Facts Concerning the Consumption and Production of Electric Power in Iowa

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Acknowledgements

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1.0 INTRODUCTION AND BACKGROUND

The use of electricity is pervasive in our lives. At home it is used for many things such as refrigeration, cooking, lighting, air conditioning, and heating. It is also used in many commercial and industrial applications. It is so much a part of our lives that we tend to overlook it until our service is interrupted. Many people don't realize how electricity is generated and delivered to them and other consumers, and they also might not understand the massive amount of infrastructure that is necessary to accomplish this task. To get a better feel for this task and the underlying infrastructure, a review of the basics of electricity supply and demand is in order.

Basic characteristics of electricity supply and demand include the following:[1]

- 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, the season, and the weather;
- electricity moves at the speed of light and many operational decisions must be 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 demand, generation, and transmission;
- generating capacity must be in place for all potential electric loads and provide reserves for system emergencies;
- the addition of new electric infrastructure is capital intensive and subject to long lead times; and
- a reliable supply of electricity is essential to economic development and human satisfaction.

The Utilities Board issued its first report titled, "Facts Concerning the Consumption and Production of Electric Power in Iowa" in August 2000. As with the first report, the data presented in this report characterize the electric utility infrastructure for the state of Iowa. These characterizations are the first steps in assessing and evaluating the production, delivery, and use of electricity in Iowa. Any stakeholder group may use the data compiled in this report to determine policy implications and recommendations for Iowa's electric utility industry. This report does not assess or evaluate the data.

[1] The characteristics are, in part, gleaned from the "Draft Working Model for Restructuring the Electric Utility Industry in Virginia, Chapter 2: Reliability," November 1997.

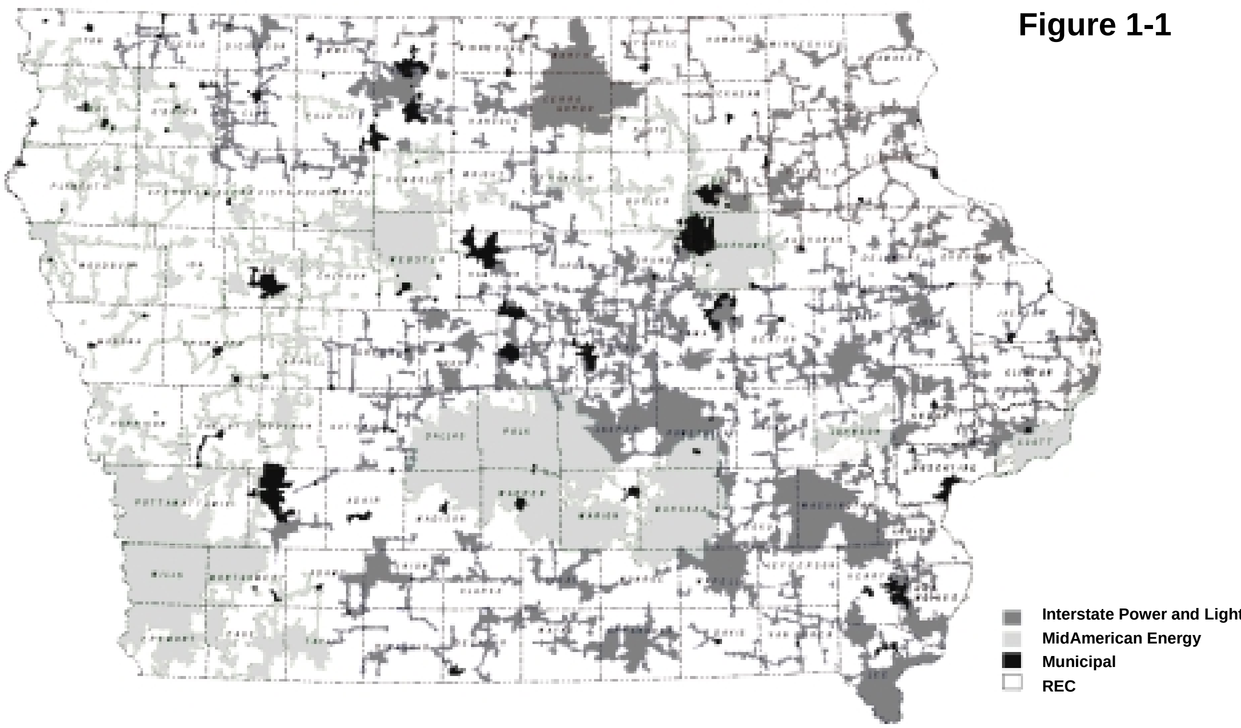
1.1 <u>Background</u>

In order to understand the data presented in the report, it is important to have a basic understanding of the electric utility industry including the different types of utility companies and the interconnected transmission grid. Subsection 1.1 provides this basic information.

1.1.1 Types of Utilities

Iowa's electric customers are served by three basic utility types: investor-owned utilities (IOUs), municipal (or publicly owned) utilities, and rural electric cooperatives (RECs). Each utility company serves an exclusive service territory. Each utility with an exclusive service territory has an obligation to provide electric service to customers in that area. **Figure 1-1** shows the service territories served by each type of utility.

Figure 1-1



IOUs are for-profit companies primarily serving urban areas of the state. Iowa is served by two IOUs – Interstate Power and Light Company (IPL) and MidAmerican Energy Company (MidAmerican). IOU retail rates and service are regulated by the IUB. Wholesale rates are regulated by the Federal Energy Regulatory Commission (FERC).

Iowa has 137 communities that operate electric utilities as a function of local government. Iowa has more municipal electric utilities than any other state, many of which have been in continuous operation for over 100 years. Municipal utilities are locally regulated through city councils or through boards of trustees appointed by the mayor and approved by the city council. All municipal utilities operate distribution systems that serve the local community and, in some cases, portions of outlying rural areas. Eighty-seven municipal utilities own and operate generating facilities that supply most or all of their energy needs. Muscatine, Ames, and Pella produce all or most of their electricity at local coal- or gas-fueled units. Forty-four municipal utilities are joint-owners of generating plants operated by other utilities. Seventy-four municipal utilities own backup or peaking generation and purchase their primary power supplies from municipal joint action entities or from other wholesale suppliers. Eight municipals own wind turbines and one (Waverly) owns and operates a small hydro facility. Forty-five municipal utilities purchase at least some of their power from the Western Area Power Administration (WAPA), the federal agency that operates hydroelectric facilities on the upper Missouri River Basin. Appendix A to this report provides a complete list of municipal electric utilities in Iowa.

RECs are locally owned, not-for-profit utilities controlled by a board of directors elected by the consumers they serve. Iowa's RECs provide electric service to more than 185,000 homes, farms, and businesses primarily in the rural areas of all 99 counties. Electric cooperatives typically have very few customers per mile of distribution line relative to the investor-owned and municipal utilities. Two types of electric cooperatives operate in Iowa: generation and transmission cooperatives (G&Ts) and distribution cooperatives. Distribution cooperatives purchase wholesale electricity from the G&T and distribute and sell this electricity to their members. Both the G&T and the distribution cooperatives are governed through a local board of directors elected by their members. Both types of RECs set their rates through the local governance process. The IUB sets the safety and service regulations that apply to the RECs. RECs securing any capital needs from the Rural Utility Service (RUS—formerly REA) are subject to RUS regulations at the federal level. Electric cooperatives subject to RUS are the only utilities required to construct their systems consistent with federal standards. If a cooperative is no longer under RUS jurisdiction, then a cooperative becomes FERC jurisdictional for its transmission tariffs and for wholesale transactions. Appendix B to this report provides a complete list of distribution cooperatives serving Iowa customers and the G&Ts serving those distribution cooperatives.

Table 1-1 provides some basic statistics by type of utility for Iowa for 2002. The data demonstrate that even though there are numerous municipals and RECs, the vast majority of the customers are served by the two investor-owned utilities in Iowa.

Table 1-1 Basic Statistics by Type of Utility Company

2002 Data	Investor-Owned	Municipals	RECs
Number of Utilities	2	137	47
Number of Customers	1,099,949	207,073	186,444
Sales to customers (MWh)	35,188,490	4,994,418	5,055,509
Percentage of Total Sales	77.8%	11.0%	11.2%

1.1.2 Reliability Over Regional Grids and the Emergence of the Wholesale Electric Market

The modern electric power industry is in the midst of a period of significant change. The way the grid is operated is evolving, though it continues to be characterized by an interconnected grid of high voltage lines (referred to as transmission lines). In the past, utilities generally operated their own systems and their goal was to provide economic dispatch,[2] with the utility's own generating units that were connected to its customers by the grid. When a purchase could be made from another utility and savings realized, such purchases were often made. The evolution of grid operations began with the passage of the Energy Policy Act in 1992 (EPACT). The EPACT vastly expanded competition in the wholesale electricity markets. Its Electricity Title[3] (Title VII) authorized persons other than utilities to build and operate power plants and it required the FERC to ensure nondiscriminatory, open access to utility transmission systems.

In response to the EPACT, the FERC issued Order 888 in April 1996, requiring IOUs to file tariffs for open-access transmission. Order 888 also encouraged utilities to form and join independent system operators (ISOs) to operate regional transmission systems and be independent of all market participants.

[2] Economic dispatch refers to bringing on-line generating units within a service or control area on a least-cost basis until all demand is served. Exceptions to economic dispatch may be made as a result of transmission constraints, requirements for generation for voltage support, differences in cost methodologies, or other "must-run" conditions.
[3] See Subtitle A, Exempt Wholesale Generators and Subtitle B, Federal Power Act; Interstate Commerce in Electricity.

In its post-Order 888 observations of the operation, planning, and expansion of regional transmission grids, the FERC found engineering, and economic inefficiencies that could affect electric system reliability and impede the growth of fully competitive bulk power markets. The FERC also observed what it believed to be continuing opportunities for undue pricing discrimination. FERC's solution to these difficulties was to issue on December 20, 1999, its order on Regional Transmission Organizations[4] (RTOs), known as Order 2000.

RTOs were the second major step in ISO evolution. Order No. 2000 required IOUs to file with FERC, by October 2000, proposals for joining a RTO, or an explanation of why the utility could not join such a regional organization. Order 2000 required that RTOs have the following four characteristics: (1) independence from market participants; (2) appropriate scope and regional configuration: (3) possession of operational authority for all transmission facilities under the RTO's control; and (4) exclusive authority to maintain short-term reliability.

Order 2000 was not to be the last FERC initiative. By mid-summer of 2000, California energy markets were in crisis.[5] In addition to launching an investigation of California markets, the FERC began considering what might be missing in its Order 2000 initiative. The result was its [still incomplete] Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR), issued on July 31, 2002. Even though the SMD NOPR remains incomplete, several of its concepts have found their way into attempts to reform Midwest markets, of which Iowa is a part. Those concepts include: (1) a reliance on bilateral contracts, with complementary short-term electricity markets; (2) operations by independent transmission providers of voluntary, bid-based, security constrained spot markets (day-ahead and real time) for energy and operating reserves, in conjunction with their responsibilities for transmission services; (3) establishment of procedures to monitor and mitigate market power; (4) use of market-based locational marginal pricing (LMP) transmission congestion management systems; and (5) a role for Regional State Committees[6] to participate in the decision-making processes of regional transmission organizations or other regional security and reliability entities.

[4] See FERC Docket No. RM99-2-000.

[5] In 1996, state legislation was signed opening California's electricity market to competition. California utilities divested much of their own generation. On May 22, 2000, the California Independent System Operator, manager of the state power grid, declared the first of dozens of Stage 2 alerts, when power reserves dropped below 5 percent. Other more serious alerts followed. Later that summer, rolling blackouts affected thousands and calls were issued for investigations into possible price manipulation in the wholesale electricity market.

[6] The IUB is a member of the first recognized Regional State Committee, named the Organization of MISO States (OMS). The OMS was organized to allow states to participate more effectively in decision-making processes related to the Midwest Independent System Operator (MISO).

In the regional markets foreseen by Order 2000/SMD, a local control area operator may (depending on contractual relationships) continue to be an important participant in dispatching power plants and ensuring reliability. However, the independent transmission provider has ultimate regional reliability responsibility and the overall combined functionality of self-generation, bilateral contracts, and short-term markets is designed to take regional electric efficiency to higher levels than have been possible historically.

As this report is being written, a massive Energy Bill was blocked in the U.S. Senate. The Energy Bill affects FERC's goals for RTO formation and the design of regional electricity market mechanisms. The bill included mandatory reliability requirements for high voltage transmission lines and incentives to spur transmission construction. The North American Electric Reliability Council (NERC)[7] has the primary responsibility for establishing and encouraging compliance with reliability guidelines for the bulk power system.[8] 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 encompasses what the industry refers to as adequacy and security. Adequacy relates to long-term planning which requires sufficient generating and transmission resources to meet projected demand in the region. Security implies that the system will continue to operate even after generating plant or transmission outages occur. NERC is comprised of regional reliability councils. Although the regional reliability councils follow NERC's guidelines, they often have different reliability requirements and enforcement measures.

The North American bulk power system includes three major transmission interconnections: ERCOT (which encompasses a large part of Texas), the Western Interconnect (which includes the western states), and the Eastern Interconnect (which includes the Midwest, South, East, and parts of Canada). Within the major interconnections are regional reliability councils and control areas. **Figure 1-2** shows the locations of the 10 regional reliability councils. Theoretically, power can flow from any point within the interconnection to any other point within the interconnection. Practically, power can only flow to a very limited degree between the interconnections.

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[7] NERC is a not-for-profit national organization whose members are ten regional reliability councils. The members of these councils come from all segments of the electric industry. These entities account for virtually all the electricity supplied and used in the United States, Canada and a portion of Baja California Norte, Mexico. NERC's mission is to ensure that the bulk electric system in North America is reliable, adequate, and secure. Though NERC currently operates a voluntary association of reliability organizations, any Energy Bill adopted seems likely to give both FERC and NERC significant statutory authority to mandate transmission reliability rules, as well as enforcement capabilities.

[8] The regional interaction of generating units, transmission facilities, and control area operators comprise the bulk power system.

Figure 1-2

Until a few years ago, most of Iowa's major utilities were a part of Mid-Continent Area Power Pool (MAPP).[9] In May 2000, Interstate Power and Light Company (IPL) left MAPP and joined Mid-America Interconnected Network (MAIN),[10] another NERC regional reliability council operating in the Midwest. Reliability in the Midwest region is maintained by reliability council members adhering to planning and operating rules that are developed by individual reliability councils and by NERC. For example, MAPP enforces reliability by requiring its member utilities to do reserve planning and by assessing after-the-fact penalties to member utilities that fail to meet reserve requirements. Also, utilities are required to provide sufficient transmission capacity to

[9] MAPP is an association of electric utilities and other electric industry participants who do business in the Upper Midwest. The MAPP organization performs three core functions: it is a regional reliability council, responsible for the safety and reliability of the bulk electric system; a regional transmission group, responsible for facilitating open access of the transmission system; and a power and energy market, where MAPP members and non-members may buy and sell electricity.
[10] MAIN's region includes all of Illinois and portions of Missouri, Wisconsin, Iowa, Minnesota and Michigan. The purpose of MAIN is to promote the reliable use of the interconnected electric systems with due regard for safety, environmental protection, and economy of service.

serve their load without relying or imposing an undue burden on other systems. To minimize the effects of the sudden loss of a generating unit or transmission line, reliability council member utilities are required to maintain sufficient capacity in reserve.

With respect to RTO participation, MidAmerican has been considering several options. IPL joined the Midwest Independent Transmission System Operator (MISO), which is the nation’s first RTO approved by FERC. The MISO was formed in 1998. The MISO’s primary objective is to direct traffic on the wholesale bulk power network. The MISO ensures that every participant in the electric industry has access to transmission. It also manages the use of lines to make sure that they don’t become overloaded. The MISO Tariff became effective in February 2002.

In the last two years, MAPP has worked on two major initiatives. One initiative was the unbundling of the MAPP restated agreement and second initiative was to integrate MAPP transmission functions with MISO. On November 30, 2001, MISO began performing the transmission-related function for MAPP. MAPP continues to provide NERC-related reliability functions and power and energy market functions for MAPP members. Effective January 2001, the MAPP Security Center became the NERC Eastern Interconnection Time Monitor.

With all the legislative and regulatory changes occurring over the last several years, it is not surprising that the transmission system is being used for purposes for which it was not designed. The system was designed to connect an individual utility’s generating units to its customer load centers and to interconnect with its neighbor utilities. The transmission system is now also being used to promote a competitive wholesale market that is fueled by power marketers.

While the wholesale market in electricity is increasingly becoming open to competition, many retail markets are not (including Iowa’s retail market). This raises issues of jurisdiction over transmission pricing. In states that have not opened their markets, retail rates continue to be set on a bundled basis. Bundled rates include the costs of generation, transmission, distribution, and customer services. At the time a state opens its retail markets, rates are unbundled and FERC assumes jurisdiction over transmission pricing. The state regulatory commission continues to price distribution service for IOUs. As such, unbundling requires the jurisdictional separation of transmission and distribution facilities. Transmission lines are typically high voltage lines that deliver electricity between generating plants or to wholesale customers. Distribution lines are typically low-voltage lines that connect the transmission system to the ultimate customer.

The FERC, in Order 888, established a seven-factor test as a guide for making this jurisdictional delineation. FERC gave the state commissions deference in applying the seven-factor test. On November 12, 1998, MidAmerican filed with the IUB a "Petition for Order Recommending Delineation of Transmission and Local Distribution Facilities," which was later approved by the IUB. On July 30, 1999, MidAmerican filed its proposed delineation with FERC. On February 4, 2000, the FERC issued an order approving the delineation. In accordance with these filings, MidAmerican's lines at 69kV and below and approximately 11 percent of MidAmerican's 161 kV lines are determined to have local distribution characteristics in accordance with the test of FERC's seven factors for local distribution. On November 26, 2002, IPL filed a petition with the IUB regarding the delineation of its transmission facilities. The IUB granted IPL's request that all of its transmission facilities at 69 kV and above be classified as transmission facilities.

1.2 Organization of the Report

As with any product or service, the provision of electricity involves the interaction of supply and demand. Consumers demand electricity and Iowa's electric utilities supply it.

Section 2.0 of this report provides information on the supply and demand for electricity and the various elements that comprise both. The need to generate electricity coincident with its consumption, coupled with the extensive time and capital required to build new electricity infrastructure, makes it necessary to plan for adequate supply to meet forecasted demand. Subsection 2.1 provides historical and forecasted data on the adequacy of supply for IPL and MAPP utilities serving Iowa. Subsection 2.2 details the unique aspects of electricity demand including customer load characteristics. An important distinction must be made between electric load and energy requirements. Electric load refers to customer demand at the time of the utility's peak demand. Since utility systems are designed and built to serve peak load, this factor is an essential element in future capacity planning. Energy requirements reflect customer consumption of kilowatt-hours (kWhs) in a given year. Demand-side management programs affect both peak load and energy requirements. Subsection 2.2.3 discusses utility demand-side management programs including program descriptions, results, and expenditures. Subsection 2.3 details electric supply by characterizing Iowa's major generating units by historical fuel use, efficiency, and diversity, in addition to cost per kWh of energy produced. Subsection 2.3.2 looks at another major source of supply for Iowa's utility companies – purchased power. Data are provided on historical power purchases from alternate energy sources and historical and future purchases from conventional generating sources. In addition, this subsection discusses the spot market for wholesale supply that was essentially created through FERC Order 888. Subsection 2.3 concludes with information regarding regional supply considerations, air emissions from conventional generating sources (primarily coal, oil, and natural gas), and a brief description of the requirements that must be met before a new generating plant is built in Iowa. The delineation has not yet been filed at FERC.

The delivery of electricity to the ultimate customer is accomplished through both transmission and distribution lines. Section 3.0 of the report looks at Iowa's delivery system including the location of vital infrastructure, the age and condition of the state's transmission and distribution infrastructure, the historical reliability of the regional delivery systems, a discussion of future changes to the transmission and distribution system and a description of the state's transmission siting requirements. The section concludes with a discussion of some of the recent regional reliability and transmission studies and a discussion of the U.S.-Canada Power System Outage Task Force's Interim Report on the causes of the August 14 blackout in the U.S. and Canada.

Section 4.0 provides a brief description of how customer service systems have changed over the last few years. Customer service includes metering, billing, and customer contact.

1.3 Limitations of the Report

While it is understood customers are concerned with both the reliability and cost of their electric supply, the data in this report concentrate more on the reliability of electric supply and the characteristics comprising electric demand. As such, utility rates are not compiled and reported. In addition, the report does not attempt to assess, evaluate, or analyze the data provided.

2.0 ELECTRIC LOAD AND SUPPLY CONDITIONS

The use of electricity places “load” on an electric utility system. Load is measured in kilowatts (kW or 1,000 watts), megawatts (MW or 1,000 kW) or gigawatts (GW or 1,000 MW). Electric load varies depending on the number and size of devices using electricity at a given time. When the sum of individual loads reaches a maximum level, the utility experiences system "peak load." In Iowa, most peak loads occur during hot summer days when air conditioning use reaches maximum levels. A utility’s “capability” for meeting its peak load is based on its electric generating capacity, either owned or available through purchase.

Section 2.1 compares historical and projected load for Iowa utilities and the adequacy of available supply to meet that load. Section 2.2 details electric demand including load and energy requirements. Section 2.3 details the various elements of electric supply.

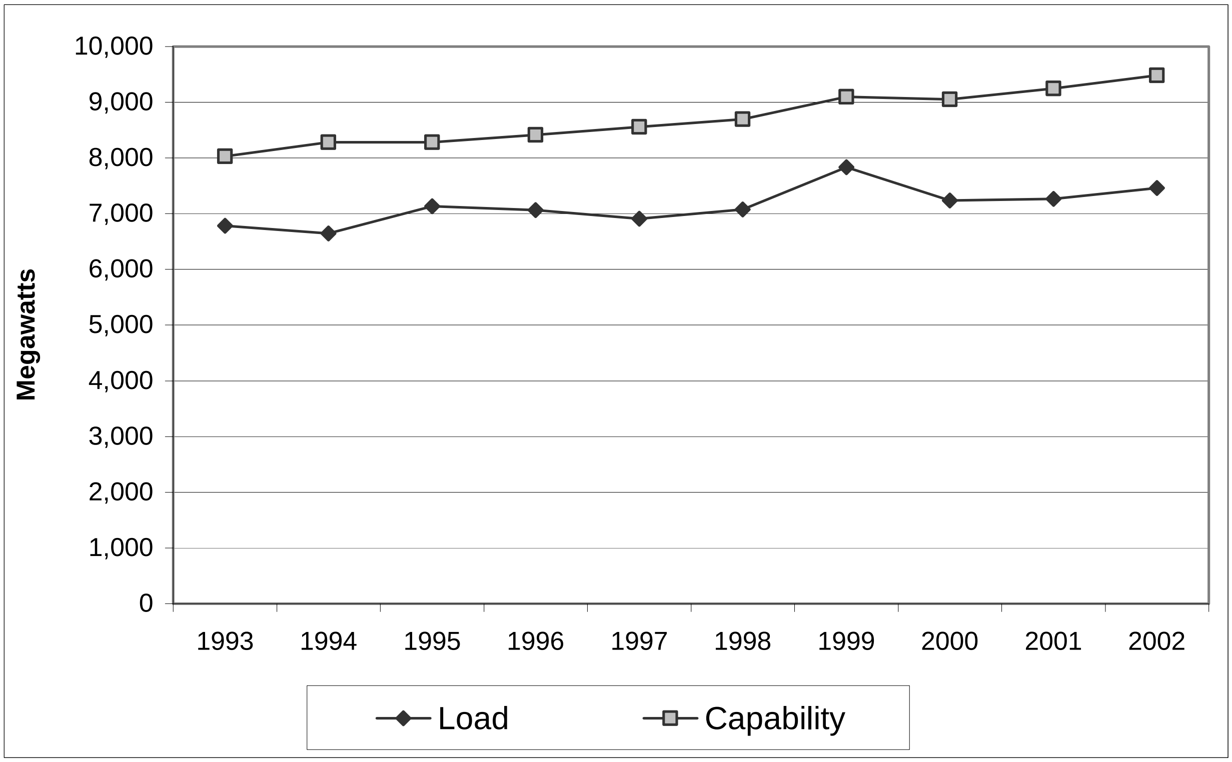
2.1 Adequacy of Supply in Meeting Current and Projected Load Requirements

This subsection compares Iowa peak loads and capabilities, both historic and forecasted, based on data reported by Iowa utilities to MAPP and data reported by Interstate Power and Light (IPL). Most Iowa utilities are (or have recently been) MAPP members. MAPP member utilities and IPL account for the vast majority of Iowa’s electricity sales. Therefore, comparisons based on MAPP utilities and IPL should provide a reasonably accurate representation of Iowa as a whole. Some MAPP utilities, principally MidAmerican and IPL, also serve smaller areas in adjacent states. The comparisons in this section involve no adjustments to derive Iowa-only data from total system data. Since utilities plan on a system-wide rather than state-by-state basis, such adjustments would add little in meaning or accuracy to the results. Similarly, no adjustments are made to account for the diversity of different times each utility reaches its respective system peak.[11]

Figure 2-1 compares historic annual peak loads and capabilities for most Iowa MAPP utilities and IPL.[12]

[11] Reporting utilities seem to regard such adjustments as minor. For example, MidAmerican has estimated the diversity adjustment within its control area at 1 percent or less, and Interstate Power and Light estimates the diversity between its east and west systems at less than 1 percent.
[12] Appendix C provides a detailed list of utilities included in Figures 2-1 and 2-2.

Figure 2-1 Historic Load and Capability

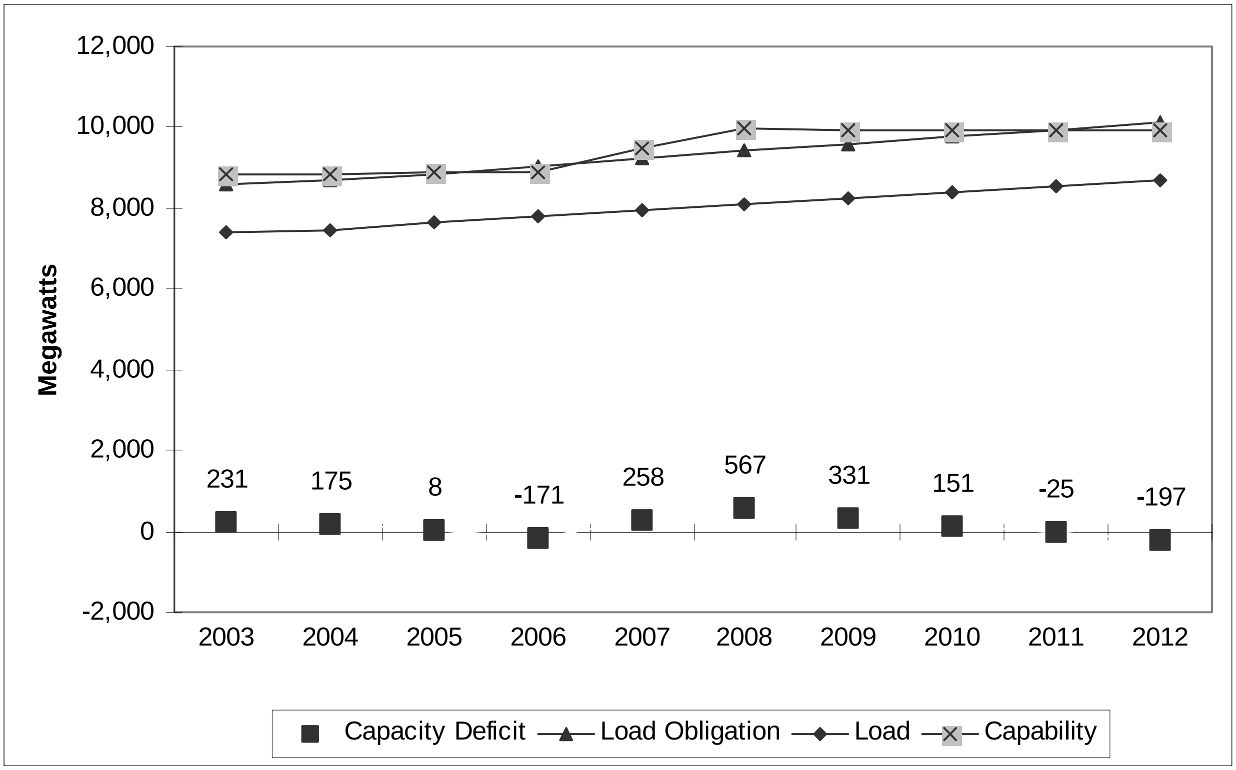


Notes: MidAmerican includes the utilities within its control area. Interstate Power and Light (IPL) includes CIPCO data.
Sources: Data for 1993-1998 from Electric Power in Iowa, August 2000. Data for 1999-2002 from MEC, IPL and Muscatine, as follows: MEC Data [IUB Data Request - Energy Supply – MEC, "Historic Load and Requirements"]; IPL [Response to IUB Data Requests_revised_JMH 08.08.03.pdf]; Muscatine [MAPP Form 3 Data].

Figure 2-2 compares forecasted annual peak loads and capabilities for Iowa MAPP utilities and IPL.[13] The line labeled "load obligation" represents annual load plus a 15 percent reserve margin. The bars labeled "capacity deficit" reflect the difference between the annual load and the annual load obligation. The forecasts assume each planning area will continue serving customers in its service area with sufficient supply resources, either through owned-generation or purchased power contracts, to cover peak loads plus a 15 percent reserve margin.

[13] Loads from several municipal utilities were added to the forecasted data: Algona, Ames, Atlantic, Harlan, Muscatine, and Pella Municipals. The municipals add less than 1 percent to projected load obligations.

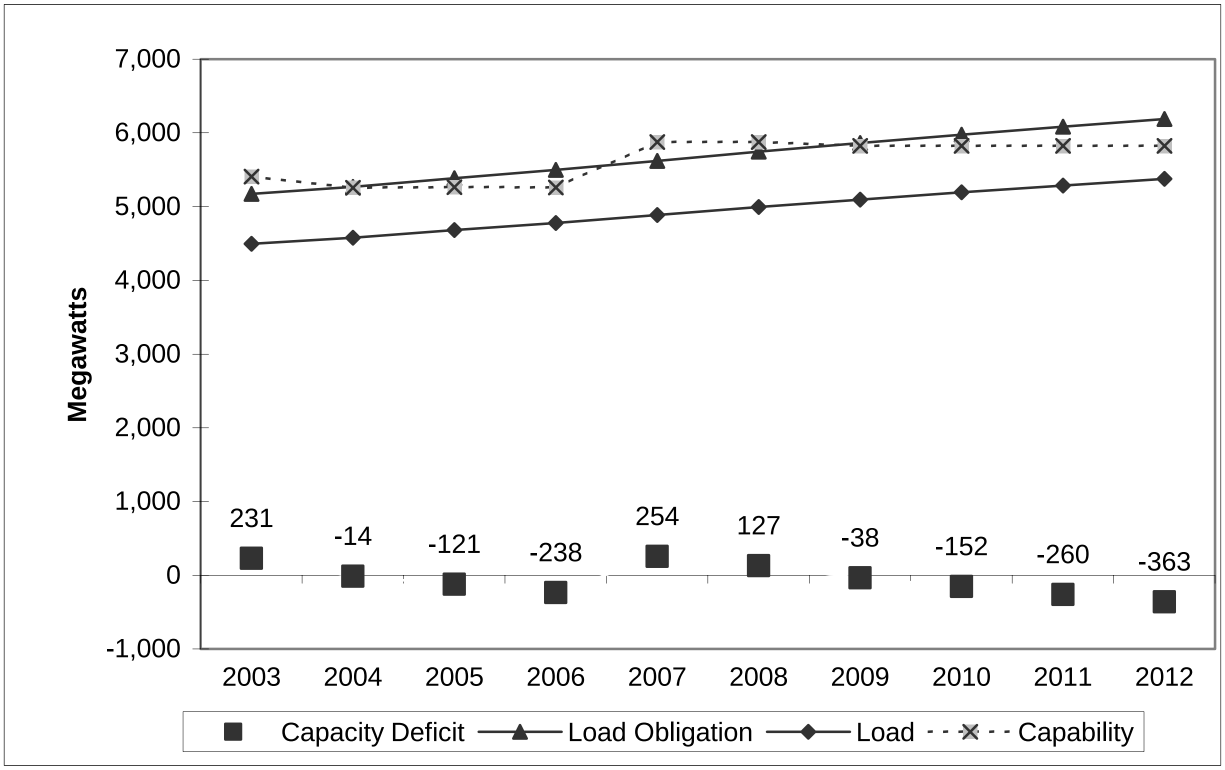
Figure 2-2 Forecasted Summer Net Load, Capability, Load Obligation, and Capability Surplus/Deficit(-)



Notes: "Net Load" is reduced for load management programs including direct load control and interruptible load. "Net Load" includes net firm power transactions. "Load Obligation" represents annual load plus a 15 percent reserve margin for MAPP utilities and annual load plus an 18 percent reserve margin for IPL. "Capability" includes any committed generation and proposed generation. Committed units are under design, under construction, authorized for construction, or for which a construction license is pending. Proposed units are planned for installation but not authorized for construction.
Sources: Draft MAPP Load and Capability Report for 2003, for Atlantic, Algona, Ames, Harlan, Muscatine and Pella. MEC Data Response, "IUB Data Request-Energy Supply-MEC," sheet MAPP L and C Data, MEC Load and Capability As submitted to MAPP in 2003. Interstate data from electronic document [Response to IUB Data Requests_revised_JMH 08.08.03.pdf]

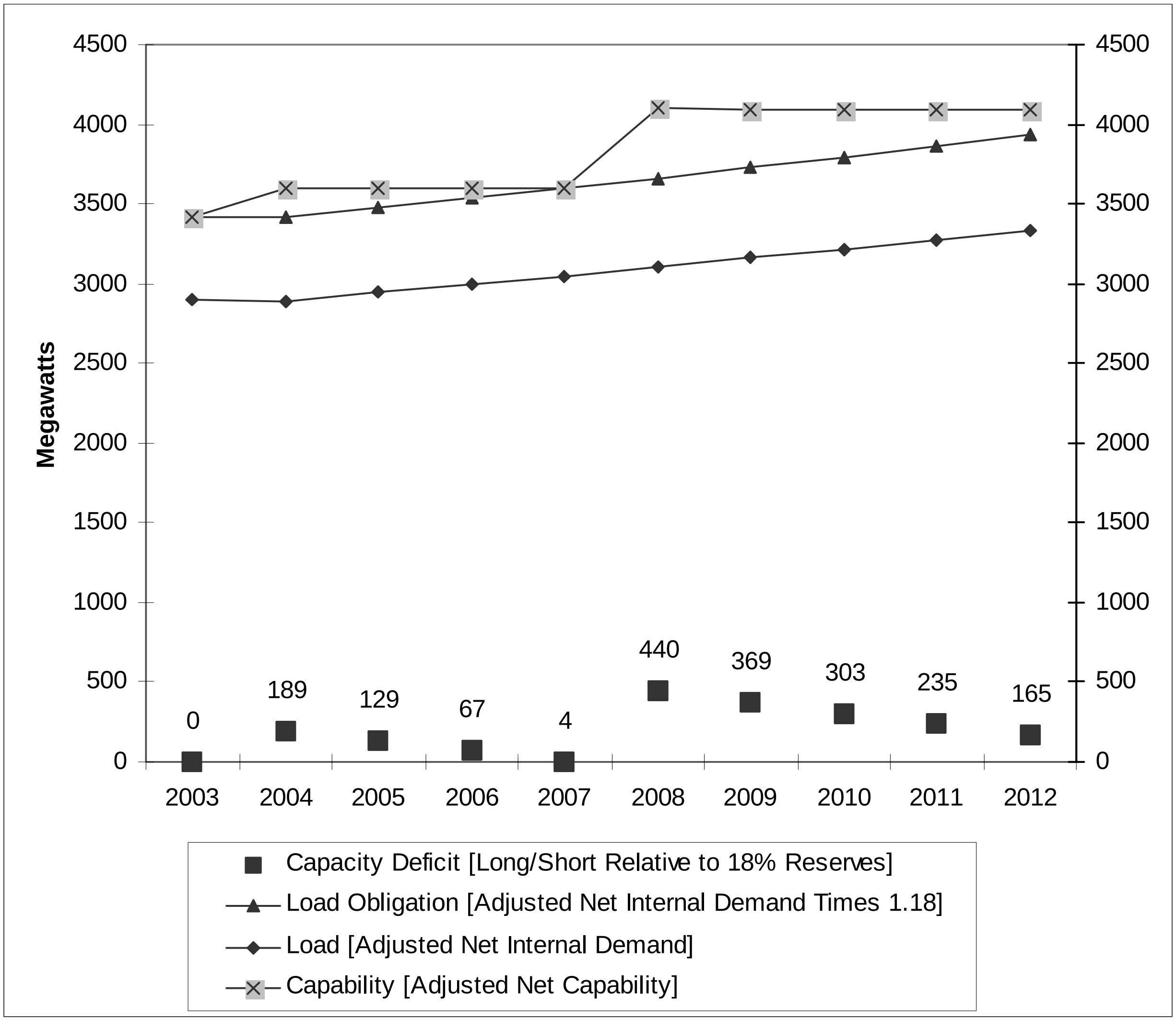
Figure 2.2 includes both MidAmerican's and IPL's control areas, which comprise most of Iowa's load and capability. **Figures 2.3 and 2.4** illustrate these same data for MidAmerican's control area (using a 15 percent reserve requirement) and IPL's control area (using an 18 percent reserve requirement). IPL, as a member of MAIN, is required to maintain reserves equal to 17 to 20 percent of peak load. IPL has chosen to hold 18 percent reserves consistent with a Public Service Commission of Wisconsin requirement. MAPP uses a 15 percent reserve requirement.

Figure 2-3 Forecasted Summer Load, Capability, Load Obligation, and Capability Surplus/Deficit(-) for MidAmerican Control Area



Notes: See Figure 2-2.
Sources: See Figure 2-2.

Figure 2-4 Forecasted Summer Load, Capability, Load Obligation, and Capability Surplus/Deficit(-) for IPL (MAIN Forecast) and CIPCO



<u>Notes</u>: See Figure 2-2.
<u>Sources</u>: See Figure 2-2.

2.2 <u>Electric Demand</u>

2.2.1 Electric Load and Energy Requirements

Electric load refers to customer demand at the time of the utility's peak demand, expressed in thousands of kW, or MW. In Iowa, peak load generally occurs in the summer. **Table 2-1** provides summer peak load forecasts over the next ten years (2003-2012) for Iowa MAPP utilities and IPL.

Table 2-1 Forecast of Summer Peak Load Requirements for Iowa MAPP Utilities and IPL (MW = 1,000 kW)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total Growth 2003-2012	Average Annual Growth 2003-12
Algona	24	25	25	26	26	27	27	28	28	29	5	1
Ames	119	121	123	124	126	128	130	132	132	132	13	1
Atlantic	26	27	27	27	27	28	28	28	29	29	3	0
Harlan	14	14	15	15	15	15	16	16	16	16	2	0
Interstate	2,865	2,892	2,943	2,996	3,049	3,103	3,159	3,215	3,272	3,331	466	52
MidAmerican	4,495	4,580	4,680	4,778	4,884	4,994	5,094	5,193	5,287	5,376	881	98
Muscatine	144	147	149	152	154	156	158	161	163	165	21	2
Pella	49	49	51	51	52	52	53	53	54	54	5	1
Total Peak MW	7,736	7,855	8,013	8,169	8,333	8,503	8,665	8,826	8,981	9,132	1,396	155
Percent Change	N/A	1.5%	2.0%	1.9%	2.0%	2.0%	1.9%	1.9%	1.8%	1.7%	18.0%	2.0%

Notes: Interstate Power and Light [IPL] includes CIPCO. MidAmerican includes the utilities within its control area. Both the MidAmerican and Interstate/CIPCO forecasts assume all load management resources are implemented.

Sources: Draft MAPP Load and Capability Report for 2003, for Atlantic, Algona, Ames, Harlan, Muscatine and Pella. MEC Data Response, "IUB Data Request-Energy Supply-MEC," sheet MAPP L and C Data, MEC Load and Capability As submitted to MAPP in 2003. Interstate data from electronic document [Response to IUB Data Requests_revised_JMH 08.08.03.pdf]

These peak load forecasts are used to derive the Capability Surplus/Deficits in **Figure 2-2** above. **Table 2-2** summarizes historical summer peak loads for MidAmerican Energy and Interstate Power and Light (1993-2002).

Table 2-2 Historical Summer Peak Load Requirements for MidAmerican Energy and IPL Control Areas (MW = 1,000 kW)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	Total Growth 1993-2002	Average Annual Growth 1993-02
Total MW	6,481	6,508	6,968	7,003	6,967	7,163	7,546	7,056	7,234	7,425	944	105
Percent Change	NA	0.42%	7.07%	0.50%	-0.51%	2.81%	5.35%	-6.49%	2.52%	2.63%	14.6%	1.6%

Notes: Utilities in this table include Interstate Power and Light (including CIPCO), MidAmerican Energy (including the utilities within its control area), and Muscatine Water and Power.
Sources: MEC Data Response, electronic document [IUB Data Request-Energy Supply-MEC; "Historic L&C"]. Interstate data from electronic document [Response to IUB Data Requests_revised_JMH 08.08.03.pdf]. Muscatine data from Muscatine MAPP Form 3 data, provided 8/12/03.

Energy requirements refer to customers' kWh usage over the course of a year. Because of the large numbers involved, energy requirements are expressed in millions of kWhs, or GWh. **Table 2-3** provides utilities' forecasted energy requirements over the next ten years (2003-2012) and **Table 2-4** summarizes historical annual energy requirements for MidAmerican Energy and Interstate Power and Light (1993-2002).

Table 2-3 Forecast of Annual Energy Requirements for Iowa MAPP Utilities and IPL (GWh= 1,000,000 kWh)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total Growth 2003-2012	Average Annual Growth 2003-12
Interstate	16,452	16,579	16,795	17,012	17,252	17,492	17,739	17,993	18,254	18,523	2,071	230
CIPCO	3,047	3,088	3,120	3,155	3,186	3,217	3,247	3,285	3,315	3,351	304	34
Algona	116	116	117	120	123	125	128	130	133	135	19	2
Ames	547	554	566	576	586	596	606	616	616	616	69	8
Atlantic	109	110	112	113	114	115	117	118	119	120	11	1
Harlan	65	65	66	67	68	69	70	72	73	74	9	1
Mid American	21,138	21,635	22,100	22,505	22,899	23,352	23,745	24,142	24,540	24,963	3,825	425
Muscatine	918	936	954	977	992	1,007	1,023	1,039	1,055	1,072	154	17
Pella	198	198	209	209	209	209	210	210	210	211	13	1
Total GWh	42,590	43,281	44,039	44,735	45,429	46,182	46,885	47,604	48,315	49,065	6,475	719.45
Percent Change	N/A	1.6%	1.8%	1.6%	1.6%	1.7%	1.5%	1.5%	1.5%	1.6%	15.2%	1.7%

Notes: MidAmerican includes the utilities within its control area. Interstate and CIPCO data are from MAIN Load and Capability data.
Sources: MID-CONTINENT AREA POWER POOL - LOAD AND CAPABILITY REPORT - 5/28/2003 - 2nd DRAFT, ANNUAL NET ENERGY REQUIREMENTS 2003 through 2012, Annual Summary by Reporting System (Chapter) VI-3. Interstate document [Response to IUB Data Requests_revised_JMH 08.08.03.pdf]

Table 2-4 Historical Annual Energy Requirements for MidAmerican Energy and Interstate Power and Light Control Areas (GWh = 1,000,000 kWh)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	Total Growth 1993-2002	Average Annual Growth 1993-02
Total GWh	32,837	34,196	35,602	36,311	37,087	38,847	39,125	39,983	39,598	40,713	7,876	875
Percent Change	N/A	4.1%	4.1%	2.0%	2.1%	4.7%	0.7%	2.2%	-1.0%	2.8%	24.0%	2.7%

Notes: MidAmerican includes the utilities within its control area. Interstate includes CIPCO data.
Sources: Data for 1993-1998 from Electric Power in Iowa, August 2000. Data for 1999-2002 from MEC, IPL and Muscatine, as follows: MEC Data [IUB Data Request - Energy Supply – MEC, "Historic Load and Requirements"]; IPL [Response to IUB Data Requests_revised_JMH 08.08.03.pdf]; Muscatine [MAPP Form 3 Data].

2.2.1.1 Cooperative Load and Energy Requirements

MAPP forecasts and historical data include most Iowa cooperative load and energy requirements. The purpose of this subsection is to separately set forth all load and energy requirements for Iowa cooperatives, including the MAPP member cooperatives represented in **Tables 2-1** through **2-4** above. **Table 2-5** provides peak load and energy requirements forecasts for the G&T cooperatives serving Iowa. Because some cooperatives are winter peaking, both summer and winter peak load forecasts are included. **Table 2-6** summarizes G&T historical peak loads and energy requirements.

Table 2-5 Forecast of Peak Load and Annual Energy Requirements for Iowa Cooperatives (MW = 1,000 kW; GWh = 1,000,000 kWh)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total Growth 2003-2012	Average Annual Growth 2003-12
Summer MW Peak Loads	1,054	1,070	1,088	1,104	1,118	1,133	1,149	1,165	1,181	1,196	142	16
Percent Change	N/A	1.48%	1.74%	1.45%	1.27%	1.36%	1.40%	1.37%	1.38%	1.26%	13.46%	1.50%
Winter MW Peak Loads	958	979	993	1,006	1,018	1,029	1,040	1,053	1,063	1,075	117	13
Percent Change	N/A	2.20%	1.37%	1.33%	1.17%	1.07%	1.09%	1.25%	1.00%	1.12%	12.21%	1.36%
GWh Energy	6,173	6,326	6,448	6,523	6,600	6,669	6,741	6,816	6,879	6,951	778	86
Percent Change	N/A	2.48%	1.93%	1.17%	1.17%	1.05%	1.08%	1.11%	0.93%	1.05%	12.60%	1.40%

Note: Includes MECAs. The total data include data for the Iowa distribution RECs associated with the following G&Ts: Central Iowa Power Cooperative (includes SIMECA) with diversity, Corn Belt Power Cooperative (excludes NIMECA but includes Webster City and Estherville), Dairyland Power Cooperative, Northeast Missouri Electric Power Cooperative, and Northwest Iowa Power Cooperative (includes SIMECA). The data for cooperatives serving more than Iowa were assigned or allocated to the applicable Iowa cooperatives.
Sources: Compiled by the IAEC.

Table 2-6 Historical Peak Load and Annual Energy Requirements for Iowa Cooperatives (MW = 1,000 kW; GWh = 1,000,000 kWh)

	1995	1996	1997	1998	1999	2000	2001	2002	Total Growth 1995-2002	Average Annual Growth 1995-02
MW Peak Loads	855	888	916	958	997	990	1,023	1,040	185	26.4
Percent Change	N/A	3.9%	3.2%	4.6%	4.1%	-0.8%	3.4%	1.6%	21.6%	3.1%
GWh Energy	4,149	4,382	4,603	5,138	5,333	5,543	5,644	6,062	1,913	273
Percent Change	N/A	5.6%	5.0%	11.6%	3.8%	3.9%	1.8%	7.4%	46.1%	6.6%

Notes: The total data include data for the Iowa distribution rural electric cooperatives associated with the following G&Ts: Central Iowa Power Cooperative (includes SIMECA) with diversity, Corn Belt Power Cooperative (excludes NIMECA but includes Webster City and Estherville), Dairyland Power Cooperative, L&O Power Cooperative, Northeast Missouri Electric Power Cooperative and Northwest Iowa Power Cooperative (includes SIMECA). The data for cooperatives serving more than Iowa were assigned or allocated to the applicable Iowa cooperatives.
Sources: Compiled by the IAEC.

2.2.1.2 Municipal Utility Load and Energy Requirements

The purpose of this subsection is to separately set forth all electric load and energy requirements for Iowa municipal utilities, including MAPP member load and energy requirements represented in **Tables 2-1** through **2-4** above. **Table 2-7** summarizes total historical peak load and annual energy requirements for Iowa municipal utilities, for the period 1993-2002.

Table 2-7 Historical Peak Load and Annual Energy Requirements for Iowa Municipal Utilities (MW = 1,000 kW; GWh = 1,000,000 kWh)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	Total Growth 1993-1998	Average Annual Growth 1993-98
MW Peak Loads	928	937	1,041	1,002	1,016	1,066	1,121	1,113	1,110	1,119	191	21
Percent Change	N/A	0.97%	11.10%	-3.75%	1.40%	4.92%	5.20%	-0.75%	-0.27%	0.82%	20.59%	2.29%
GWh Energy	4,051	3,898	4,298	4,385	4,531	4,714	4,769	4,858	4,902	4,994	943	105
Percent Change	N/A	-3.78%	10.26%	2.02%	3.33%	4.04%	1.17%	1.87%	0.91%	1.88%	23.28%	2.59%

Notes: The totals are summations of data for individual municipal utilities and are not adjusted for diversity.
Sources: Form EIA-861 reports for Iowa municipal utilities as compiled by the IAMU.

2.2.2 Electric Load and Customer Characteristics

Electric load is evaluated in several different ways. For example, the concept of "load factor" indicates the degree to which generating capacity is being utilized by comparing annual energy requirements, or average load, with peak load.[14] As a measure of utilization, load factor is expressed as a percentage. **Table 2-8** summarizes historical Iowa load factors by type of utility, compared to average load factors for the United States as a whole. Year-to-year variations may suggest sensitivity to weather conditions.

[14] Load factor may be computed by: 1) deriving average load by dividing annual energy requirements by the number of hours in the year (typically 8,760 hours); and 2) dividing this result by peak load.

Table 2-8 Historical Iowa Electric Load Factors

	1995	1996	1997	1998	1999	2000	2001	2002
IPL	66.9%	66.0%	68.3%	70.4%	65.6%	69.6%	66.7%	67.7%
MidAmerican	52.6%	55.7%	56.8%	57.1%	52.7%	56.4%	54.9%	53.7%
Municipals	49.0%	51.8%	53.1%	52.6%	50%	52%	51%	54%
RECs	55.4%	56.2%	57.4%	61.2%	61.1%	63.8%	63.0%	66.6%
U.S. Average	55.4%	57.2%	56.3%	56.4%	55.4%	57.4%	55.9%	NA

Notes: Years 1995-1999: Data for Interstate and MidAmerican are for the companies only, not their control areas. Complete 1999 data are available for Interstate only. RECs' data, according to the IAEC, include Municipal Electric Cooperative Association (MECA) members. MECA members are not removed from the Municipals data because, according to the IAEC, they are not full requirements customers of the G&T cooperatives that serve them. The impact on the results is minor.
Notes: Years 2000-2002: Data for MidAmerican is for the control area. Data for IPL is for IPL only.
2000 Report Sources: Interstate data: MAPP Form 3 filings and internal company data, compiled by Interstate; MidAmerican data: internal company and Platts' PowerDat data, compiled by MidAmerican; Municipals data: Form EIA-861 reports for Iowa municipal utilities, compiled by the IAMU; RECs data: annual load summaries for G&T cooperatives serving Iowa, compiled by the IAEC; U.S. Average data: Electric Power Annual, 1998, Vol. 2, Energy Information Administration, Tables 33 and 35, pp. 58-60, compiled by IUB Staff.
2003 Report Sources: IPL and MEC data from internal reports. REC data provided by the IAEC. Municipal data provided by the IAMU.

Load and energy requirements can also vary by geographic area. **Table 2-9** shows differences in historical electric sales for the largest Iowa metropolitan areas served by IOUs (Interstate Power and Light and MidAmerican) and by municipal utilities.

Table 2-9 Iowa Historical Electric Sales by Metropolitan Area and for the State As a Whole (GWH = 1,000,000 kWh)

Metropolitan Area	Serving Utility	1995 GWH	1996 GWH	1997 GWH	1998 GWH	1999 GWH	2000 GWH	2001 GWH	2002 GWH	Average Annual Growth 1995-2002
Cedar Rapids	IPL	2,268	2,479	2,690	2,767	2,801	2,869	2,872	2,879	3.8%
Council Bluffs	MEC	541	596	595	620	621	709	680	719	4.7%
Davenport	MEC	1,719	1,722	1,762	1,730	1,993	1,971	1,875	1,876	1.3%
Des Moines	MEC	4,010	4,083	4,185	4,302	4,435	4,547	4,601	4,716	2.5%
Dubuque (1)	IPL	N/A	718	735	749	759	747	724	726	0.2%
Iowa City	MEC	779	785	789	809	924	809	877	905	2.3%
Sioux City	MEC	910	917	938	963	974	996	1,027	1,071	2.5%
Waterloo	MEC	1,236	1,222	1,240	1,340	1,254	1,163	1,120	1,243	0.1%
Ames	Muni	386	412	473	502	527	534	550	578	7.1%
Cedar Falls	Muni	330	330	339	351	383	392	417	396	2.9%
Denison	Muni	122	123	129	133	135	139	143	139	2.0%
Muscatine	Muni	819	841	856	889	892	874	839	826	0.1%
Pella	Muni	146	154	161	170	177	185	181	181	3.4%
Spencer	Muni	127	131	135	134	160	167	164	161	3.9%
Waverly	Muni	99	104	107	112	113	118	121	127	4.0%
Webster City	Muni	119	123	124	134	151	157	154	157	4.5%
State of Iowa	All	34,301	34,999	36,148	37,318	38,034	39,088	NA	NA	NA

Notes: (1) Data for Dubuque was reestimated for 1996-2002 and includes only Dubuque Iowa Sales, Key West and Asbury.
Sources: IPL data compiled by IPL. MidAmerican data compiled by MidAmerican. Municipal data from EIA 861 reports for Iowa municipal utilities, compiled by the IAMU. State of Iowa data from Electric Power Annual, 1995-98, Energy Information Administration, compiled by IUB Staff.

2.2.3 Energy Efficiency and Load Management

2.2.3.1 Program Descriptions and Discussion

Iowa Code Sections 476.6(17) and 476.6(19) authorize a variety of initiatives intended to improve the energy efficiency of Iowa homes and businesses. Energy Efficiency Programs now being implemented by IOUs include:

- Energy savings or **Energy Efficiency programs** save annual use of energy (kWh) and reduce peak load (kW). Examples include: 1) residential programs providing rebates and loans for home insulation, high efficiency furnaces, air conditioners, and other appliances; and 2) nonresidential programs providing rebates for commercial lighting, heating, cooling and refrigeration, or high-efficiency industrial motors and improvements to manufacturing processes.

- **Low-Income programs** target low-income customers for weatherization and other energy efficiency measures.

- **Tree Planting programs** provide assistance to customers and communities to plant and care for trees.

- **Load management programs** provide incentives to customers to change their patterns of energy use, shifting load away from expensive peak periods. Typical programs include: 1) direct control of air conditioners; 2) discounts for industrial customers willing to interrupt their usage during peak periods; and 3) time-of-use rates that shift peak period usage by pricing higher during peak periods and lower during off-peak periods.

- **Research and development programs** are carried out through the Iowa Energy Center and the Center for Global and Regional Environmental Research. These programs are funded by a surcharge on all electric and natural gas utilities.

Load management by utilities is typically achieved through programs that offer customers lower rates or rebates for reducing the customer's use of electricity at a future point in time. The customer allows the utility to directly shut off part of the customer's load (direct load control) or agrees to reduce load by a certain amount (interruptible load) when the utility calls on the customer to do so, typically during peak load periods.

2.2.3.2 Energy Efficiency and Load Management Savings

Energy efficiency and load management have succeeded in reducing both load and energy requirements for Iowa electric utilities. **Tables 2-10** through **2-15** present cumulative MW load savings from both energy efficiency and load management programs for IOUs (**Tables 2-10** and **2-11**), RECs (**Tables 2-12** and **2-13**), and municipal utilities (**Tables 2-14** and **2-15**).

Table 2-10 Investor-Owned Utilities - MW Savings Due To Energy Efficiency

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Cumulative MW Savings	3	9	19	37	63	93	123	142	159	185	211	236	268

Notes: The table above reflects only MW savings for energy efficiency. IOU source data included savings due to load management.
Sources: Data for 1990-1998 from a report by IOUs, August 12, 2000, Tables 1.4.1.2.c and 1.4.1.2.d. Interstate data for 1999-2002 from IPL Electronic data, labeled "Iowa DSM 1999 THROUGH 2000 Update for YE2002 (09-09-03)". MEC data for 1999-2002 from electronic data, labeled "IUB Data Request - Tables 2 - 10-11-16-19 - MEC."

Table 2-11 Investor-Owned Utilities - MW Savings Due To Load Management

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Cumulative MW Savings	176	192	246	451	514	565	582	655	704	652	618	624	570

Notes: IOU data for 1990-1998 includes 99 MW of interruptible load for Interstate prior to the initiation of DSM programs. IOU data includes savings associated with all load management programs, including 1997-1999 curtailments for the former Iowa-Illinois Gas and Electric. A comparison with the data provided by IOUs for the IUB Report of November 24, 1999 shows approximately 175 MW of load management savings existing prior to 1990 and credited to Energy Efficiency through 1998. The comparison also shows additional IOU load management of 14 MW in 1997 and 47 MW in 1998.
Sources: Data for 1990-1998 from a report by IOUs, August 12, 2000, Tables 1.4.1.2.c and 1.4.1.2.d. Interstate data for 1999-2002 from IPL Electronic data, labeled "Iowa DSM 1999 THROUGH 2000 Update for YE2002 (09-09-03)". MEC data for 1999-2002 from electronic data, labeled "IUB Data Request - Tables 2 - 10-11-16-19 - MEC."

Table 2-12 Rural Electric Cooperatives - MW Savings Due to Voluntary Energy Efficiency

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Cumulative MW Savings	12	17	26	35	15	17	14	17	18	21	22	26	29

Notes: In the IAEC report, MW savings were provided as one aggregate total. The data for utilities' capacity and energy savings are the result of utilities' analyses of their programs, provided in formal filings and informal reports to the IUB. The chart above compiles the results of the utilities' data.
Sources: Data from the IAEC- EE Sum IAEC Jt. Filing Co-ops; Report of IUB Staff, November 24, 1999. Additional data from energy efficiency plans jointly filed by the IAEC in 2000 and 2002.

Table 2-13 Rural Electric Cooperatives - MW Savings Due to Voluntary Load Management

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Cumulative MW Savings	10	10	0	0	19	20	46	48	50	53	54	57	59

Notes: In the IAEC report, MW savings were provided as one aggregate total. The data for utilities' capacity and energy savings are the result of utilities' analyses of their programs, provided in formal filings and informal reports to the IUB. The chart above compiles the results of the utilities' data.
Sources: Data from the IAEC- EE Sum IAEC Jt. Filing Co-ops; Report of IUB Staff, November 24, 1999. Additional data from energy efficiency plans jointly filed by the IAEC in 2000 and 2002.

Table 2-14 Municipal Utilities - MW Savings Due to Voluntary Energy Efficiency

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Cumulative MW Savings	29	58	65	72	78	84	84	85	87	104	109	114	116

Notes: The data for utilities' capacity and energy savings are the result of utilities' analyses of their programs, provided in formal filings and informal reports to the IUB. The chart above compiles the results of the utilities' data.
Sources: 1990-1998, Report of IUB Staff, November 24, 1999. 1999-2002, Energy Efficiency Plans filed by Municipal Utilities with the IUB, in 2000 and 2002.

Table 2-15 Municipal Utilities - MW Savings Due to Voluntary Load Management

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Cumulative MW Savings	16	32	56	80	111	147	162	179	190	195	202	209	216

Notes: The data for utilities' capacity and energy savings are the result of utilities' analyses of their programs, provided in formal filings and informal reports to the IUB. The chart above compiles the results of the utilities' data.
Sources: 1990-1998, Report of IUB Staff, November 24, 1999. 1999-2002, Energy Efficiency Plans filed by Municipal Utilities with the IUB, in 2000 and 2002.

Tables 2-16 through **2-18** present cumulative GWh energy savings for IOUs (**Table 2-16**), RECs (**Table 2-17**), and municipal utilities (**Table 2-18**).

Table 2-16 Investor-Owned Utilities - GWh Savings Due to Energy Efficiency (1 GWh = 1,000 MWh = 1,000,000 kWh)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Cumulative GWh Savings	7	31	66	146	258	391	500	593	655	732	849	969	1,099

Notes: The data for utilities' capacity and energy savings are the result of utilities' analyses of their programs, provided in formal filings and informal reports to the IUB. The chart above compiles the results of the utilities' data.
Sources: Report by IOUs, August 12, 2000, Tables 1.4.1.2.a and 1.4.1.2.b. Electronic data provided by IOUs in 2003. Informal reports of IOUs.

Table 2-17 Rural Electric Cooperatives - GWh Savings Due to Voluntary Energy Efficiency (1 GWh = 1,000 MWh = 1,000,000 kWh)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Cumulative GWh Savings	14	20	23	28	39	47	59	69	76	83	84	94	105

Notes: The data for utilities' capacity and energy savings are the result of utilities' analyses of their programs, provided in formal filings and informal reports to the IUB. The chart above compiles the results of the utilities' data.
Sources: Data from the IAEC- EE Sum IAEC Jt. Filing Co-ops; Report of IUB Staff, November 24, 1999. Additional data from energy efficiency plans jointly filed by the IAEC in 2000 and 2002.

Table 2-18 Municipal Utilities - GWh Savings Due to Voluntary Energy Efficiency (1 GWh = 1,000 MWh = 1,000,000 kWh)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Cumulative Annual GWh Savings	24	47	56	64	74	83	90	97	100	104	112	124	133

Notes: The data for utilities' capacity and energy savings are the result of utilities' analyses of their programs, provided in formal filings and informal reports to the IUB. The chart above compiles the results of the utilities' data.
Sources: 1990-1998, Report of IUB Staff, November 24, 1999. 1999-2002, Energy Efficiency Plans filed by Municipal Utilities with the IUB, in 2000 and 2002.

Tables 2-19 through **2-21** present annual expenditures for energy efficiency and load management by IOUs (**Table 2-19**), RECs (**Table 2-20**), and municipal utilities (**Table 2-21**).

Table 2-19 Total Investor-Owned Utility Energy Efficiency and Load Management Expenditures ($1,000s)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Annual $1,000s Expenditures	3,185	13,146	19,921	30,775	41,855	45,859	42,743	31,359	30,460	26,394	27,603	32,270	32,408

Note: Interstate expenditures for Load Management from 1990-2002 do not include incentives to industrial customers, which amount to approximately $21,000,000.
Sources: IOU Report, August 2, 2000, Tables 1.4.1.1.a and 1.4.1.1.b. IOU data responses, IPL - 9/9/03 and MEC - 7/1/03.

Table 2-20 Total Rural Electric Cooperative Voluntary Energy Efficiency and Load Management Expenditures ($1,000s) - Revised to Include Eastern Iowa REC

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Annual $1,000s Expenditures	2,359	2,648	3,613	3,981	4,863	5,128	4,901	5,459	5,562	5,953	5,899	6,876	6,425

Notes: The data for utilities' capacity and energy savings are the result of utilities' analyses of their programs, provided in formal filings and informal reports to the IUB. The chart above compiles the results of the utilities' data.
Sources: Data from the IAEC- EE Sum IAEC Jt. Filing Co-ops; Report of IUB Staff, November 24, 1999. Additional data from energy efficiency plans jointly filed by the IAEC in 2000 and 2002.

Table 2-21 Total Municipal Utility Voluntary Energy Efficiency and Load Management Expenditures ($1,000s)

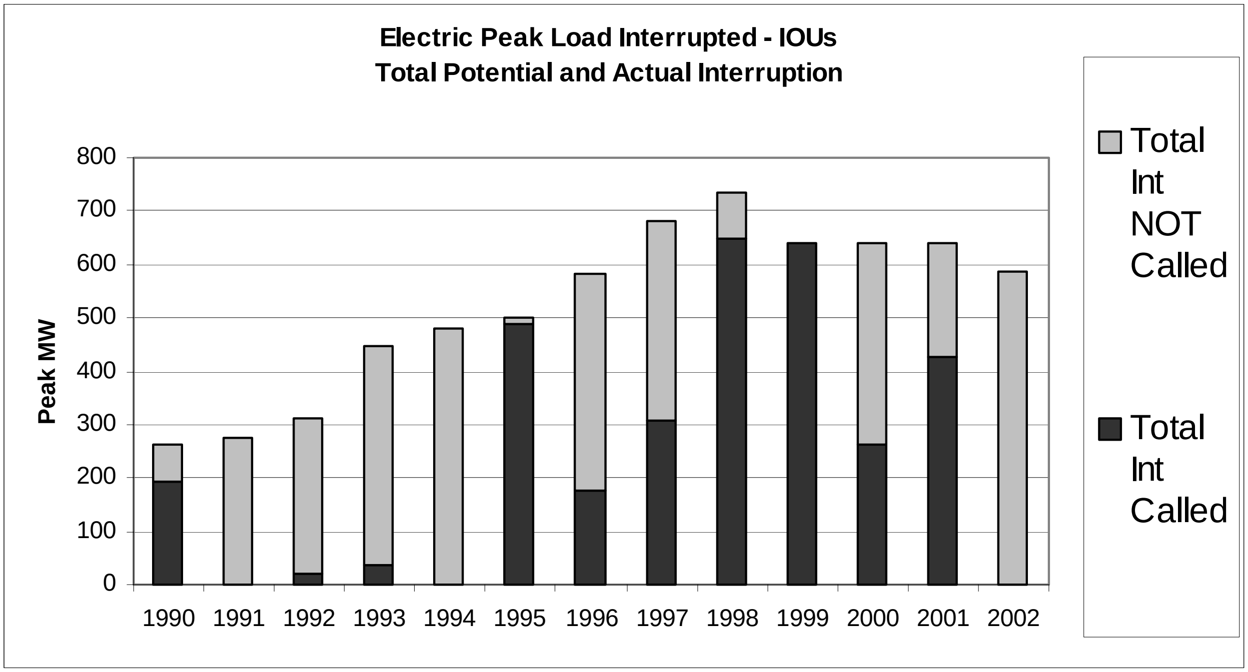
	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Annual $1,000s Expenditures	3,222	3,222	3,218	3,218	2,098	1,741	2,108	2,144	2,144	3,478	2,506	2,205	2,657

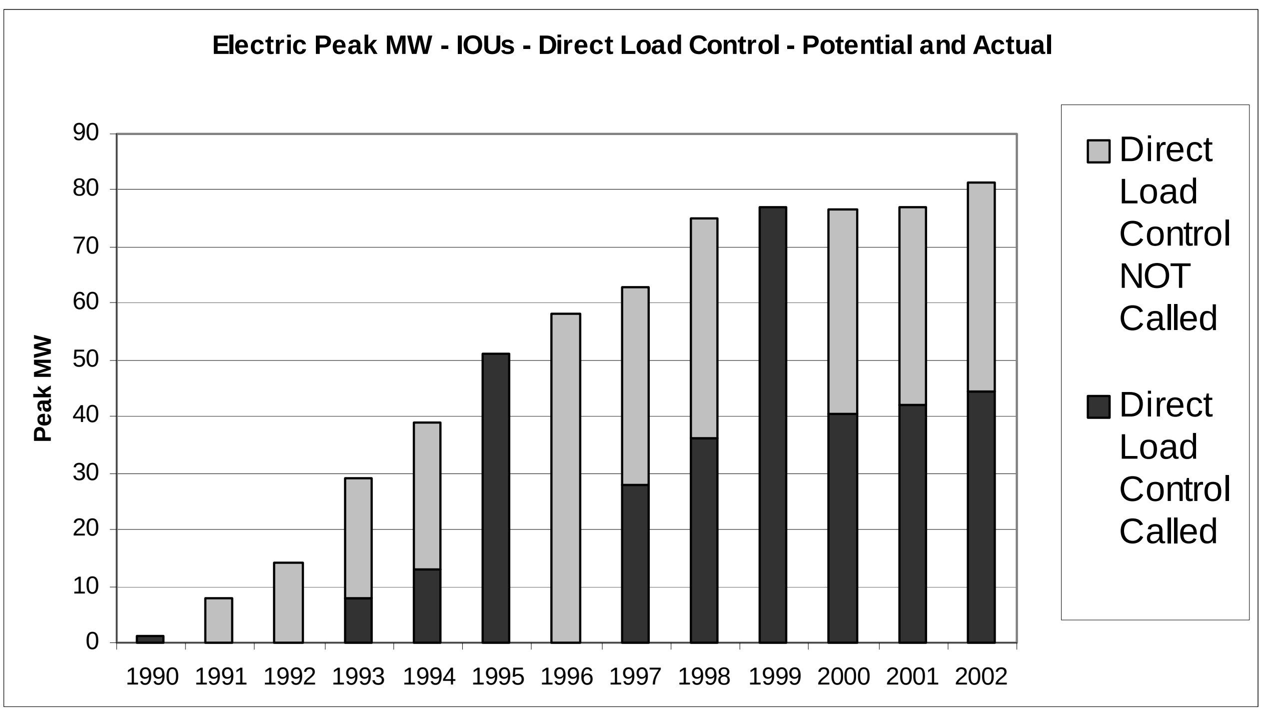
Notes: 1998 estimate from 1997.
Sources: IUB Staff Report, September 16, 1999. 1999-2002, Energy Efficiency Plans filed by Municipal Utilities with the IUB, in 2000 and 2002.

2.2.3.3 Potential and Actual Load Management

Potential load management is the total load available for reduction by direct load control and interruptible load. Actual load management is the actual load reduction called for and achieved through direct load control or interruption. **Figure 2-5** compares potential and actual load management, for both interruptible load (Int) and direct load control (Direct LC), over the past several years for Iowa IOUs.

Figure 2-5 Interruptions and Peak Load Control for Investor-Owned Utilities -- Potential and Actual





<u>2000</u>: Report by IOUs, August 12, 2000, Table 1.1.2.1b "Estimated Interruption Called (MWs)," Table 1.1.2.1c "Estimated Interruption Not Called (MWs)," Table 1.1.2.1d "Estimated Air Conditioner/Water Heating Called (MWs)," Table 1.1.2.1e "Estimated Air Conditioner/Water Heating Not Called (MWs)."
<u>Sources, 2003:</u> IOU data responses, IPL - 9/9/03 and MEC - 7/1/03.

2.3 Electric Supply

Several sources of supply are available to meet the customer demand described in subsection 2.2. An Iowa utility may generate its own power for use by its consumers, or it may purchase power from another utility or power marketer either in or outside the state. Subsection 2.3 provides data on generation owned by Iowa's utilities, non-utility generation, and IOU data related to overall purchased power commitments. Price data from the emerging wholesale market is provided, as well as other regional supply considerations. Limited data on air emissions from fossil-fuel-fired generation are also presented. The subsection concludes with a brief discussion of Iowa's generation siting requirements.

2.3.1 Existing Generating Plants

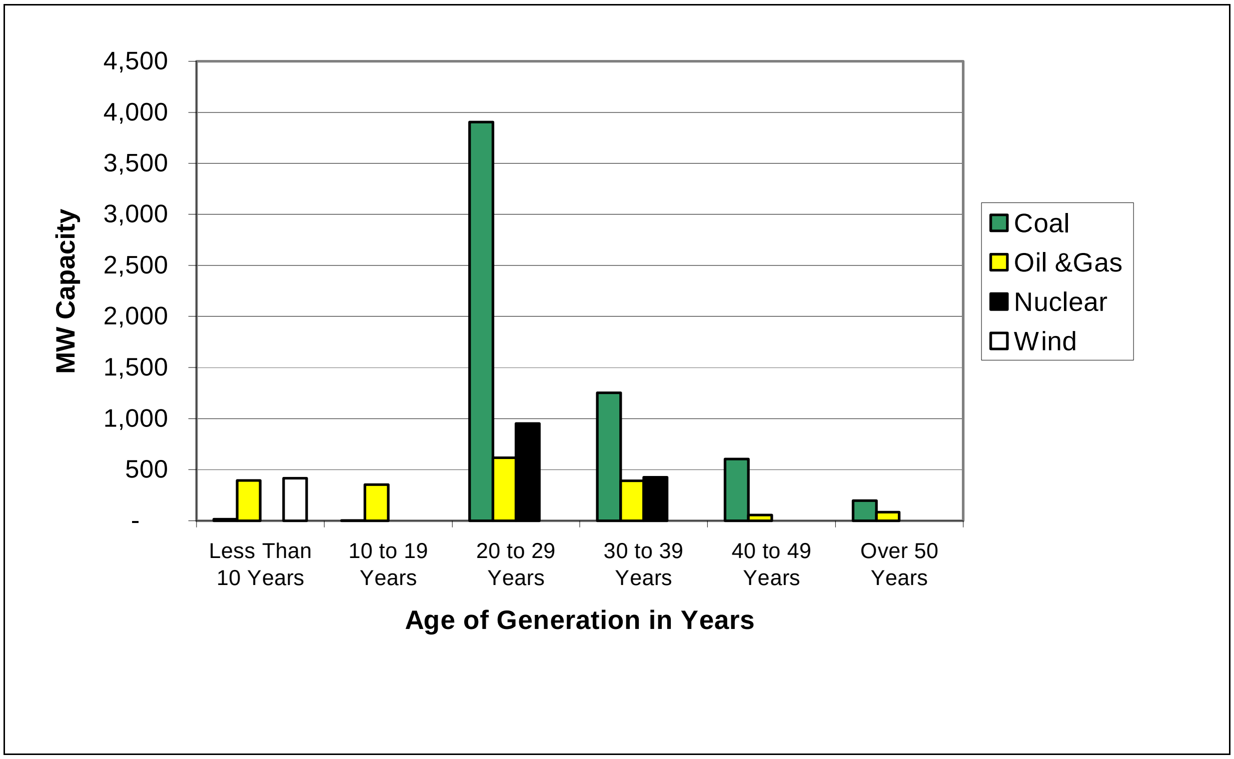
Generating plants use a variety of fuel sources including water (or hydro), uranium (or nuclear), coal, natural gas, oil, biomass, and wind. Generating units using coal, gas, or oil are referred to as fossil-fuel-fired generating units. The size of a generating unit is commonly defined in megawatts (MW). The MW designation refers to the generating capacity of the unit. MW capacity multiplied by the number of hours in the year (8760) provides the maximum amount of electricity in megawatt hours (MWh) the plant is capable of producing in a given year, assuming the unit is never unavailable due to maintenance or forced outage. **Appendix D** provides a list of utility generators providing power to Iowa consumers, and **Appendix E** provides a list of non-utility generators.[15]

This subsection provides historical information for all generating units owned by MidAmerican Energy and Interstate Power & Light, and generating units owned by other Iowa utilities. Throughout this subsection, these generating units, plus MidAmerican's long-term capacity purchase from Nebraska Public Power District's Cooper Station ("Cooper Contract"), will be labeled "Iowa utility-owned generation." With the exception of the Cooper Contract, the data do not include purchased power commitments unless explicitly noted.[16] In addition, the plant data do not include generating facilities owned by non-Iowa entities selling power to Iowa utilities such as the generating facilities of Associated Electric Cooperative, Inc., Dairyland Power Cooperative, Ameren, the Western Area Power Administration, Basin Electric Power Cooperative, and Missouri River Energy Services.[17] Since purchased power (with the noted exceptions) is not included in these data, it would be inappropriate to use these data to characterize Iowa's consumption fuel mix. The data may be used to characterize Iowa's production fuel mix.

[15] These lists are not all inclusive.
[16] In noted cases, the data include IOU wind contracts.
[17] Iowa municipal utilities that are members of Missouri River Energy Services (MRES) have rights of ownership in the Laramie River Station through MRES. The figures and tables in subsection 2.3 do not include this generation.

Figure 2-6 illustrates the generating capacity of Iowa utility-owned generation plus IOU wind contracts. **Table 2-22** shows the data used in **Figure 2-6**.

Figure 2-6 Generating Capacity by Age and Type (MW)



Sources: Form EIA-860A, Form EIA-860B and other sources as compiled by Platts, a division of the McGraw-Hill Companies. Data provided by MidAmerican.

Table 2-22 Generating Capacity of Iowa Utility-Owned Generation plus the IOU Wind Contracts by Age and Type (MW)

	Less than 10 Years	10 to 19 Years	20 to 29 Years	30 to 39 Years	40 to 49 Years	50+ Years	Total By Fuel
Coal	16	3	3,906	1,254	605	196	5,980
Oil	293	203	275	95	23	63	952
Gas	101	151	343	297	33	22	947
Nuclear	0	0	952	425	0	0	1,377
Wind	418	0	0	0	0	0	418
Hydro	0	2	0	0	0	9	11
Total	828	359	5,476	2,071	661	290	9,685

Notes: Nameplate ratings were used for wind generation, and summer ratings were used for all other generation. Includes MidAmerican's share of the Quad Cities nuclear station in Illinois and MidAmerican's share of output from the Cooper nuclear station in Nebraska.
Sources: Form EIA-860A, Form EIA-860B and other sources as compiled by Platts, a division of the McGraw-Hill Companies. Data provided by MidAmerican.

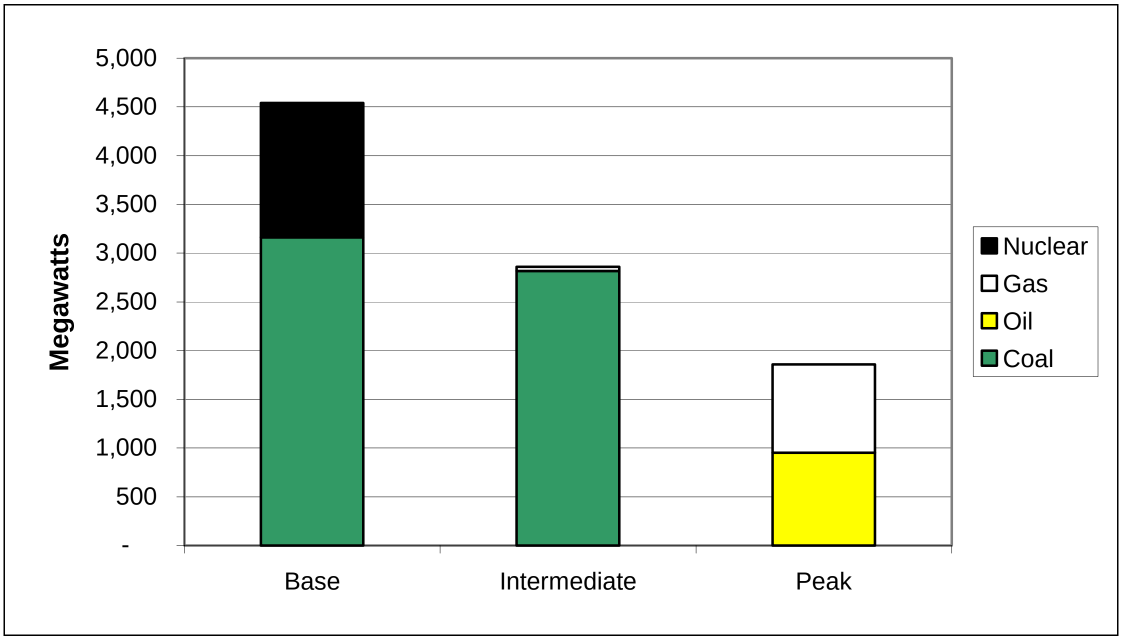
Generating plants are typically classified as base, intermediate, or peaking based on operation, unit type, fuel type, size of unit, age of unit, and average annual heat rate (i.e., efficiency). Base load units generally include hydro units, nuclear units, and newer, larger coal-fired units. Some extremely efficient gas-fired units may also be operated as base load units. Intermediate units generally include older or smaller coal-fired units, gas-fired steam units, and newer, more efficient gas-fired units. Peaking units generally include gas- and oil-fired combustion turbines and internal combustion engines.

Figure 2-7 and **Table 2-23** classify generating units in Iowa by typical use. Generating units were classified using the following criteria:

- Base - A plant that is operated whenever it is available. The plant’s output may be reduced for decreased load or market price conditions.
- Intermediate - A plant operated a substantial portion of the time. Depending on the system, intermediate units typically operate 1,500 to 5,000 hours per year.
- Peaking - A plant used to generate electricity only for the highest system loads. Peaking plants are typically used up to 1,500 hours per year.

Two other types of units have not been classified as base, intermediate, or peaking, because they cannot be dispatched by electric utilities. These are IOU wind generation contracts, and other small generators that primarily serve their own load with any excess sold to the utilities. These are intermittent sources that provide electricity only “as available.”

Figure 2-7 Use of Iowa Utility-Owned Generation



Sources: Form EIA-860A, Form EIA-860B and other sources as compiled by Platts, a division of the McGraw-Hill Companies. Data Provided by MidAmerican.

Table 2-23 Typical Use of Iowa Utility-Owned Generation Plus IOU Wind Generation Contracts

Type of Use	Fuel Type	Capacity (MW)
Base	HYDRO	11
Base	NUCLEAR	1,376
Base	COAL	3,163
Intermediate	COAL	2,818
Intermediate	GAS	41
Peak	GAS	906
Peak	OIL	952
As Available	WIND	418
As Available	OTHER SMALL	8

Notes: Includes MidAmerican's share of the Quad Cities nuclear station in Illinois and MidAmerican's share of output from the Cooper nuclear station in Nebraska.
Sources: Form EIA-860A, Form EIA-860B and other sources as compiled by Platts, a division of the McGraw-Hill Companies. Data provided by MidAmerican.

2.3.1.1 Historical Fuel Use and Efficiency

The goal of economic dispatch is to efficiently dispatch the available mix of generating units on an electric system to provide the least-cost electric energy to serve a range of system demands. Since fuel represents the largest portion of the cost to operate a generating unit (except for wind and hydro generation), fuel cost may be used to develop a preliminary order of units to be dispatched to serve load. Since the fuel costs for uranium are lower than fossil fuel, nuclear units are normally dispatched after hydro units and before any fossil-fuel-fired units. Coal-fired units are generally brought on-line before any gas- or oil-fired generation is brought on-line because coal is the lowest cost fossil fuel. Wind turbines are used whenever available.

Unit efficiency may change the preliminary unit dispatch order based on fuel cost. Unit efficiency is measured by the unit heat rate. The heat rate equals the quantity of energy input (measured in British thermal units, or Btus) divided by the quantity of energy output (measured in kWhs). The lower the heat rate, the more efficient the unit. The measured heat rates for units vary depending on the design, age, and condition of the unit, ambient temperature, and the level of operation.[18] High-efficiency, combined-cycle gas units may have heat rates well below coal-fired steam units. Even though the cost of gas is currently substantially higher than the cost of coal, there is a crossover point based on the relative cost of gas and coal where a high-efficiency combined-cycle gas unit would have a lower input fuel cost than a low-efficiency coal unit. In such a case, the coal unit would move higher in the dispatch ranking than the combined-cycle gas unit.

Additional factors that may change the system-wide economic dispatching of generating units include:

- <u>Area Protection</u> – Provide support to the transmission system in an area.
- <u>Transmission Relief</u> – Adjust transmission line flows by changing generation levels to ease transmission congestion.
- <u>Must-Run Units</u> – Keep a unit on-line in order to minimize the unit's cost of operation, startup, shutdown costs, and "wear and tear" costs, or for conditions requiring continuous operation of those units. Conditions that might require continuous unit operation include unit testing or a need to burn coal from in-plant storage.
- <u>Limited Operating Hours</u> – Restrict a unit's operation to comply with environmental restrictions.

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[18] Each generating unit's heat rate varies over the normal operating range of the unit. Nearly all units are less efficient as the capacity approaches the unit's minimum generation level, and most efficient near the maximum generation level. As a result, the cost to operate a generating unit, assuming a constant fuel cost, will decrease in terms of cents per kilowatt-hour as the unit's output is increased. Warmer ambient temperatures generally reduce the operating capability of generating units.

Table 2-24 shows historical annual generation for Iowa utility-owned generation by unit type. In this case, generation is characterized in GWh. Steam (i.e., fossil) generation (as presented in the table) is typically fueled by coal, gas, or oil.

Table 2-24 Iowa Electric Utility-Owned Generation by Plant Type (GWh)

Year	Steam Generation GWh	Nuclear Generation GWh	Hydro Generation GWh	Other Generation GWh	Total Generation GWh
1993	25,638	6,878	12	97	32,625
1994	26,135	6,671	23	107	32,936
1995	28,201	7,921	21	104	36,247
1996	28,034	8,941	20	69	37,064
1997	28,721	8,923	19	254	37,917
1998	31,403	9,001	20	436	40,860
1999	31,407	10,144	23	391	41,965
2000	33,080	9,928	23	298	43,329
2001	30,646	9,723	18	326	40,713
2002	28,936	9,452	22	180	38,590

Notes: Includes all utility-owned generating units located in Iowa and other units owned and operated by Interstate located outside Iowa. Also includes MidAmerican's share of the Quad Cities nuclear station in Illinois and MidAmerican's share of output from the Cooper nuclear station in Nebraska. Does not include non-utility generation, such as wind contracts.
Sources: Various sources as compiled by Platts, a division of the McGraw-Hill Companies. Data provided by MidAmerican.

Table 2-25 shows historical capacity factors by plant type. The capacity factor of a generating plant, or group of plants, represents the percentage of electricity the plant actually generated compared to electricity it is capable of generating for a specific time period.

Factors that may affect the capacity factor of each type of plant include:

- Economic dispatch – Use of the lowest-cost generation to serve load.
- Load following – Adjustments to the amount of total generation to match the load. Loads, including customer loads plus sales less purchases, change almost constantly. These changes require changes to the mix of generating units producing electricity.
- Scheduled Maintenance – Periods when units are out of service for maintenance.
- Forced outage – Periods when the unit must be shut down or generation must be reduced to perform unscheduled maintenance and repairs.

The increase in capacity factors for coal and nuclear units are primarily due to increases in native load energy requirements and increased energy sales to other utilities. Increased unit availability of nuclear units also results in higher capacity factors for those units.

Table 2-25 Capacity Factors by Utility Plant Type for Iowa Utility-Owned Generation

Year	Steam	Nuclear	Hydro	Other
1993	51.8%	63.3%	27.4%	0.9%
1994	51.1%	58.9%	51.2%	0.9%
1995	55.2%	69.9%	46.3%	0.9%
1996	54.9%	78.7%	44.7%	0.6%
1997	56.2%	78.9%	41.6%	2.1%
1998	61.3%	79.6%	44.7%	3.5%
1999	62.5%	90.1%	49.5%	2.9%
2000	62.2%	87.5%	50.3%	2.2%
2001	63.3%	83.1%	40.0%	2.5%

Notes: Capacity factors were calculated using the higher of the reported summer or winter capacity and net annual generation, excluding station use. Based on the same generating units reflected in Table 2-24.
Sources: Various sources as compiled by Platts, a division of the McGraw-Hill Companies. Data provided by MidAmerican.

Table 2-26 shows the percentage of each type of fuel used for Iowa utility-owned generation. For comparison purposes, the quantity of each fuel used was converted to Btus, a measure of heat content.[19]

Table 2-26 Percent of Heat Input by Fuel Type - Iowa Utility-Owned Generation

Fuel Type	1998	1999	2000	2001	2002
COAL	78.1%	75.1%	76.6%	77.4%	77.1%
NUCLEAR	19.8%	23.2%	22.0%	20.9%	21.1%
GAS	1.7%	1.3%	1.1%	1.4%	1.7%
OIL	0.3%	0.3%	0.2%	0.3%	0.1%
HYDRO	0.0%	0.0%	0.0%	0.0%	0.0%
WOOD	0.1%	0.1%	0.0%	0.0%	0.0%
OTHER	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Notes: This table lists the percent of heat input of each fuel at all types of plants. The gas percentage includes gas used at plants with primary fuel types of coal, oil, or other primary fuels. The table reflects the same generating units as Table 2-24.
Sources: Various sources as compiled by Platts, a division of the McGraw-Hill Companies. Data provided by MidAmerican.

[19] Typical Btu conversion rates are: Low Btu coal – 8,400 Btus per pound, high Btu coal – 10,500 Btus per pound, natural gas – 1000 Btu per cubic foot, and oil – 140,000 Btus per gallon.

2.3.1.2 Projected Fuel Diversity

The Energy Information Administration (EIA) conducts energy forecasts for the U.S. The EIA[20] produced estimates of U.S. energy consumption by sector for three scenarios: a reference case, a low economic growth case, and a high economic growth case. **Table 2-27** shows the EIA value for actual Btus used in 2001 and the forecast of the number of Btus used to produce electricity in 2010. **Table 2-27** also shows the annual average growth in the use of each type of fuel from 2001 to 2010 under each EIA growth scenario.

Table 2-27 U.S. Energy Consumption for Electric Generators (Quadrillion Btu per year) and Annual Average Change in Consumption from 2001 to 2010

		2001 Reference	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth
Oil	Consumption	1.3	0.4	0.4	0.5
	Annual Change		*-12.3%*	*-12.3%*	*-10.1%*
Natural Gas	Consumption	5.4	6.6	6.9	7.4
	Annual Change		*2.3%*	*2.8%*	*3.6%*
Steam Coal	Consumption	19.8	22.4	22.7	22.9
	Annual Change		*1.4%*	*1.5%*	*1.6%*
Nuclear	Consumption	8.0	8.4	8.4	8.4
	Annual Change		*-0.5%*	*-0.5%*	*-0.5%*
Renewable	Consumption	3.0	4.5	4.5	4.5
	Annual Change		*4.6%*	*4.6%*	*4.6%*

Sources: Energy Information Administration, Annual Energy Outlook 2003, Table B2, Energy Consumption by Sector and Source, pp. 150-151.

[20] Energy Information Administration, Annual Energy Outlook 2003, Table B2, Energy Consumption by Sector and Source, pp. 150-151.

Table 2-28 shows EIA's forecasted changes in the percentage shares of fuel energy inputs used to generate electricity.

Table 2-28 U.S. Energy Consumption for Electric Generators - Type of Fuel Used as a Percentage of Total Fuel for Generation

	2001 Reference	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth
Oil	3.4%	0.9%	0.9%	1.1%
Natural Gas	14.3%	15.5%	16.0%	16.8%
Steam Coal	52.6%	52.6%	52.6%	52.1%
Nuclear	21.2%	19.7%	19.4%	19.1%
Renewable Energy	8.0%	10.6%	10.4%	10.2%
Electricity Imports	0.5%	0.7%	0.7%	0.7%
Total	100.0%	100.0%	100.0%	100.0%

Sources: Energy Information Administration, Annual Energy Outlook 2003, Table B2, Energy Consumption by Sector and Source, pp. 150-151.

The EIA forecast shows an increase in the total amount of energy used to generate electricity, with more than one percent average annual growth between 2001 and 2010. Gas and renewable energy use are forecasted to increase, both in terms of Btus and percentage share of total Btus. EIA forecasts a decrease in Btus and percentage shares for nuclear energy and oil. Btus from coal are forecasted to increase, with percentage shares remaining about the same.

2.3.1.3 Cost of Generation

Table 2-29 presents historical costs per MWh delineated by fuel type and expense category.[21] Generation expenses are often categorized as fuel and non-fuel. As stated previously, fuel is the primary cost component of fossil-fuel-fired generation. Non-fuel expenses play a larger role in nuclear and hydro generation.

[21] These costs do not include capital costs, depreciation expenses, taxes, or generation overhead.

Table 2-29   Generation Cost per MWh by Fuel Type – Iowa Generation

	Steam Generation ($/MWh)			Nuclear Generation ($/MWh)			Hydro Generation ($/MWh)		
Year	Fuel	Non-Fuel	Total	Fuel	Non-Fuel	Total	Water Expense	Non-Water Expense	Total
1993	12.45	4.01	16.46	5.67	21.29	26.96	0.00	14.83	14.83
1994	12.06	4.05	16.11	6.34	25.29	31.63	0.00	10.52	10.52
1995	11.88	3.43	15.31	6.49	20.88	27.37	0.00	9.05	9.05
1996	11.79	3.43	15.22	6.38	16.16	22.55	0.00	10.75	10.75
1997	11.73	3.62	15.36	6.20	18.29	24.49	0.00	33.47	33.47
1998	10.73	3.48	14.21	5.21	16.89	22.10	0.00	17.70	17.70
1999	10.01	3.54	13.55	5.50	14.72	20.22	0.00	24.61	24.61
2000	10.37	3.85	14.22	5.82	12.03	17.85	0.00	20.57	20.57
2001	10.41	4.04	14.45	5.75	11.44	17.19	0.00	25.72	25.72
2002	10.46	4.13	14.59	6.57	10.54	17.11	2.64	16.18	18.82

Notes: Includes MidAmerican's share of the Quad Cities nuclear station in Illinois and MidAmerican's share of output from the Cooper nuclear station in Nebraska.
Sources: Various sources as compiled by Platts, a division of the McGraw-Hill Companies. Data provided by MidAmerican.

2.3.1.4 Non-Utility Generation

The non-utility category includes units connected to the utility grid, and units that serve only electric customers' internal loads. **Appendix E** provides a list of Iowa non-utility generators.[22] The largest plants in this category are Archer Daniels Midland in Cedar Rapids (230 MW), Storm Lake Wind Power 1&2 (193 MW), Hancock County Windfarm (98 MW), Top of Iowa Windfarm (80 MW), the Cerro Gordo Wind Project (42 MW), and Archer Daniels Midland in Clinton (31 MW).

2.3.2 Purchased Power

Purchased power is another source of supply used to serve Iowa's load and energy requirements. This subsection presents: 1) historical and projected purchased power commitments as accredited with MAPP; 2) a discussion and delineation of IOU energy purchases from alternate energy sources (more commonly known as renewable energy sources, such as wind generation); and 3) summary data from the Midwest's wholesale spot electricity market.

[22] The list is not all-inclusive.

2.3.2.1 Purchased Power Commitments for Iowa's Investor-Owned Utilities

Table 2-30 shows historical and projected purchased power commitments for MidAmerican and Interstate, including the total of summer and participation purchases and sales accredited with MAPP or MAIN.

Table 2-30 Historical and Projected Purchased Power Commitments (MW)

	MidAmerican Energy (MAPP)				Interstate Power & Light (MAPP)		
	Total Purchases	Total Sales	Net Purchases		Total Purchases	Total Sales	Net Purchases
1993	792	605	187		406	75	331
1994	786	571	215		416	75	341
1995	756	556	200		446	75	371
1996	672	406	266		426	75	351
1997	634	299	335		455	60	395
1998	630	287	343		425	0	425
1999	620	289	331		530	7	523
					Interstate Power & Light (MAIN – excluding CIPCO)		
2000	809	256	553		*483*	*162*	*321*
2001	685	5	680		*341*	*26*	*315*
2002	877	255	622		*513*	*0*	*513*
2003	709	320	389		*507*	*100*	*407*
2004	588	388	200		*33*	*0*	*33*
2005	54	36	18		*33*	*0*	*33*
2006	54	40	14		*33*	*0*	*33*
2007	102	0	102		*33*	*0*	*33*
2008	102	0	102		*33*	*0*	*33*
2009	102	50	52		*27*	*0*	*27*
2010	102	50	52		*27*	*0*	*27*
2011	102	50	52		*27*	*0*	*27*
2012	102	50	52		*27*	*0*	*27*

Notes: Total purchases and sales equal total firm and participation power transactions accredited with MAPP or MAIN. MidAmerican's accredits all purchased power commitments with MAPP. Interstate accredited purchased power commitments with MAPP through 1999 (including the Central Iowa Power Cooperative, or CIPCO). In 2000, Interstate began accrediting purchased power commitments with MAIN (excluding CIPCO). MidAmerican purchase commitments include an approximate 385 MW participation power purchase contract with Cooper Power Station, for 1993-2004.
Sources: MidAmerican: 1993-2003 MAPP Annual Load & Capability Reports; Interstate: 1993-1999 MAPP Annual Load & Capability Reports, and MAIN data provided by Interstate.

2.3.2.2 *Power Purchases from Alternate Energy Sources (Background and Summary Table)*

The Alternate Energy Production (AEP) statute (Iowa Code Section 476.41 – 476.45) was enacted in 1983 to encourage the development of AEP facilities by mandating special incentive rates to be paid by utilities for AEP purchases. Federal law requires utilities to purchase AEP at rates based on the utilities' incremental avoided costs.[23] In 1983, avoided-cost rates were not considered high enough to encourage AEP development. The Iowa AEP statute mandated higher, incentive rates for AEP purchases.

The first IUB rules to implement the statute were adopted in 1983 (Docket No. RMU-83-30), and provided for a statewide AEP purchase rate of 6.5 cents per kWh. This statewide rate was challenged by Iowa electric utilities and was eventually overturned by the Iowa Supreme Court in 1987. The Court ruled that the IUB's rules went beyond the AEP statute by setting a statewide AEP rate rather than utility-specific rates, and by disregarding specific ratemaking factors listed in the statute. The Court also ruled that the AEP statute could not be applied to non-rate regulated utilities (i.e., most rural electric cooperatives and municipal utilities).

The IUB proposed new rules in January 1988 (Docket No. RMU-88-4), attempting to establish AEP incentive purchase rates that would encourage AEP development, based on the statute's ratemaking factors. However, both criteria could not be satisfied under the original statute. Statutory changes were needed to design rates high enough to encourage AEP development. These statutory changes were enacted in 1990.[24] The IUB implemented the changes through rules adopted in June 1991 (Docket No. RMU-90-35). The rules established statewide incentive purchase rates for AEP capacity and energy based on revised statutory ratemaking factors. The rates were adjustable, according to the length of the AEP contract, up to a maximum combined rate of 6-cents per kWh.

In 1992, the IOU purchase obligation was changed to a proportional share of 105 MW, based on each utility's share of the utilities' combined Iowa electric peak demand. The IUB implemented this change through rules adopted in July 1993 (Docket No. RMU-92-16).

In 1996, the Alternate Energy Revolving Loan Program (Iowa Code § 476.46) was enacted to provide low-interest loan incentives for AEP development. This program is administered by the Iowa Energy Center.

[23] Avoided costs are the costs the utility would otherwise incur in either producing the power itself or purchasing it from other sources.

[24] Specifically, the changes: 1) permitted the Board to set statewide AEP purchase rates; 2) changed the definition of "next generating plant" to be the "electric utility's next coal-fired base load electric generating plant, whether planned or not, based on current technology and undiscounted current cost;" and 3) allowed the Board to consider environmental and economic externality factors. A further provision limited each IOU's AEP purchase obligation to 15 MW.

In 1997, the FERC overturned the AEP incentive rates mandated by the AEP statute and IUB rules, to the extent they required utilities to pay more than avoided costs for their AEP purchases (FERC Docket No. EL95-51-000). However, the FERC also ruled that the AEP statute and IUB rules could require utilities to make specific purchases from AEP facilities. Therefore, in the context of a separate proceeding (Docket Nos. AEP-95-1 through AEP-95-5), the IUB required IOUs to fulfill the remainder of their statutory 105 MW AEP purchase obligation, by a date-certain. The IOUs responded by entering into several AEP purchase contracts, selected through competitive bidding.

Table 2-31 shows historical renewable energy purchases by Iowa utilities over the past five years (1998-2002). These purchases include the IOUs' 105 MW AEP purchase obligation, plus additional renewable purchases by Iowa utilities in excess of AEP statutory requirements. This includes firm hydropower purchases from the Western Area Power Administration (WAPA). WAPA hydropower is produced by out-of-state hydroelectric facilities on the Missouri river. The purchase totals in Table 2-31 do not include 25 Hz hydro or WAPA non-firm hydro purchases.[25]

[25] 25 Hz hydro is based on an older power standard, generally no longer used by customers (60 Hz generation is the current industry standard). WAPA non-firm hydro is purchased on an interruptible (i.e., "as available") basis, making it subject to sizable annual fluctuations. By 2002, Interstate was no longer purchasing 25 Hz hydro from Ameren, and WAPA non-firm hydro purchases had dropped to 65,400 MWh (from a high of 315,377 MWh in 1999).

Table 2-31 Renewable Energy Purchases by Iowa Utilities (MWh = 1,000 kWh)

	1998 MWh	1999 MWh	2000 MWh	2001 MWh	2002 MWh
Wind	3,138	411,180	602,864	608,187	666,288
Hydro	7,984	17,963	62,980	77,632	103,166
WAPA Hydro	1,207,811	1,192,371	1,205,780	1,173,281	1,184,270
SWPA Hydro[26]	N/A	N/A	N/A	N/A	N/A
Biomass	60,665	85,367	85,015	81,737	83,520
Other	1,572	2,145	15,468	22,197	27,667
Renewable Totals	**1,281,170**	**1,709,026**	**1,972,107**	**1,963,034**	**2,064,911**
Total Iowa MWh Sales	37,318,292	38,033,812	39,087,867	39,214,000	40,082,000
Renewable Totals As a Percentage of Total Iowa MWh Sales	**3.4%**	**4.5%**	**5.0%**	**5.0%**	**5.2%**

Sources: Purchase data compiled by Interstate, MidAmerican, the Iowa Association of Electric Cooperatives (IAEC), and the Iowa Association of Municipal Utilities (IAMU). Note there have been some revisions to 1998 and 1999 purchase data since the previous report (*Electric Power in Iowa, August 2000*). Total Iowa MWh sales data compiled by IUB Staff from Energy Information Administration (EIA), *Electric Sales and Revenue*, 1998-2000, Table 17, and from *Electric Power Monthly*, March 2003, Table 47.

2.3.2.3 Wholesale Spot Market

As described in subsection 1.2 – Background, the Energy Policy Act of 1992 (EPACT), coupled with FERC Order 888, created a wholesale spot market in electricity. Specifically, the EPACT advanced the growth of non-utility power producers by creating a new class of non-utility generators called "exempt wholesale generators" (EWGs). The EPACT allowed companies, including public utility holding companies, to develop and operate EWGs anywhere in the world. EWGs may sell wholesale power at market rates and are exempt from the cost-of-service regulation to which utilities are subject. Utilities must provide wholesale power transmission service to EWGs and other third parties at cost-based rates, under the same open access transmission regulations as any other capacity. The impact of the EPACT can be seen in the growth in the number of non-utility generating facilities. From 1997 to 1998, the total installed capacity of non-

[26] SWPA hydro is hydropower from the Southwestern Power Administration (SWPA), purchased by Iowa RECs. SWPA purchase data was not available at the time of submission. In previous years, annual purchases from SWPA have averaged 38,000 MWh.

utility generating facilities grew 32.5 percent.[27] Non-utility capacity in 1998 was equivalent to 12.6 percent of the total U.S. electric industry capacity[28] compared to 7 percent in 1991.[29] The FERC implemented the provisions of the EPACT, in part, through FERC Order 888.

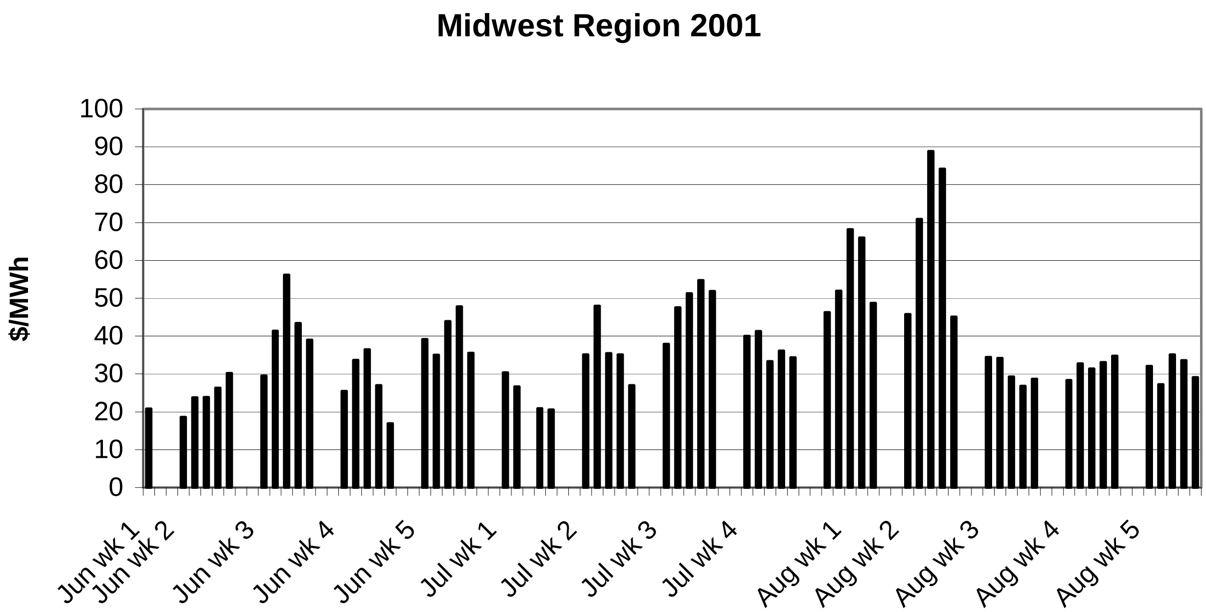
The EPACT and Order 888 enabled new organizations, such as power marketers, to purchase, transmit and resell electric power across traditional electric utility borders. Power marketers, like traditional utilities, buy and sell electric power in the wholesale market. Some of these power marketers own generation, however none of them own transmission or distribution facilities.

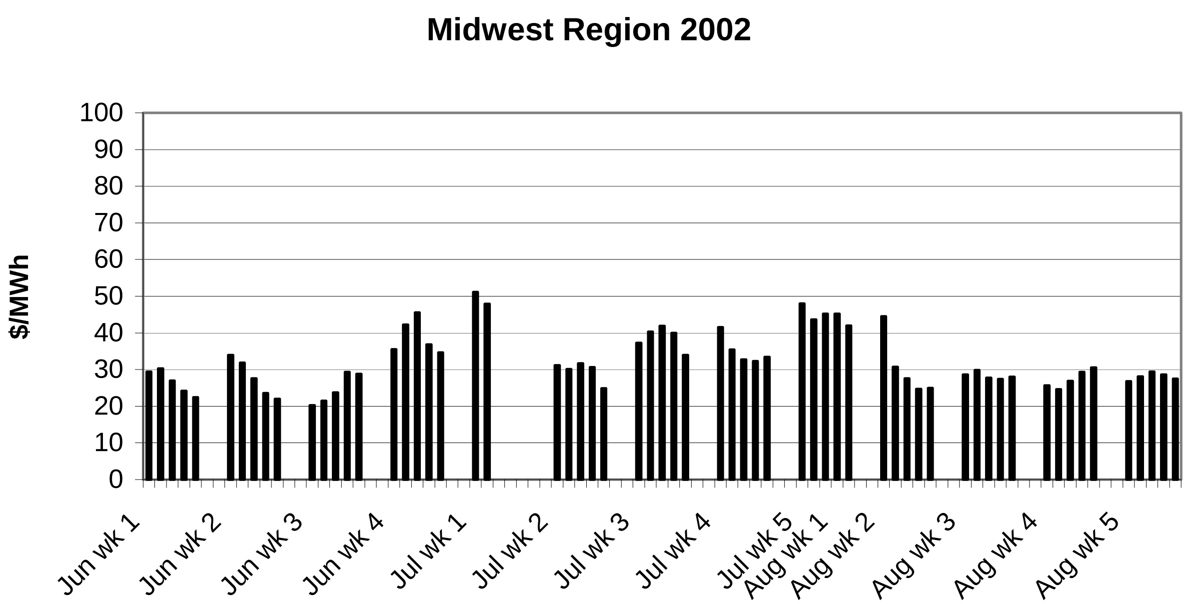
As a next step in the development of wholesale markets, the FERC issued Order 2000. It encourages utilities that own transmission facilities to turn over control of those facilities to regional transmission organizations. Following that, the FERC issued its proposal for a Standard Market Design (SMD) in 2002. SMD outlines the markets and market structure that the FERC expects to see in the regional transmission organizations. At this time, SMD has not been formally adopted by the FERC and it is still the subject of debate at the state and federal level. However, many aspects of SMD are being adopted as the regional markets are developed.

The wholesale spot market in electricity is another source of supply to serve Iowa's load and energy requirements. **Figure 2-8** tracks the wholesale market prices in the Midwest region for the summer in the years 2001 and 2002. Some of the data was not available for July and August 2001 and July 2002. **Figure 2-9** provides average next day firm prices for different regions of the Midwest by year. Spikes in wholesale spot prices for electricity occur when capacity and/or energy in the region is in short supply.

[27] Electric Power Annual 1998, Vol. II, Energy Information Administration, December 1999, p. 10. Much of the increase was caused by the sale of utility generating facilities to non-utility companies.
[28] Electric Power Annual 1998, Vol. II, Energy Information Administration, December 1999, p. 10.
[29] Electric Power Annual 1991, Energy Information Administration (Form EIA-0348(91)), February 1993, p. 9.

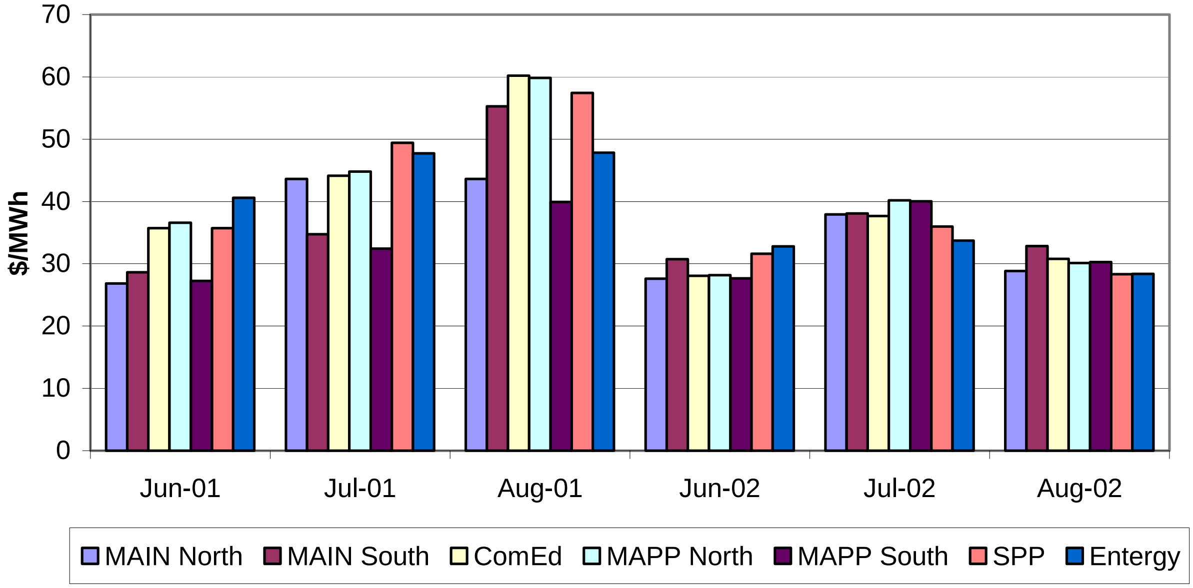
Figure 2-8 Average Next-Day Firm Electricity Prices -- Midwest Region





Source: MegawattDaily.

Figure 2-9 Average Next-Day Firm Electricity Prices – Midwest Region 2001-2002



Notes: MAIN, North – Transactions in eastern WI and portion of MI Upper Peninsula. Excludes deliveries into ComEd. MAIN, South – Transactions in IL and eastern MO. Excludes deliveries into ComEd. ComEd – Transactions into ComEd. MAPP, North – Transactions in ND, SD, MN, Manitoba, and portions of MT and central WI. MAPP, South – Transactions in NE and IA and portions of MT and central WI. SPP, North – Transactions in KS, OK, and parts of MO and AR. Excludes deliveries to Entergy. Entergy – Deliveries into Entergy.
Source: MegawattDaily.

2.3.3 Regional Generation Supply Considerations

Aside from concerns over fuel prices (especially natural gas), the addition of new generation capacity should otherwise promote stable purchased power contract prices and spot wholesale prices in the Midwest. **Table 2-32** shows projected near-term (2002-2006) planned generation and demand growth in the Midwest, by regional reliability council, as reported by the North American Electric Reliability Council (NERC).

Table 2-32 Planned Generation Capacity Growth in the Midwest as Reported by NERC (MW)

NERC Region	2002 Net Internal Demand	Estimated 2006 Internal Demand	Estimated Percent Change	2002 Planned Capacity	Estimated 2006 Planned Capacity	Estimated Percent Change	2002 Reserve Margin	Estimated 2006 Reserve Margin	Estimated Percent Change
ECAR	96,328	106,012	10.1%	122,995	155,274	26.2%	27.7%	46.5%	18.8%
MAIN	53,352	57,503	7.8%	70,842	76,930	8.6%	32.8%	33.8%	1.0%
MAPP	31,773	35,438	11.5%	39,915	40,345	1.1%	25.6%	13.8%	-11.8%
SPP	39,942	43,428	8.7%	47,591	49,458	3.9%	19.2%	13.9%	-5.3%
TOTAL	221,395	242,381	9.5%	281,343	322,007	14.5%	27.1%	32.9%	5.8%

Notes: Reserve margin is planned capacity in excess of net internal demand.
Sources: North American Electric Reliability Council (NERC), *Reliability Assessment 2002-2011*, Table 2. Compiled by IUB Staff.

The NERC Reliability Assessment for 2002-2011 estimates that planned capacity growth will exceed demand growth for the Midwest as a whole, but may fall behind demand growth in the MAPP and SPP regions based on current estimates. NERC reports that MAPP nonetheless believes it will maintain adequate reserve margins through a combination of monitoring and financial penalties. NERC notes most utilities in the MAPP region intend to meet their margin requirements with gas-fired plants requiring short construction lead times.[30] NERC also notes that most of MAIN's planned additions are gas-fired.[31] Regarding SPP, NERC notes that planned capacity projections do not take into account merchant plant additions anticipated for the 2002-2006 period.[32]

[30] North American Electric Reliability Council, *Reliability Assessment 2002-2011*, pp. 47-48.
[31] Ibid, pp. 44-45.
[32] Ibid, pp. 63-64.

2.3.4 SO2 and NOx Emissions from Fossil-Fuel-Fired Generation

Sulfur Dioxide (SO2) and oxides of nitrogen (NOx) are emitted when electricity is produced through the burning of fossil fuels. SO2 and NOx (in combination) are precursors to acid rain.

On November 15, 1990, President Bush signed into law the Clean Air Act Amendments of 1990 (CAAA). Title 4 of the CAAA calls for a ten million-ton reduction in utility emissions of SO2 and a two million-ton reduction in NOx. The SO2 reduction was achieved in two phases. Phase 1 began on January 1, 1995, whereupon 265 generating units were required to reduce their emissions to a rate of 2.5 pounds of SO2/MMBtu (i.e., million Btus) multiplied by their average annual fuel consumption in Btus for the years 1985 through 1987 (the unit's "baseline"). Six Iowa units were affected under Phase I: Burlington Generating Station, Des Moines Energy Center Unit 7,[33] George Neal Unit 1, M.L. Kapp Unit 2, Prairie Creek Unit 4, and Riverside Generating Station Unit 5. Phase II began on January 1, 2000, with all existing utility generating units required to reduce SO2 emissions to a level not to exceed 1.2 lbs/MMBtu multiplied by the unit's baseline. Phase II reduction levels are calculated so that total utility emissions never exceed approximately 8.9 million tons annually. This level of emissions is permanent, meaning that all new generating units cannot emit any SO2 unless the owner acquires emission allowances from the allowance trading market or the United States Environmental Protection Agency (EPA).[34]

The CAAA also required unit owners and/or operators to install low NOx burners at each unit compatible with the technology. Units were required to comply with the CAAA's NOx requirements at the same time they were required to comply with the SO2 requirements.

Table 2-33 shows SO2 and NOx historical emission rates (in lbs/MMBtus) and tonnage from fossil-fuel-fired generation in Iowa. The table also shows annual heat input in Btus for the previous five years.

[33] The Des Moines Energy Center Unit 7 has since been retired and dismantled.
[34] The CAAA established a system by which utility emitters of SO2 can trade "allowances." An allowance is essentially an EPA-issued license to emit one annual ton of SO2. The owner(s) of new generating facilities must obtain allowances to offset new SO2 emissions or, alternatively, reduce generation from other sources that have been issued allowances.

Table 2-33 Coal-Fired Unit Emissions

	1998	1999	2000	2001	2002	% Change 1998-2002
Annual Heat Input 10^{12} Btu	386.370	387.313	392.186	388.628	393.081	+ 1.74%
Annual NO_X Emissions (Tons)	81,082	80,202	78,636	78,455	78,941	- 2.64%
Annual NO_X Emission Rate (lb/MMBtu)	0.420	0.414	0.401	0.404	0.402	- 4.30%
Annual SO_2 Emissions (Tons)	171,728	156,069	132,240	133,537	127,826	- 25.56%
Annual SO_2 Emission Rate, (lb/MMBtu)	0.889	0.805	0.700	0.687	0.650	- 26.84%

Source: U.S. Environmental Protection Agency; Compiled by MidAmerican.

2.3.5 Generation Siting Requirements

The siting of new generation in the region depends, in part, on state rules and regulations governing certification. Iowa Code chapter 476A requires that before building any electric power generating plant or a combination of plants at a single site, with a total capacity of twenty-five megawatts or more, the plant builder must obtain a certificate from the Iowa Utilities Board (Board) authorizing such construction. The certificate is also required when an alteration at an existing generating plant results in a 10% increase or more in the capacity of the facility if the increase is more than or equal to 25MW. The proceeding for the issuance of a certificate or an amendment to a certificate is treated in the same manner as a contested case proceeding before the Board. Upon acceptance of an application by the Board, a public hearing is scheduled in the county where the proposed facility is to be built. The Board, if it determines that the public interest would not be adversely affected, may waive any of requirements pertaining to certification. A certificate is issued if the Board finds all of the following:

1. Whether the facility is consistent with legislative intent, the economic development policy of the state, and will not be detrimental to provision of adequate and reliable electric service.

2. The applicant is willing to construct, maintain, and operate the facility pursuant to the provisions of the certificate.

3. The construction, maintenance, and operation of the facility are consistent with reasonable land use and environmental policies and consonant with reasonable utilization of air, land, and water resources, considering available technology and the economics of available alternatives.

IOWA CODE § 476A also requires the applicants to meet permitting, licensing, and zoning requirements of other agencies. The Iowa Department of Natural Resources (IDNR) reviews all air construction permit applications to see if a source or modification may cause or contribute to a violation of the national ambient air quality standards.

3.0 DELIVERY SYSTEM CONDITIONS

Once electricity is produced, it must be delivered. This delivery is accomplished through transmission facilities (usually high-voltage lines connecting generating units or wholesale customers to the electric utility system) and distribution lines (usually low-voltage lines connecting retail customers to transmission facilities). The next subsection looks at the location of existing transmission and distribution facilities, as well as other infrastructure, needed to serve Iowa load. Data on the age of existing transmission and distribution facilities are also provided. Subsection 3.2 discusses the historical reliability of the delivery system and constraints on the transmission system. Subsection 3.3 discusses the future of Iowa's transmission and distribution facilities.

3.1 Existing Transmission and Distribution Facilities

3.1.1 Location of Facilities

Major factors affecting the location of generating facilities include access to: 1) major population (or load) centers, 2) fuel supplies, 3) transmission facilities, 4) water supplies, 5) environmental impacts, and 6) social considerations. **Figures 3-1 through 3-3** provide three maps showing the location of infrastructure needed to supply electricity to Iowa's consumers. **Figure 3-1** shows the location of major generating units, 115 kV to 345 kV transmission lines, and cities with population of over 50,000. **Figure 3-2** shows the location of major electric generating units, major natural gas pipelines, and cities with over 50,000 population. Pipelines are used to transport natural gas to generating units that burn natural gas as fuel. **Figure 3-3** shows the location of major electric generating units, rail lines, and cities with over 50,000 population. Rail lines are used to transport coal to generating units that burn coal as fuel.

Figure 3-1

Iowa Electric Generation and Electric Transmission With Cities over 50,000 Population

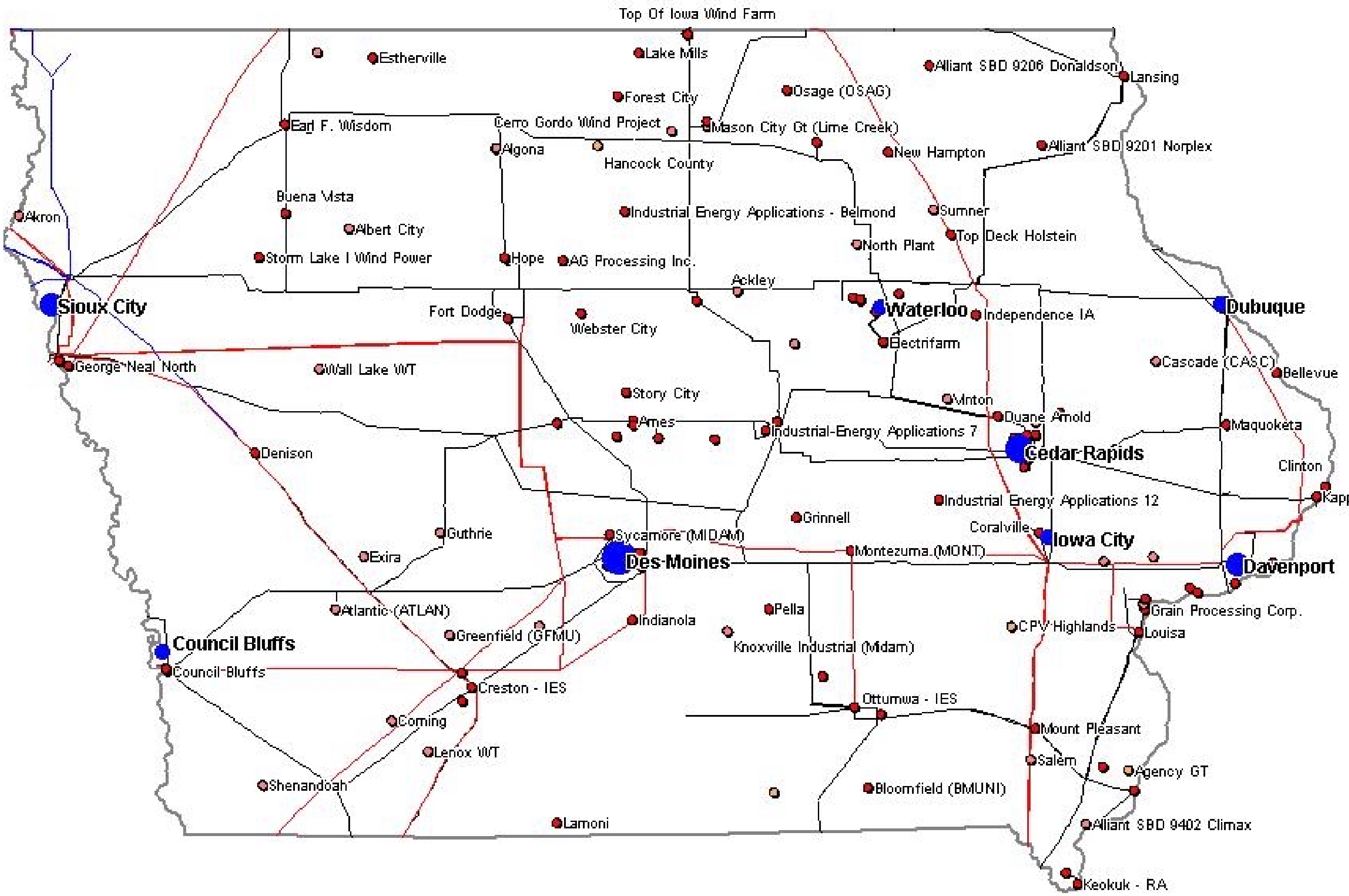


Figure 3-2

Iowa Electric Generation and Gas Pipelines
With Cities over 50,000 Population

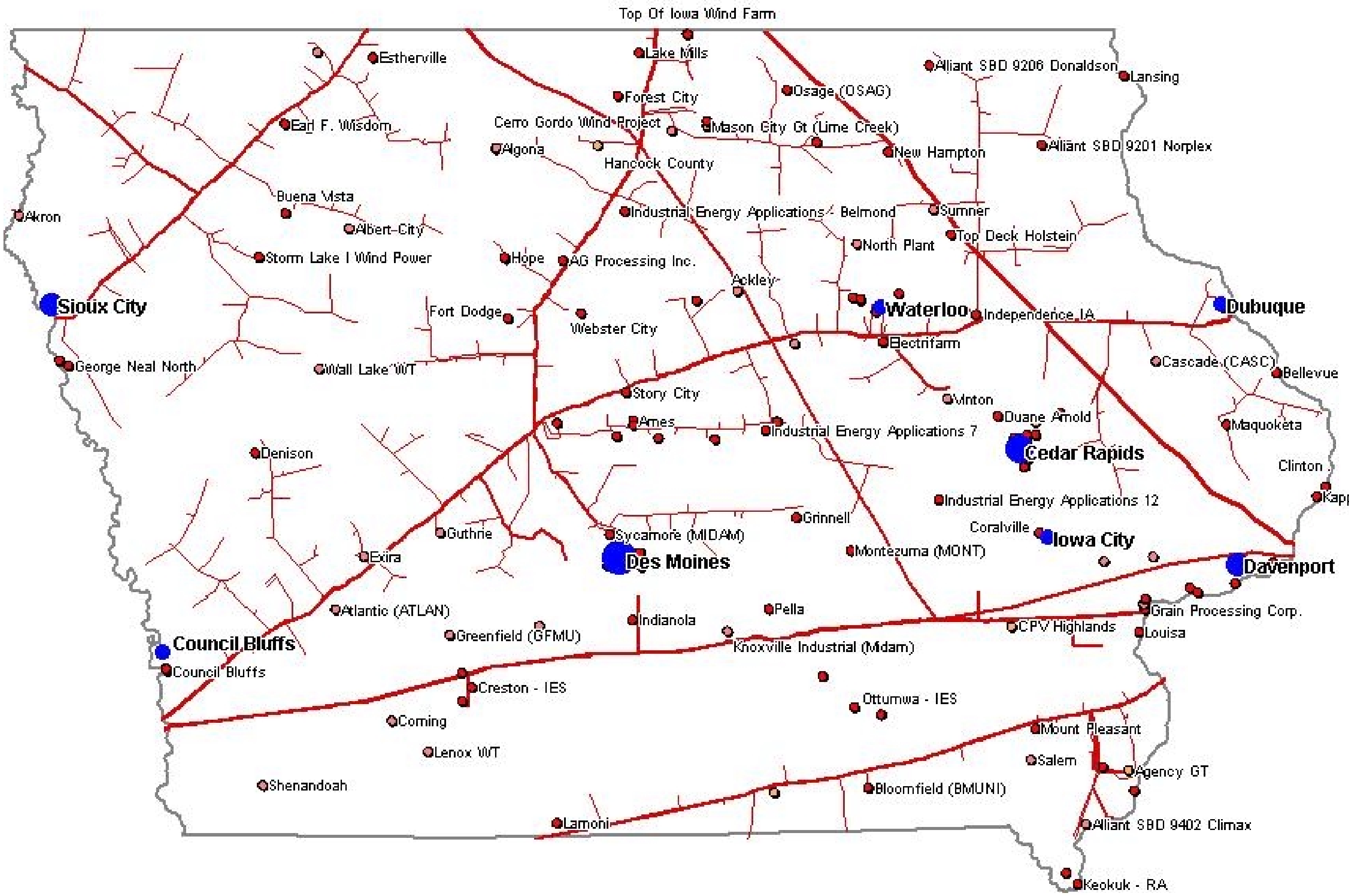
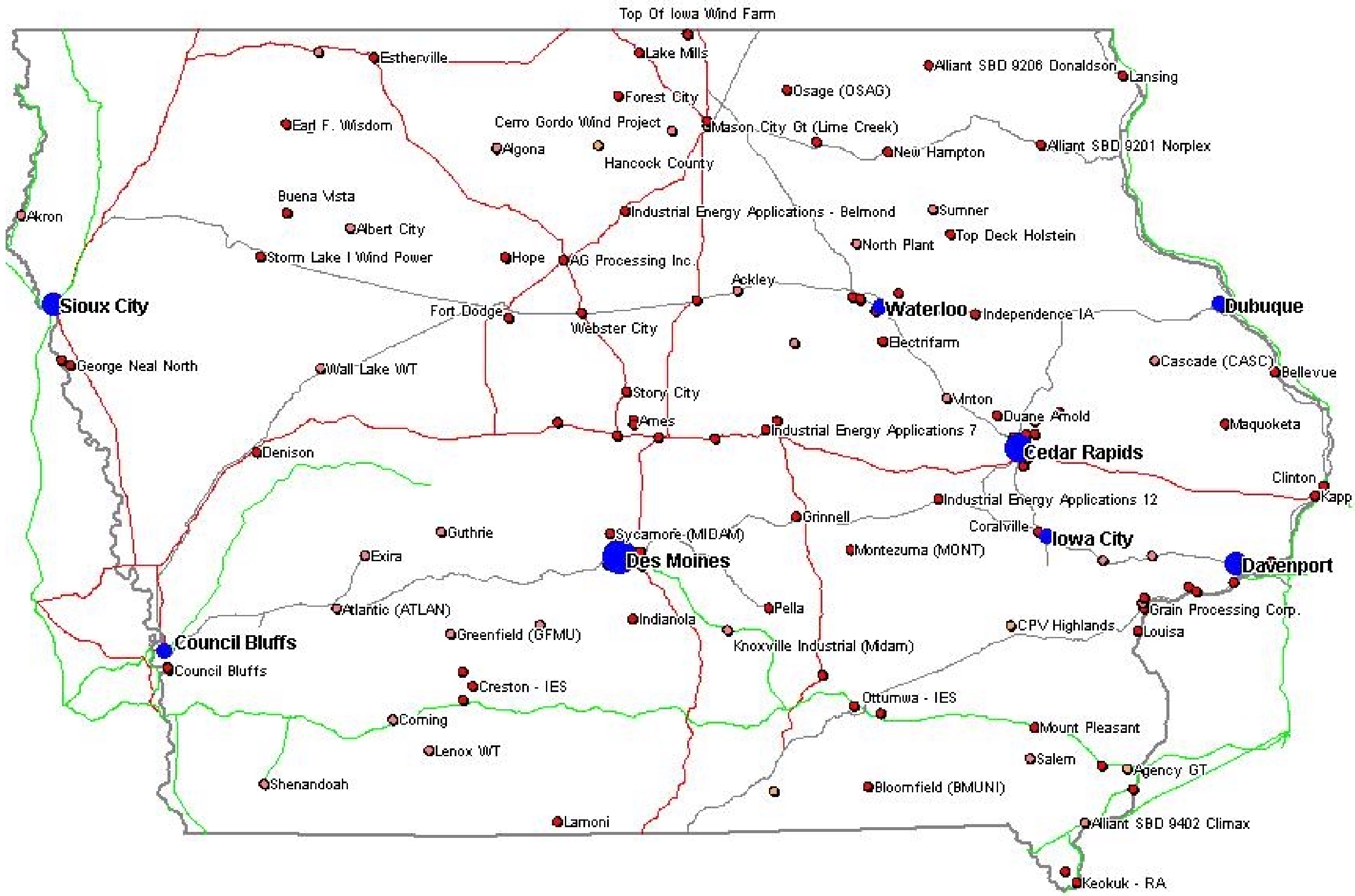


Figure 3-3

Iowa Electric Generation and Rail Lines
With Cities over 50,000 Population



3.1.2 Age of Existing Facilities

Iowa's existing transmission and distribution systems have been constructed and operated since the early 1900's. The transmission and distribution facilities are operated at nominal voltages of 345 kV, 230 kV, 161 kV, 115 kV, 69 kV, 34.5 kV, 25 kV, 13 kV, and 4 kV.

The vintages of MidAmerican's and Interstate (IPL)'s transmission and distribution systems are provided in **Table 3-1** and **Figures 3-4 through 3-8**. The age of facilities in Table 3-1 corresponds to the dates when these facilities were originally built or completely rebuilt. Accounting records were used to determine the ages of facilities in the figures. Due to accounting procedures, these figures may underestimate the actual ages of facilities that remain in-service. A small percentage of these data include facilities outside of Iowa.

Table 3-1 provides information concerning the vintage of MidAmerican's and IPL's high voltage lines.

Table 3-1 Miles of Line by Age

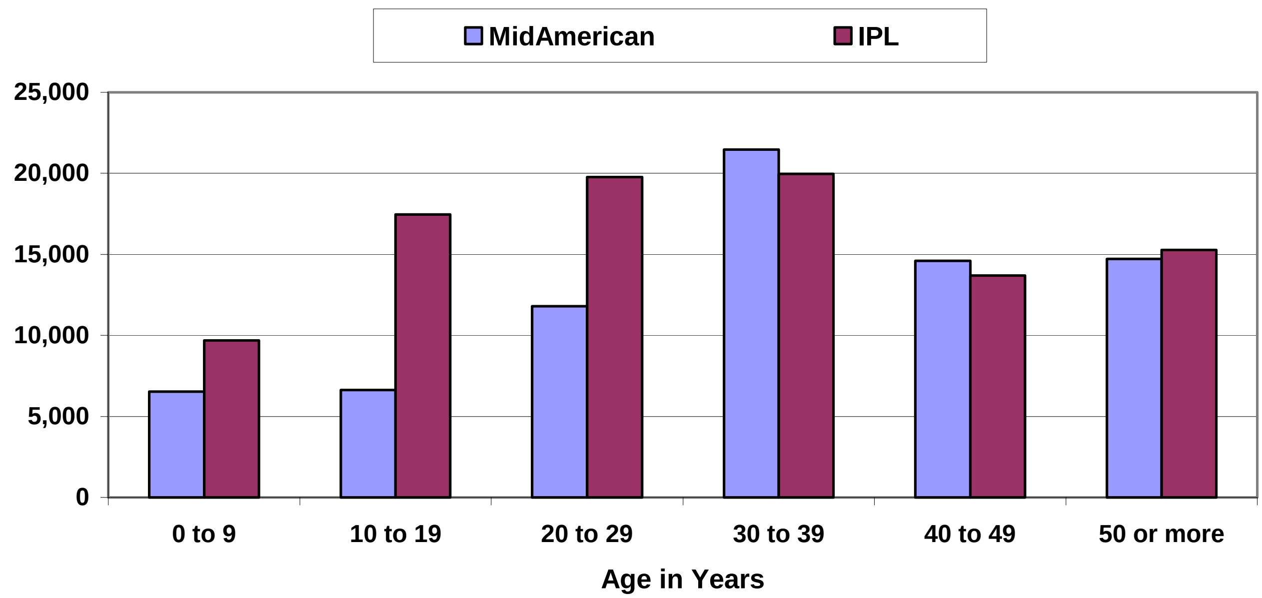
Age in Years =>		**0-9**	**10-19**	**20-29**	**30-39**	**40-49**	**50+**	**Total**
345 kV	MidAmerican	55	84	269	512	0	0	920
	IPL	2	87	47	79	0	0	214
161 kV	MidAmerican	48	60	157	290	437	344	1336
	IPL	52	106	445	428	26	5	1062
115 kV	MidAmerican	0	0	0	0	0	0	0
	IPL	8	16	11	25	201	116	378
69 kV	MidAmerican	157	232	354	494	357	255	1849
	IPL	220	598	468	371	270	120	2047
34.5 kV	MidAmerican	4	10	0	19	156	0	189
	IPL	263	293	355	435	351	585	2281

Notes: The total may exclude miles of line of unknown age. For MidAmerican, the age of 34.5 kV lines with 40 or more years of service is estimated. The numbers represent MidAmerican's and IPL's equivalent share of jointly owned lines. For IPL, the data for the 2003 report were found by running a query on IPL's GIS system. For the 2000 submittal a different database was used. IPL believes GIS data are more accurate since they are a much closer match to the FERC Form 1 totals, which includes some area outside of Iowa. This may cause variance in the final numbers. IPL data ignores age of the conductor.

Sources: Information provided by MidAmerican and IPL.

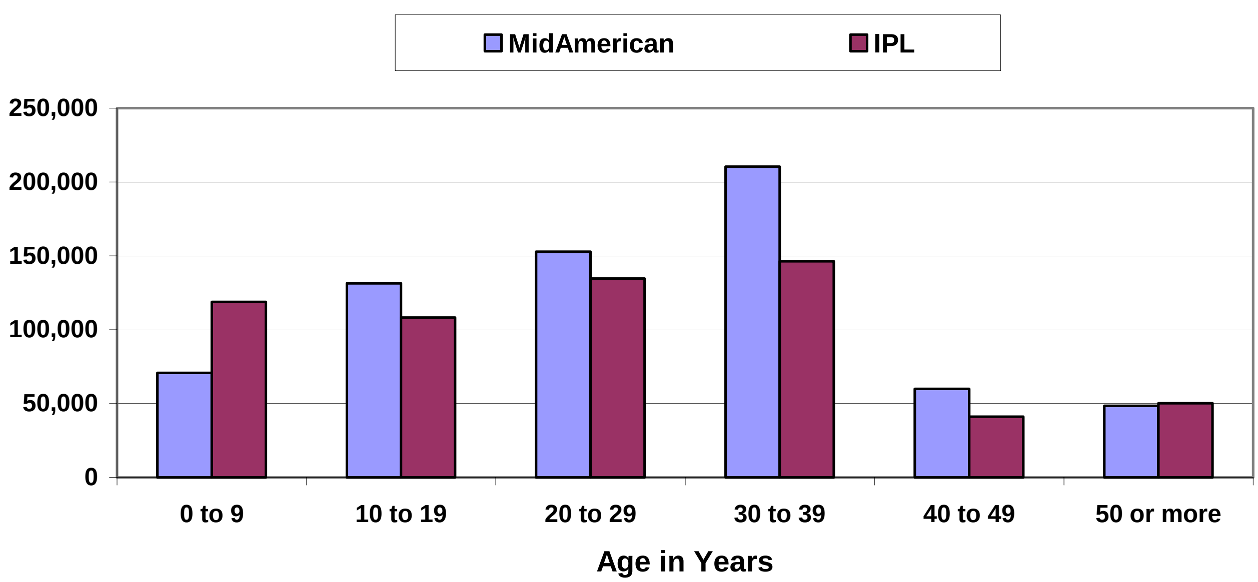
Figures 3-4, 3-5 and 3-6 provide vintages for poles and conductors for various voltage levels for MidAmerican and IPL. **Figures 3-7 and 3-8** provide the age of certain transformers for MidAmerican.

Figure 3-4 Number of Poles - 34.5 kV and above



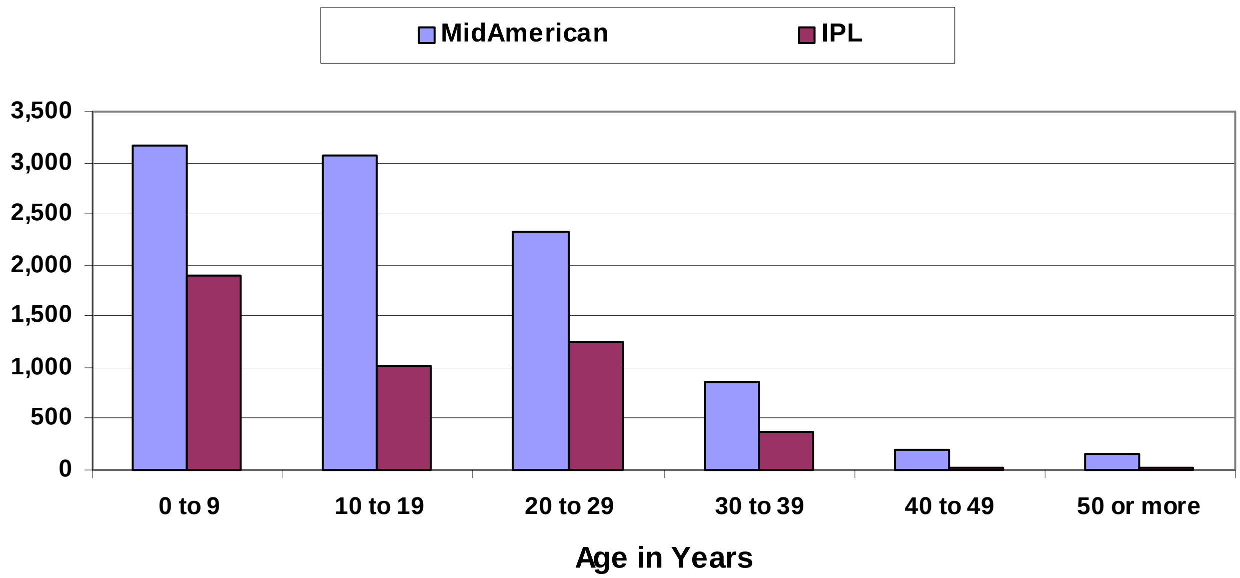
Sources: Information provided by MidAmerican and IPL.

Figure 3-5 Number of Poles - 13 kV and Below



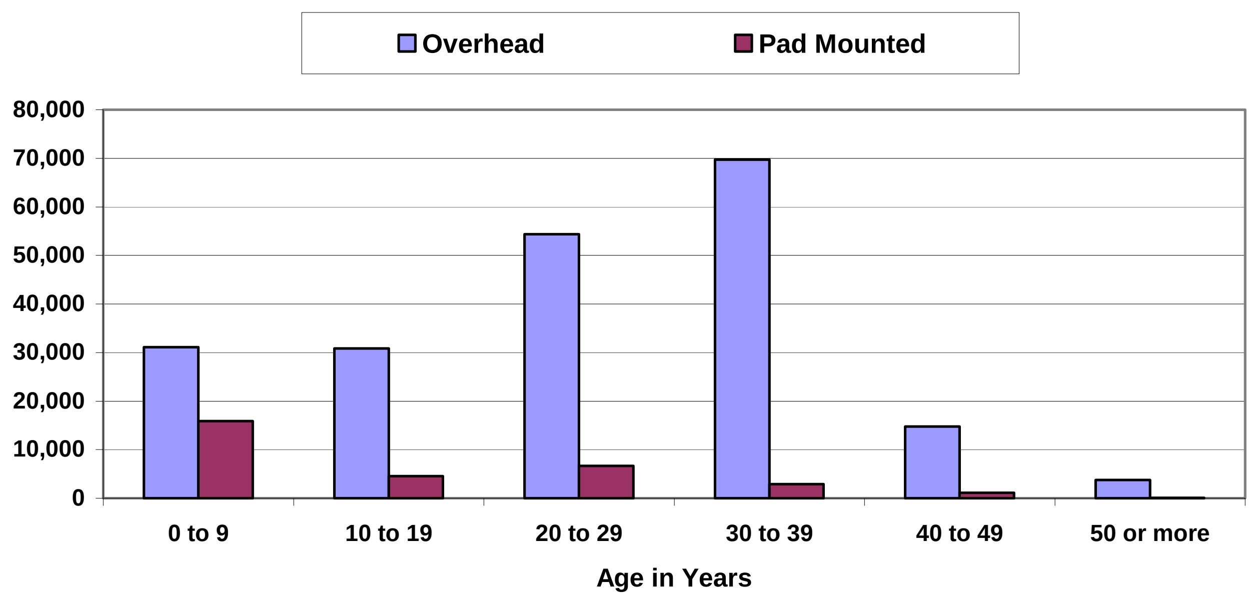
Sources: Information provided by MidAmerican and IPL.

Figure 3-6 Miles of up to 13 kV Underground Conductor



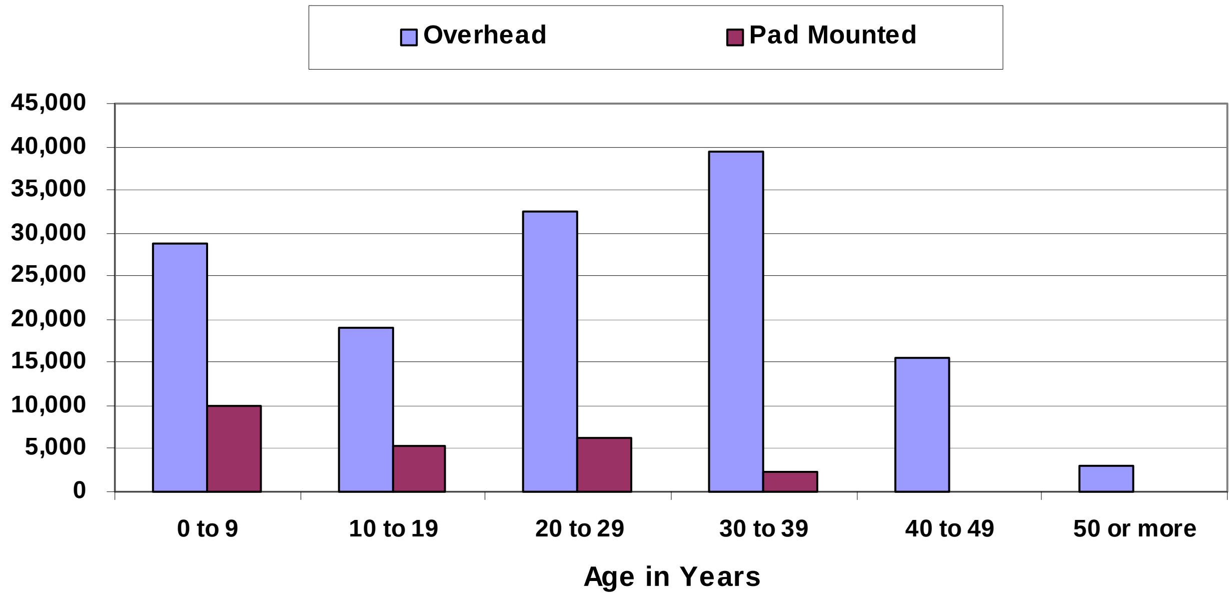
Sources: Information provided by MidAmerican and IPL.

Figure 3-7-1 Number of MidAmerican Distribution Transformers - Up to 13 kV



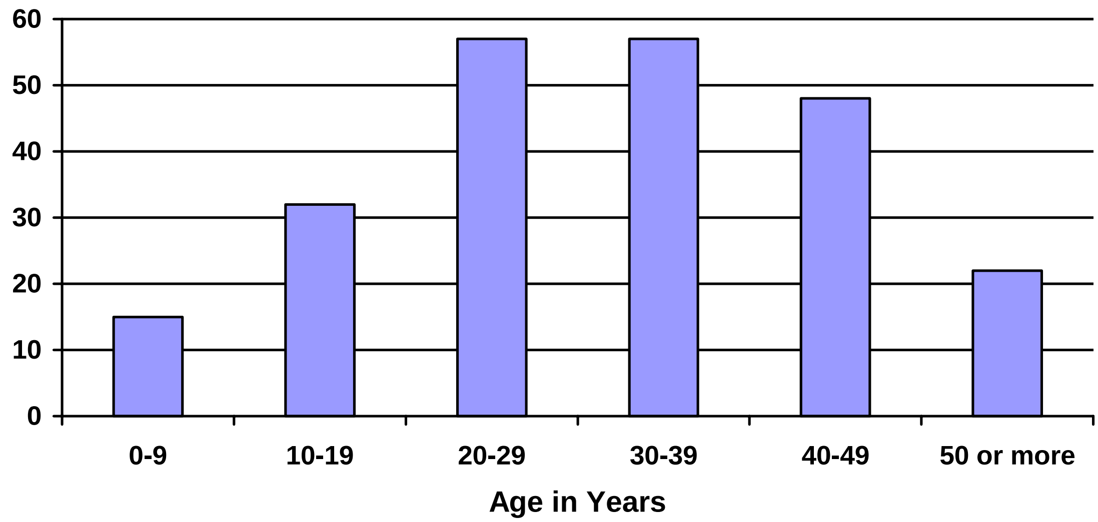
Sources: Information provided by MidAmerican.

Figure 3-7-2 Number of IPL Distribution Transformers - Up to 13 kV



Sources: Information provided by IPL.

Figure 3-8 Number of MidAmerican Power Transformers



Notes: A power transformer transfers electric energy in any part of the circuit between the generator and the distribution primary circuits.
Sources: Information provided by MidAmerican.

Table 3-2 provides total pole miles for 115 kV and above transmission lines solely owned by the RECs. While these data depict the year a line segment was constructed, the line may have been rebuilt, converted, reconductored, or upgraded since the time the line was originally constructed.

Table 3-2 115 kV and above Pole Miles Owned by RECs

	Pole miles		
Year of Construction	**115 kV**	**161 kV**	**345 kV**
1940-1949	0	60	0
1950-1959	39	84	0
1960-1969	0	184	0
1970-1979	0	149	0
1980-1989	5	30	0
1990-1999	20	13	7
Total	**64**	**520**	**7**

Source: Iowa Association of Electric Cooperatives.

3.2 Reliability of Delivery Systems

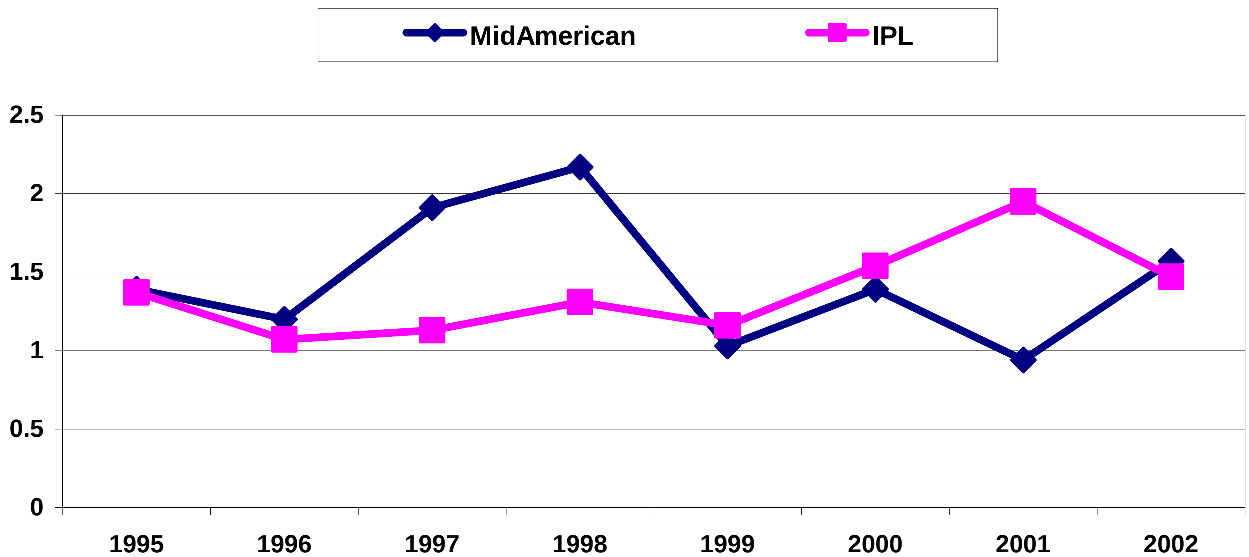
3.2.1 Reliability Indices

Reliability indices are used to indicate the reliability of electric service. These indices include:

- System Average Interruption Frequency Index (SAIFI) – SAIFI indicates the average number of service interruptions per customer. It is calculated as the ratio of the total number of customer interruptions to the total number of customers served.
- System Average Interruption Duration Index (SAIDI) – SAIDI indicates the average time that customers are interrupted. It is calculated as the ratio of the sum of customer interruption duration divided by the total number of customers served.
- Customer Average Interruption Duration Index (CAIDI) – CAIDI indicates the average time required to restore service to the average customer. It is calculated as the sum of customer interruption duration divided by the total number of interruptions.

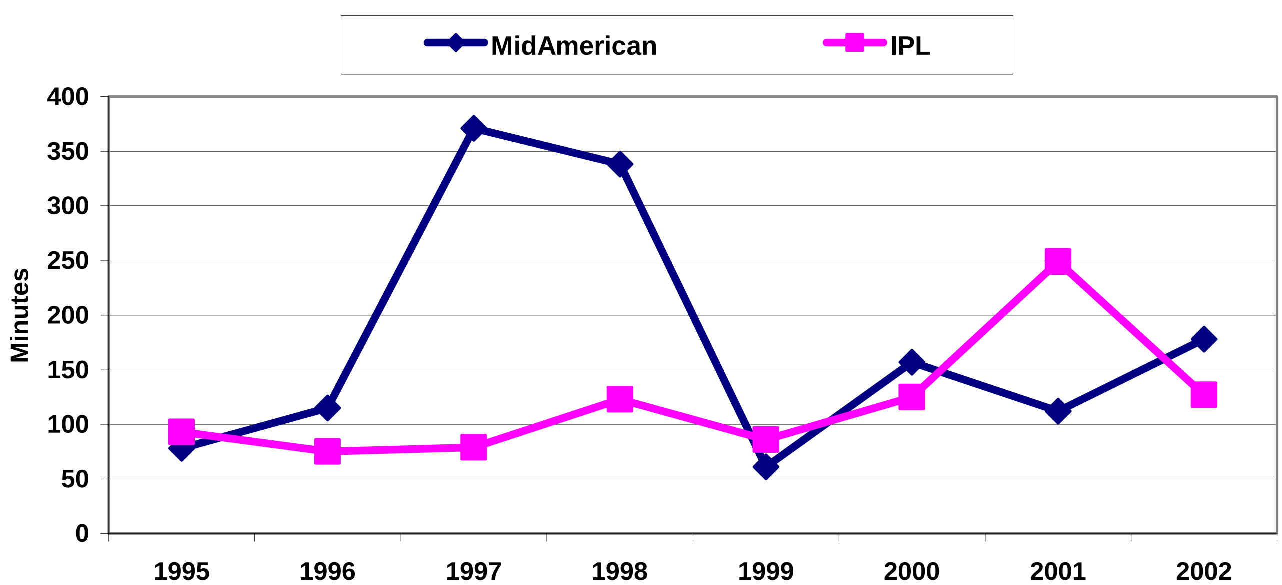
Figures 3-9 and 3-10 and 3-11 give the SAIFI, SAIDI, and CAIDI for MidAmerican and IPL since 1995. These indices include portions of MidAmerican's and IPL's systems located outside of Iowa. Outages due to storms and other major events are also included.

Figure 3-9 SAIFI



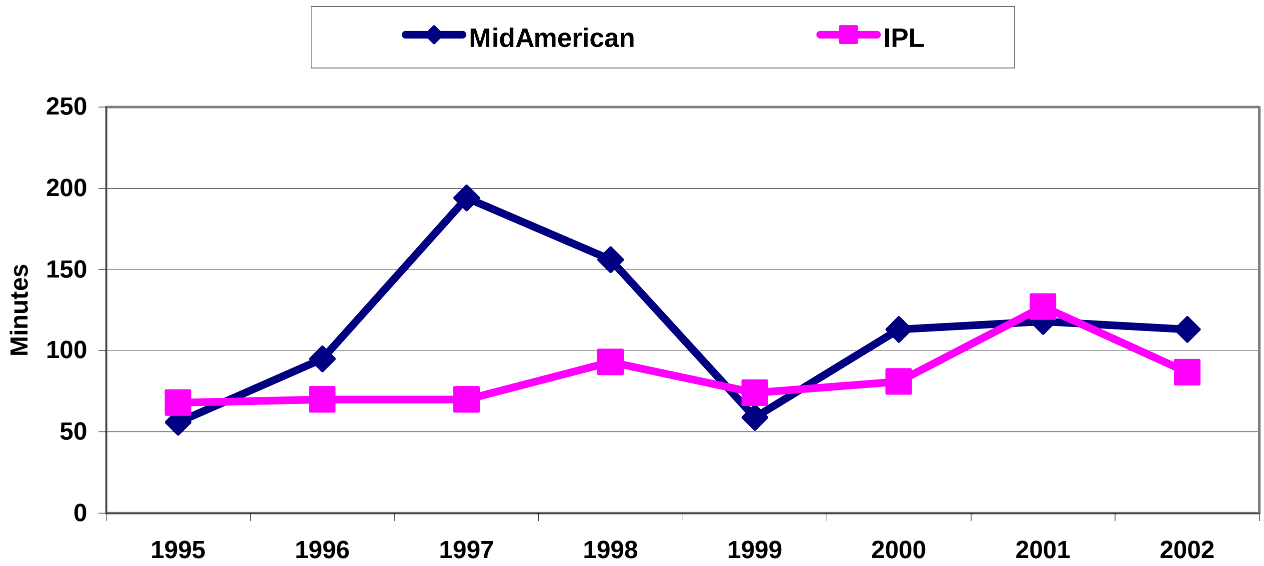
Notes: Differences in yearly indices and by utility are largely due to weather.
Sources: Information provided by MidAmerican and IPL.

Figure 3-10 SAIDI



Notes: Differences in yearly indices and by utility are largely due to weather.
Sources: Information provided by MidAmerican and IPL.

Figure 3-11 CAIDI



Notes: Differences in yearly indices and by utility are largely due to weather.
Sources: Information provided by MidAmerican and IPL.

3.2.2 MAPP Bulk Transmission System Outage Reports (2000 and 2001)

Mid-Continent Area Power Pool (MAPP) Composite System Reliability Working Group issued a report in June 2001 entitled "MAPP Bulk Transmission System Outage Report." This report provides historical performance information for MAPP's 230 kV and above systems for the 1991-2000 timeframe and for the year 2000 alone. The report provides several observations.

Outages are rare on 500 kV systems.[35] In the year 2000, there were no forced and 6 planned outages on the 500 kV systems.[36]

[35] Iowa utilities do not operate 500 kV lines.
[36] Forced outages refer to outages that were unplanned. Forced outages occur due to failure of generating units, transmission and distribution lines and transmission/distribution-related facilities.

For the 345 kV system, as was the case in 1999, there were fewer forced outages with shorter duration in 2000 as compared to the year before. The causes for forced outages were:

Cause	**1999**	**2000**
Weather	62%	51%
Terminal equipment failure	5%	21%
Foreign interference	7%	7.5%
Contamination or environment	6%	4%
Transmission line equipment failure	5%	12.5%
Human error	5%	2.5%

For 345 kV lines, again there were more planned outages with shorter duration in the reporting year (2000) as compared to the year before. Some of the major causes were:[37]

Cause	**1999**	**2000**
Transmission line maintenance	35%	33%
Terminal maintenance	26%	14%
Construction	14%	21.5%

For the 230 KV system, there were more planned and forced outages in 2000 versus 1999. There was one outage that lasted several months. The major causes for forced outages were weather (51%), terminal equipment failure (21%), and transmission line equipment failure (12.5%). Some major reasons for planned outages were line maintenance (33%), construction (21.5%), and terminal maintenance (14%).

For the period 1991-2000, three or more bulk transmission line sections were not available 56.6% of the time. Major causes for forced transformer outages are weather and terminal equipment failure. The seasonal outage rate for the period 1991-2000 is almost twice as large during the summer months as the winter months. This has been the trend in MAPP and is probably due to frequent lightning related weather during summer.

[37] Planned outages refer to outages purposefully caused by the utility in order to perform maintenance or refuel (in the case of nuclear units).

3.2.3 Iowa Electric System Reliability

Iowa's transmission system used for bulk power transfers consists of MidAmerican, IPL, and several cooperative and municipal systems. Most transfers occur over 345 kV, 161 kV, and 115 kV transmission lines. The MidAmerican system is under MAPP. IPL is under the Midwest Independent System Operator (MISO)[38] control. The MISO Open Access Transmission Tariff (OATT) took effect on February 1, 2002, for transmission service and related tariff responsibilities. The Iowa electric system is planned in accordance with North American Electric Reliability Council (NERC), MISO, MAPP, and local system planning criteria as filed by individual utilities in FERC Form 715. The overall system reliability is evaluated for system normal, N-1, N-2, some breaker failure, and known multiple element contingencies. Any thermal, voltage or dynamic violations are mitigated through system improvements, enforcements, and/or operating guides.[39]

3.2.3.1 Constraints

Transmission facilities have limited capability, similar to generating units. When a transmission line reaches its capability it is considered "constrained." Constrained transmission interfaces limit the flow of power within the region and between regions.

MAPP monitors nineteen (19) interfaces within its region. These constraints can limit MAPP imports and exports. MAPP conducts steady-state studies annually that provide an indication of the strength of the transmission system and the necessary information to analyze the MAPP transmission network. The MAPP constrained interfaces are calculated to only allow transmission service requests that will not exceed the known available transfer capability in a specific direction. MidAmerican uses the MAPP process for transmission service request analysis while IPL uses the MISO process for transmission service request analysis.

Figure 3-12 provides Firm Capacity Transmission Service refusals by MISO from March 2002 through June 2003. Refusals are made by priority groups. Firm transmission service has priority over non-firm service. Requests are evaluated on how the request affects transmission interfaces in the area.

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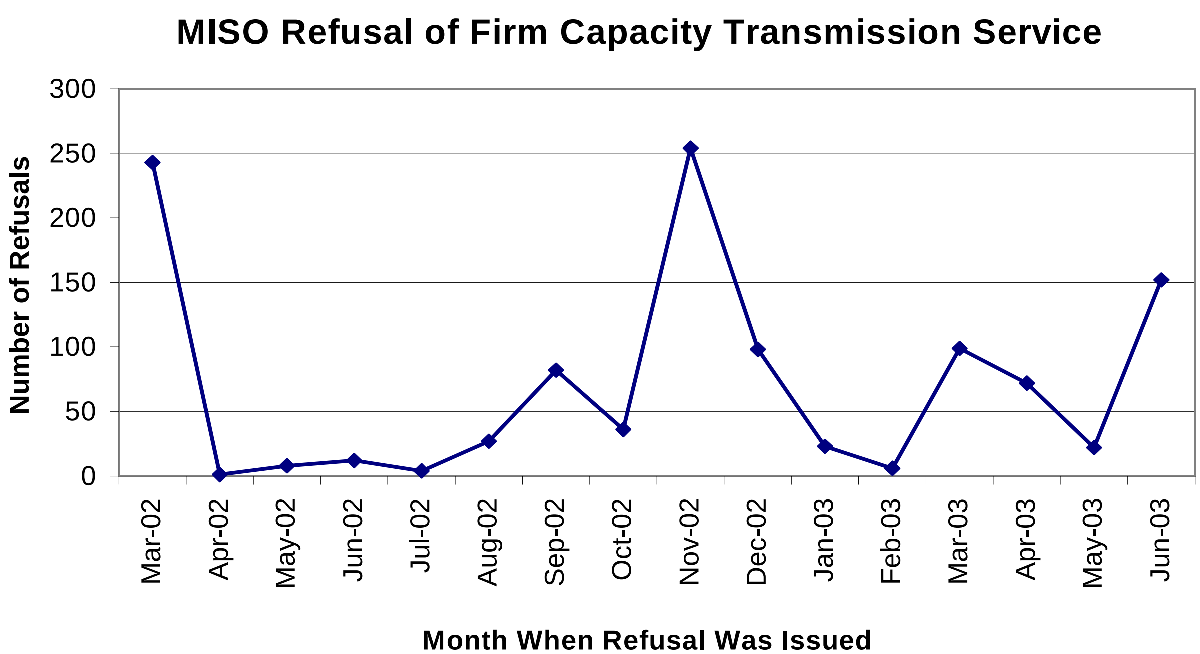
[38] MISO is the first Regional Transmission Organization approved by FERC. MISO is anon-profit organization and is responsible for monitoring the electric transmission system that delivers power from generating plants to wholesale power transmitters (the entities that deliver power to distribution companies that, in turn, deliver power to residential and commercial customers).

[39] Operating guides – Operating practices that a system functioning as part of a control area may wish to consider. The application of operating guides is optional and varies to accommodate local conditions and needs.

Figure 3-12



Source: Information provided by IPL.

3.2.3.2 Potential Iowa Constrained Interfaces and Transfer Limits

The Iowa Transmission Working Group's (ITWG's)[40] Sub-Regional Transmission Plan update was issued in August of 2003. This plan identified that the constrained interfaces in Iowa were defined due to heavy bulk power transfers from Mid-America Interconnected Network (located east of Iowa) to MAPP and Southwestern Power Pool (SPP).[41] Market conditions continue to produce high flows through Iowa in nearly all directions. The Poweshiek-Reasoner flowgate was defined in July of 2001 and the Quad Cities West flowgate was defined in May 2001.

The Poweshiek-Reasnor 161 kV flowgate was established to prevent overloads on the parallel and underlying 161 kV system to the Hills-Montezuma-Bondurant 345 kV system. The Quad Cities West flowgate was defined to prevent overloads on the Quad Cities-Sub 91 345 kV line for the single contingent loss of the Cordova-East Moline 345 kV line and the East Moline 345kV transformer.

[40] ITWG is made up of representatives from Iowa utilities that own transmission. The ITWG recommendations are combined with recommendations from other regional transmission working groups to form the MAPP regional transmission plan. A representative from the IUB staff typically attends the ITWG meetings.
[41] SPP is a Reliability Council that serves all or part of eight southwestern states.

IPL and MISO defined flowgates that are located primarily in eastern Iowa with the major concerns being loss of the Quad Cities-Rock Creek 345 kV, loss of the Arnold-Hazleton 345 kV, loss of Wempleton-Paddock 345 kV, and loss of Montezuma-Bondurant 345kV. The primary flow at issue is southeast to north transfers.

Western Area Power Administration's Denison transformer may be at risk of overload beyond emergency levels at certain pre-contingent load levels. An operating guide is in place to define load levels and responses. Transformer additions at Denison should allow the removal of operating guide restrictions.

3.3 <u>Future of the State's Transmission and Distribution Systems</u>

3.3.1 Scheduled Transmission System Construction

The most recent ITWG Sub-Regional Transmission plan lists planned transmission projects and upgrades. The following projects (at 100 kV and above) are currently scheduled:

⇒ IPL Twin Rivers - Viele 161 kV line: This 12.5 mile line will increase reliability in the Keokuk, Iowa, region. The line will loop the existing radial 161 kV line. The current in-service date for the line is November 2003.

⇒ IPL Lime Creek - Emery 161 kV line (second circuit): IPL plans to build a second 161 kV circuit from Lime Creek to Emery Substation in Cerro Gordo County, Iowa. The 25-mile line is needed to increase reliability of the Mason City 69 kV network due to through-flow. Other 69 kV loading and voltage issues will be addressed in the future by tapping a 161/69 kV substation on the new line. This line has been identified for several years as a limiting element for transfers in studies performed by both MAPP and MAIN. The in-service date is May 2005.

⇒ IPL Poweshiek - Reasnor 161 kV Rebuild: IPL plans to rebuild this 20.7 mile. This line is in poor condition and is also a constrained interface in MAPP and MISO. The rebuild and associated capacity increase will remove this line section from being a limitation for power transfers. The in-service date is June 2004.

⇒ IPL Capacitor Banks at Wellsburg: IPL plans to add a 14.4 MVAR 115 kV capacitor bank at Wellsburg. The in-service date is December 2004.

⇒ IPL Capacitor Banks at Iowa Falls: The two 14.4 MVAR 115 kV capacitor banks at Iowa Falls are scheduled to be in-service by May 2005.

⇒ Cedar Falls Utilities 161 kV Union Sub - Deere Engine Sub: Cedar Falls Utilities is proposing to build an 8.5 mile 161 kV transmission line from its Union Sub to MidAmerican's Deere Engine Sub with a new 161/12.47kV substation in the southern part of the Cedar Falls Industrial Park. The in-service date is December 2004.

⇒ Corn Belt Power Coop Drager Sub: Corn Belt Power Coop is adding a new 161/69 kV substation in Carroll County. An 84 MVA top rated transformer will be installed with two 69 kV line outlets. The in-service date is November 2003.

⇒ MidAmerican NE Ankeny - IPL Jasper - Perry 161 kV Tap: MidAmerican plans to construct 1.2 miles of double-circuit 161 kV line from IPL's Perry - Jasper 161 kV line to a new NE Ankeny switching station to serve load growth in the Ankeny area and to relieve potential single contingency overloads on 69kv lines and transformers in the area. The in-service date is October 9, 2003.

⇒ MidAmerican Ankeny - NE Ankeny 161 kV Line: MidAmerican plans to construct 6.0 miles of 161 kV line in Ankeny to serve load growth in the Ankeny area and to relieve potential single contingency overloads on the Sycamore transformers and lines in the Sycamore area. The in-service date is March 1, 2005.

⇒ MidAmerican Ankeny - Sycamore 161 kV line: MidAmerican plans to construct 7.0 miles of 161 kV line from the Ankeny to Sycamore to serve load growth in the Ankeny area and to relieve potential single contingency overloads on the Sycamore transformers and lines in the Sycamore area. The in-service date is March 1, 2005.

⇒ MidAmerican DPS - Reasnor 161 kV Upgrade: MidAmerican plans to reconductor the DPS - Reasnor 161 kV line to increase the line rating, specially during summer peak conditions. The in-service date is December 1, 2005.

⇒ MidAmerican Norwalk Substation: MidAmerican plans to develop and construct a new 345-161 kV Substation with a 560 MVA transformer, 345 kV line terminals to S.E. Polk and Madison County and 161 kV terminals to Greenfield Plaza and Winterset Junction. The in-service date is October 1, 2004.

⇒ MidAmerican CBEC - Grimes 345 kV Line: MidAmerican plans to construct a 140 mile 345 kV line from CBEC to Grimes. MEC will also construct a new 345 kV Grimes substation near where the Sycamore-Lehigh 345 kV line leaves common right-of-way with the Booneville-Sycamore line. The in-service date is September 1, 2006.

⇒ MidAmerican CBEC - Sub 1206 161 kV Line: MidAmerican plans to construct a 9-mile 161 kV line from CBEC to OPPD Substation 1206 using T2-795 ACSR conductor or equivalent. The in-service date is June 1, 2005.

⇒ MidAmerican Sub 1206 - Sub 1217 161 kV Line: MidAmerican plans to construct a 10-mile 161 kV line to provide outlet facilities for the CBEC Unit 4 and allow operation of the system in a reliable and economic manner. The in-service date is June 1, 2005.

⇒ MidAmerican CBEC - Avoca 161 kV Rebuild: MidAmerican will rebuild and re-conductor 33 miles of the CBEC to Avoca 161 kV line. The in-service date is June 1, 2006.

⇒ MidAmerican CBEC 345/161 kV 560 MVA transformer Unit 2: MidAmerican will install a 2nd 345/161 kV 560 MVA auto-transformer at CBEC-4 to provide generation outlet capability. The in-service date is August 1, 2006.

⇒ MidAmerican Grimes 345/161 kV 560 MVA Transformer: Install a 2nd 345-161 kV 560 MVA auto-transformer at the new Grimes substation to provide generation outlet capability. The in-service date is June 1, 2006.

⇒ Replace MidAmerican Avoca 161/69 kV transformer: MidAmerican will upgrade the Avoca 161/69 kV 28 MVA transformer to an 83 MVA top rated unit to provide generation outlet capability during contingencies. The in-service date is December 31, 2003.

⇒ MidAmerican Atlantic 161/69 kV Transformer Unit 2: MidAmerican will install a 2nd 161/69 kV 50 MVA transformer to provide generation outlet capability during contingencies. The in-service date is June 1, 2007.

⇒ MidAmerican Cooper - St. Joseph 345 kV terminal (Cooper South Terminal Upgrades): MidAmerican will upgrade the Cooper - St. Joseph 345 kV terminals for 2000 amp capability. The Fort Calhoun South and Cooper South constrained interfaces have hampered MAPP to SPP transactions and the siting of new generation resources in Iowa and surrounding areas. The additional generation in Council Bluffs will have a positive impact on the Fort Calhoun South constraint and the planned terminal upgrades on the Cooper South interface will have a positive impact on the Cooper South constraint.

⇒ Eagle 230/69 kV Transformer: NIPCO's Eagle addition will be a 150 MVA transformer with an in-service date of December 2003.

⇒ Western Area Power Administration - Creston Improvements: It is planned to modernize and upgrade the Creston Substation by June of 2004 by replacing selected breakers and installing a 36 MVAR capacitor to the 161 bus to aid voltage support during peak load periods and during certain outages in the area.

⇒ Western Area Power Administration - Denison Improvements: It is planned to install a 33 MVAR capacitor on the 69 kV bus at Denison to aid voltage support during peak load periods and during outages in the area.

3.3.2 Transmission Siting Requirements

Iowa's transmission siting requirements are detailed in IOWA CODE Chapter 478. As of April 1, 2002, a person shall not construct, erect, maintain, or operate a transmission line, wire, or cable that is capable of operating at an electric voltage of 69 kV or more outside of cities for the transmission, distribution, or sale of electric current without first procuring from the utilities board a franchise granting authority. Before April 1, 2002, the voltage threshold to obtain a franchise was set at 34.5 kV.

To obtain a franchise, a petition containing route, design, and purpose for the transmission line must be filed with the Board. If over one mile of private property would be affected by the construction, a public information meeting must be held, at least 30 days, before the petition is filed. Notice of the petition is required to be published in a newspaper in the project area, and a public hearing is required if objections are filed or if the petitioner seeks the right of eminent domain.

Before granting the franchise the Board must find that the project is necessary to serve public use and bears reasonable relationship to an overall plan of transmitting electricity in the public interest. The Board must accept the proposed route, and may grant the right of eminent domain where necessary.

3.4 Regional Reliability and Transmission Studies

Subsection 3.4 discusses some of the recent regional reliability and transmission studies. It concludes with a discussion of the U.S.-Canada Power System Outage Task Force's Interim Report on the causes of the August 14 blackout in the U.S. and Canada.

MAPP to SPP Transfers: One of the four primary recommendations of the MAPP Regional Plan for 2000 through 2009[42] was that additional MAPP to SPP transfer capability study work be carried out by a joint Iowa/Nebraska/SPP study group. Based on this recommendation, utilities in Iowa, Nebraska, Missouri, and Kansas formed the Joint Iowa/Nebraska/SPP study group (group) to consider plans for increasing the transfer capability between MAPP and SPP.

The group focused its analysis on the Fort Calhoun South and Cooper South constrained interfaces. This analysis studied Outage Transfer Distribution Factor transfer capability excluding Transmission Reliability Margin and Capacity Benefit Margin. It was based upon linear Managing and Utilizing System Transmission analyses and non-linear Alternating Current Contingency Analysis using a 1999 series joint Iowa-Nebraska case.

[42] MAPP develops updates to its regional plan as appropriate between biennial regional plan cycles.

Sixteen individual transmission improvement alternatives were proposed by the study participants to alleviate the constraints imposed by these interfaces. The group supported Option 1 composed of three of the original 16 alternatives:

<u>Option 1 – Estimated cost $20.7 million</u>

Alternate 4: Build new 161 kV line from Fort Calhoun to Sub 701.

Alternate 5: Rebuild existing 161 kV lines from Raun to Tekamah to Sub 1226.

Alternate 15A: Upgrade 345 kV line from Cooper to St. Joseph and from Cooper to Fairport for 2000 Amp capability.

Option 1 performed as well or better than the other options and was also the least cost alternative. Option 1 resulted in an approximate 2500 MW increase in incremental transfer capability considering only the Fort Calhoun South interface and about 1100 MW increase to incremental transfer capability considering only the Cooper South interface. The increase in incremental transfer capability could be different as the specified sources and sinks were specifically designed to stress these interfaces. Specific transfer analyses would be required by the constrained interface owners to confirm any incremental transfer capacity increases.

The group did not recommend any specific option due to significant generation additions planned in Iowa. The group did recognize and support Option 1 as the most cost-effective way to upgrade transfer capability from MAPP to SPP.

MISO Transmission Expansion Plan 2003 (MTEP-03): MISO issued its first transmission expansion plan in 2003. The plan was developed with input from stakeholders through multiple forums at MISO. The plan consists of both a "plan" to ensure the ongoing reliability of the MISO transmission system and an "analysis" of issues impacting the development of commercially beneficial expansions. The plan included planned and proposed projects. "Planned projects" are recommended by MISO to be completed by the identified service dates. "Proposed projects" are tentative solutions to identified needs, and require additional study. The total estimated direct costs of planned and proposed alternatives are $1.8 billion for the period 2002-2007. Costs for planned projects are estimated to be $1,324 million and the costs of proposed projects are estimated to be $471 million.

The MISO expansion plan includes a proposed project for Iowa and southern Minnesota and Dakotas ($661 million). The proposed project looks at a 345 kV loop in southern Minnesota and north-central Iowa. The proposed project was devised by MISO in discussion with transmission owners in Iowa and Minnesota as a means of increasing capacity in the area for the possible delivery of wind and coal generation interconnection requests in this constrained area. This proposal showed favorable results in reducing marginal energy costs in the high wind and high coal scenarios. The high wind scenario assumed large amounts of gas generation, some coal generation and 10,000 MW of wind generation predominantly in Minnesota, Iowa, and the Dakotas. The high coal scenario assumed 6,000 MW of generation with about half of the units located in Minnesota and the Dakotas and the other half in Wisconsin, southern Illinois, Indiana, and Kentucky.

U.S and Canada Power System Outage Task Force (Interim Report: Causes of the August 14th Blackout in the United States and Canada"): On August 14, 2003, large portions of the Midwest and Northeast U.S. and Ontario, Canada, experienced an electric power blackout that affected 50 million people. On August 15, President George W. Bush and Prime Minister Jean Chrétien directed that a joint U.S.-Canada Power System Outage Task Force (Task Force) be established to investigate the causes of the blackout and how to reduce the possibility of future outages. The Task Force divided its work into two phases:

Phase I: Investigate the outage to determine its causes and why it was not contained.
Phase II: Develop recommendations to reduce the possibility of future outages and minimize the scope of any that occur.

In November 2003, the Task Force issued an "Interim Report: Causes of the August 14th Blackout in the United States and Canada" (Report) on the findings of the Phase I investigation. The Report is now subject to public review and comment. The Report will be finalized and made part of the Final Report. The Task Force will hold three public forums in which the public will have the opportunity to comment on the Report and to present recommendations. The following are some highlights from the Report:

<u>Status of the Northeast power grid before the blackout began.</u> Determining that the system was in a reliable state at the time the outage began is important in understanding the causes of the blackout. This means that none of the electrical conditions at the time the outage began were the cause of the blackout. This eliminates high power flows to Canada, unusual system frequencies, low voltages earlier in the day of or the days prior to the outage, or availability of generators and transmission lines as the direct, principal, or sole causes of blackout.

<u>How and Why the Blackout Began.</u> The blackout was caused by deficiencies in specific practices, equipment, and human decisions that coincided that afternoon. There were three groups of causes. The first cause was inadequate situational awareness at an Ohio utility, FirstEnergy Corporation (FE). The second cause was that FE failed to adequately manage tree growth in its transmission rights-of-way. The third cause was the failure of the interconnected grid's reliability organization to provide effective diagnostic support. The Report found violations of NERC reliability standards. These initial findings are subject to further review by NERC and additional violations could be found.

The blackout can be divided into seven phases. The first four phases correlate to the major changes within FE's system and the surrounding area in the hours leading up to the cascade. In Phase 1, the normal afternoon degrades. In Phase 2, FE's computer failed. In Phase 3, three FE 345 kV lines failed. In Phase 4, FE's 138 kV system collapsed in Northern Ohio and the Sammis-Star line was lost. Before the loss of this line the blackout was only a local problem in Ohio. The uncorrected problems in northern Ohio developed to a point that a cascade[43] was inevitable.

The cascade stage of the blackout. After the local problems in Ohio evolved in the first four phases, the next three phases of the blackout related to the cascade stage. In Phase 5, shortly before the collapse, large electricity flows were moving across FE's system from generators in the south to loads in northern Ohio, eastern Michigan and Ontario. This path became unavailable when the FE system collapsed. The electricity took alternative paths to loads located along the shores of Lake Erie. Transmission lines in these areas were already heavily loaded and some lines began to trip. In Phase 6 of the blackout, the entire northeastern U.S. and the province of Ontario separated and became a large electrical island. This island, which had been importing power prior to the cascade, became unstable. Once the split took place, the cascade was isolated. In Phase 7, the final phase, the large electrical island was deficient in generation with large power swings and surges. As a result, transmission lines and generators tripped breaking the island into smaller islands. Some islands were able to reach equilibrium without the loss of service.

The investigation concluded that the following factors most likely caused the cascading to stop:

- The effects of disturbance travel over lines and become dampened the further they are from the initial point. Thus, at some point the voltage and current swings are not sufficient for lines to trip.
- Higher voltage lines and more densely networked lines are better able to absorb voltage and current swings.
- Some areas that became isolated from the unstable part of the grid were able to retain sufficient on-line generation or import generation from other parts of the grid to stabilize the system. Some areas were able to do automatic load shedding to stabilize the system.

[43] A cascade occurs when there is a sequential tripping of numerous transmission lines and generators in a widening geographic area. Most common protective relays cannot distinguish between the currents and voltages seen in a cascade from those caused by a fault. This leads to more and more lines and generators being tripped which increases the outage area. Automatic separation protects equipment from physical damage.

The August 14 blackout compared with previous major North American outages. The August 14 Blackout had several causes and factors in common with the earlier outages (the Report considered seven major outages):

- Inadequate vegetation management;
- Failure to ensure operation within secure limits;
- Failure to identify emergency conditions and communicate those conditions to neighboring systems;
- Inadequate operator training; and
- Inadequate regional visibility over the power system.

New causal features were:

- Dysfunction of a control area's SCADA/EMS[44] system; and
- Lack of adequate backup capability.

Performance of nuclear power plants affected by the blackout. The Report concludes that:

- All nuclear plants that shut down or disconnected from the grid responded automatically to grid conditions;
- All nuclear plant responses were consistent with their designs;
- Safety conditions were effectively accomplished; and
- The nuclear plants did not trigger the outage or inappropriately contribute to its spread.

Physical and cyber security aspects of the blackout. The Report concludes that there is no evidence that viruses and worms prevalent across the internet at the time of the outage had any significant impact on power generation and delivery systems. No intelligence reports before, during, or after the outage indicated any specific terrorist plans or operations against the energy infrastructure. Further data collection and analysis will be undertaken to test the interim findings and to fully examine cyber security aspects of the outage.

[44] SCADA-Supervisory Control and Data Acquisition System – a system of remote control and telemetry used to monitor and control the electric system; EMS – Emergency Management System is a control system used to monitor the real time performance of various elements of the electric system and to control generation and transmission facilities.

4.0 CUSTOMER SERVICE

Customer service primarily refers to billing, metering, and customer contact. This section of the report provides a brief description of recent changes in billing, metering, and outage reporting systems used by the IOUs, the RECs, and the municipal utilities.

4.1 Billing Systems

Technological changes in the U.S. economy are changing the manner in which businesses bill their customers for the services they provide. Technological changes are also having an impact on customer access to the data points that are used in the billing process and the billing medium (i.e., paper or electronic).

Interstate Power and Light Company (IPL)*:* IPL completed the integration of two separate Customer Information Systems (CISs) into a single CIS in 2002. The former IES and IPC CISs were integrated into a single IPL CIS. This common IPL CIS serves customers in the Iowa IPL area as well as IPL customers in Minnesota and Illinois. The integrated IPL CIS allows for billing functions, billing information, and customer information to be handled through a single CIS for all Iowa customers.

IPL established industry-recognized Internet access for customer self-service in 2001. Internet-accessible customer self-service is available to customers at two levels. The first level is named “Your Account” and allows customers to securely view their account and billing information on a secure Internet site. A customer enrolled in “Your Account” may also perform limited billing transactions. (e.g. sign up for billing-related programs such as Budget Billing). The second level of Internet access for customers is electronic bill presentment and payment named Paywise. Customers enrolled in Paywise may electronically receive, review, and pay their bills through a secure Internet site.

IPL is currently investigating increasing the number and types of internet-accessible customer self-service options available to customers.

MidAmerican Energy Company*:* MidAmerican continues to use the Customer Service System (CSS) implemented in November 1998 for billing purposes. Several enhancements have been made since the original implementation date. Some of the enhancements were to gain efficiencies internally. Many of the enhancements were to improve service to MidAmerican’s customers. Frequent changes are implemented to improve service to customers as well as gain efficiencies. Recent changes include: additional changes to budget billing plan functionality; summary billing enhancements; address verification and standardization; increased functionality allowing additional rates to system bill; duplex printing which provides flexibility in printing on both the front and back side of the bill; collection arrangement functionality; account activity statement modifications; revenue protection functionality; account retrieval improvements;

interface to new workforce management system; and improvements in response time. An enhancement to landlord functionality will be implemented by year-end. Other enhancements are planned for the remainder of 2003 and beyond. CSS has the capability of billing gas, electricity, lighting, and any non-service product offered by MidAmerican. CSS currently bills over 1.2 million service points each month and has the ability to bill several times that amount. Scalability is limited only by the current processor capacity and disk space.

Rural Electric Cooperatives (RECs)*:* Many of Iowa's RECs outsource some or all of the services related to billing. This is accomplished primarily to achieve economies of scale, to leverage investment in technological changes, and to leverage experts in computer programming. Electronic billing via the Internet is another option that is being considered by several RECs.

Municipals: Consumers of Iowa's municipals are billed utilizing either a paper bill mailed within an envelope or a postcard type bill. The systems supporting these billing processes vary from utility to utility. Some utilities utilize their own billing systems and processes while other utilities use a wide variety of systems and processes. Electronic billing is an option that is being investigated by some municipals.

4.2 Metering

Interstate Power and Light Company (IPL): The IPL meter reading functions are managed as part of its Customer Care organization. This organization houses the customer information and manages customer contact. IPL continues to assess and expand the use of metering technology. IPL currently uses hand-held devices for meter reading the majority of customers' meters. Automated Meter Reading (AMR) technology is being used in certain areas with a primary focus on safety and hard to access locations. Meters at industrial customers' locations are remotely interrogated or probed using the handheld units.

MidAmerican Energy Company: MidAmerican has approximately 600,000 meters installed within Iowa. Approximately 90 percent of those meters are residential installations. Meter information is collected through various technologies such as handheld computers, radio technology, and power-line-carrier. MidAmerican presents meter information on the internet via a web site and is looking to expand those capabilities. Additionally, AMR technology continues to be a consideration and will be pursued if a solid business case presents itself.

Rural Electric Cooperatives (RECs): Iowa's RECs have meters in all 99 counties of Iowa. Meter data are collected using a variety of processes, varying from AMR technologies to handheld meter reading devices to allow member-consumers the option to read their meter. Most of Iowa's RECs have either deployed AMR technologies or are in the process of implementing or investigating various AMR systems. Changes in metering practices are dependent on customer acceptance of such practices.

Municipals: Iowa municipal electric utilities serve nearly 200,000 customers or meters. A variety of hand-held and automated meter reading systems are in-place among municipal utilities.

4.3 Automatic Outage Reporting

Interstate Power and Light Company (IPL): IPL's Distribution Management System (DMS) analyzes outages on the distribution system and aids in the development of switching plans. The system uses incoming calls generated from within the Customer Information System to conduct the outage analysis. The application calculates the probable outage device based on the location of the incident(s) on the electric system. As more trouble calls are received, the application will automatically recalculate the probable outage device based on the outage analysis rules. Once the outage is confirmed and service is restored, a callback list is generated for the customer service consultants to verify the service has been restored. Also, when an outage is confirmed, the dispatcher may enter the cause and estimated restoration time. This information is entered into all affected customers' account histories. This provides consultants near real time information as well as historical information for individual customers. Outage data is collected and archived within a reporting tool. The reporting tool provides a restored outage history and allows outages to be reviewed and filtered in a variety of ways for additional analysis (i.e., outage type, outage ID, cause, substation, feeder number, etc.). The DMS also aids in the development of switching plans. Plans may be submitted within a test mode to help determine validity and flag any operational concerns.

MidAmerican Energy Company: MidAmerican's Electric Outage Management System (EOMS) provides both real-time and historical customer outage information. Outage data collected include location, cause, start date and time, end date and time, and customers affected. The real-time and historical outage statistics may be interrogated and summarized by district, service center, substation, circuit, or customer. This allows for calculation of both frequency and duration of outage related statistics. The data collected are based upon incoming customer calls. In real time, the EOMS system aids the outage restoration process as it automatically groups associated customer outages together to determine the location of the device that opened. A summary of outage orders and the status or such orders is displayed on-line. As each order progresses through the various stages (order assigned, crew dispatched, crew arrives on site, estimated service restoration, actual service restoration, and order completed), dates and times are entered for each stage and displayed on-line. As orders are completed, the outage occurrence, cause, action taken, and any crew remarks are noted and become part of the outage history. This provides the customer service associates both real time and historical information.

Rural Electric Cooperatives (RECs): Some RECs have undertaken a distribution automation project called Supervisory Control and Data Acquisition. When completed, this system will allow monitoring and control from the central office of many substations, substation devices, and line switching applications. This monitoring will allow operators to view information in the field without dispatching a crew. The control aspect will allow some protective devices to be controlled in the office so, when an outage occurs, the problem can be resolved in a much quicker manner. Line crews can fix the problem without going back to the substation to reactivate the protective device. The system will also provide more detailed information for planning and targeting system upgrades.

Cooperatives that borrow money from Rural Utility Service (RUS--formerly REA) are required to annually report certain data regarding outages. Because of the small number of consumers, physical locale to the member, the inherent accountability to the member-consumer, and the accountability to RUS, many cooperatives have relied on more traditional processes of outage reporting.

List of Acronyms

AEP – Alternate Energy Production

AMR – Automated Meter Reading

Btu – British Thermal Unit

CAAA – Clean Air Act Amendments

CAIDI – Customer Average Interruption Duration Index

DMS – Distribution Management System

EIA – Energy Information Administration

EOMS – Electric Outage Management System

EPACT – Energy Policy Act

FCTS – Firm Capacity Transmission Service

FERC – Federal Energy Regulatory Commission

FPA – Federal Power Act

G&T – Generation and Transmission Cooperative

GW – Gigawatt

GWh – Gigawatt Hour

IAC – Iowa Administrative Code

IAEC – Iowa Association of Electric Cooperatives

IAMU – Iowa Association of Municipal Utilities

IDNR – Iowa Department of Natural Resources

IESC – Iowa Electrical Safety Code

ITWG – Iowa Transmission Working Group

IUB – Iowa Utilities Board

IOU – Investor-Owned Utility

ISO – Independent System Operator

IPL – Interstate Power and Light Company

KV – Kilovolt

kW – Kilowatt

kWh – Kilowatt Hour

LC – Load Control

List of Acronyms Continued

MAIN – Mid-American Interconnected Network

MAPP – Mid-Continent Area Power Pool

MEC – MidAmerican Energy Company

MISO – Midwest Independent System Operator

MW – Megawatt

MWh – Megawatt Hour

NERC – North American Electric Reliability Council

NIMECA – North Iowa Municipal Electric Cooperative Association

NIPCO – Northwest Iowa Power Cooperative

NOx – Oxides of Nitrogen

OMS – Outage Management System

PBR – Performance-Based Regulation

PSD – Prevention of Significant Deterioration

PJM – Pennsylvania, New Jersey, Maryland Power Pool

PUC – Public Utilities Commission

REA – Rural Electric Association

REC – Rural Electric Cooperative

RTO – Regional Transmission Organization

RUS – Rural Utility Service

SAIDI – System Average Interruption Duration Index

SAIFI – System Average Interruption Frequency Index

SIMECA – South Iowa Municipal Electric Cooperative Association

SO2 – Sulfur Dioxide

SPP – Southwest Power Pool

WAPA – Western Area Power Administration

WIRE – Wisconsin Interface Reliability Enhancement

WUMS – Wisconsin-Upper Michigan System

WPL – Wisconsin Power and Light

Glossary of Terms

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.

Base Load Capacity – Base-load units run near full capacity continuously day and night, all year long. Base-load units have high initial costs and low fuel costs. Typically coal fired, nuclear, and hydroelectric units are base-load units.

Billing Services – Billing and collection for delivery services.

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.

Curtailment – A reduction in the scheduled capacity or energy.

Customer – A person that consumes or uses electric energy.

Demand – Electric power measured in kilowatts.

Deregulation – The elimination of regulation from a previously regulated industry or sector of an industry.

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.

Electric Cooperative – An electric utility service provider formed or organized as an Electric Cooperative under the laws of Iowa or elsewhere.

Glossary of Terms Continued

<ins>Energy</ins> – Electric energy measured in kilowatt-hours (kWh).

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

<ins>Firm Power</ins> – 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.

<ins>Generation and Transmission Electric Cooperative (G&T)</ins> – 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.

<ins>Independent System Operator (ISO)</ins> – 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.

<ins>Interconnected System</ins> -- A system consisting of two or more individual electric systems that normally operate in synchronism and have connecting tie lines.

<ins>Interface</ins> -- The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.

<ins>Intermediate Load Capacity</ins> -- Intermediate load units fit between base load capacity and peaking capacity in both first costs and fuel costs. Intermediate load units are designed to be “cycled,” that is turned off regularly at night or on weekends and loaded up and down rapidly during the time it is on the line in order to take the load swings on the system. Older smaller base-load units and hydro units with restrictions on water use are some times used as intermediate units. Natural gas and oil fired units are also used as intermediate units.

<ins>Load Factor</ins> – 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.

<ins>Municipal Utility</ins> – A city enterprise engaged in the production, delivery, service, or sales of energy established pursuant to Code of Iowa Chapter 388. Municipal Utility includes a combined utility system.

Glossary of Terms Continued

Power Transformer – A power transformer transfers electric energy in any part of the circuit between the generator and the distribution primary circuits.

Peaking Capacity – Peaking units are run only during daily peak load periods during seasonal peak times and during emergencies. Peaking units generally have low initial costs and high fuel costs. Combustion turbines and pumped-storage hydro units are the typical peaking units.

Tie Line – A circuit connecting two or more control areas or systems of an electric system.

Time-of-Day Rate Structure – A rate structure that allows the price of electricity to the end-user to change at predetermined intervals (e.g., every half-hour) through out the day.

Transformer (up to 13 kV) – Transformer is an electric device, which when used, will raise or lower the voltage of alternating current of the original source. This type of transformer is typically used to transform distribution circuit primary voltage to customer utilization voltage.

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

Utility – An entity that owns or operates facilities for furnishing electric services to the public for compensation and subject to rate or service jurisdiction of the Board pursuant to Code of Iowa Chapter 476.

LIST OF APPENDICES

APPENDIX A
IOWA'S MUNICIPAL UTILITIES

1. Afton
2. Akron
3. Algona
4. Alta
5. Alta Vista
6. Alton
7. Ames
8. Anita
9. Anthon
10. Aplington
11. Atlantic
12. Auburn
13. Aurelia
14. Bancroft
15. Bellevue
16. Bloomfield
17. Breda
18. Brooklyn
19. Buffalo
20. Burt
21. Callender
22. Carlisle
23. Cascade
24. Cedar Falls
25. Coggon
26. Coon Rapids
27. Corning
28. Corwith
29. Danville
30. Dayton
31. Denison
32. Denver
33. Dike
34. Durant
35. Dysart
36. Earlville
37. Eldridge
38. Ellsworth
39. Estherville
40. Fairbank
41. Farnhamville
42. Fonda
43. Fontanelle
44. Forest City
45. Fredericksburg
46. Glidden
47. Gowrie
48. Graettinger
49. Grafton
50. Grand Junction
51. Greenfield
52. Grundy Center
53. Guttenberg
54. Harlan
55. Hartley
56. Hawarden
57. Hinton
58. Hopkinton
59. Hudson
60. Independence
61. Indianola
62. Keosauqua
63. Kimballton
64. La Porte City
65. Lake Mills
66. Lake Park
67. Lake View
68. Lamoni
69. Larchwood
70. Laurens
71. Lawler
72. Lehigh
73. Lenox
74. Livermore
75. Long Grove
76. Manilla
77. Manning
78. Mapleton
79. Maquoketa
80. Marathon
81. McGregor
82. Milford
83. Montezuma
84. Mount Pleasant
85. Muscatine
86. Neola
87. New Hampton
88. New London
89. Ogden
90. Onawa
91. Orange City
92. Orient
93. Osage
94. Panora
95. Paton
96. Paullina
97. Pella
98. Pocahontas
99 Preston
100. Primghar
101. Readlyn
102. Remsen
103. Renwick
104. Rock Rapids
105. Rockford
106. Sabula
107. Sanborn
108. Sergeant Bluff
109. Shelby
110. Sibley
111. Sioux Center
112. Spencer
113. Stanhope
114. Stanton
115. State Center
116. Story City
117. Stratford
118. Strawberry Point
119. Stuart
120. Sumner
121. Tennant
122. Tipton
123. Traer
124. Villisca
125. Vinton
126. Wall Lake
127. Waverly
128. Webster City
129. West Bend
130. West Liberty
131. West Point
132. Westfield
133. Whittemore
134. Wilton
135. Winterset
136. Woodbine
137. Woolstock

APPENDIX B
IOWA'S RURAL ELECTRIC COOPERATIVES

Associated Electric Cooperative, Inc. - www.aeci.org
Is owned and provides wholesale power to six regional member systems that in turn provide service to 51 local electric cooperative systems in Missouri, southeast Iowa and northeast Oklahoma. Three of the 51 are Iowa-based distribution systems that are served from one of the six regional member systems of Associated. The Regional system that serves the three Iowa distribution systems is Northeast Missouri Electric Power Cooperative (three Iowa based member distribution systems and five Missouri based member distribution systems).
Headquarters: Springfield, Missouri

- Northeast Missouri Electric Cooperative, Palmyra, Missouri.
  - Access Energy Cooperative (Mt. Pleasant, Iowa)
  - Chariton Valley Electric Cooperative (Albia, Iowa)
  - Southern Iowa Electric Cooperative (Bloomfield, Iowa)

Basin Electric Power Cooperative - www.basinelectric.com
Serves 124 rural electric member cooperative systems that in turn serve approximately 1.7 million consumers in the nine states of North Dakota, South Dakota, Montana, Wyoming, Minnesota, Nebraska, Iowa, Colorado and New Mexico.
Ten regional member-owner cooperatives or districts made up of local distribution cooperatives (Two in Iowa)
Headquarters: Bismarck, N.D.

- Northwest Iowa Power Cooperative (NIPCO), Le Mars, Iowa
  - Harrison County Rural Electric Cooperative (Woodbine, Iowa)
  - Iowa Lakes Electric Cooperative (Estherville, Iowa)
  - Nishnabotna Valley Rural Electric Cooperative (Harlan, Iowa)
  - North West Rural Electric Cooperative (Orange City, Iowa)
  - Western Iowa Municipal Electric Cooperative Association (Manning, Iowa)
    - *Anthon Municipal Utility*
    - *Aurelia Municipal Electric Utility*
    - *Hinton Municipal Electric*
    - *Manning Municipal Light Plant*
    - *Mapleton Municipal Electric*
    - *Onawa Municipal Electric Light Plant*
  - Western Iowa Power Cooperative (Offices in Onawa and Denison, Iowa)
  - Woodbury Rural Electric Cooperative (Moville, Iowa)
- L&O Power Cooperative, Rock Rapids, Iowa
  - Lyon REC (Rock Rapids, Iowa)
  - Osceola Electric Co-op Inc. (Sibley, Iowa)

APPENDIX B CONTINUED

Central Iowa Power Cooperative - www.cipco.org
Generates and transmits power to 13 rural electric cooperatives and one municipal electric cooperative.
Headquarters: Cedar Rapids, Iowa
Operation Centers: Creston and Wilton, Iowa.

- Clarke Electric Cooperative (Osceola, Iowa)
- Consumers Energy (Marshalltown, Iowa)
- East-Central Iowa REC (Urbana, Iowa)
- Eastern Iowa Light and Power Cooperative (Wilton, Iowa)
- Farmers Electric Cooperative (Greenfield, Iowa)
- Guthrie County REC (Guthrie Center, Iowa)
- Linn County REC (Marion, Iowa)
- Maquoketa Valley Electric Cooperative (Anamosa, Iowa)
- Midland Power Cooperative (Jefferson, Iowa)
- Pella Cooperative Electric Assn. (Pella, Iowa)
- Rideta Electric Cooperative (Mt. Ayr, Iowa)
- Southern Iowa Municipal Electric Cooperative Association (SIMECA)
    - *Brooklyn Municipal Utilities*
    - *Cascade Municipal Utilities*
    - *Corning Municipal Utilities*
    - *Earlville Municipal Utilities*
    - *Fontanelle Municipal Utilities*
    - *Gowrie Municipal Utilities*
    - *Greenfield Municipal Utilities*
    - *Lamoni Municipal Utilities*
    - *Lenox Municipal Utilities*
    - *Stuart Municipal Utilities*
    - *Villisca Municipal Power Plant*
    - *Winterset Municipal Utilities*
- Southwest Iowa Service Cooperative (Corning, Iowa)
- TIP REC (Brooklyn, Iowa)

Dairyland Power Cooperative - www.dairynet.com
Three Iowa member distribution systems and 18 Wisconsin member distribution systems, three Minnesota member distribution systems and one Illinois member distribution system.
Headquarters: La Crosse Wisconsin

- Allamakee-Clayton Electric Cooperative, Inc. (Postville, Iowa)
- Hawkeye Rural Electric Cooperative (Cresco, Iowa)
- Heartland Power Cooperative (Office in St. Ansgar and Thompson, Iowa)

APPENDIX B CONTINUED

Corn Belt Power Cooperative - www.cbpower.com
11 member distribution systems and one Municipal Electric Cooperative Association
Headquarters: Humboldt, Iowa

- Boone Valley Electric Co-op (Renwick, Iowa)
- Butler County REC (Allison, Iowa)
- Calhoun County Electric Cooperative Association (Rockwell City, Iowa)
- Franklin REC (Hampton, Iowa)
- Glidden REC (Glidden, Iowa)
- Grundy County REC (Grundy Center, Iowa)
- Humboldt County REC (Humboldt, Iowa)
- Iowa Lakes Electric Cooperative (Estherville, Iowa)
- Midland Power Cooperative (Jefferson, Iowa)
- North Iowa Municipal Electric Cooperative Association (NIMECA) - www.nimeca.com
  - *Alta Municipal Power Plant*
  - *Bancroft Municipal Utilities*
  - *Coon Rapids Municipal Utilities*
  - *Graettinger Municipal Light Plant*
  - *Grundy Center Municipal Light and Power*
  - *Laurens Municipal Light and Power*
  - *Milford Municipal Utilities*
  - *New Hampton Municipal Light Plant*
  - *Spencer Municipal Utilities*
  - *Sumner Municipal Light Plant*
  - *City of Webster City*
  - *West Bend Municipal Utilities*
- Prairie Energy Cooperative (Offices in Garner & Clarion)
- Sac County REC (Sac City, Iowa)

Iowa also has some consumers who are served by distribution electric cooperatives that have their headquarters in other states and serve a small percentage of their member-consumers in Iowa. These cooperatives are as follows: Atchison-Holt Electric Cooperative (Rock Port, Missouri), Federated Rural Electric Cooperative Association (Jackson, Minnesota), Freeborn-Mower Electric Cooperative (Albert Lea, Minnesota), Grundy Electric Cooperative (Trenton, Missouri), Nobles Electric Cooperative (Worthington, Minnesota), Tri-County Electric Cooperative (Rushford, Minnesota) and United Electric Cooperative (Maryville, Missouri).

Cooperative distribution systems not associated with a particular G&T cooperative include Pleasant Hill Community Line (Webster City, Iowa) and Farmers Electric Cooperative (Kalona, Iowa).

APPENDIX C
INVESTOR-OWNED UTILITY REPORTING TO MAPP AND MAIN

<u>MidAmerican:</u>

The following utilities are included in MidAmerican's 2002 MAPP reporting:

Alta Municipal Power Plant[1]
Bancroft Municipal Utilities[1]
Cedar Falls Municipal Utilities
Coon Rapids Municipal Utilities[1]
Corn Belt Power Cooperative[2]
Estherville, Iowa
Graettinger Municipal Light Plant[1]
Grundy Center Municipal Light & Power[1]
Indianola, City of
Laurens Municipal Light & Power[1]
MidAmerican Energy Company
Milford Municipal Electric Utilities[1]
Montezuma City of
New Hampton Municipal Light Plant[1]
Spencer Municipal Utilities[1]
Sumner Municipal Light Plant[1]
Waverly, City of
Waverly Municipal Electric Utility
Webster City, City of[1]
West Bend Municipal Utilities[1]

[1] Member of North Iowa Municipal Electric Cooperative Association.
[2] Corn Belt Power Cooperative includes its associated member systems.

<u>Interstate Power and Light Company</u>:

Interstate Power and Light Company reported for the following utilities in its 2002 MAPP and MAIN reporting:

Interstate Power and Light Company
Central Iowa Power Cooperative
Alta Vista, City of
Bellevue, City of
Dundee, City of
Fairbank, City of
Grafton, City of
Hanover, City of
Readlyn, City of
Sabula, City of
Tipton, City of[3]
West Point, City of

[3] Not served by IPL as of 1/1/2002.

APPENDIX D
IOWA UTILITY GENERATORS

Plant Owner	Plant Name	Unit No.	Prime Mover	Fuel Type	Summer Capacity MW
Algona Municipal Utilities	Algona	3	IC	FO2	0.5
Algona Municipal Utilities	Algona	4	IC	FO2	0.8
Algona Municipal Utilities	Algona	5	IC	FO2	1.1
Algona Municipal Utilities	Algona	6	IC	FO2	3.3
Algona Municipal Utilities	Algona	7	IC	FO2	4.3
Algona Municipal Utilities	Algona	8	IC	FO2	4.7
Algona Municipal Utilities	Algona	9	IC	FO2	4.7
Algona Municipal Utilities	George Neal South	4	ST	SUB	18.35
Alta Municipal Power Plant	Alta	1	IC	FO2	0.90
Alta Municipal Power Plant	Alta	3	IC	FO2	.95
Amana Society Service	#1-12		IC	FO2	24
Ames Municipal Electric System	Ames	7	ST	SUB	33
Ames Municipal Electric System	Ames	8	ST	SUB	70
Ames Municipal Electric System	Ames – GT	GT1	GT	FO2	18
Anita Municipal Utilities	Anita	1	IC	FO2	0.16
Anita Municipal Utilities	Anita	2	IC	FO2	0.16
Anita Municipal Utilities	Anita	3	IC	FO2	0.24
Anita Municipal Utilities	Anita	4	IC	FO2	0.3
Anita Municipal Utilities	Anita	5	IC	FO2	0.3
Anita Municipal Utilities	Anita		IC	FO2	1.83
Atlantic Municipal Utilities	Atlantic	6	GT	NG	10.1
Atlantic Municipal Utilities	Atlantic	1	IC	NG	4
Atlantic Municipal Utilities	Council Bluffs	3	ST	SUB	21.01
Bancroft Municipal Electric Plant	George Neal South	4	ST	SUB	2.18
Bancroft Municipal Electric Plant			IC	FO2	.23
Bancroft Municipal Electric Plant			IC	FO2	.55
Bancroft Municipal Electric Plant			IC	FO2	1.8
Bancroft Municipal Electric Plant			IC	FO2	1.8
Bellevue Municipal Utilities	Bellevue	1	IC	FO2	0.53
Bellevue Municipal Utilities	Bellevue	4	IC	FO2	0.6
Bellevue Municipal Utilities	Bellevue		IC	FO2	1.83
Bellevue Municipal Utilities	Bellevue	5	IC	FO2	0.75
Bellevue Municipal Utilities	Bellevue	6	IC	FO2	2.4
Bellevue Municipal Utilities	Bellevue	7	IC	FO2	1.6

APPENDIX D - Continued

Plant Owner	Plant Name	Unit No.	Prime Mover	Fuel Type	Summer Capacity MW
Bloomfield Municipal Utilities	Bloomfield	1	IC	NG	2.3
Bloomfield Municipal Utilities	Bloomfield	2	IC	FO2	0.2
Bloomfield Municipal Utilities	Bloomfield	3	IC	NG	2
Bloomfield Municipal Utilities	Bloomfield	4	IC	FO2	0.25
Bloomfield Municipal Utilities	Bloomfield	5	IC	NG	0.8
Bloomfield Municipal Utilities	Bloomfield	6	IC	NG	1.2
Brooklyn, City of			IC	FO2	.2
Brooklyn, City of			IC	FO2	.2
Brooklyn, City of			IC	FO2	.27
Brooklyn, City of			IC	NG	.55
Brooklyn, City of			IC	NG	1.05
Cascade Electric & Gas Dept.			IC	FO2	.7
Cascade Electric & Gas Dept.			IC	FO2	1.9
Cascade Electric & Gas Dept.	Cascade	3A	IC	FO2	1.86
Cascade Electric & Gas Dept.			IC	FO2	.58
Cedar Falls Utilities	Cedar Falls GT		GT	NG	17.79
Cedar Falls Utilities	Cedar Falls GT	1	GT	NG	22.27
Cedar Falls Utilities	Council Bluffs	3	ST	SUB	26.06
Cedar Falls Utilities	George Neal South	4	ST	SUB	15.6
Cedar Falls Utilities	Iowa Dist. Wind Gen. Project	1	WT	WI	0.75
Cedar Falls Utilities	Iowa Dist. Wind Gen. Project	2	WT	WI	0.75
Cedar Falls Utilities	Iowa Dist. Wind Gen. Project	3	WT	WI	0.75
Cedar Falls Utilities	Streeter Station	6	ST	BIT	19.95
Cedar Falls Utilities	Streeter Station	7	ST	BIT	36.6
Central Iowa Power Coop	Council Bluffs	3	ST	SUB	96.67
Central Iowa Power Coop	Duane Arnold	1	NB	UR	112.9
Central Iowa Power Coop	Fair Station	1	ST	BIT	23.4
Central Iowa Power Coop	Fair Station	2	ST	BIT	41
Central Iowa Power Coop	Louisa	1	ST	SUB	31.27
Central Iowa Power Coop	Summit Lake	CC1	CC	FO2	80.2
Central Iowa Power Coop	Summit Lake	IC1	IC	FO2	1
Central Iowa Power Coop	Summit Lake	IC2	IC	FO2	1
Central Iowa Power Coop	Summit Lake	IC4	IC	FO2	1
Central Iowa Power Coop	Summit Lake	IC5	IC	FO2	1
Coggon, City of			IC	FO2	.5
Coggon, City of			IC	FO2	.5
Coggon, City of			IC	FO2	2

APPENDIX D - Continued

Plant Owner	Plant Name	Unit No.	Prime Mover	Fuel Type	Summer Capacity MW
Coon Rapids Municipal Utilities	George Neal South	4	ST	SUB	3.24
Coon Rapids Municipal Utilities			IC	FO2	1.83
Coon Rapids Municipal Utilities			IC	FO2	1.83
Coon Rapids Municipal Utilities			IC	FO2	1.83
Corn Belt Power Coop	Council Bluffs	3	ST	SUB	31.94
Corn Belt Power Coop	Duane Arnold	1	NB	UR	56.45
Corn Belt Power Coop	Earl F. Wisdom	ST	ST	BIT	37.3
Corn Belt Power Coop	George Neal South	4	ST	SUB	72.57
Corn Belt Power Coop	Webster City		GT	FO2	20.7
Corning, City of			IC	FO2	.69
Corning, City of			IC	FO2	.98
Corning, City of			IC	FO2	1.36
Corning, City of			IC	FO2	.48
Corning, City of			IC	FO2	2.85
Dayton Light & Power Dept.	Dayton	5	IC	FO2	1.83
Durant Municipal Electric Plant	Durant	4	IC	FO2	0.58
Durant Municipal Electric Plant	Durant	5	IC	FO2	0.57
Durant Municipal Electric Plant			IC	FO2	2.07
Durant Municipal Electric Plant	Durant	7	IC	FO2	1.88
Eldridge Municipal Light Dept.	Louisa	1	ST	SUB	3.4
Estherville, City of			IC	FO2	1.1
Estherville, City of			IC	FO2	2.7
Estherville, City of			IC	FO2	3.6
Estherville, City of			IC	FO2	3.6
Estherville, City of			IC	FO2	1.7
Estherville, City of			IC	FO2	2.7
Estherville, City of			IC	FO2	1.83
Estherville, City of			IC	FO2	1.83
Farmers Electric Cooperative - Kalona	Frytown	1	IC	FO2	1.8
Farmers Electric Cooperative - Kalona	Frytown	2	IC	FO2	1.8
Forest City Light & Power	Forest City	1	IC	FO2	1.23
Forest City Light & Power	Forest City	2	IC	FO2	2.2
Forest City Light & Power	Forest City	3	IC	FO2	3.25
Forest City Light & Power	Forest City	5	IC	FO2	0.7
Forest City Light & Power	Forest City	IC4	IC	FO2	6.2
Gowrie Municipal Utilities	Gowrie	1	IC	FO2	1
Gowrie Municipal Utilities	Gowrie	2	IC	FO2	1

APPENDIX D - Continued

Plant Owner	Plant Name	Unit No.	Prime Mover	Fuel Type	Summer Capacity MW
Graettinger Municipal Utilities	George Neal South	4	ST	SUB	1.06
Graettinger Municipal Utilities			IC	FO2	.45
Graettinger Municipal Utilities			IC	FO2	1.08
Graettinger Municipal Utilities			IC	FO2	1.83
Grand Junction Municipal Light Plant	Grand Junction	2	IC	FO2	1.6
Greenfield, City of			IC	FO2	1
Greenfield, City of			IC	FO2	1.85
Greenfield, City of			IC	FO2	2.75
Greenfield, City of			IC	FO2	1.88
Greenfield, City of			IC	FO2	1.88
Grundy Center, City of			IC	FO2	2
Grundy Center, City of			IC	FO2	3
Grundy Center, City of			IC	FO2	3
Harlan Municipal Utilities	Louisa	1	ST	SUB	5.44
Hartley, City of			IC	FO2	.7
Hopkinton Municipal Utilities	Hopkinton	1	IC	FO2	1.6
Hopkinton Municipal Utilities	Hopkinton	IC2	IC	FO2	1.71
Hopkinton Municipal Utilities	Hopkinton	IC3	IC	FO2	1.2
Independence Municipal Light Plant	Independence IA	1	IC	FO2	2.35
Independence Municipal Light Plant	Independence IA	1B	IC	FO1	1.86
Independence Municipal Light Plant	Independence IA	4	IC	FO2	0.8
Independence Municipal Light Plant	Independence IA	4A	IC	FO1	1.86
Independence Municipal Light Plant	Independence IA	4B	IC	FO1	1.86
Independence Municipal Light Plant	Independence IA	5	IC	FO2	0.8
Independence Municipal Light Plant	Independence IA	6	IC	FO2	2.8
Independence Municipal Light Plant	Independence IA	7	IC	FO2	5.8
Independence Municipal Light Plant	Independence IA	8	IC	FO2	1.86
Independence Municipal Light Plant	Independence IA	9	IC	FO2	1.86
Indianola Municipal Utilities	Indianola	7	GT	FO2	18.1
Indianola Municipal Utilities			GT	FO2	21.2
Indianola Municipal Utilities	Indianola	1	IC	FO2	0.3
Indianola Municipal Utilities	Indianola	2	IC	FO2	1
Indianola Municipal Utilities	Indianola	3	IC	FO2	0.8
Indianola Municipal Utilities	Indianola	4	IC	FO2	1.1
Indianola Municipal Utilities	Indianola	5	IC	FO2	3.4
Indianola Municipal Utilities	Indianola	6	IC	FO2	4.1
Interstate Power & Light Company	Agency GT	1	GT	NG	17.67
Interstate Power & Light Company	Agency GT	2	GT	NG	17.61
Interstate Power & Light Company	Agency GT	3	GT	NG	17.12
Interstate Power & Light Company	Agency GT	4	GT	NG	17.64

APPENDIX D - Continued

Plant Owner	Plant Name	Unit No.	Prime Mover	Fuel Type	Summer Capacity MW
Interstate Power & Light Company	Ames	1	IC	FO2	1
Interstate Power & Light Company	Ames	2	IC	FO2	1
Interstate Power & Light Company	Anamosa	HC1	HC	WAT	0.25
Interstate Power & Light Company	Burlington	GT1	GT	NG	16.86
Interstate Power & Light Company	Burlington	GT2	GT	NG	17.84
Interstate Power & Light Company	Burlington	GT3	GT	NG	18.03
Interstate Power & Light Company	Burlington	GT4	GT	NG	18
Interstate Power & Light Company	Burlington	1	ST	SUB	214.12
Interstate Power & Light Company	Dubuque	ST2	ST	BIT	13.05
Interstate Power & Light Company	Fox Lake	4	GT	FO2	19.46
Interstate Power & Light Company	Fox Lake	1	ST	NG	12.47
Interstate Power & Light Company	Fox Lake	2	ST	NG	12.02
Interstate Power & Light Company	Fox Lake	3	ST	NG	85.05
Interstate Power & Light Company	George Neal North	3	ST	SUB	144.2
Interstate Power & Light Company	George Neal South	4	ST	SUB	138.64
Interstate Power & Light Company	Grinnell	1	GT	NG	25.56
Interstate Power & Light Company	Grinnell	2	GT	NG	22.74
Interstate Power & Light Company	Hills	1	IC	FO2	1.94
Interstate Power & Light Company	Hills	2	IC	FO2	1.81
Interstate Power & Light Company	Iowa Falls	1	HC	WAT	0.54
Interstate Power & Light Company	M L Kapp	1	ST	NG	17.72
Interstate Power & Light Company	M L Kapp	2	ST	BIT	217.97
Interstate Power & Light Company	Lansing	IC1	IC	FO2	1
Interstate Power & Light Company	Lansing	IC2	IC	FO2	1
Interstate Power & Light Company	Lansing	1	ST	BIT	16.34
Interstate Power & Light Company	Lansing	2	ST	BIT	11.19
Interstate Power & Light Company	Lansing	3	ST	BIT	31.61
Interstate Power & Light Company	Lansing	4	ST	SUB	257.99
Interstate Power & Light Company	Louisa	1	ST	SUB	28
Interstate Power & Light Company	Maquoketa	1	HC	WAT	0.6
Interstate Power & Light Company	Maquoketa	2	HC	WAT	0.6
Interstate Power & Light Company	Marshalltown	1	GT	FO2	56.2
Interstate Power & Light Company	Marshalltown	2	GT	FO2	57.06
Interstate Power & Light Company	Marshalltown	3	GT	FO2	57
Interstate Power & Light Company	Mason City Gt (Lime Creek)	1	GT	FO2	36.48
Interstate Power & Light Company	Mason City Gt (Lime Creek)	2	GT	FO2	36.69
Interstate Power & Light Company	Montgomery	1	GT	FO2	19.92
Interstate Power & Light Company	North Centerville	1	GT	FO2	24.91
Interstate Power & Light Company	North Centerville	2	GT	FO2	26.37

APPENDIX D - Continued

Plant Owner	Plant Name	Unit No.	Prime Mover	Fuel Type	Summer Capacity MW
Interstate Power & Light Company	Ottumwa	1	ST	SUB	345.69
Interstate Power & Light Company	Prairie Creek	1A	ST	NG	2
Interstate Power & Light Company	Prairie Creek	2	ST	SUB	20.7
Interstate Power & Light Company	Prairie Creek	3	ST	SUB	45.22
Interstate Power & Light Company	Prairie Creek	4	ST	SUB	143
Interstate Power & Light Company	Red Cedar	1	GT	NG	18.02
Interstate Power & Light Company	Sixth Street	2	ST	BIT	2.39
Interstate Power & Light Company	Sixth Street	4	ST	BIT	6.45
Interstate Power & Light Company	Sixth Street	7	ST	BIT	20.11
Interstate Power & Light Company	Sixth Street	8	ST	BIT	30.2
Interstate Power & Light Company	Sutherland	1	ST	BIT	33.56
Interstate Power & Light Company	Sutherland	2	ST	BIT	32.59
Interstate Power & Light Company	Sutherland	3	ST	BIT	80.94
Kimballton, City of			IC	FO1	.4
La Porte City Municipal Utilities			IC	FO1	1.1
La Porte City Municipal Utilities	La Porte	3A	IC	FO1	1.78
La Porte City Municipal Utilities	La Porte	4A	IC	FO1	1.78
La Porte City Municipal Utilities			IC	FO1	.8
Lake Park Municipal Utilities	Lake Park	2	IC	FO2	0.8
Lamoni Municipal Utilities	Lamoni	1	IC	FO2	2.75
Lamoni Municipal Utilities	Lamoni	2	IC	FO2	0.15
Lamoni Municipal Utilities	Lamoni	3	IC	FO2	0.22
Lamoni Municipal Utilities	Lamoni	4	IC	FO2	0.55
Lamoni Municipal Utilities	Lamoni	5	IC	FO2	1.05
Lamoni Municipal Utilities	Lamoni	6	IC	FO2	0.53
Laurens Municipal Light & Power	George Neal South	4	ST	SUB	3.24
Laurens Municipal Light & Power			IC	FO2	.75
Laurens Municipal Light & Power			IC	FO2	.75
Lenox, City of			IC	FO2	.3
Lenox, City of			IC	FO2	1.1
Lenox, City of			IC	FO2	.9
Lenox, City of			IC	FO2	2
Lenox, City of			WT	WI	.75
Manilla, Town of			IC	FO2	.4
Manilla, Town of			IC	FO2	.5
Maquoketa Municipal Power	Maquoketa	3	IC	NG	2
Maquoketa Municipal Power	Maquoketa	4A	IC	FO1	1.86
Maquoketa Municipal Power	Maquoketa	5	IC	NG	1.55
Maquoketa Municipal Power	Maquoketa	6	IC	NG	2.4

APPENDIX D - Continued

Plant Owner	Plant Name	Unit No.	Prime Mover	Fuel Type	Summer Capacity MW
Maquoketa Municipal Power	Maquoketa	7	IC	NG	6.5
Maquoketa Municipal Power	Maquoketa	8	IC	FO2	1.83
Maquoketa Municipal Power	Maquoketa	9	IC	FO1	1.83
McGregor Municipal Utilities	McGregor	1	IC	FO2	1.21
McGregor Municipal Utilities	McGregor	2	IC	FO2	0.27
McGregor Municipal Utilities	McGregor	3	IC	FO2	0.55
MidAmerican Energy Company	Coralville	1	GT	NG	16
MidAmerican Energy Company	Coralville	2	GT	NG	16
MidAmerican Energy Company	Coralville	3	GT	NG	16
MidAmerican Energy Company	Coralville	4	GT	NG	16
MidAmerican Energy Company	Council Bluffs	1	ST	SUB	43
MidAmerican Energy Company	Council Bluffs	2	ST	SUB	88
MidAmerican Energy Company	Council Bluffs	3	ST	SUB	664.9
MidAmerican Energy Company	Electrifarm	1	GT	NG	55.5
MidAmerican Energy Company	Electrifarm	2	GT	NG	63.1
MidAmerican Energy Company	Electrifarm	3	GT	NG	67
MidAmerican Energy Company	George Neal North	1	ST	SUB	135
MidAmerican Energy Company	George Neal North	2	ST	SUB	300
MidAmerican Energy Company	George Neal North	3	ST	SUB	370.8
MidAmerican Energy Company	George Neal South	4	ST	SUB	253.16
MidAmerican Energy Company	Knoxville Industrial	1	IC	FO2	2
MidAmerican Energy Company	Knoxville Industrial	2	IC	FO2	2
MidAmerican Energy Company	Knoxville Industrial	3	IC	FO2	2
MidAmerican Energy Company	Knoxville Industrial	4	IC	FO2	2
MidAmerican Energy Company	Knoxville Industrial	5	IC	FO2	2
MidAmerican Energy Company	Knoxville Industrial	6	IC	FO2	2
MidAmerican Energy Company	Knoxville Industrial	7	IC	FO2	2
MidAmerican Energy Company	Knoxville Industrial	8	IC	FO2	2
MidAmerican Energy Company	Louisa	1	ST	SUB	598.14
MidAmerican Energy Company	Lundquist	1	IC	FO2	2
MidAmerican Energy Company	Lundquist	10	IC	FO2	2
MidAmerican Energy Company	Lundquist	2	IC	FO2	2
MidAmerican Energy Company	Lundquist	3	IC	FO2	2
MidAmerican Energy Company	Lundquist	4	IC	FO2	2
MidAmerican Energy Company	Lundquist	5	IC	FO2	2
MidAmerican Energy Company	Lundquist	6	IC	FO2	2
MidAmerican Energy Company	Lundquist	7	IC	FO2	2
MidAmerican Energy Company	Lundquist	8	IC	FO2	2
MidAmerican Energy Company	Lundquist	9	IC	FO2	2

APPENDIX D - Continued

Plant Owner	Plant Name	Unit No.	Prime Mover	Fuel Type	Summer Capacity MW
MidAmerican Energy Company	Moline	GT1	GT	NG	16
MidAmerican Energy Company	Moline	GT2	GT	NG	16
MidAmerican Energy Company	Moline	GT3	GT	NG	16
MidAmerican Energy Company	Moline	GT4	GT	NG	16
MidAmerican Energy Company	Moline	HY1	HC	WAT	0.8
MidAmerican Energy Company	Moline	HY2	HC	WAT	0.8
MidAmerican Energy Company	Moline	HY3	HC	WAT	0.8
MidAmerican Energy Company	Moline	HY4	HC	WAT	0.8
MidAmerican Energy Company	Ottumwa	1	ST	SUB	372.06
MidAmerican Energy Company	Pleasant Hill	1	GT	FO2	35
MidAmerican Energy Company	Pleasant Hill	2	GT	FO2	35
MidAmerican Energy Company	Pleasant Hill	3	GT	FO2	78
MidAmerican Energy Company	Portable Power Modules	ALL	IC	FO2	56
MidAmerican Energy Company	Quad Cities	1	NB	UR	212.25
MidAmerican Energy Company	Quad Cities	2	NB	UR	212.25
MidAmerican Energy Company	River Hills	1	GT	NG	14.5
MidAmerican Energy Company	River Hills	2	GT	NG	14.5
MidAmerican Energy Company	River Hills	3	GT	NG	14.5
MidAmerican Energy Company	River Hills	4	GT	NG	14.5
MidAmerican Energy Company	River Hills	5	GT	NG	14.5
MidAmerican Energy Company	River Hills	6	GT	NG	14.5
MidAmerican Energy Company	River Hills	7	GT	NG	14.5
MidAmerican Energy Company	River Hills	8	GT	NG	14.5
MidAmerican Energy Company	Riverside	3HS	ST	SUB	5
MidAmerican Energy Company	Riverside	5	ST	SUB	130
MidAmerican Energy Company	Shenandoah	1	IC	FO2	2
MidAmerican Energy Company	Shenandoah	10	IC	FO2	2
MidAmerican Energy Company	Shenandoah	2	IC	FO2	2
MidAmerican Energy Company	Shenandoah	3	IC	FO2	2
MidAmerican Energy Company	Shenandoah	4	IC	FO2	2
MidAmerican Energy Company	Shenandoah	5	IC	FO2	2
MidAmerican Energy Company	Shenandoah	6	IC	FO2	2
MidAmerican Energy Company	Shenandoah	7	IC	FO2	2
MidAmerican Energy Company	Shenandoah	8	IC	FO2	2
MidAmerican Energy Company	Shenandoah	9	IC	FO2	2
MidAmerican Energy Company	Sycamore	1	GT	NG	74.5
MidAmerican Energy Company	Sycamore	2	GT	NG	74.5

APPENDIX D - Continued

Plant Owner	Plant Name	Unit No.	Prime Mover	Fuel Type	Summer Capacity MW
MidAmerican Energy Company	Waterloo	1	IC	FO2	2
MidAmerican Energy Company	Waterloo	2	IC	FO2	2
MidAmerican Energy Company	Waterloo	3	IC	FO2	2
MidAmerican Energy Company	Waterloo	4	IC	FO2	2
MidAmerican Energy Company	Waterloo	5	IC	FO2	2
MidAmerican Energy Company	Waterloo	6	IC	FO2	2
MidAmerican Energy Company	Waterloo	7	IC	FO2	2
MidAmerican Energy Company	Waterloo	8	IC	FO2	2
MidAmerican Energy Company	Waterloo	9	IC	FO2	2
MidAmerican Energy Company	Waterloo	10	IC	FO2	2
Milford Municipal Utilities	George Neal South	4	ST	SUB	2.18
Milford Municipal Utilities			IC	FO2	.6
Milford Municipal Utilities			IC	FO2	.25
Milford Municipal Utilities			IC	FO2	.4
Milford Municipal Utilities	Milford	5	IC	FO2	1.83
Milford Municipal Utilities	Milford	6	IC	FO2	1.83
Milford Municipal Utilities	Milford	7	IC	FO2	1.83
Montezuma Municipal Light & Power			IC	FO2	.18
Montezuma Municipal Light & Power			IC	FO2	.5
Montezuma Municipal Light & Power			IC	FO2	1.02
Montezuma Municipal Light & Power			IC	NG	1.58
Montezuma Municipal Light & Power			IC	NG	2.25
Montezuma Municipal Light & Power	Montezuma	8	IC	FO2	1.83
Montezuma Municipal Light & Power	Montezuma	9	IC	FO1	1.83
Mount Pleasant Utilities	Mount Pleasant	D	IC	FO2	2
Mount Pleasant Utilities			IC	FO2	2
Mount Pleasant Utilities			IC	FO2	2
Mount Pleasant Utilities			IC	FO2	2
Mount Pleasant Utilities			IC	FO2	2
Mount Pleasant Utilities			IC	FO2	2
Mount Pleasant Utilities			IC	FO2	2
Mount Pleasant Utilities			IC	FO2	2
Mount Pleasant Utilities			IC	FO2	2
Mount Pleasant Utilities			IC	FO2	2
Mount Pleasant Utilities			IC	FO2	2
Mount Pleasant Utilities			IC	FO2	2
Muscatine Power & Water	Muscatine	8	ST	BIT	50.17
Muscatine Power & Water	Muscatine	8A	ST	SUB	18.98
Muscatine Power & Water	Muscatine	9	ST	SUB	164.2

APPENDIX D - Continued

Plant Owner	Plant Name	Unit No.	Prime Mover	Fuel Type	Summer Capacity MW
New Hampton Municipal Light Plant	New Hampton	3	IC	NG	3.5
New Hampton Municipal Light Plant	New Hampton	4	IC	NG	5
New Hampton Municipal Light Plant	New Hampton	5	IC	NG	5
New Hampton Municipal Light Plant	New Hampton	7	IC	FO2	4.84
New Hampton Municipal Light Plant	New Hampton	8	IC	FO2	4.84
New London			IC	FO2	1.83
New London			IC	FO2	1.83
New London			IC	FO2	1.83
New London			IC	FO2	1.83
Northwest Iowa Power Coop	George Neal South	4	ST	SUB	56.35
Ogden, City of			IC	FO2	.48
Ogden, City of			IC	FO2	1
Ogden, City of			IC	FO2	2.5
Onawa, City of			IC	FO2	3
Osage Municipal Light & Power Dept.	Osage	5	IC	FO2	3.13
Osage Municipal Light & Power Dept.	Osage	6	IC	FO2	6.07
Osage Municipal Light & Power Dept.	Osage	7	IC	FO2	3.64
Osage Municipal Light & Power Dept.	Osage	8	IC	FO2	3.64
Pella Municipal Power & Light Dept.	Pella	5	ST	BIT	13
Pella Municipal Power & Light Dept.	Pella	6	ST	BIT	24.5
Pocahontas, City of			IC	FO2	1.83
Pocahontas, City of			IC	FO2	1.83
Preston, City of			IC	FO2	.6
Preston, City of			IC	FO2	.6
Preston, City of			IC	FO2	1.8
Preston, City of			IC	FO2	.5
Preston, City of			IC	FO2	1
Primghar, City of			IC	FO2	.08
Primghar, City of			IC	FO2	.2
Primghar, City of			IC	FO2	.2
Rock Rapids, City of			IC	FO2	2.5
Rockford Municipal Light Plant			IC	PET	.49
Rockford Municipal Light Plant			IC	PET	.9
Rockford Municipal Light Plant	Rockford	6	IC	PET	1.63
Sanborn, City of			IC	FO2	.2
Sanborn, City of			IC	FO2	.2
Sanborn, City of			IC	FO2	.5
Sanborn, City of			IC	FO2	.6

APPENDIX D - Continued

Plant Owner	Plant Name	Unit No.	Prime Mover	Fuel Type	Summer Capacity MW
Sibley Municipal Utilities	Sibley No One	2	IC	FO2	1.9
Sibley Municipal Utilities	Sibley No One	3	IC	FO2	1.14
Sibley Municipal Utilities	Sibley No One	4	IC	FO2	1.83
Sibley Municipal Utilities			IC	FO2	1.02
Spencer Municipal Utilities	George Neal South	4	ST	SUB	7.55
Spencer Municipal Utilities	Spencer	GT1	GT	FO1	18.1
State Center Municipal Electric Light	State Center	1	IC	FO1	0.6
State Center Municipal Electric Light	State Center	2	IC	FO1	0.6
State Center Municipal Electric Light	State Center	3	IC	FO1	1.36
State Center Municipal Electric Light	State Center	4	IC	FO1	1.36
State Center Municipal Electric Light	State Center	6	IC	NG	2.5
Story City, City of			IC	FO2	1.36
Story City, City of			IC	FO2	2.07
Story City, City of			IC	FO2	3.16
Story City, City of			IC	FO2	2.07
Story City, City of			IC	FO2	2.07
Story City, City of			IC	FO2	3.16
Strawberry Point Municipal Light	Strawberry Point	4	IC	FO2	1.83
Strawberry Point Municipal Light	Strawberry Point	6	IC	FO2	1.83
Stuart, City of			IC	FO2	.65
Stuart, City of			IC	FO2	1.1
Stuart, City of			IC	FO2	1
Sumner, City of			IC	FO2	2.5
Sumner, City of			IC	FO2	.8
Sumner, City of			IC	FO2	1.83
Tipton Municipal Utilities	Louisa	1	ST	SUB	3.4
Tipton Municipal Utilities			IC	NG	2
Tipton Municipal Utilities			IC	NG	1.15
Tipton Municipal Utilities			IC	NG	1.15
Traer, City of			IC	FO2	1
Traer, City of			IC	FO2	1
Traer, City of			IC	FO2	.5
Traer, City of			IC	FO2	1.25
Traer, City of			IC	FO2	2
Traer, City of			IC	FO2	1.83
Traer, City of			IC	FO2	1.83

APPENDIX D - Continued

Plant Owner	Plant Name	Unit No.	Prime Mover	Fuel Type	Summer Capacity MW
Villisca, City of			IC	NG	.8
Villisca, City of			IC	FO2	.3
Villisca, City of			IC	NG	.3
Villisca, City of			IC	FO2	.6
Vinton, City of			IC	FO2	1.25
Vinton, City of			IC	FO2	.5
Vinton, City of			IC	FO2	2.5
Vinton, City of			IC	FO2	3.75
Vinton, City of			IC	FO2	5.63
Vinton, City of			IC	FO2	3
Waverly Light & Power	East Hydro	1	HC	WAT	0.11
Waverly Light & Power	East Hydro	2	HC	WAT	0.19
Waverly Light & Power	East Hydro	3	HC	WAT	0.18
Waverly Light & Power	Louisa	1	ST	SUB	7.48
Waverly Light & Power	North Plant	10	IC	FO2	7
Waverly Light & Power	North Plant	5	IC	NG	1.25
Waverly Light & Power	North Plant	6	IC	NG	1.35
Waverly Light & Power	North Plant	7	IC	NG	3.5
Waverly Light & Power	North Plant	8	IC	NG	3.75
Waverly Light & Power	North Plant	9	IC	NG	3.75
Waverly Light & Power	Northwest Wind	GEN1	WT	WI	0.75
Waverly Light & Power	Northwest Wind	GEN2	WT	WI	0.75
Waverly Light & Power	South Plant	1	IC	FO2	1.95
Waverly Light & Power	South Plant	2	IC	FO2	1.95
Waverly Light & Power	South Plant	3	IC	FO2	1.95
Waverly Light & Power	South Plant	4	IC	FO2	1.95
Waverly Light & Power	South Plant	5	IC	FO2	1.95
West Bend Municipal Utility	West Bend	1	IC	FO2	1.1
West Bend Municipal Utility	West Bend	3	IC	FO2	0.9
West Bend Municipal Utility	West Bend	4	IC	FO2	2
West Liberty Municipal Electric Dept.	West Liberty	1	IC	FO2	0.75
West Liberty Municipal Electric Dept.	West Liberty	2	IC	FO2	2.1
West Liberty Municipal Electric Dept.	West Liberty	3	IC	FO2	2.7
Whittemore, City of			IC	FO2	.59
Whittemore, City of			IC	FO2	1.14

APPENDIX D - Continued

Plant Owner	Plant Name	Unit No.	Prime Mover	Fuel Type	Summer Capacity MW
Winterset, City of			IC	FO2	1.35
Winterset, City of			IC	FO2	1.75
Winterset, City of			IC	FO2	4.48
Winterset, City of			IC	FO2	2
Winterset, City of			IC	FO2	2
Winterset, City of			IC	FO2	2
[Various Companies]	Iowa Dist. Wind Gen. Project	2	WT	WI	0.26
[Various Companies]	Iowa Dist. Wind Gen. Project	3	WT	WI	0.26
MidAmerican Energy Co./NPPD	Cooper Station		NB	UR	385
Total Capacity (MW)					8,963.84

Source: Compiled by Platts, a division of the McGraw-Hill Companies (Powerdat Data base) and provided by MidAmerican on June 30, 2003. Changes made to Interstate Power and Light Company information (provided by IPL), Municipal Electric information (provided by IAMU), and Rural Electric Cooperative information (provided by IAEC).

Appendix E
Iowa Non-Utility Generators

Company Name	Plant Name	Nameplate Capacity MW
AG Processing, Inc.	AG Processing Inc.	8.50
Alliant Energy Applications, Inc.	Industrial Energy Applications 1	1.83
Alliant Energy Applications, Inc.	Industrial Energy Applications 2	2.96
Alliant Energy Applications, Inc.	Industrial Energy Applications 3	2.15
Alliant Energy Applications, Inc.	Industrial Energy Applications 4	1.14
Alliant Energy Applications, Inc.	Industrial Energy Applications 5	1.60
Alliant Energy Applications, Inc.	Industrial Energy Applications 6	3.10
Alliant Energy Applications, Inc.	Industrial Energy Applications 7	5.80
Alliant Energy Applications, Inc.	Industrial Energy Applications 8	5.50
Alliant Energy Applications, Inc.	Industrial Energy Applications 9	16.00
Alliant Energy Applications, Inc.	Industrial Energy Applications 10	1.14
Alliant Energy Applications, Inc.	Industrial Energy Applications 11	1.00
Alliant Energy Applications, Inc.	Industrial Energy Applications 12	2.65
Alliant Energy Applications, Inc.	Indust. Enr. Applications – Belmond	4.79
Alliant Energy Applications, Inc.	Indust. Enr. Applications – Cedar Rapids	1.60
Alliant Energy Applications, Inc.	Indust. Enr. Applications – Ft. Madison	8.00
Alliant Energy Applications, Inc.	Indust. Enr. Applications – North Pointe	1.25
Alliant Energy Corp.	Top Deck Holstein	0.28
Archer Daniels Midland Co.	Cedar Rapids – ADM	230.00
Archer Daniels Midland Co.	Clinton – ADM 1	7.50
Archer Daniels Midland Co.	Clinton – ADM 2	3.50
Archer Daniels Midland Co.	Clinton – ADM 3	9.38
Archer Daniels Midland Co.	Clinton – ADM 4	4.00
Archer Daniels Midland Co.	Clinton – ADM 5	7.00
Archer Daniels Midland Co.	Des Moines – ADM	7.90
BIO-Energy Partners	Metro Park East Landfill Gas 1	0.80
BIO-Energy Partners	Metro Park East Landfill Gas 2	0.80
BIO-Energy Partners	Metro Park East Landfill Gas 3	0.80
BIO-Energy Partners	Metro Park East Landfill Gas 4	0.80
BIO-Energy Partners	Metro Park East Landfill Gas 5	0.80
BIO-Energy Partners	Metro Park East Landfill Gas 6	0.80
BIO-Energy Partners	Metro Park East Landfill Gas 7	0.80
BIO-Energy Partners	Metro Park East Landfill Gas 8	0.80
Cargill, Inc.	Cargill Inc. – Corn Milling Div.	16.00
Cedar Rapids Hydro Dam	5-in-1 Dam Hydroelectric	2.10
Davenport, City of	Davenport Water Pollution Control 1	0.82
Davenport, City of	Davenport Water Pollution Control 2	0.82
Davenport, City of	Davenport Water Pollution Control 3	0.82
Enron Wind Development Corp.	Storm Lake Wind Power 1 [Alta]	80.25
Enron Wind Development Corp.	Storm Lake Wind Power 2 [Alta]	112.50
Entergy, Midwest Renewable, and Zilkha Renewable	Top of Iowa Windfarm	80.10

Appendix E - Continued
Iowa Non-Utility Generators

Company Name	Plant Name	Nameplate Capacity MW
FPL Energy, Inc.	Cerro Gordo Wind Project	42.00
FPL Energy, Inc.	Hancock County Windfarm	98.00
Integrated Comm. Area WWTP	Des Moines Metro WWTP 1	0.60
Integrated Comm. Area WWTP	Des Moines Metro WWTP 2	0.60
Iowa Methodist Medical Center	Iowa Methodist Medical Center 1	1.50
Iowa Methodist Medical Center	Iowa Methodist Medical Center 2	1.50
Iowa Methodist Medical Center	Iowa Methodist Medical Center 3	0.50
Iowa State University	Central Heating Plant (IOSTUN) 1	13.20
Iowa State University	Central Heating Plant (IOSTUN) 2	11.50
John Deere Co.	John Deere Dubuque Works 1	3.50
John Deere Co.	John Deere Dubuque Works 2	3.00
John Deere Co.	John Deere Dubuque Works 3	7.50
Ottumwa Water Works	Ottumwa Water Works & Hydroelectric 1	1.00
Ottumwa Water Works	Ottumwa Water Works & Hydroelectric 2	1.25
Ottumwa Water Works	Ottumwa Water Works & Hydroelectric 3	1.00
Northern Alternative Energy	Sibley Wind Farm 1	0.60
Northern Alternative Energy	Sibley Wind Farm 2	0.60
University of Iowa	University of Iowa - Main Power 1	3.00
University of Iowa	University of Iowa - Main Power 2	3.00
University of Iowa	University of Iowa - Main Power 3	15.00
University of Northern Iowa	University of Northern Iowa	7.50
Yuba-Bear River	Des Moines Metro WWTP	0.60
Total Capacity (MW)		855.33

Sources: Data provided by Interstate and MidAmerican on June 30, 2003. MidAmerican data compiled by Platts, a division of the McGraw-Hill Companies (Powerdat Data Base).
Notes: Discrepancies in facility capacity estimates were resolved by other sources: Metro Park East Landfill Gas Facility (by U.S. DOE Energy Efficiency and Renewable Energy website); Hancock County Windfarm (by FPL Energy website); Storm Lake Wind Power-Alta (by U.S. DOE Energy Efficiency and Renewable Energy website); Top of Iowa Windfarm (by Midwest Renewable Energy Corp. website); and Cedar Rapids-ADM (by Docket No. GCU-98-1).