconsin, require the reporting of worst-performing circuits and an explanation of plans for improvement. This requirement allows the PUC to address local reliability issues that system-wide analyses and targets might miss.

IAEC argues that such a list of poorly performing circuits is a necessary tool for the Board to enforce performance standards. However, ALT is concerned that such a list would be misunderstood by the public and states it is not reasonable or possible to provide an accurate list. In addition, MEC argues that such a list may “not be indicative of a situation requiring remedial action.”[27]

Should a nondiscriminatory requirement for restoring transmission and distribution service be imposed upon owners and operators?

When a major outage occurs, owners of electrical systems must decide which facilities to repair and in what order. Historically, decisions on transmission line repair priority have been based on restoring service to the largest areas or

[27] MEC March 26, 1998, response to staff’s policy questions (I.2c). See Appendix C, p. 69.

numbers of customers without power. Decisions on distribution system priorities have been based on first restoring critical public facilities (hospitals, police and fire departments, etc.) and then on repairs benefiting the largest number of customers. However, restructuring may introduce incentives to schedule repairs in a manner that would be discriminatory and not necessarily in the best interests of customers. A transmission line owner might chose to first repair lines benefiting affiliates regardless of the number of consumers impacted. A distribution system owner might first restore service to its own, or an affiliate's, power customers to the detriment of customers served by competing power providers. At least one state statute[28] specifically requires that entities owning, operating, or controlling transmission and/or distribution facilities restore service after outages in a nondiscriminatory way without regard to whether a customer buys its electric supply from the utility, its affiliate, or an alternative electric supplier. Policy makers may want to consider placing non-discrimination provisions in Iowa law.

What about reliability regulation of municipal utilities?

It is not at all certain what change, if any, in regulation should be encouraged for municipals. Most municipals are only distribution entities, and as such, appear to impose little risk on the system's reliability. Furthermore, the customers of municipal utilities are also the voters that demand accountability of any managers who give reliability too little emphasis. Presumably for these reasons, IAMU argues for continued local control and asks for exemption from any recording and reporting or other reliability standards. In addition, IAMU believes that "reliability standards for generation and transmission apply to municipals through NERC and MAPP."[29]

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[28] See Illinois Public Act 90-561, "Electric Service Customer Choice and Rate Relief Act of 1997," Section 16-125 of Article XVI.

[29] IAMU, "Response to the IUB questions regarding Reliability and Quality of Service," April 1998, p. 4.

However, if retail competition is allowed, two interesting questions arise. (1) What if a municipal utility wants to sell power to retail customers outside its jurisdiction? Policy makers need to ask whether that municipal utility should or should not meet the same standards (including supply reliability) as any other alternative supplier. (2) What if a municipal utility offers delivery service to a retail customer to purchase from other entities? A case may be made that some higher authority than the municipal government may be needed to resolve disputes, including those entailing reliability and possibly retail wheeling charges. For example, that municipal utility could be required to meet specific reliability targets for its customers who buy from other entities.

Should performance measures be used?

Industry Indices

One option used by a number of states is the adoption of benchmarks against which to measure the indices of reliability.[30] If reliability falls short of the benchmark, a penalty is imposed. In a few cases, a positive incentive is also allowed for reliability above the benchmark.[31] ALT recommends positive incentives only and suggests performance-based rates looking at, among other variables, the total customer outage minutes instead of the industry reliability indices. IAEC suggests that a task force be assigned to determine reasonable standards for four different categories: (1) urban vs**.** rural; (2) transmission over 100 kV; (3) sub-transmission (between 15 and 100 kV); and (4) distribution (below 15 kV).

In general, a benchmark should have certain characteristics: (1) it should be easily available; (2) it should be unambiguous; and (3) should be appropriate to the task. None of these characteristics are obvious at this time.

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[30] Examples include Colorado, Louisiana, Massachusetts, New York, Ohio, Oregon, Pennsylvania, Rhode Island, and Wisconsin.

[31] New York regulation used to have both positive and negative incentives associated with reliability performance vis-à-vis benchmarks. More recently, decisions have apparently dropped the rewards but retained the penalties.

First, with the rapid pace of mergers and the associated discordant records and procedures, the historical record of data to build benchmark indices is not good. Second, judgment as to what is excluded and included in the indices seems to be an integral part of data collection--especially when storm-related outages are excluded. Judgment can change over time and almost certainly will alter as incentives change. And third, a benchmark based upon historical data may not be appropriately applied going forward. Why? For one, indices will reflect not only changing performance but also the way data are collected. There is literally a revolution going on as computerization is gradually brought to bear on this job. Data collected with manual procedures do not appear to be strictly comparable with the more accurate, comprehensive data from automated systems. Whether these concerns can be overcome adequately to produce realistic benchmarks will require a concerted effort among parties and probably Board proceedings.

The difficulty of establishing meaningful benchmarks[32] may ease as more data are generated from the computerized outage management systems and with the growth in staff experience and Board oversight. However, whether benchmarks are used or not, policy makers could require that utilities provide analysis of their data, especially of any negative trends or occurrences which fail to sustain or improve on the past record. This presumably could be done on a number of different levels.

Customer Targets

An alternative to benchmarks based upon indices might be the adoption of specific customer targets as was done in Illinois. The Illinois rules specify different customer-level targets for each of three different voltage classes: (1)

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[32] The Illinois commission has ruled that "establishing numerical targets based on statistical interruption indexes is neither necessary nor a meaningful measure of reliability performance." See Illinois Commerce Commission, "Order," Implementation of Section 16-125 of the Public Utilities Act, Docket No. 98-0036, p. 18.

transmission (2) sub-transmission; and (3) distribution.[33] The PUC will assess whether the providers of transmission and distribution service have an adequate process to identify, analyze, and correct reliability problems for customers whose outages exceed the targets.

Tracking of reliability on the customer level would be most likely for those transmission and distribution providers who have automated outage management systems. Fortunately, the major IOUs appear to be rapidly approaching this capability.

Policy Considerations

In developing any restructuring legislation, policy makers may want to consider the following:

1) Retaining existing oversight authority and responsibility to promote reliability among all jurisdiction entities, including RECs.
2) Making oversight authority more explicit and at a minimum, specify authority and responsibility for assessing and assuring the reliability of the transmission and distribution systems.
3) Expanding oversight to cover municipals that offer distribution and transmission services to CESPs or who want to make power sales outside their territories.
4) Adding authority to impose fines and/or sanctions for an unacceptable degradation of system reliability. Any such penalties should be able to take effect even in the absence of a rate case.
5) Requiring that Delivery Service Providers adopt and implement procedures for restoring delivery services after outages on a nondiscriminatory basis.

Furthermore, the Board may want to continue outage reports for notification purposes and to consider opening a rulemaking to solicit comments on the following proposals:

1) Adopt industry accepted indicators, such as System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") to monitor the performance and

[33] Ibid., p. 13.

reliability of transmission and distribution systems. This should also include momentary indicators.

2) Require annual filings of all indices currently calculated as well as those required by rule. This should include an explanation of changes in trends and planned or on-going improvements aimed to improve reliability.
3) Require annual filings of worst-circuit data with explanations and plans for improvements.
4) Impose explicit recording and reporting procedures for reliability data for all jurisdictional entities.
5) Encourage moves from manual to automated outage management systems.
6) Encourage the larger automated jurisdictional entities to track reliability by customer and establish customer benchmarks for these entities.

3.2 POWER QUALITY

Power quality is the delivery to customers of electricity in the form of a perfect 60-Hz sine wave at standard voltage levels. Maintaining appropriate levels of power quality is primarily a distribution function.

Current Statute and Rules

Currently IAC 199-20.7 provides standards for quality of service. Rules 20.7 (1 through 10) cover standards for frequency, voltage limits retail, voltage balance, voltage limits service for resale, exceptions to voltage requirements, voltage surveys and records, voltage measurements, and equipment for voltage measurements. These rules are intended to implement IOWA CODE §§ 476.2 and 476.8 which provide general requirements for providing electric service in Iowa.

Staff Analysis

Current Iowa rules provide for acceptable levels for voltage delivery to customers by the incumbent utilities. However, it is not certain that all owners and/or operators of electric lines and the new CESPs in the electric market would be subject to this existing authority. Any restructuring legislation needs to be broad enough to ensure that all new providers of electric service meet power quality standards.

Policy Considerations

In developing any restructuring legislation, policy makers may want to consider the following:

1) Retention of statutory authority to provide oversight for power quality.
2) New authority to ensure that all new providers of electric service meet existing Iowa power quality standards.

3.3 INSPECTION AND MAINTENANCE

This issue applies to all transmission and distribution lines in the state. Staff has reviewed efforts by other states (see Appendix B) in the following areas: a) inspection and maintenance plans; b) preventative maintenance; c) record keeping and reporting requirements; and d) tree trimming.

Current Statute and Rules

The Board has adopted inspection and maintenance plan requirements for electric utilities, including RECs and municipals, in IAC 199-25, the Iowa Electrical Safety Code (IESC). These rules have been in effect since 1983. As part of those rules, the Board requires that electrical facilities comply with ANSI C2-1997, the National Electrical Safety Code (NESC), which is adopted with minor modifications.

These rules require that each electric utility have an Inspection and Maintenance Plan. In addition, these rules specify record-keeping requirements that facilitate Board monitoring. Board staff periodically inspect utility records for compliance with the plan, and also inspect a sampling of electrical facilities to ensure that the owner's inspections under its plan are finding maintenance needs and taking appropriate corrective action.

To construct, erect, maintain, or operate an electric transmission line capable of operating at over 34,500 volts, the owner must obtain a franchise from the Board under IOWA CODE chapter 478. The franchise must be extended (renewed) at intervals not exceeding 25 years. The ability to inspect and maintain the line may be an issue in franchise proceedings. When a franchise extension is sought, Board staff examine the line to determine if it is being properly maintained in compliance with the IESC. These inspections are conducted separately from others conducted under the Board's safety inspection program, which are more random and may only examine a sample portion of any individual electric line.

Staff Analysis

Inspection and Maintenance

Most states have adopted, or are proposing to adopt, the NESC. Iowa has been a national leader in adopting these types of standards. The preventative maintenance issues are adequately addressed by the existing Iowa inspection and maintenance plan requirements. However, the concern exists that increased competitive pressures may mean reduced preventive maintenance.

IAC 199-25 was promulgated under IOWA CODE chapters 476 (regulated utilities) and 478 (electric transmission line franchising). Continued regulation addressing the physical condition of electrical facilities after restructuring is probably necessary. However, it is not certain that all owners and/or operators of electric lines in a restructured environment would be subject to Board's authority under either statute as it currently exists. Any restructuring legislation needs to be broad enough to ensure that the facilities of all entities that own and/or operate electric transmission or distribution facilities, not just traditional utilities, are subject to Board oversight.

Tree Trimming

According to a Report to the President, major outages in Western US in the summer of 1996 "might have been averted by more intensive tree-trimming or line maintenance programs . . ..."[34] The California PUC has since adopted extensive standards for tree trimming practices and procedures.[35] Closer to home, recent events in the Midwest (the snowstorm of October 1997, and the windstorms of the summer of 1998) have also demonstrated the role trees can play in outages. Section 218 of the NESC suggests, but does not require, trimming of trees that may interfere with conductors. Iowa utilities typically have preventive tree trimming programs, but there is concern that increased competitive pressures under restructuring will lead to reduced expenditures for preventive maintenance or that new entrants will not adequately provide for this activity.

Policy Considerations

In developing any restructuring legislation, policy makers should consider the following:

1) Ensuring that all owners and/or operators of electrical facilities, including new entrants that are not traditional utilities, are subject to the Board's oversight of inspection and maintenance activities.

[34] US Department of Energy, "The Electric Power Outages in the Western United States, July 2-3, 1996: A Report to the President," August 1996, p. 11.

[35] California PUC, "Opinion" and "Order," Docket I.94-06-012, January 23, 1997.

In addition, the Board should:

1) Continue to monitor the frequency and severity of outages caused by trees and tree limbs.

3.4 SAFETY CONCERNS

Current Statute and Rules

Currently IAC 199-20.5 addresses engineering practice and IAC 199-20.8 defines safety standards. IAC 199-25 creates the IESC which specifically adopts ANSI C2-1997, NESC with some modifications. These rules are periodically updated to reflect new NESC editions.

As was discussed in Section 3.3, “Inspection and Maintenance,” Iowa electric utilities are required by Board’s rules to periodically inspect and maintain their facilities. Board staff conducts safety code compliance inspections of electric facilities, and safety is also considered in electric transmission line franchise proceedings.

Staff Analysis

Iowa already has a safety program. In analyzing the replies from Iowa utilities to staff’s data requests, most suggest that no changes in Iowa rules are needed to ensure adequate safety. Several stated that their safety records are testimonials to the sufficiency and usefulness of the existing framework.

However, again as discussed in Section 3.3, there is concern that new transmission or distribution service providers may take a form that escapes the Board’s safety jurisdiction. Argument can be made that all owners and/or operators of electrical facilities should be subject to the same safety requirements. Any restructuring statute should consider provisions to ensure that all forms of operators would be included.

Policy Considerations

In developing any restructuring legislation, policy makers should consider the following:

1) Retention of current Board oversight of all utilities for safety requirements.
2) Explicitly extending Board safety oversight to any and all new entities that might own or operate transmission or distribution facilities.

In addition, the Board should:

1) Continue to monitor referenced safety standards to keep Iowa rules updated to current editions.

4. CUSTOMER SERVICE QUALITY AND MONITORING

This section deals with the following types of utility/supplier/customer interaction that might occur under retail competition:

1) Minimum Customer Service Standards
2) Dispute Resolution
3) Consumer Privacy

In general, distribution utilities should maintain, at a minimum, current levels of customer services. This requires the retention of the Board's current authority and possibly some additional authority.

4.1 MINIMUM CUSTOMER SERVICE STANDARDS

This section addresses questions of customer access and company response to customer concerns--for example, timely service connections, service repairs, and reconnections.

Current Statute and Rules

IAC 199-20, as based upon IOWA CODE § 476.3 and 476.8, addresses service requirements of electric utilities. Board's rules do not provide installation, repair, or missed commitment guidelines. However, IAC 199-20.4(15) does provide that disconnection may not take place unless the utility is prepared to reconnect the service the same day if payment or other arrangements are made.

While IAC 199-20.4(2) does require utility representatives to provide prompt and courteous response to customer inquiries, there are no current guidelines for answering calls or monitoring call centers in the provision of electric service.

Staff Analysis

Recently, the Board adopted quality of service standards for telephone service. (IAC 199-22.6) These include: (1) standards for connection service; (2) standards for reestablishing service following interruptions, including priorities; and (3) standards for emergencies. As stated earlier, reliable electricity is a crucial part of a citizen's life-style. Therefore, similar standards for electric service may be judged as even more important. While the lack of telephone service for a week is inconvenient for most customers, the lack of electricity for a week may have adverse impacts far beyond mere inconvenience.

Another candidate for oversight is availability of customer access. It is becoming more difficult for customers to have face-to-face contact with utility representatives. This problem may worsen in a competitive environment. Policy makers may want to consider requiring utility companies to maintain records on minimum service standards, including meeting scheduled commitments given to customers.

Some states also impose guidelines for call centers. Monitoring how quickly calls are answered would indicate to a PUC any deterioration in performance and promote remedial action on the company's part. For example, electric utility companies might be required to acknowledge most calls within 20 seconds. Similar requirements are currently required by IAC 199-22.5(10) for local telephone service here in Iowa.

Policy Considerations
In developing any restructuring legislation, policy makers may want to consider requiring minimum service quality standards be included in a code of conduct for anyone certified to provide electric service.[36]

4.2 <u>DISPUTE RESOLUTION</u>

Current Statute and Rules

IOWA CODE § 476.3 gives the Board authority to investigate complaints filed against a utility. IAC 199-6, 20.1(3)"b," and 20.4(20) provide that customer complaints be investigated promptly and thoroughly.

Currently, the majority of disputes handled by the Board are between the IOUs and their customers, although some disputes have occurred between companies. All disputes are handled via the Board's complaint process which ranges from informal procedures to formal proceedings.

When a routine written complaint is brought against a utility, the utility is given 20 days to respond, and then the Board staff proposes a resolution. If the parties do not agree with the resolution, the opportunity for a formal proceeding is available. Complicated disputes are generally docketed.

Staff Analysis

In addition to traditional disputes, new types of disputes between CESPs and other market participants may require additional Board oversight and procedures for resolution. As more participants enter the marketplace, both the number and complexity of disputes will increase. For example, a CESP may bring a complaint against a distribution or transmission company. Also, disputes may be complicated by the fact that complaints may overlap into more than one jurisdiction. An example of this would be a dispute between a state-regulated distribution company and an FERC-regulated transmission company. At a

[36] See Section 2 on Certification of CESPs and aggregators.

minimum, any restructuring legislation needs to include language giving the Board jurisdiction over complaints and disputes concerning reliability, service, and safety related issues. This jurisdiction should be expanded to include all CESPs.

The telephone industry has seen many problems created with the federal Telecommunication Act of 1996, especially in cases involving jurisdictional disputes, such as slamming, cramming, and billing. Any restructuring of the electric industry should address these concerns. For example, customers and other parties could be allowed to bring an action before the Board instead of having to rely upon court remedies.

Policy makers may want to consider authority to impose fines and/or sanctions on companies that violate Board's rules. Current laws require that the fines be used for low-income home energy assistance.

Some states also charge a processing fee for complaints. The Board could consider adopting rules to impose a processing fee on the company that is found to be in violation of the statute, rules, or tariffs. This fee would be different from civil penalties.

Policy Considerations

In developing any restructuring legislation, policy makers may want to consider the following:

1) Retention of authority to allow the Board to provide a neutral forum to address complaints and maintain a process for formal hearings.
2) New authority to impose fines and/or sanctions for violations of Board's rules.
3) Expansion of complaint authority to include all CESPs, including, at a minimum, reliability, customer service, and safety oversight.
4) Expansion of Board authority to adopt rates protecting end-user consumers from fraud and other unfair, deceptive, and abusive business practices. Strong penalties should be imposed for violations of these rules.

5) Authority to charge a complaint-processing fee to the company that is found to be in violation of the statute, rule, or tariff.

4.3 CUSTOMER PRIVACY RIGHTS

Current Statute and Rules

Currently, the only statute relating directly to customer privacy is IOWA CODE § 476.56 which requires release of usage data to owners, prospective renters, or purchasers of property.

There are specific rules, IAC 199-20.4(1), as to what utilities must provide to customers; however, these do not address customer privacy rights. It may be possible in a rulemaking to add additional language limiting what a utility can do with customer data.

Staff Analysis

The majority of respondents to staff's data request believe that customer consent should be required before customer information is released. IAEC believes a customer's name, address, service provider, and delivery voltage should be public while all other data should be held confidential. IAMU is concerned it must comply with open meeting and public record statutes.

Protecting customer information is only one part of the equation. It is also necessary to address the problem that customer information may be a barrier to competition. If a customer's current utility is not required to allow access to certain customer data, that utility may be in an advantageous position. On the other hand, it is important that some type of mechanism be in place to also protect the customer.

As the long distance telephone market was opened to competition, the biggest complaint from customers concerned bombardment by telemarketers. Current federal law[37] provides some safeguards from telemarketers, and policy makers may want to consider funding for a customer education program that explains to customers their rights relating to telemarketing activities. Included in this federal law are the following safeguards: 1) prohibiting certain telemarketing activities, including times which are off limits for calling; 2) disclosing of costs; 3) restricting calls to customers not wishing to be called; and 4) disclosing the purpose of the call is to sell goods and services. Policy makers may also want to require the distribution company to maintain a listing of all customers who have requested that they not be called.

Policy Considerations

Based on the above analysis and discussions with the customer education team and the universal service team, policy makers may want to consider the following in developing any restructuring legislation:

1) Authority to specify what types of customer information are public and what types of customer information should be confidential.
2) Authority to develop rules promoting customer protection.
3) Authority for funding of a customer education program.

[37] Federal Trade Commission, "Telemarketing and Consumer Abuse Protection Act," 15 U.S.C. §6101-6108. Also, Federal Communications Commission, "Telephone Consumer Protection Act," 47 U.S.C. §§ 227-228.

APPENDIX A

OUTAGE INDICES[38]

SAIFI (System Average Interruption Frequency Index) is the average number of interruptions per customer during the year. It is calculated by dividing the total annual number of customer interruptions by the total number of customers served during the year.

CAIFI (Customer Average Interruption Frequency Index) is the average number of interruptions for those customers who experience interruptions during the year. It is calculated by dividing the total annual number of customer interruptions by the total number of customers affected by interruptions during the year.

CAIDI (Customer Average Interruption Duration Index) is the average interruption duration time for those customers that experience an interruption during the year. It approximates the average length of time required to complete service restoration. It is determined by dividing the annual sum of all customer interruption durations by the total number of customers' interruptions.

SAIDI (System Average Interruption Duration Index) is the average interruption duration per customer served during the year. It is determined by dividing the sum of all customer interruption durations by the total number of customers.

ASAI (Average Service Availability Index) is the fraction of time that the average customer has service provided during the year. It is determined by dividing the customer service availability by the customer hours of service demanded.

SASAI (System Average Service Availability Index) is the fraction of time that the power was on.

RUS (Rural Utility Service--old Rural Electric Administration) standard:

For outages over 5 minutes in length, the following equation is used:

$$\frac{\text{Minutes of Outage Time}}{\text{Number of Customers Impacted}} = \text{Average Outage Hours}$$

[38] These definitions were taken from the responses of ALT, MEC , and IAEC to staff queries--see Appendix C.

APPENDIX B

ACTIVITY IN OTHER JURISDICTIONS[39]

1. BULK POWER MARKETS

Georgia staff summary states reserve sharing is one of the advantages of an interconnected system. Spinning and supplemental reserves are needed in case of contingencies or customer demand in excess of plant capability. Reserves may be obtained from spare generating units or through interconnection. The proper level of generating reserves (i.e., reserve margin) depends on system characteristics, such as types of generators, load growth, and demand conditions. Normally, the desired reserve margin is set by a loss of load probability (LOLP) analysis designed to assure that blackouts and brownouts will be limited. Reserves can be offset by interruptible arrangements.

New Jersey staff report concludes uninterrupted, reliable electric service is an absolute necessity. While there is no reason to expect that the electric power industry cannot function like other competitive commodity markets, the industry does have some unique characteristics. As a result, some have argued that the ISO must institute mechanisms to assure that adequate capacity will be in place. This is an area that will be specifically addressed in each utility's filed restructuring plan. We note that some change to the existing two years forward, methodology is necessary, and that this is likely to be a region-wide issue.

A **Texas** staff report states utility's reserve margin is the amount by which its generation capacity exceeds its expected peak demand. The NERC Reliability council operating in Texas requires its member utilities to maintain a minimum 15 percent reserve margin to ensure that one or more plants can shut down without compromising the system's ability to meet expected load. The extent of excess capacity will be affected by the amount of non-utility generation capacity available, the rate at which Texas electricity demand grows, and the degree to which technological and/or market efficiencies may reduce the quantity of reserves required to maintain reliability. Excess capacity can contribute to competition and lower the market price of electricity, because utilities can use their excess capacity to generate power for sale to power marketers and other wholesale purchasers.

[39] The organizational format of issues in this Appendix effectively parallels the organization of the main report.

Montana Senate Bill 390 requires an electric supplier to acquire a license and provide a proof of financial integrity and a demonstration of adequate reserve margins or the ability to obtain those reserves.

Pennsylvania House Bill 1509 requires that the Commission ensures continuation of safe and reliable electric service to all consumers in the Commonwealth, including: the maintenance of adequate reserve margins by electric suppliers in conformity with the standards required by the North American Electric Reliability Council (NERC) and the regional reliability council appropriate to each supplier or any successors to those reliability entities, and in conformity with established industry standards and practices.

Illinois House Bill 362 requires 1) establishment of an independent operating entity to assure reliable operation of the transmission systems that will bring power from competitive market supplier, 2) the PUC to adopt new transmission reliability rules covering previously neglected aspects of reliability oversight, 3) the PUC to establish criteria for assessing the reliability performance and reporting on utilities' delivery services and facilities, 4) periodic review of reliability and identification of deficiencies, 5) provides an ability for victims of controllable outages to seek compensation from the utility for actual damages suffered.

After 1997 summer outages in eastern **Wisconsin,** the Wisconsin legislature enacted an electric reliability bill aimed at preventing future power shortages. The statute streamlines the regulatory process, encourages investment in new power plants, and requires all transmission owning utilities to transfer control of transmission assets to an ISO by June 30, 2000. The statute eliminates the requirement for utilities' biennial advance plans and instead requires the PUC to prepare a biennial strategic energy assessment that evaluates the adequacy and reliability of the state's current and future energy supply. The statute raises the limits for a certificate of public convenience and necessity for new generating units from 12 MW to 100 MW. It also authorizes construction and operation of wholesale merchant plants. A utility affiliate could own and operate a merchant plant with PUC approval. The statute raises the limits on new transmission line siting from 100 kV and more than a mile long to 230 kV, if the line and all related construction activity are located entirely within existing transmission right-of-way. Each transmission utility would have to transfer control over to an ISO or to divest its interest in them. If either was not done voluntarily, the PUC would by June, 30, 2000, have to order the utility to apply to the applicable federal agency to transfer control of transmission to a federally approved regional ISO or to divest interest to an independent transmission owner. The statute also requires the PUC to promulgate rules that allow the PUC to reduce revenue requirements of a public utility by an amount that reflects the fixed capital costs of generating units within the state that are incurred to make sales to customers outside the state whom the public utility does not have a duty to serve.

Wisconsin commission, on September 18, 1997, directed the utilities to do system planning based on an 18 percent reserve margin for the period until 2002. The commission stated that the utilities should develop a reserve allocation system that would require automatic sharing of reserves up to a minimum level with compensation to the providing utility paid by the deficient system.

2. CERTIFICATION OF SUPPLIERS/AGGREGATORS

As of July 1, 1998, all states that have restructuring statutes or are looking at restructuring have certification requirements or are considering them. All states require basic information such as names, addresses, telephone numbers, etc. Following is a brief discussion of some unique features required in other states' certification requirements:

California statute initially relaxed certification requirements. All entities providing electric service to residential and small commercial customers were only required to be registered. Commission approval was not required. Requirements included: 1) disclosure of penalties or sanctions in the previous ten years; 2) proof of financial viability; and 3) proof of technical and operational ability. On March 26, 1998, the Commission adopted changes that heightened the certification requirements. This change resulted from many occurrences of fraudulent activity. As part of the change, providers would need to have service agreements in place with all distribution utilities. In addition, the application fee was increased from $100 to a $25,000 security deposit or bond.

A **Kansas** report specifically required evidence that applicants had the ability to enter into binding interconnection arrangements for transmission and distribution. Licenses would be valid for five years and be renewable. Coops and municipals electing to serve only in their assigned service territories would not need to be licensed.

The **Montana** statute specified that RECs were not required to be licensed if they only sold power within their exclusive territory, or to other REC's customers with the consent of that customer's REC

Wisconsin's staff report proposed that an application for certification must include a listing of the other states in which application is also made. In addition, certification must be renewed annually. Customers are not obligated to pay for service received from a non-licensed provider.

Michigan's staff report discussed three levels of certification used in other states.[40] The first gives the commission authority to approve/reject each proposal and also authority to impose conditions or limits. This level, while being the most stringent, provides the most customer protection. This is similar to what was done in Pennsylvania.

The second level of certification was a type of self-scoring verification. Electric service providers would be required to file the same information as in the first method. However, approval would be assumed unless objections were filed. Penalties could be imposed if applications were found to be inaccurate or standards not met. This is similar to what was done in Rhode Island.

The lowest level of certification is basic registration. Electric service providers file basic information with the commission and registration involves no review by the commission. California's use of this method led to problems that later resulted in strengthening on the California certification requirements.

Michigan separated out the requirements for suppliers and aggregators. Michigan defined an aggregator as a broker who combined the loads of small customers to facilitate the purchase of electricity without taking title to the power. If a marketer actually took title to the power being purchased and then resold it to the aggregated group of customers, that aggregator would then be considered a supplier and must follow the certification requirements for suppliers.

Michigan designed a code of conduct for both aggregators and suppliers. Listed below is a summary of each:

<u>Supplier Code of Conduct:</u> Suppliers commit to:

1) provide accurate, understandable, standardized customer materials;
2) truth in advertising;
3) provide accurate and verifiable generation source information;
4) comply with standardized customer enrollment procedures;
5) comply with standardized billing procedures;
6) provide accurate customer service information;
7) not engage in unauthorized switching practices; and
8) maintain a toll-free telephone number for handling customer information and complaints.

<u>Aggregator Code of Conduct:</u> Aggregators commit to:

1) provide accurate, understandable, standardized customer materials;
2) truth in advertising;
3) pass along information on generation sources;

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[40] The Michigan staff report concluded that the second level of certification best meets the needs of Michigan's competitive electricity market.

4) requiring written approval for each participating customer;
5) not forcing customers to aggregate;
6) provide for continuity of service should primary supplier fail;
7) maintain a toll-free telephone number for handling customer information and
8) complaints; and
9) agree to allow all entities within a geographic boundary to participate. (This is basically to avoid cherry picking.)

3. RELIABILITY STANDARDS[41]

3.1 MONITORING RELIABILITY

Staff's October 1997 report[42] briefly summarized efforts in California, Colorado, New Hampshire, New York, Ohio, Pennsylvania, Rhode Island, and Wisconsin. More recent research notes not only continued progress in these states but also efforts in Louisiana, Illinois and Oregon.

Using a collaborative process, the **Louisiana** commission[43] has issued a general order specifying interim reliability standards applicable to all electric distribution systems within their jurisdiction and identifying possible fines for non-compliance. The commission notes it may need to refine these standards if the electric industry is restructured. The current standards include recording, reporting, and minimum performance levels for frequency and duration indices. This includes identifying and improving the performance of worst-performing circuits in each region. Fines up to $500,000 are specified as possible.

Illinois' recent restructuring statute required the commission adopt "rules and regulations for assessing and assuring the reliability of the transmission and distribution systems . . ..."[44] That statute specified in considerable detail the responsibilities of any entity, including for alternative retail suppliers, that own, control or operate transmission and distribution facilities. The commission has subsequently adopted, with some modification, comprehensive consensus rules of the parties to the evidentiary hearings. Among other things, these rules require a utility to file an annual report detailing the reliability of its service and explaining its plans for reliability improvements. Utilities are required to follow the reliability history of each customer and meet minimum reliability targets for

[41] Perhaps a sign of the times, New Jersey PUC has already established a Bureau of Service Quality and Reliability.

[42] Bittner, Chancy, "State Initiatives to Assure Reliability," Iowa Utilities Board, October 1997.

[43] Louisiana Public Service Commission, "General Order," Docket No. U-22389. In Re: Ensuring Reliable Electric Service, April 15, 1998.

[44] Illinois Public Act 90-561, op. cit., Section 16-125 of Article XVI.

customers in three different voltage classes (transmission, sub-transmission, and distribution levels.). However, the Commission found that "establishing numerical targets based on statistical interruption indexes is neither necessary nor a meaningful measure of reliability performance."[45]

Oregon has also recently accepted utility-specific service quality performance measures.[46] A revenue requirement reduction appears possible with non-compliance in areas of customer complaints, outage duration, outage frequency, safety violations, vegetation management, and inspection and maintenance requirements.

Ohio's rulemaking[47] provides for service reliability indices and performance targets; semi-annual distribution circuit performance reporting; and reporting on emergency policies and procedures.

3.2 POWER QUALITY

A **California** report[48] notes that the same competitive pressures that could adversely affect customer service and maintenance could similarly impact power quality. The report notes that the issue is very complex and quantification very difficult. It recommends that a team be formed to investigate definitions and customer expectations regarding power quality.

New York notes that power quality problems can include momentary interruptions; high or low voltage; voltage spikes and transients; flickers and voltage sags, surges and short-time over-voltages; and harmonics and noise. Its PUC requires that each utility maintains a power quality program (including performance objectives and procedures) and make annual reports (including data on the number of power quality complaints received and investigations conducted during the year).[49]

Illinois statute and rules give ComEd customers the right, under certain circumstances, to file for actual damages caused by outages or substandard voltage levels.

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[45] Illinois Commerce Commission, op. cit., p. 16.

[46] Oregon PUC, "Service Quality Measures," Docket UE94, Order 98-191, May 5, 1998.

[47] Ohio PUC, "Electric Service and Safety Standards, Chapter 4901:10 of the Ohio Administrative Code," Case No. 97-1578-EL-ORD, 1998.

[48] California Commission Advisory and Compliance Division, "Electric Service and Safety Standards Investigation Workshop Report," February 13, 1996, pp. 2, 88.

[49] New York Public Service Commission, "Order Adopting Changes to Standards on Reliability and Quality of Service," Case 96-E-0979, February 26, 1997.

3.3 <u>INSPECTION AND MAINTENANCE</u>

California, **Massachusetts,** and **Pennsylvania** address maintenance requirements in their statutes. The codes of Massachusetts and Pennsylvania and the proposed California statute all require conscientious inspection and maintenance of transmission and distribution systems to continue and enhance the reliability of the delivery of electricity. (Pennsylvania's proposal does not include specific inspection and maintenance standards./ p.5) Preliminary research on preventative maintenance in the state statutes of Maine, Montana, New Hampshire, Nevada, Oklahoma, and Rhode Island found no reference to this topic.

Only the proposed **Wisconsin** service rules and the **California** Order on Pacific Gas and Electric Company address record keeping and reporting requirements. These states would require verification from their utilities that they are maintaining adequate electric systems.

Wisconsin's proposed rulemaking to create service rules refers to tree trimming but does not impose any safety clearances. (WI PSC113.0511, .0512, and .0513) On January 23, 1997, **California's** PUC (Decision 97-01-044) adopted final standards for tree trimming near power lines. For voltages up to 105 kV, the minimum clearance under normal weather variations is 18 inches. No other state rules or codes directly refer to tree trimming.

None of the other state rules, proposed rules, or standards reviewed, nor the IOWA CODE or rules, directly refer to alternative service providers.

3.4 <u>SAFETY CONCERNS</u>

Pennsylvania requires transmission and distribution facilities to be installed and maintained in conformity with the NESC and such other standards practiced by the industry in a manner sufficient to provide safe and reliable service.

California does not specifically mention the NESC but does say PUC shall consider, among other things, "applicable codes" in setting its standards.

Montana has few or no rules beyond the NESC and requirements of regional reliability councils.

Ohio has adopted the NESC.

Massachusetts requires distribution companies to file reports each year comparing the performance during the previous calendar year to the service quality standards and any applicable national standards adopted.

Arizona proposes to extend the existing Commission rules regarding requirements to meet NESC, ASME Boiler & Pressure Vessel Codes and "applicable ANSI codes and standards" to any non-utility generator.

From a report to the House of Representatives - "The electric industry in **Delaware** should be restructured based on six principles, one of which is *Current public policy goals of customer equity, safety reliability, environmental protection, and economic development should be maintained.*"

A **Michigan** staff report suggests funding for employee retraining to assure that employees are not negatively impacted by restructuring. This would lead to better employee safety and public safety by assuring a work force that is familiar with the different practices caused by restructuring.

4. CUSTOMER SERVICE QUALITY AND MONITORING

4.1 MINIMUM CUSTOMER SERVICE STANDARDS

The **Ohio** PUC has proposed rules that any distribution company failing to meet the minimum standards set forth in the rules for any two months within a 12 month period shall notify the PUC and submit a report of any remedial action taken. This includes standards for timely installations. The rule also specifies retention requirements.

The **Ohio** PUC has also proposed rules on telephone response answering time for customer calls. They recommend that each electric distribution company's average answer time for customer calls not exceed sixty seconds. By definition, a call is deemed answered when the operator, service representative or automated system is ready to render assistance and/or accept information necessary to process the call. Companies using a menu-driven automated answering system must provide customers the option to transfer to a live attendant at any time during the call or if the customer does not interact with the menu. In addition, customers shall not be delayed from reaching the queue by promotional or merchandising material they do not select.

While **Indiana** has not yet established rules on this matter, a report suggests that monitoring of the incumbent companies and their marketing affiliates for unfair advantage over competitors should be an agency activity.

The **Wisconsin** PUC proposed that the utility keep a record of the length (and frequency) of delays in meeting scheduled commitments given to customers. This includes such requests as new service installs, facility modifications or relocations, meter changes, reads or tests, etc. Wisconsin proposed that the utility document all contacts and actions relative to deferred payment agreements and disputes.

The **California** statute requires that registered entities provide the PUC with access to their accounts, books, papers, and documents in investigation of customer abuse.

4.2 DISPUTE RESOLUTION

Customer Complaints

The **California** legislature mandates that the PUC continue to accept, compile and attempt to informally resolve consumer complaints. Consumers have the option to proceed with complaints against registered entities through an action filed with the court system or through the PUC. However, the same issue cannot be raised in both forums.

The California PUC recognized two categories of complaints that would require regulatory oversight and a process to resolve these problems. The two categories of problems are: 1) customer-specific complaints, where services provided do not match the customer's understanding of what was offered; and 2) market abuse where whole classes of customers are being excluded from the market or where unfair or discriminatory practices are being applied. Although the PUC has regulation to resolve disputes, they acknowledged changes should be made as the industry changes. The following six mechanisms were identified for redress where a legitimate complaint exists: 1) customers should have appropriate no cost or low-cost access to redress; 2) customers are entitled to neutral dispute resolution; 3) customers are encouraged to mediate; 4) penalties should be used to solve industry problems; 5) complainants should be able to access market data; and 6) the PUC should be able to refer patterns of abuses to other authorities.

The **Ohio** PUC proposed diligent response to customers who are subject to disconnections or emergency cases. They proposed that the distribution and electric service company shall investigate customer complaints and provide an interim report within three business days of the date of the complaints to the customer and the PUC. If the distribution and electric service company have not completed their investigation within ten business days they are required to provide an update to the customer and/or PUC. Five business days after completion of the investigation, the utility must provide the results to the customer or PUC staff. The utility is required to notify the customer that the PUC staff will mediate complaints, if the customer disputes the findings. Additionally, the PUC proposed that the utility make good faith efforts to settle unresolved disputes, including meeting with customers at a reasonable time and place.

The **Pennsylvania** PUC proposed that customer complaints should be processed timely and efficiently. The PUC agreed to allow the parties flexibility to develop a process that works best for each disco and supplier. However, the process developed must comply with PUC guidelines.

According to the **Wisconsin** PUC's proposed rules, when a dispute occurs, the utility shall: 1) investigate the matter promptly and completely; 2) advise the customer of the results of the investigation; and 3) attempt to resolve the dispute. After the customer has pursued the available remedies with the utility, he or she may request the PUC staff informally review the dispute and issue an informal recommendation of settlement. Informal reviews may be made orally or in writing. The PUC may request the utility to investigate the dispute and respond in 5 business days. Extensions may be granted to allow additional time to complete an investigation. PUC staff shall make informal determination for settlement and communicate to the utility and customer by phone or mail. There shall be 7 days between the date the PUC staff telephones or mails written notice of terms of settlement after informal review and any subsequent disconnection. Either party may request a formal review. Within 7 days of the request the PUC shall determine whether to grant a formal review. Either party may request the PUC to reconsider its formal determination. Request for formal determination must be within 20 days of the PUC decision.

The **Maryland** PUC finds that the existing customer service protection should be maintained including the disclosure of terms and conditions of service, billing requirements, privacy protection and dispute resolution procedures.

The **Vermont** PUC envisions that appropriate alternative dispute resolution mechanisms be created and that necessary support staff to manage increased workload be obtained. Funding for this function may be supported by service providers who generated the costs.

Oregon uses "At Fault Customer Complaints" as one of eight service quality performance measures which can penalize company by up to $1,000,000 per year for each of the eight variables.

<u>Dispute Resolution</u>

The most common theme from other states' analyses is that the number and complexity of disputes will increase substantially in a competitive electric environment. A **Vermont** PUC report specifically stated that jurisdiction over consumer abuses should extend to all new competitive providers and should include matters such as unfair trade practices, including fraud and misrepresentation. Section 21 of the July 16, 1997, Nevada Statute includes language establishing a consumer relations division for the purpose of dealing with disputes. **Wisconsin**, along with several other states, laid groundwork detailing how disputes would be dealt with procedurally.

4.3 CUSTOMER PRIVACY RIGHTS

Customer privacy issues have not been addressed in great detail in other states. **California** has determined that individual customer specific information is to be considered private unless customer consent is given. However, group data are to be considered public information. **Delaware** and **New Hampshire** are studying ways in which customers can protect their names and phone numbers from being made public. The most common theme regarding privacy is to require customer consent before releasing information. This has been used in several states to date.

Massachusetts, in DPU-96-100, has language that details the Federal Trade Commission's telemarketing and Consumer Abuse Protection Act. Massachusetts believes the current statute relating to telemarketing activities is adequate and will attempt to educate the public as to what is included in this statute. **Maine**, in Docket No. 97-590, is also investigating whether the federal rule is adequate or if Maine should expand on it.

APPENDIX C

QUESTIONS AND RESPONSES TO DATA REQUESTS

The data queries, sent out March 3, 1998, were not comprehensive. This was deliberate. Staff did not send out questions on topics for which they already had access to information adequate to form a policy position. The judgment of what to ask and not to ask was made with the understanding that the Advisory Group would, in any case, have a later opportunity to fully contribute their insights and suggestions.

Each of the questions sent out are listed below in bold Italics, followed by only a brief summary of responses given. Copies of the full individual responses are available upon request.

General Policy Questions and Responses[50]

I. Reliability Questions

1. ***If the Iowa Utilities Board were to impose uniform standardized indices of system reliability:***

a) ***Which measures would you propose for application to <u>all</u> investor-owned utilities? Provide all associated definitions and formulas.***

b) ***Which measures would you propose for application to cooperative and municipal utilities? Provide all associated definitions and formulas.***

c) ***Should there be a difference between what's required for investor-owned utilities and what's required for cooperatives and municipals? If yes, explain fully why.***

MEC proposes the use of SAIFI, CAIDI, and CAIFI for assessing system reliability. These same indices should be applied also to RECs and municipal utilities. "It is fundamental that the same standards be applied to all utilities."

ALT recognizes that most utilities calculate SAIFI, CAIDI, and SAIDI but notes that comparison on these indices among utilities is inappropriate. Differences among utilities (like in philosophy, policies, procedures, definitions, infrastructure, and technology) all impact the indices' values. An

[50] These questions were sent to all members of the Advisory Board.

example is the difference between infrastructures required in a rural versus an urban market. Another example is the differences in accuracy and validity of inputs that come from an automated system versus a manual system of tracking reliability.

IAEC proposes that a task force be assigned to determine a reasonable standard and then a survey should be made of utilities to see if the selected standard would have been met in the last 10 year's outage history. Different standards should be developed for (1) rural versus urban facilities, (2) transmission facilities, (3) sub-transmission facilities, and (4) distribution facilities. However, these standards should apply equally to all utilities. Northwest Iowa Power Cooperative (**NIPCO**) adds that reliability can be assured by adherence to Inspection and Maintenance Plans approved by the Board. Uniform standards, such as the NESC and NEC, should be used by all utilities.

IAMU states it has no position at this time on what should be measured or reported. However, municipal utilities should be exempted. Also, new state standards may not be necessary for generation and transmission reliability. FERC currently has a policy-making docket (PL98-3-000) open on this.

2. ***If the Iowa Utilities Board imposed new reporting and recording standards:***

   a) ***What indices should be reported and which just accumulated and provided upon request?***

ALT recommends that each utility continue to track their own indices and provide these to the Board on request.

MEC is in the process of installing a new automated electric outage management system and recommends that a utility should not have to extensively modify its entire recording system to support indices other than the SAIFI, CAIDI, and CAIFI that it now can provide. The addition of ASAI or SAIDI would not be a problem.

IAEC notes there is little difference between "recording" and "recording and reporting" and, therefore, proposes that selected indices all be reported in annual reports to the Board. It is also critical that definitions of reporting criteria are all commonly understood.

IAMU states requiring municipal utilities to collect or report reliability measure is unnecessary and would be unduly burdensome. Most utilities are just too small and lack the staff and technical resources.

OCA states that all relevant indices currently being accumulated should be reported.

b) Should the indices in the report provide for just aggregate performance or should it provide circuit level data?

ALT notes that the ability to track reliability by circuit is dependent upon using an automated system. Not all of ALT is yet automated. Also, because of significant differences among circuits (e.g., overhead or underground, urban or rural, three phase or single phase, etc.), comparison of "relative reliabilities would require additional knowledge above and beyond what the indices can provide."

MEC suggests only aggregate indices be reported. Detailed circuit data, along with other pertinent data, should be used internally. Circuit-by-circuit comparisons are inappropriate due to many differences that exist among circuits.

IAEC state that indices should be reported at the distribution substation level at the minimum with consideration given to the distribution multi-phase circuit level. However, these data are only available on the aggregate level for some RECs and would take time to compile for lower levels.

OCA responds: "Circuit level."

c) ***Should a list of poorly performing circuits be part of a publicly available annual report?***

ALT is concerned that such a list would be misunderstood and states it is not reasonable or possible to provide an accurate list. **MEC** argues that such a list may "not be indicative of a situation requiring remedial action" and, in any case, is concerned that such a listing could result in undue and unnecessary public concern. In contrast, **IAEC** argues that such a list is a necessary tool for the Board to enforce performance standards. **OCA** gives a simple "Yes."

d) ***If annual reports of reliability indices, perhaps even at circuit level, were required, what filing date would you propose? What standard template form for this report would you recommend?***

Both **ALT** and **MEC** propose June 1. The template should require name of reporting entity and its geographic areas. **IAEC** suggests a simple template and filing on March 31. OCA gives December 31

e) ***Should reporting of major outage events include not only the number of customers affected and the longest interruption, but also number of crews assigned to restore service?***

ALT, **MEC,** and **IAEC** all answer "No." The size of the crew is related to the nature of the outage and extent of repairs and not by the number of customers affected. Only the **OCA** states the number of crews assigned should be given.

3. ***Do you have a developed position on how to best assure reliability in a restructured industry? If yes, please provide. [Inclusion of a copy of referenced materials is appreciated.]***

ALT states that the Board could adopt reliability standards but the Board should not add new measures or try to micro-manage. Regulators should reward utilities for improving reliability but not punish for failing to meet a predetermined index. They suggest a "system of PBR applied to several important customer requirements. At this time, ALT proposes the following: (1) emergency response; (2) total customer outage minutes in lieu of indices like SAIDI; (3) billing accuracy; and (4) call center performance.

Regarding the "condition, operation and maintenance of delivery facilities," **MEC** states that "to the extent bifurcated regulation remains the norm, it is critical that state and federal regulators do not adopt inconsistent reliability criteria for the portions of the delivery system that they claim to regulate." Disputes among states and federal authorities on this may actually endanger reliability.

MEC is also concerned about the impact on reliability of "improper administration and use of the delivery system," especially as they interface with multiple suppliers and multiple users. Will there be a shift of these functions from the control area operator to an ISO? State legislation should address the question. Also, since an ISO would need control over most of the delivery system (including the state-regulated portion), there is a need to resolve jurisdictional uncertainties and clearly designate who is responsible for doing what.

IAEC, at time of responding, did not have a developed position. **NIPCO** states that it may be appropriate to require separate service quality standards for suppliers and distributors because supplier outages generally affect more customers.

IAMU states that municipal utilities should be excluded from proposals to address reliability and quality of service issues. Their regulation and governance will not change with restructuring. The risks to reliability rest more in the area of IOUs. It is inappropriate, and wasteful of already scarce regulatory resources, to try to level the playing field while obscuring rational differences in treatment.

OCA, at time of responding, did not have a developed position. However, it was noted that for generation reliability, a Board electric supplier certification process is appropriate as is requiring that all electric suppliers be affiliated with a power pool and reliability council in the future. As to transmission and distribution reliability, the Board will likely continue its current jurisdiction and that is adequate.

4. Should the electric industry in Iowa move from voluntary efforts to mandatory requirements in order to assure reliability and quality of service under a restructured industry for each of the following?

a) Investor-owned utilities?

b) Municipals?

c) Cooperatives?

Both **ALT** and **MEC** say “No.” If more oversight is needed, ALT suggests a PBR mechanism to encourage reliability. MEC would resist a move to mandatory requirements or increased oversight unless a definitive showing of the need is made. If there were deterioration in reliability or quality of service, then alternatives would need to be explored via some forum of stakeholders.

IAEC states that mandatory requirements for reliability and quality of service will be necessary if retail access and customer choice are mandated. Without these standards, some utilities may collect tariff revenues and let facilities deteriorate.

IAMU states that indices of reliability may be useful to the Board in its continuing regulation of the distribution monopoly of IOUs, but municipal utilities should not so burdened.

OCA simply says “Yes” to all three parts of the question.

The American Association of Retired Persons (**AARP**) proposes that the Board be authorized to establish mandatory minimum standards of service quality and reliability for electric service. In addition, they should have authority to enforce these standards and administer severe penalties for non-compliance.

5. Does the Iowa Utilities Board have adequate authority to force mandatory compliance to reliability and quality of service rules for each of the following. If not, what specific authority would be needed.

a) Investor-owned utilities?

b) Municipals?

c) Cooperatives?

ALT states that the Board has authority to assure IOUs' safe and reliable service. However, it is unclear how that authority is separated and demarcated from that of FERC. **MEC** is quite concerned that state and federal regulators resolve their jurisdictional disputes. **IAEC** opines that these questions require a legal interpretation.

IAMU states the Board may need additional authority to facilitate regional approaches to transmission planning and siting which impact transmission system reliability.

OCA states the Board has adequate authority with respect to all three types of utilities, at least for transmission and distribution reliability objectives.

II. Safety

1. How do the existing safety standards, per IOWA ADMIN. CODE 199-20.8 and 25.5, live up to or fail to provide useful information to the utilities, the Board, and the public?

MEC, IES Utilities Inc.(**IES**), **and IPC** indicate that their safety records are testimonials to the sufficiency and usefulness of the existing framework. IAEC recommends that the reference to NESC 1987 clearances found in 25.2(2)b.4 be eliminated. The NESC, or most recent edition, would be more useful than the 1987 version. **IAMU** states that the existing standards will ensure continued quality service while protecting the safety of utility workers and the public. **OCA** says satisfactory.

2. The purpose of uniform standards will insure adequate service and secure safety to all persons engaged in the construction, maintenance, operation, or use of the systems and to the public in general. Please list the uniform standards that you would propose must be followed by all utilities.

MEC, IES, IPC, IAEC and **IAMU** state that the current standards should apply. **IAMU** notes that new standards for operator certification and training are being developed within NERC and that the continuing commitment to safety can be seen by the growth of the Association's safety programs

3. ***Will it be necessary for changes in the Iowa law or rules to ensure adequate safety, if competition in generation was allowed? If yes, what?***

IES, IPC, and **OCA** state that no changes in Iowa rules will be required. **MEC** suggests looking at the response to Question I.3.

III. Inspection and Maintenance

1. ***Inspection and Maintenance Plans are currently required in IOWA ADMIN. CODE 199-25.3 which implicitly protect public safety through its standards for the construction, operation, maintenance, and use of electric utility overhead and underground distribution and transmission systems and substations. Are these rules adequate or should changes be made?***

IAMU, OCA, IAEC, ALT, and MEC indicate that the present Inspection and Maintenance Plans in IAC 199-25.3 are adequate and no other additional rules are needed. **ALT** has started to use a predictive maintenance program (PdM) that, in the ideal case would schedule maintenance just before failure, thereby avoiding equipment outage or maintenance not required.

2. ***Will it be necessary for changes in the Iowa law to ensure adequate inspection and maintenance, if competition in generation was allowed? If yes, what?***

OCA, ALT, and MEC indicate that no new Iowa laws would be needed to ensure adequate inspection and maintenance, if competition in generation was allowed. **IAEC** feels a legal interpretation would be needed to answer this question.

IV. Other Questions

1. ***To what extent do you anticipate a need for changes in interconnection procedures in order to maintain the integrity of the electricity system while avoiding barriers of entry for alternative suppliers in case competition in generation is allowed?***

MEC does not anticipate a need for change in their current procedures. Nor does **ALT**, except possible as required by an ISO.

The Department of Natural Resources (**DNR**) recommends the Board establish standardized interconnection procedures for alternative energy providers. This should not be unduly burdensome and should include standards for liability insurance.

NIPCO states that interconnections should be based on single contingency and stability planning as done on a regional basis.

AARP supports the establishment of an ISO to maintain the integrity of the electric system while avoiding barriers of entry problems. **OCA** states the reasonable interconnection policies should be allowed.

2. ***Customer privacy has become an issue in some restructuring efforts. Staff is concerned that information given to utilities by customers could have value to other entities and could be sold.***

   a) ***Explain your view on customer privacy if the Iowa electric industry is restructured. In this analysis, address what types of customer information should be public and what information should be private.***

   b) ***What types of mechanisms could be used to guarantee that customer information is kept confidential?***

MEC was very clear in believing that all customer data was an asset to the company, and therefore the property of the shareholders. Data is only released upon consent of the customer. The sole exception is the release of usage patterns for properties required under IOWA CODE § 476.56.

ALT supports current law and believes the release of individual customer information should only be allowed with customer consent.

IAMU notes that it must comply with the open meeting and public record laws. IAMU would request that it be allowed to address the public records provision of the Iowa law in any proposed legislation.

OCA believes that no customer information should be released without customer consent.

AARP also believes that customer information should be kept confidential unless written authorization is obtained.

IAEC believes that name, address, service provider and delivery voltage should be public with all other data being private. IAEC also believes that confidentiality agreements may be necessary to guarantee customer privacy. However, they do also agree that this type of agreement may deter optimal effectiveness.

3. ***Should the Board monitor service quality? If yes, how specifically would you suggest that the Board do this?***

ALT proposes no change in service quality and monitoring. It would be impossible to develop a tracking mechanism that would be meaningful to all utilities. It is the company's perception that strict policies reduce flexibility and the ability to be innovative in a competitive market. ALT suggests the utilities be rewarded through economic incentive for performance. They recommend using PBR using emergency responses, electric reliability, billing, and call center performance to evaluate and reward utilities.

IAEC and **MEC** are in agreement with ALT that it is impossible to establish standards for quality of service and monitoring compliance. They believe the current Board's complaint process to investigate complaint is an effective tool.

OCA responded with a simple "yes".

AARP suggested that the Board establish standards for quality of service and monitor compliance to ensure residential customers benefit from restructuring. AARP believes the Board should be allowed to penalize the company when they do not comply with the standards.

4. ***Is it appropriate for the Board to require separate service quality standards for suppliers and distributors?***

ALT expressed that there may be a need for separate service quality standards.

AARP recommended imposing requirements to ensure the quality of service "is as good as the present quality of service provided by the regulated electric utility".

OCA believes there should be separate service quality standards for suppliers and distributors.

IAEC suggests there may need to have different standards for suppliers and distributors depending on the how the terms are defined.

MEC suggests separate standards make sense in most cases.

Technical Questions and Responses[51]

I. Reliability Questions

1. What measures[52] does your company currently use to measure and track reliability?

a) ***Provide precise definitions and equations for each measure generated and/or used by your company. Also any operational decision guides for application to incoming data. Also your procedures and practices for maintenance of records of data and analysis.***

IES uses the SAIDI index, but can also produce other indices. **IPC** uses SAIDI, SASAI, CAIDI, and SAIFI indices. The last index is calculated separately for sustained and for momentary outages. **MEC** uses SAIDI, ASAI, CAIDI, CAIFI and SAIFI.

IAEC states that the RUS guideline of no more than 1 outage hour per customer is applicable to the G&T's operations while the standard of no more than 5 outage hours per customer is applicable to the distribution REC. The significance of outage hours must always be analyzed in context--e.g., cause of outage, rural versus urban, incidence of storms. **NIPCO** notes its only measure of reliability is substation outage hours on an aggregate basis.

IAMU states that practices vary widely and that most municipal utilities track little of the data necessary for reliability indices. A few larger ones use ASAI and CAIDI.

See **APPENDIX A** for the definitions of these indices.

b) ***Specify the levels of the system (utility wide, primary distribution circuit, or other) for which measures provided under "a" above are applied. Name the districts or divisions for which you track reliability separately.***

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[51] These questions were aimed primarily at the utilities but were also sent to parties judged to have technical interests and/or knowledge. The mailing included IES, MEC, IPC, IAEC, IUA, IAMU, OCA, and IBEW--Local 204. Although recently merged, IPC and IES are referenced separately for the technical questions (which deal with the present and the past) while ALT, the newly merged result, is referenced for the forward-looking policy questions.

[52] Examples of indices include, but are not limited to: System Average Interruption Duration Index (SAIDI); System Average Interruption Frequency Index (SAIFI); and Momentary Average Interruption Frequency Index (MAIFI).

IES uses a utility-wide measure, but could produce individual circuit measurements. **IPC** measures are tracked utility-wide, by state, by district, and by primary distribution circuit. **MEC** has two separate systems (east and west) to track reliability data. The west is more manual and allows for assessment only at the system level. The east is more automated and allows for assessment down to the customer level.

IAEC states that outage data for distribution RECs are generally provided on a system-wide basis although some apparently compile data by substation, circuit and phase. G&Ts generally record outage data by substation, distribution REC, operating district, and by total system.

c) ***How, <u>specifically</u>, are storms and other extraordinary events handled in each of these measures? If these are excluded, what precisely defines when and if an event should be excluded?***

IES excludes storm-related outages when SAIDI is greater than 10 minutes. **IPC** reviews major storms on a case-by-case basis with only very rare exclusions taken. **MEC** does not exclude storms and other extraordinary events. **IAEC** members, for the most part, exclude the effects of storms and acts of god.

d) How do you arrive at an affected customer count when only part of a circuit is down?

IES and **IPC** appear to both use estimates based upon reference to maps. For **MEC,** the computerized outage management for the east system produces estimates based upon its files while the west system is based more on manual estimates. **IAEC** typically count consumers past the affected device.

e) How is the beginning of an outage identified by your utility?

This typically is initiated by a call from a customer (**IES**, **IPC**, **MEC**, and **IAEC**). However, awareness may also be sparked by some automated equipment or sudden drops in load or a SCADA[53] signal.

f) How is the end of an outage defined by your utility?

[53] Supervisory Control and Data Acquisition System. The primary function of a SCADA system is to automatically collect data (such as line kWh, line amperes, bus voltages, breaker positions) from substations and generating stations. The second function is supervisory control which permits the operator at a central location to operate on/off or raise/lower types of devices remotely while following the result of such actions through the data-acquisition portion of the system. Some of the SCADA functions are breaker control, tap-changing transformer control, generator start/stop control, voltage and var control, system alarming, and line load monitoring.

For **IES**, **IPC**, and **MEC,** an outage is considered ended when utility facilities are restored to the point of customer attachment. **IAEC** states this is typically the meter for distribution RECs and the delivery point substation for G&Ts.

g) ***Do your reliability measures give equal weight to the following two types of customers for the same outage: a single residential customer and a single REC or municipal customer who may have hundreds of end-users disadvantaged by your outage?***

All IOUs appear to count only their specific customers in their measurement indices (**IES**, **IPC**, **MEC**). However, larger customers and those with a public safety concern may get priority for restoration of service. **IAEC** measures apparently do count the number of customers served by customers for G&Ts.

h) What, if any, method could be used to assure that reliability indices reflect actual end-users disadvantaged and not just defined customers of the reporting utility?

Summary: The IOUs (**IES**, **IPC**, **MEC**) appear to feel it is the responsibility of the connecting utility (in this case the REC or municipal) to track end-user indices. **IAEC** suggests that all end-use residential, commercial and industrial customers be counted.

i) Are incidents of high or low voltage counted in your outage statistics?

Not for **IES**, **IPC** or **MEC**. **IAEC** states it might be recorded.

j) For the outages caused to some customers in the process of restoring power, are the additional interruptions counted in the indices? Are the durations of these additional outages included in your indices?

IES does not include either the additional customers or duration incurred in the process of restoring power while **IPC** and **MEC** do. **IAEC** states not for distribution RECs but maybe for the G&Ts.

k) Explain fully your company's operational decisions, data gathering, record keeping, and calculations currently used to comply with Board Rule 20.2(5)c.

Both **IES** and **IPC** generate an outage report whenever more than 1000 customers are without power for more than one hour. In addition, if the outage impacts over 5000 customers, a call to the Board Engineering Section is made.

Data gathering, record-keeping and monitoring the magnitude of outages to determine if a report needs to be filed is part of System Operations for **MEC.** The east system is currently computerized while the west system is still manually generated.

IAEC states that the 2 percent rule is not reasonable for RECs and suggest a better guideline would be annual reporting instead of immediate reporting.

2. ***How are the reliability measures discussed in the prior question used specifically to affect operations--e.g., maintenance or investment decisions?***

   IES links outage information down to individual lines, considering root cause and benefit/cost analysis to suggest improvements. **IPC** identifies poorly performing distribution circuits based on interruption indices and focuses on improving those circuits. **MEC** uses the indices to identify problems, investigates causes, and schedules maintenance and improvements on benefit/cost basis.

   IAEC states that these measures may effect maintenance by causing adjustments to maintenance schedule or immediate on-site repair, as well as identifying problem areas. Cost must also be considered.

3. ***Provide the most recent ten-year history of any and all reliability measures you currently generate and/or use. [If a full ten years is not available, provide for the years that are available.]***

   IES provided SAIDI history back through 1994 while **IPC** provided annual figures for SASAI, SAIDI, CAIDI, AND SAIFI (for both sustained and momentary outages) and other data back through 1991. **MEC** provided annual figures for ASAI, CAIFI, SAIFI, CAIDI, SAIDI back through 1991, except CAIFI was not available for the west system.

4. ***If available, provide the percentage breakdown of annual outages due to each of the following levels: distribution, transmission, and generation. Do this for each of the last 10 years.***

   This is not available for **IES**, **IPC**, or **MEC.**

5. ***Provide the name and phone number of company employees authorized to discuss technical details regarding reliability and quality of service issues.***

   IES & **IPC:** Dave Broihahn at (319) 557-2287.

MEC: Robert Jared at (319) 333-8005

II. Safety Questions

1. *What measures[54] or standards do your company currently impose to reduce the possibility that an accident[55] to an employee or other person does not repeat?*

IES and **IPC** state that all lost time accidents are formally investigated. Recommendations are implemented and lessons learned are shared with all field employees. **MEC** investigates the accidents and analyzes the results. If warranted, changes are made to safety policies and procedures or operating standards as appropriate. Changes are communicated to employees through monthly and quarterly safety meetings and there is training on the appropriate safety policy, procedure or operating standard. **IAEC** has compliance with NESC, Iowa Occupational Safety and Health Standards (IOSH), Administrative Rules (IAC), Iowa Department of Transportation, along with a thorough and complete accident investigation aimed at prevention. RECs monitor accidents individually and in aggregate. All RECs have on-going training in hazard recognition, and comprehensive safety and health training programs for all employees. Monthly safety meetings are held to discuss the OSHA required safety topics.

2. *Provide the name and phone number of the company employees authorized to discuss technical details regarding safety issues.*

IES: Robert McCracken at (319) 398-4155.
IPC: Larry Kirby at (319) 582-5421 ext. 407.
MEC: Robert Jared at (319) 333-8005

III. Inspection & Maintenance Questions

1. *What standards exist within your company for service response times to maintenance problems?*

IAEC states that reliability, safety, and clearance matters are handled immediately. Board safety inspection reports also receive immediate attention. Otherwise periodic maintenance review items are completed within 1 year. **IES, IPC, and MEC** all indicate that there are no exact standards for service response times. Electric system outages and hazardous defects or conditions that would jeopardize public safety are corrected immediately. Other abnormalities noted are sorted and scheduled

[54] See IAC 199-20.8(1).

[55] An accident is defined in IAC 199-25.5.

by management personnel and are repaired based upon threat to the public or outage, other work and rebuilds in the area, lines physically accessible, and resources available.

2. ***Provide the most recent ten-year history of the number of maintenance supervisors and workers, miles of electric lines, and number of customers or meters for your company. [If a full ten years is not available, provide for the years that are available.]***

IES provided its customer count for the past 6 years, the miles of lines for the past 4 years, and the number of supervisors and workers for the past 2 years. **IPC** provided its customer count and miles of line for the past 6 years and the number of supervisors and workers for the past 4 years. **MEC** provided its customer count for the past 7 years, the miles of lines for the past 10 years, and the number of supervisors and workers for the past 4 years. However, the miles count has some incomplete data.

3. ***Have procedures for working with other utilities during emergency situations changed in the last few years. If yes, in what way?***

IAEC indicates no major differences. **IES, IPC, and MEC** indicate no changes.

4. ***Provide the name and phone number of the company employees authorized to discuss technical details regarding inspection and maintenance issues.***

IES and IPC: Dave Broihahn, General Manager of Customer Operations at (319) 557-2287. **MEC:** Robert P. Jared, Senior Attorney-Energy Delivery at (319) 333-8005; FAX (319) 333-8021

IV. Other Questions

1. ***Provide any statistics and analysis of call center response over the last ten years.***

IES data shows that over 90 percent of telephone calls received are answered. Staff is unclear if the abandoned calls are those that are hung-up because they are put on hold or in cue that receives a busy signal.

IPC has no data because they do not use a centralized center.

IAEC has no data but notes that some RECs are moving to a 24 hour dispatch with trained dispatchers.

MEC provided information on call center from January 1997 through February 1998.

Additional information was requested regarding the increase in abandoned calls in January and February 1998 when compared to the same time in 1997. MEC contributed two reasons for the increase in abandoned calls: 1) increase in trunk line capacity and 2) consolidation of the three call centers into one. Instead of customers receiving a busy signal, customers' call are placed in call queue. Some customers hang up and tended to call back.

When the call centers consolidated, the company had to hire and train employees. At first, the new employees were not as prompt in responding to inquirers.

2. ***Provide any statistics and analysis of company's response to billing problems over last ten years.***

IPC, **IES**, and **MEC** all state that these statistics are already furnished to the Board on an annual basis.

3. ***Provide any statistics and analysis which addresses whether there has been any change in amount of time taken to read meters for new, changed, or terminated service?***

The meter reading procedures, and time required, at **IPC** and **IES** have been stable for some time. **MEC** does not maintain statistics on this.

4. ***Does your company define critical customers? Is reliability to this group tracked separately?***

MEC does not track reliability of customer groups separately although the standards are the same for each customer. Both **IPC** and **IES** are sensitive to the needs of critical (health) customers but do not track reliability separately.

5. ***Is your company participating in reliability councils? If yes, give details for each involvement. What future expectations are currently held?***

IPC, **IES**, and **MEC** are currently members of MAPP and all will likely continue to participate in a regional reliability council in the future.

V. For MidAmerican Energy Only

1. ***In a letter on January 30, 1998, to the editor of Quad City Times, Stan Bright states that "in 1997, an unusually stormy year, . . . electric reliability was greater than 99.99 percent." What methodology and***

data were used to make this assertion? How does this compare with past 10 years?

This was based upon the Average System Availability Index (ASAI).

APPENDIX D

SUMMARY OF COMMENTS TO DRAFT REPORT[56]

ALPHABETIC LIST OF RESPONDENTS

- Alliant (ALT)
- Department of Natural Resources (DNR)
- Iowa Association of Electric Cooperatives (IAEC)
- Iowa Association of Municipal Utilities (IAMU)
- Large Energy Group (LEG)
- MidAmerican Energy (MEC)

ALLIANT (ALT)

General

- An emphasis on performance measures should be sought rather than the adoption of reliability standards with the necessity of creating huge unmanageable and unhelpful databases.

Bulk System

- Reserve margin requirements and customer load forecasts may not be workable where generators are no longer required to serve specific customers.
- Regional planning organization, market price signals, and/or penalties may be better than reserve margin requirements and load forecasts for assessing and encouraging long-term supply adequacy.

Reliability Standards

Assessing and Assuring

- Rather than imposing specific indices, the Board should consider requiring each utility to file a reliability plan detailing indices they will report, including specific targets and timelines. Accountability might tie to a performance-based ratemaking (PBR) approach.
- However, if standards and indices are imposed, then they should apply uniformly to all service providers irrespective of the ownership (IOUs, Municipals, or RECs) and be imposed at a system level with the utilities managing to those levels.

[56] This is a summary of comments received in response to the Draft Reliability Report issued in September 1998.

- The Board would need to provide calculation rules to insure consistency among service providers.
- The Board might want to consider separating factors that influence reliability indices into controllable and uncontrollable categories.
- The use of worst performing circuits may reach a point of diminishing returns.
- The number of distribution circuits are so great as to make reasonable utilization of data unlikely.
- Managing reliability at the customer level would be too cumbersome and unmanageable.
- Information on "age, condition, and performance" of delivery facilities is spotty, and a report would require costly inventorying. ALT questions whether such information can be utilized cost-effectively.
- ALT concurs with itemized policy considerations but would focus on rewarding excellence (via a PBR mechanism) rather than punishing failure.
- ALT concurs with some, and takes exception to other, proposals suggested by the report for rulemaking.

Nondiscriminatory Basis

- ALT supports this proposal.

DEPARTMENT OF NATURAL RESOURCES (DNR)

Bulk System

- DNR agrees with the recommendation to establish standardized interconnection procedures for alternative energy providers. This should include standards for liability insurance.

IOWA ASSOCIATION OF ELECTRIC COOPERATIVES (IAEC)

General

- Regulatory goals of restructuring should be: 1) to maintain the reliability of the delivery system, and 2) to provide nondiscriminatory delivery access to users.
- "Reliability of the delivery system is key to the success and facilitation of the market interactions in a bilateral contract market."
- Concerns and recommendations are likely to change as a result of additional staff reports.

Glossary Suggestions

- The staff report should adopt the terminology developed in the ABI sessions.

Bulk System

- The cooperatives believe that planning for future generation is best addressed through the competitive market with little, if any, regulatory intervention.
- The reliability of generation should be subject to 1) contracts between parties, including consumers, and 2) the requirements of the regulated Control Area Operator rules or the facilitating transmission entity (e.g., possibly, an ISO).
- The competitive energy market will efficiently and effectively balance the necessary generation reserve margins.
- Iowa's new statute should not contain any specific reserve requirement, which might impose a competitive disadvantage to Iowa generation, with adverse impact on economic development.
- To encourage reserve sharing, each generation participant should be a member of a regional reliability council.
- A minimum level of formal requirements for local and regional transmission planning should be established although, at this point, it is difficult to tell where and how.

Licensing

- The purpose of establishing licensing requirements is to assure that consumers actually receive competitive products and services.
- Costly, over-developed licensing procedures should be avoided. Consumer protection is also afforded via default provisions and universal service mechanisms.
- "The licensing criteria should encourage a competitive generation market, erect minimal barriers to entry, and focus primarily, if not exclusively, on the financial capability of the entity selling the energy to Iowa consumers."
- Licensing requirements should include:
  1. A bond to assure financial commitment.
  2. A requirement to maintain a corporate office in Iowa.
  3. Information to allow Board contact.
  4. A requirement to participate or be a member in the appropriate transmission facilitator (or ISO).
- Application for licensing should be quick; three months could constrain market development.
- "All existing cooperative providers should be grandfathered initially as retailers and aggregators operating inside or outside their service area as a cooperatively structured retailer or as a for-profit entity."

Reliability Standards

Assessing and Assuring

- The requirement to collect and report the information cited on pages 36 and 37 of the draft report is inappropriate in a competitive generation market and heightens entry barriers.
- IAEC argues the Board authority over them is limited to power quality and safety issues and whether it covers reliability would require a judicial interpretation.
- Minimum requirements for reliability and quality of service in the regulated transmission service should apply to IOUs, Municipals, and RECs while being sensitive to the differential nature of rural systems.
- Small market participants may be unduly burdened by some of the proposed filing requirements.

Power Quality

- As the new market develops, power quality concerns become greater, and the Board should counter lowered power quality driven by consumer-side activities.

Inspection and Maintenance

- The Board's inspection and maintenance policy positions should continue but for jurisdictional facilities only.

Safety Oversight

- The Board's safety oversight should continue, except in the case where a new cooperative may be established.

Customer Service Quality

Minimum Quality of Service Standards

- IAEC disagrees with any proposal that imposes quality of service standards (via the code of conduct within the licensing process) upon the new generation retailers.
- Service connection is the responsibility of the Delivery Service Provider.
- Requirements for changing suppliers should be addressed during implementation planning by establishing notification and interaction requirements for retailers and other market participants.

Disputes and Sanctions

- The Board forum to resolve disputes and complaints should be limited to both investor-owned distribution utilities and service and safety requirements of those entities under its jurisdiction.

- Disputes between consumers and a cooperative should go to the local governing board and then district court.
- A code of conduct is necessary for transactions between regulated and non-regulated affiliates, but any imposed on cooperatives should be less restrictive than that imposed on IOUs.
- No new Board authority to impose sanctions is necessary.
- Complaint-processing fees should be imposed upon a jurisdictional entity at fault. This could also include a nominal fee upon the complaining party.

<u>Customer Privacy</u>

- Consumer information should be held as confidential and released only upon receipt of a signed consumer consent form.
- Distribution entities should not have to maintain a public list of all customers requesting not to be called.
- A review of consumer protection rules and their applicability should be undertaken, balancing the desire to encourage a competitive market with the need to protect consumers.
- While in agreement with the need for a consumer education program, the cooperatives wish to retain control of any program funded by their monies.

IOWA ASSOCIATION OF MUNICIPAL UTILITIES (IAMUs)

Glossary Suggestions

- The definition for Alternative Energy Producer (AEP) should refine what is meant by small hydroelectric facility.

Bulk System

- IAMU agrees that one system operator should coordinate the use of the state's transmission system and should be truly independent of market participants. This is a minimum prerequisite to retail competition.
- A truly independent system operator should prevent market power though the operation of transmission, provide reasonable and equitable access, and safe and reliable operation.
- It is not necessary to require all incumbent generation suppliers (IGSs) to be members of NAERO and the regional reliability councils. It is only necessary that the end-use obligation for all IGSs be included in the calculation of reserve capacity.

Licensing

- Municipal utilities, even those who elect to serve customers outside their service territories, should be exempt from licensing requirements.
- Municipal aggregators should also be exempt.

Reliability Standards

Assessing and Assuring

- Municipal utilities should not be subject to the uniform requirements for tracking system outages through standard indices.
- Requiring the collection of outage data by municipal utilities that serve customers outside their service areas creates an artificial barrier to entry. By definition, the delivery would be over the delivery systems of another utility and that transmission would be subject to regional reliability standards.

Inspection and Maintenance & Safety Oversight

- Municipal utilities are currently required to maintain safety inspection plans and are subject to inspections of facilities and records by Board staff. IAMU anticipates this will continue.

Customer Service Quality

Disputes and Sanctions

- It is neither necessary nor prudent for the Board's complaint authority to be expanded to cover municipal utilities.
- Expansion of Board authority fails to acknowledge the Board's limited regulatory capacity that is not apt to grow with restructuring.

LARGE ENERGY GROUP (LEG)

General

LEG's "fundamental concern about system reliability is that is does not deteriorate from its current level following re-structuring." However, LEG feels continued regulation of the delivery system adequately addresses the concern that competitive pressures may reduce preventive maintenance.

Glossary Suggestions

- LEG provided definitions (and/or suggested improvements for the definitions) for ancillary service, power suppliers, power marketers, bulk power systems, distribution service, incumbent generation supplier, and unbundling.

Bulk System

- Reserve capacity requirements should be addressed by regional reliability councils and not included in an Iowa statute.

- The state should require power suppliers to be members of a power pool that is part of a reliability council.
- LEG supports the concept of ISOs. Transmission systems should be independent of supply and distribution operations.
- Generation portfolio mix is best left to the market place.
- The Board should ensure power supply reliability by allowing distribution utilities to collect penalties from customers for failure of third parties to provide supply. Consumers' bilateral contract may allow for transfer of penalty to their suppliers.

Licensing

- Regulators should register power suppliers and marketers and impose a code of conduct on all suppliers, marketers and brokers. State requirements should not conflict or be duplicative of federal requirements.
- Regulation should focus on power quality and reliability requirements and allow the market to establish technical, financial, and managerial ability. Excessive licensing requirements heightens market barriers.
- Tariffs should not be required as part of licensing; prices should be market-based.
- A statewide default provider should be an option.
- Delivery owners, not power suppliers, should have right-of-way licensing requirements.
- Any licensing requirement that power suppliers agree to continue service as long as that customer remains eligible is inappropriate.
- Requirements for back-up power should not be a licensing requirement but addressed in purchase agreement.
- Pre-determination of the customer base for licensing is unnecessary.

Reliability Standards

<u>Assessing and Assuring</u>

- Distribution will not be deregulated, and regulators should require reliable distribution service independent of restructuring.
- Traditional utility outage statistics are not adequate.

<u>Nondiscriminatory Basis</u>

- Delivery function and power supply function should be completely separate so that restoration of delivery services after outages will be on a nondiscriminatory basis.

<u>Power Quality</u>

- Power quality rules need to be updated irrespective of restructuring initiatives. Current rules do not adequately address spikes, blinks,

transients, harmonics, and power characteristics. The Institute of Electrical and Electronic Engineers (IEEE) is a good source for power quality standards.
- The Board could enforce power quality by allowing distribution utilities to charge penalties from customers for failure of third parties. Consumers' bilateral contract may allow for transfer of penalty to their suppliers.

Customer Service Quality

Minimum Quality of Service Standards

- Customer service quality should not be allowed to deteriorate after restructuring. However, competition should not be delayed until new standards are developed.

Disputes and Sanctions

- LEG supports Board jurisdiction over complaints concerning reliability of delivery service, billing, and safety issues.

Customer Privacy

- Customer information should be held in confidence and not be generally available to others without customer consent.

MIDAMERICAN ENERGY (MEC)

General

- MEC envisions generators NOT having a relationship with retail customers but only selling wholesale to Competitive Electric Supply Providers (CESPs). CESPs, not generators, would have the retail relationship and be subject to certification and reliability requirements. Any such requirement should 1) be reasonable, 2) not place anyone at an unfair disadvantage, and 3) not create a barrier to entry.
- Only the delivery function would continue to be price regulated. Other retail services such as billing, metering, etc. will be provided in a competitive market.

Glossary Suggestions

- The report should be refined to talk about CESPs instead of alternative generation suppliers (AGSs) and IGSs when talking of certification requirements and Board regulation.
- MEC also appended a Glossary of Terms that apparently represents an evolving, non-complete effort of the ABI group.

Bulk System

- The current statutes and rules regarding excess capacity will not be appropriate under the end-state competitive market. The markets, not regulators, will determine fuel mix and fuel sources and to whom to sell. State regulators will retain some review of siting.
- MAPP reserve capacity obligations will need to be revised to shift the focus from generation to delivery system operators (e.g., ISOs, GridCos) and users (CESPs and consumers) of the delivery system.
- MEC cautions that ISOs may be only one possible form assumed by the evolving delivery market.
- MEC argues that requiring generators to maintain a generation reserve margin is inappropriate and would competitively disadvantage these Iowa entities. If Iowa imposes a reserve requirement, it should be on the retailers.
- If the Board needs load-forecasting data, it should make this a condition of certification of retailers. It is inappropriate to require this data from generators.
- There will not be “utility” generation portfolios in the end-state for the Board to review.
- It should be the responsibility of the retailers to provide ancillary services such as volt ampere reactive (VAR) support and voltage support, for which they should get adequate compensation.

Licensing

- MEC agrees the Board should certify those who engage in retail sales but notes these are retailers, not generators.
- Redlining legislation should be careful not to preclude legitimate market segmentation—the very essence of competitive markets.
- Regarding licensing requirements:
  1. The Board should not be in the business of approving or identifying customer bases.
  2. Retailers should not have to file compliance tariffs.
  3. Any requirement for fuel procurement data should be imposed upon retailers, not generations. MEC questions whether adequate justification exists for any such requirement.
- It is unclear why aggregators should provide publicly available pricing information and arrangements for back-up power. And why only aggregators and not other retailers?

Reliability Standards

<u>Assessing and Assuring</u>

- The concern that delivery service reliability might be adversely impacted by competitive pressures is “totally unwarranted” as is staff’s proposal for additional reporting requirements. As long as delivery service remains regulated and reasonable cost recovery is allowed, reliability will be maintained.

- All owners of delivery service facilities, whether that of a REC, Muni, or IOU, should be subject to the same reliability standards. Smaller providers can hire automated tracking procedures done for them. Any use of "worst performing circuits" should be done cautiously and with care.

Power Quality

- MEC argues that maintaining power quality is a responsibility of the retailer and not the distributors but agrees that all new providers should meet power quality standards.

Customer Service Quality

Customer Privacy

- In the end-state envisioned by MEC, it would be ineffective and useless to require the Delivery Service Provider to maintain a list of customers who don't wish to be called by retailers.