GRAND ISLAND UTILITIES

INTEGRATED RESOURCE PLAN

Prepared for:
Western Area Power Administration

Prepared by:
Grand Island Utilities

April 2012

1.0 Background Information

The Grand Island Utilities Department (GIUD) generates and distributes electricity and water to homes, businesses, and industries in and near Grand Island, Nebraska. Within the boundaries of its 83 square mile service area the Utilities Department supplies approximately 24,500 customers with electrical service, and provides water distribution service to approximately 15,700 customers. GIUD is owned by the customers it serves and is governed by the Grand Island City Council as a financially self-supporting entity of the City of Grand Island. No taxes are used for the operation of the Utilities Department as all departmental operations are financed through electric and water sales revenue.

2.0 Integrated Resource Plan History

The Energy Policy Act of 1992 mandated that electric utilities periodically produce and adopt an Integrated Resource Plan (IRP). Grand Island's Integrated Resource Planning process began in 1996. This consisted of initial consideration of: 58 conservation options, 3 load building options, 2 load management options, and 18 supply side options. After screening, 9 supply side options and 5 demand side programs were examined in greater detail. Ultimately, supply side expansion was the realistic option. Subsequent Integrated Resource Plans, in 2001 and 2003, examined supply side options.

The initial concern was to satisfy an impending capacity need. IRP, 2001 resulted in the addition of two 34 MW (summer rating) combustion turbines at Burdick Station. IRP, 2001 was adopted by the Grand Island City Council on March 27, 2001, followed by a Public Hearing at the Nebraska Power Review Board on May 4, 2001.

IRP, 2003 considered the integration of 30 MW of Omaha Public Power District's (OPPD) Nebraska City Unit #2 (NC2) participation with GIUD generation. In the decade following the 2009 commissioning, Grand Island anticipates saving a total of $37 million, by not operating Burdick Station steam units on natural gas. In addition to the savings, GIUD gained additional generating capacity. After construction contracts were negotiated by OPPD, GIUD's participation share increased to 33 MW.

Certainty of Whelan Energy Center #2 (WEC2) project was not established until 2006, IRP, 2007 documented the consideration of issues which lead to contract ratification. Integrated Resource Plan, 2007 (IRP, 2007) was a continuation of the financial analysis presented in IRP, 2003. There were two significant differences which prevented WEC2 from being as cost effective as NC2. First, capital costs experienced a rapid and unexpected escalation. Second, the NC2 analysis had already claimed the most lucrative displacement of natural gas fired energy; this is recognized with IRP, 2003 stating that additional base-load generation will not be needed until after 2014.

The concern of IRP, 2007 was the fine-tuning of a planning window with other regional utilities, in contrast to IRP, 2003 which considered acquisition of base-load resources and IRP, 2001's concern with satisfying an impending capacity deficit.

Since the release of IRP, 2007, the economy has gone through a significant decline. This decline has reduced load growth and pushed out the need for additional capacity from 2018 to approximately 2030. IRP, 2012 provides a summary of current capacity conditions and estimates for future capacity needs. With the addition of NC2 and WEC2 in recent years, Grand Island's capacity is satisfied for the foreseeable future.

3.0 Existing Supply

Grand Island Utilities owns and operates two power stations with a combined rated capability of 273 megawatts (MW). GIUD also participates in several jointly utilized facilities. The capability and fuel mix of the generating capacity at each site is summarized in Table 3-1. The power stations are individually summarized in the following subsections.

Summary of Grand Island Utilities Existing Power Supply			
Station & Unit No.	**In-Service Year**	**Primary Fuel**	**Rated Capability MW**
Platte Generating Station	1982	Coal	100.0
Burdick Station Steam Unit #1	1957	Natl Gas	16.0
Burdick Station Steam Unit #2	1963	Natl Gas	22.0
Burdick Station Steam Unit #3	1972	Natl Gas	54.0
Burdick Station Combustion Turbine #1	1968	Natl Gas	13.0
Burdick Station Combustion Turbine #2	2003	Natl Gas	34.0
Burdick Station Combustion Turbine #3	2003	Natl Gas	34.0
Nebraska City Unit #2 – Joint	2009	Coal	33.0
Whelen Energy Center Unit #2 – Joint	2011	Coal	15.0
Ainsworth Wind Farm – Joint	2005	Wind	1.0
Elkhorn Ridge Wind Farm – Joint	2009	Wind	1.0
Laredo Ridge Wind Farm – Joint	2011	Wind	1.0
WAPA Firm - Contract	1991	Hydro	9.0
TOTAL			333.0

Table 3-1

3.1 Platte Generating Station

The Grand Island Electric Utility's primary power plant is the Platte Generating Station (PGS). The facility consists of one coal fired unit that went into commercial operation in 1982 with a net output of 100 MW. PGS has enjoyed a high level of reliability since going into commercial operation in 1982. During the past five years, PGS has had a unit availability of 93.7%, with a forced outage rate of 0.34% and operating at a capacity factor of 70.9%.

3.2 Burdick Station

The Burdick Station includes three steam turbine generators and three gas turbine generators. The station was placed in service in 1957 with additional units placed in service in 1963, 1968, 1972 and 2003. All units are equipped for natural gas and fuel oil operation.

Since the placement of the Platte Generating Station into service in 1982, the Burdick steam units have moved from intermediate service to peaking reserve capacity. Over the past five year period, the Burdick Station generation averaged only 0.4% of the total Grand Island Electric System generation.

3.3 Nebraska City Unit #2

Beginning in 2009, GIUD began receiving power from Omaha Public Power District's (OPPD) Nebraska City Unit #2. This unit is a 660 MW coal-fired power plant. It is one of two coal-fired power plants located on the site just south and east of Nebraska City, NE.

3.4 Whelen Energy Center Unit #2

Beginning in 2011, GIUD began receiving power from Public Power Generation Agency's (PPGA) Whelen Energy Center Unit #2. This unit is a 220 MW coal-fired power plant. It is one of two coal-fired power plants located on the site just east of Hastings, NE.

3.5 Wind Farm Participation

GIUD has made efforts to be involved in developing technologies regarding renewable energy. Presently, the most cost effective form of renewable energy is large scale wind energy. Since 1998, GIUD has participated with other Nebraska utilities in wind turbine projects. Presently, the state of Nebraska doesn't have a Renewable Portfolio Standard

(RPS) and GIUD doesn't have an internal renewable energy goal. However, Nebraska Public Power District (NPPD), for example, maintains an internal goal of 10% renewable energy by 2020. If GIUD were to set a similar goal, a total of approximately 25 MW of Wind capacity would be needed. In 2011, 0.876% of GIUD's energy needs were generated by wind energy.

3.5.1 Springview Project

GIUD first became involved with wind energy in 1998 with the development of the "Nebraska Distributed Wind Generation Project" or NDWG, often referred to as the "Springview Project" because of its proximity to that community in north central Nebraska. The project included two 750 kilowatt wind turbines installed near Springview, Nebraska. Half of the cost of the project was funded by a grant from the Electric Power Research Institute/Department of Energy-Turbine Verification Program. NDWG was a joint project among Nebraska utilities that included Auburn Utilities, GIUD, KBR Power District, Lincoln Electric System, the Municipal Energy Agency of Nebraska and NPPD. GIUD received an average of six megawatt hours of energy per month from NDWG. Due to rising maintenance costs, increasing equipment failures and unit downtime, this facility was decommissioned in August of 2007. Including the salvage value of the turbines, the final production cost was approximately $23/megawatt hour. Two new direct drive wind turbines were recently installed at the Springview site as another joint project that GIUD is pursuing participation in.

3.5.2 Ainsworth Project

In addition to NDWG, GIUD is also a participant in the Ainsworth Wind Energy Farm (AWEF) near Ainsworth, NE. This facility was constructed in 2005 and consists of thirty-six 1.65 megawatt turbines for a total project output of 59.4 megawatts. GIUD has a one megawatt participation level in AWEF. AWEF is another joint project that is operated by Nebraska Public Power District, and includes participation by Omaha Public Power District, the Municipal Energy Agency of Nebraska, GIUD, and JEA of Jacksonville, Florida. Since the start of AWEF, GIUD has received an average of 274 megawatt hours of energy per month. Currently, the total production cost of power received from AWEF is approximately $47 per megawatt hour.

3.5.3 Elkhorn Ridge

Elkhorn Ridge Wind, LLC (Elkhorn) is an 80 MW wind farm located near the town of Bloomfield in northeast Nebraska. It consists of twenty-seven 3 megawatt turbines. It began commercial operation January 1, 2009. Unlike AWEF, Elkhorn is a privately owned facility. NPPD entered into a Power Purchase Agreement with Elkhorn to purchase all power produced by the facility. GIUD then signed a Power Sales Agreement with NPPD to purchase a 1 MW share of the power produced at Elkhorn.

3.5.4 Laredo Ridge

Laredo Ridge Wind, LLC (LRW) is an 80 MW wind farm located near the town of Petersburg in northeast Nebraska. It consists of fifty-four 1.5 megawatt turbines. It began commercial operation February 1, 2011. Similarly to Elkhorn, LRW is a privately owned facility. NPPD entered into a Power Purchase Agreement with LRW to purchase all power produced by the facility. GIUD then signed a Power Sales Agreement with NPPD to purchase a 1 MW share of the power produced at LRW.

3.6 Purchase Power Agreement with WAPA

GIUD has a long-term agreement with the Western Area Power Administration (WAPA) providing capacity and energy to the City. The firm energy and capacity provided by WAPA is summarized in Table 3-2.

Month	Energy (kWh)	Capacity (KW)
January	2,763	4,790
February	2,721	5,113
March	2,237	4,790
April	2,450	4,790
May	2,547	6,182
June	3,504	9,153
July	3,294	9,153
August	3,924	9,057
September	2,702	6,709
October	2,442	5,751
November	2,437	4,790
December	2,440	4,790

Table 3-2

3.7 Station Capacity Factors

PGS is on-line most hours of the year, and provides the majority of electric energy for GIUD retail customers. The Burdick Station generating units operate primarily in peaking mode. Burdick Station has run fewer hours during the past several years with the addition of NC2 and WEC2. Table 3-3 shows the percentage supply for all GIUD resources and capacity factor for each GIUD owned unit for the past four years.

	2008		2009		2010		2011	
	% Supply	Capacity Factor	% Supply	Capacity Factor	% Supply	Capacity Factor	% Supply	Capacity Factor
PGS	91.61%	75.81%	82.78%	67.54%	75.68%	64.33%	74.05%	63.35%
Burdick Steam Unit #1	0.01%	0.07%	0.03%	0.18%	0.01%	0.03%	0.01%	0.03%
Burdick Steam Unit #2	0.04%	0.14%	0.07%	0.26%	0.01%	0.03%	0.01%	0.03%
Burdick Steam Unit #3	0.00%	0.00%	0.63%	0.95%	0.00%	0.00%	0.00%	0.00%
Burdick Gas Turbine #1	0.01%	0.06%	0.01%	0.06%	0.06%	0.40%	0.03%	0.23%
Burdick Gas Turbine #2	0.85%	2.06%	0.16%	0.39%	0.08%	0.21%	0.04%	0.09%
Burdick Gas Turbine #3	0.57%	1.39%	0.13%	0.31%	0.06%	0.15%	0.12%	0.31%
NC2	0.00%	N/A	14.88%	N/A	23.00%	N/A	27.00%	N/A
WEC2	0.00%	N/A	0.00%	N/A	0.00%	N/A	3.40%	N/A
Wind	0.42%	N/A	0.72%	N/A	0.75%	N/A	1.39%	N/A
WAPA	4.62%	N/A	4.67%	N/A	4.48%	N/A	4.45%	N/A
Purchases /Sales	1.87%	N/A	-4.09%	N/A	-4.13%	N/A	-10.50%	N/A

Table 3-3

4.0 Public Input

GIUD operates under a Mayor - Council form of government. Formal public meetings are conducted twice monthly. In addition, there are frequent planning sessions, open to the public, during which no formal action may be taken. Meetings are advertised and reported by the local news media. Proceedings are also broadcast on low power City television, with cable TV access. All decisions regarding additional capacity acquisition must be approved by the City Council.

5.0 Environmental Considerations

5.1 Emissions Limits

The Clean Air Act of 1990, and in particular the Acid Rain Rule, placed emissions limitations on generating facilities for SO2 and NOx, and required the installation of continuous emissions monitoring systems (CEMS) to monitor CO2, NOx, SO2 and opacity for proving compliance and providing accounting for the above mentioned emissions. Burdick Units B-3, GT-2, and GT-3 and Platte Unit 1 are subject to the Acid Rain Rule.

Burdick Generating Station burns natural gas and oil and only emits a few tons per year of SO2.

Under the Acid Rain Rule, Platte Generating Station (PGS) Unit 1 has SO2 allowances for 2,926 tons of emissions per year. In the calendar year 2011, PGS Unit 1 emitted 2,301 tons of SO2 which equates to 0.67 pounds of SO2 per million Btus of heat input. Under Acid Rain rule, PGS is required to hold SO2 allowances equal to their emissions. This is accomplished by banking unused allowances from previous years.

A summary of the monitored pollutant limits and their averages are listed in Table 5-1.

Pollutant	3 Year Average 2009-2011	Emission Limitation
NOx –annual average	0.343 lb/MMBtu	0.40 lb/MMBtu
SO2 – 3 hour average	0.694 lb/MMBtu	1.2 lb/MMBtu
Opacity	3.3 %	20% 6-minute average

Table 5-1

The Nebraska Department of Environmental Quality (NDEQ) insures these and other permitted requirements are met under their Title V Air Permit Program. Recent air inspections performed by NDEQ indicate GIUD is compliance with all conditions of plant air operating permits.

5.2 Regulations

Over the past year the electric utility industry has seen increased regulatory action from the Environmental Protection Agency (EPA). The EPA published a new regulation for power plant air emissions on July 7, 2011, the Cross State Air Pollution Rule (CSAPR), which was scheduled to replace the Clean Air Interstate Rule on January 1, 2012. The rule has lowered the annual amount of nitrous oxides (NOx) emissions that can be released as a result of the combustion process in the plant boiler, and this lower amount becomes the limiting constraint on the generating output of the Platte Generating Station, about 45% of its maximum capacity. This loss in generating capacity must be replaced by higher cost options of purchasing power from the regional market or using the gas-fueled facilities at Burdick Station. To meet the requirements of the CSAPR, the plant engineering staff researched methods to reduce the amount of NOx released from the boiler. Installing new low NOx burners with separate over-fire air ducts to lower the NOx emission rate from the unit was evaluated to be the long-term solution to allow full operating capacity for the plant The project includes furnishing and installing all of the combustion system components necessary to lower the NOx emissions from the Platte boiler to a rate of 14 #/mmBtu, or about one-fourth of its current permitted rate. The system is planned to be installed during a plant maintenance outage in the last quarter of 2012. Although the CASPR is currently stayed pending court action, staff has elected to continue with the long term compliance plans in expectation of a final ruling mid-year 2012.

On February 16, 2012 the EPA published the Mercury and Air Toxics Standards (MATS), requiring the maximum achievable control technology for mercury and other hazardous pollutants from electric generating units. Compliance is required by March, 2015, although an additional one year for compliance may be granted by individual states. This rule is independent from the CSAPR proceedings.

To achieve long-term compliance for MATS, it is anticipated that GIUD will need to install a fabric filter, carbon injection system, and either a dry sorbent injection or a dry scrubber at Platte Generating Station, along with associated by-product removal systems and disposal sites, in the next three to four years. It is estimated that these modifications will cost the utility approximately $35 Million and take 3 to 5 years for financing, design, and construction. Current plans are to complete this installation during the last quarter of 2014 to coincide with a scheduled plant maintenance outage. This will provide a margin for the implementation of the system and minimize plant downtime. Currently GIUD is working with outside contractors to fully evaluate control equipment options.

Other rules in various stages of promulgation are anticipated to have a potential impact on utilities. They include revisions to the National Ambient Air Quality Standards (NAAQS), the clean water effluent guidelines, and coal combustion waste management rules. In late March 2012 the EPA decided to not make an adjustment to the current NOx and SOx NAAQS. States now have the duty to develop State Implementation Plans or SIPs outlining to the EPA how they anticipate meeting ambient air standards. Nebraska currently meets all NAAQS but will be making changes to the SO2 SIP pending EPA approval. With a high degree of uncertainty surrounding future regulatory action GIUD staff closely monitors the regulatory rulings.

6.0 Conservation/Demand Side Management

Nebraska consistently ranks within the top ten lowest electricity cost states in the nation. This low cost along with abundant excess capacity makes conservation and demand side management programs difficult to justify. The low costs are a direct result of abundant low cost coal generation. If EPA regulations continue to be implemented, limiting the use of and increasing the cost of coal generation, Nebraska utilities could see a significant shift in average prices. Conservation and demand side management will continue to be examined in the future as additional environmental regulations are added. There may be a point in the future where an aggressive conservation program is economically feasible.

7.0 Excess Power Sales

GIUD has had an abundance of excess power during the past few years. When possible, this power is sold to surrounding utilities. Arrangements have been made with several utilities in an effort to maximize sales of excess power. The down economy and the recent commercial operation of several large baseload units in the area have made the market extremely soft. In addition, Southwest Power Pool (SPP), the Regional Transmission Operator (RTO) for Nebraska, is moving toward an integrated market to begin in 2014. These market changes have the potential of making the current way of selling excess power obsolete. Because of these changes, GIUD is pursuing load and generation registration with SPP in order to participate in the market. This has the potential for maximizing profits on excess power during off peak periods as well as reducing energy prices for customers.

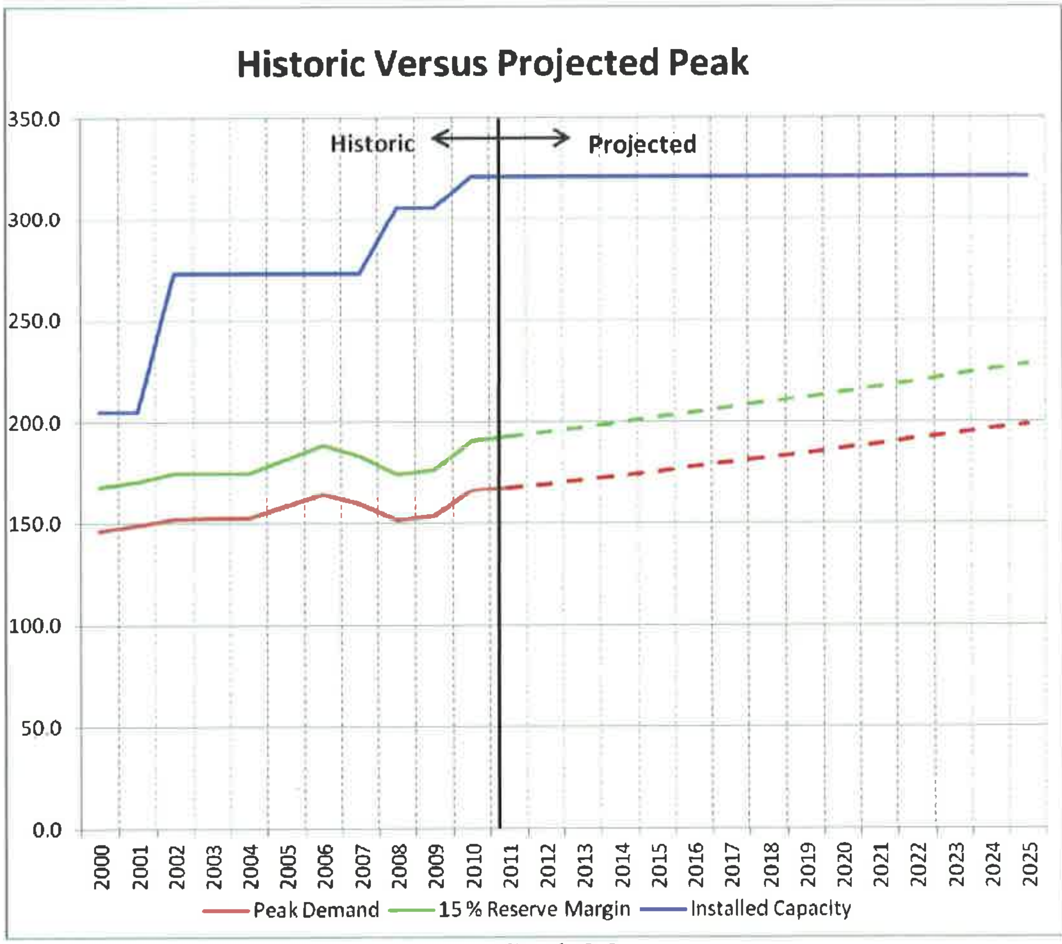
8.0 Load Projections

GIUD makes monthly projections of demand and energy requirements. A times series is used based upon historical load. This series originally included data beginning in 1978. However, it was apparent that including the late 1970's time frame produced an inaccurate projection due to the aggressive addition of air conditioning load during that period of time. Since 2007, the time series is based upon data beginning in 2000. This provides a much more accurate projection. Results are graphically displayed in order to identify anomalies which may evolve into trends. The graphs are included as Appendix A. Table 8-1 shows the current projections out to 2025 with five years of historical data.

Year	Summer Peak Demand	Winter Peak Demand
2007	159.6 MW	107.6 MW
2008	151.8 MW	114.4 MW
2009	153.6 MW	117.6 MW
2010	166.1 MW	118.3 MW
2011	167.9 MW	110.5 MW
2012	170 MW	120 MW
2013	172 MW	123 MW
2014	174 MW	126 MW
2015	176 MW	130 MW
2016	179 MW	133 MW
2017	181 MW	137 MW
2018	183 MW	140 MW
2019	185 MW	144 MW
2020	187 MW	148 MW
2021	190 MW	152 MW
2022	192 MW	156 MW
2023	194 MW	160 MW
2024	196 MW	165 MW
2025	199 MW	169 MW

Table 8-1

With the addition of NC2 and WEC2, the use of Burdick generation for peaking is minimized. At the current load growth rate, Burdick generation will not see pre NC2 and WEC2 usage until approximately 2025. From a capacity standpoint, GIUD has plenty of capacity to satisfy needs beyond 2025. See graph 8-2 below.



Graph 8-2

9.0 Reliability

GIUD tracks reliability statistics in an effort to curb negative trends and attract new industry. GIUD maintains a high level of reliable electric service. The current reliability statistics are shown in Appendix B.

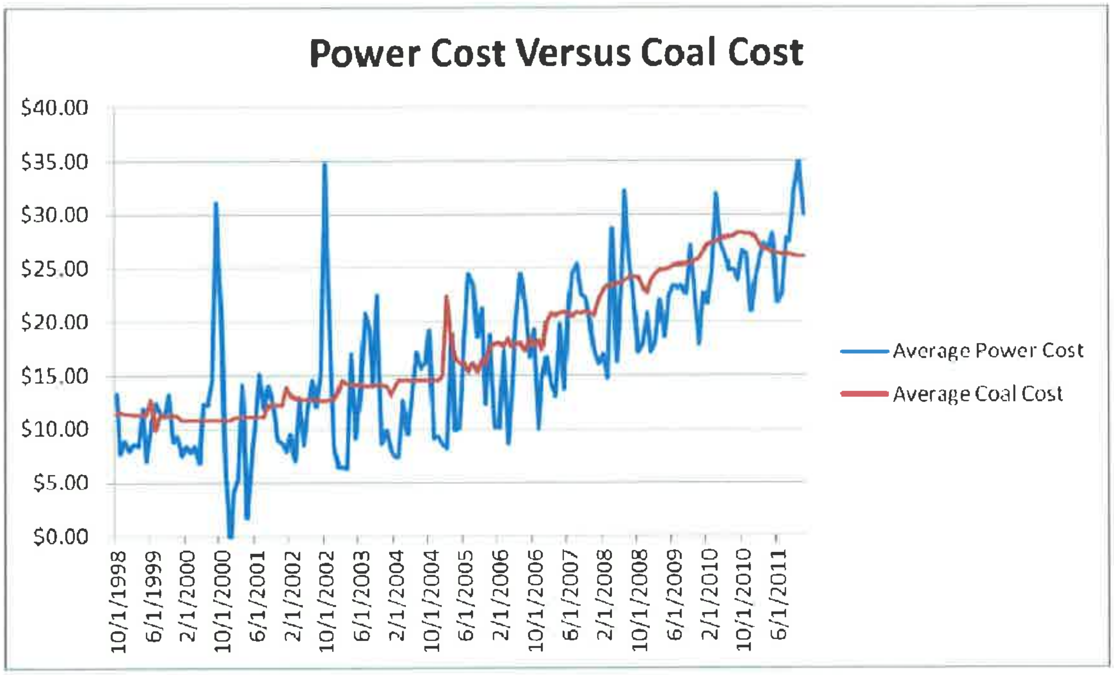
10.0 Historic And Average Power Cost

Coal and natural gas prices have experienced an incline over the past several years. Coal prices, historically, have been much more constant than natural gas prices. GIUD is hesitant to rely heavily on natural gas fired generation due to the fuel volatility. Graph 10-1 below shows the historical prices of GIUD coal and natural gas generation in $/MWh during the past seven years:

Graph 10-1

GIUD expects PGS coal generation costs to go up during the next several years due to new EPA emissions standards and regulations. However, NC2 and WEC2 prices should remain fairly flat since both units are new and already meet the latest proposed regulations.

For years, average cost of power for GIUD customers stayed consistently in the $10 per MWh price range. This was due to low cost local generation and low cost supplemental power available for purchase from surrounding utilities. During the past eight years, average cost of power has increased with a current average cost approaching $35 per MWh. This rise is due to several factors including the addition of NC2 and WEC2 and associated transmission and debt service, increased transportation cost for coal and an increase in the price of coal itself. Graph 10-2 shows the rise in both coal prices and corresponding power prices since 1998.



Graph 10-2

With NC2 and WEC2 fully incorporated into the average power cost, it is anticipated that, despite rising PGS generation costs, prices will stabilize in the near future. However, this could drastically be impacted by more stringent EPA coal restrictions.

11.0 Implementation Plan

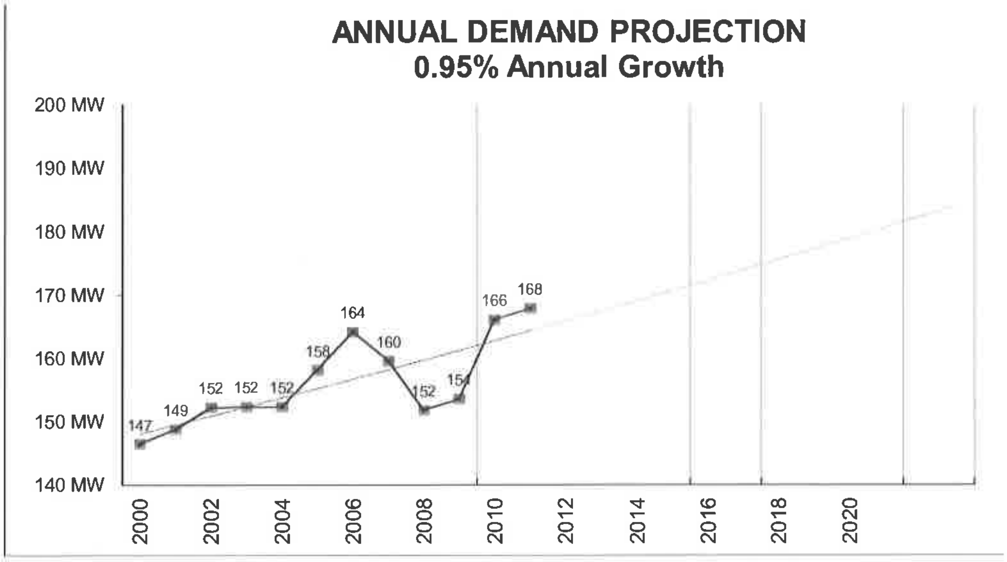
With the current trends and the recent addition of NC2 and WEC2 capacity, GIUD has enough excess capacity to last well beyond 2020. This additional capacity should allow GIUD to obtain some profit by selling additional energy utilizing the current and future energy markets. Load will continue to be trended and additional capacity will be added as needed. However, at the present time, additional capacity is not expected to be needed until beyond 2025.

APPENDIX "A"

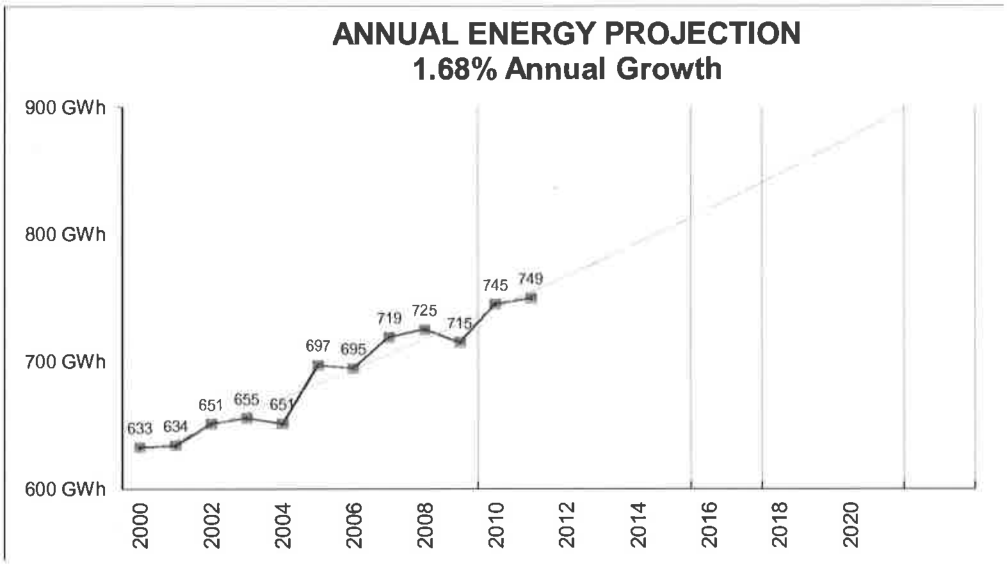
MONTHLY DEMAND & ENERGY SUMMARY

26-Mar-12

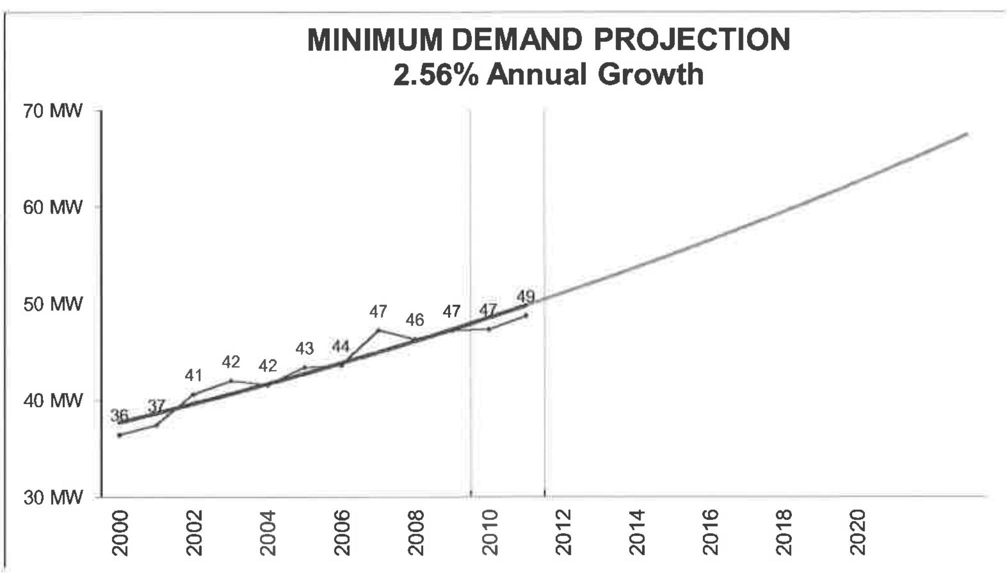
YEAR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
JAN	87.0 MW	93.8 MW	96.6 MW	99.8 MW	90.6 MW	102.2 MW	107.6 MW	110.0 MW	117.6 MW	115.2 MW
FEB	88.4 MW	89.2 MW	92.2 MW	94.0 MW	101.8 MW	104.8 MW	103.4 MW	103.1 MW	105.5 MW	118.3 MW
MAR	88.8 MW	92.8 MW	87.4 MW	90.4 MW	91.0 MW	95.0 MW	99.2 MW	103.6 MW	97.8 MW	102.2 MW
APR	100.4 MW	98.3 MW	99.0 MW	89.4 MW	96.8 MW	95.0 MW	99.2 MW	99.1 MW	94.2 MW	96.9 MW
MAY	125.7 MW	105.3 MW	109.4 MW	125.8 MW	123.6 MW	117.0 MW	103.2 MW	114.4 MW	123.6 MW	128.9 MW
JUN	140.1 MW	138.4 MW	133.4 MW	144.6 MW	144.2 MW	142.0 MW	143.8 MW	153.6 MW	147.5 MW	152.0 MW
JUL	152.3 MW	152.4 MW	152.4 MW	158.2 MW	164.2 MW	154.8 MW	151.8 MW	150.1 MW	154.0 MW	165.9 MW
AUG	142.9 MW	150.7 MW	145.8 MW	157.6 MW	159.0 MW	159.6 MW	147.4 MW	145.8 MW	166.1 MW	167.9 MW
SEP	135.2 MW	121.8 MW	131.4 MW	135.2 MW	108.4 MW	132.2 MW	118.6 MW	113.0 MW	133.4 MW	152.0 MW
OCT	103.5 MW	99.2 MW	89.2 MW	127.8 MW	112.0 MW	112.8 MW	95.4 MW	97.3 MW	106.8 MW	108.2 MW
NOV	87.9 MW	87.0 MW	95.8 MW	99.8 MW	102.6 MW	97.4 MW	100.4 MW	93.6 MW	107.2 MW	99.2 MW
DEC	91.0 MW	94.8 MW	99.2 MW	106.4 MW	100.0 MW	107.4 MW	114.4 MW	113.6 MW	106.5 MW	110.5 MW
SUM. MAX.	152.3 MW	152.4 MW	152.4 MW	158.2 MW	164.2 MW	159.6 MW	151.8 MW	153.6 MW	166.1 MW	167.9 MW
WIN. MAX.	98.3 MW	99.0 MW	99.2 MW	106.4 MW	104.8 MW	107.6 MW	114.4 MW	117.6 MW	118.3 MW	110.5 MW
JAN	50,689 MWh	52,190 MWh	53,931 MWh	57,176 MWh	53,447 MWh	59,992 MWh	62,212 MWh	62,522 MWh	64,698 MWh	66,152 MWh
FEB	45,314 MWh	46,888 MWh	49,764 MWh	48,203 MWh	51,135 MWh	54,963 MWh	56,800 MWh	54,233 MWh	57,771 MWh	58,583 MWh
MAR	49,645 MWh	49,907 MWh	49,963 MWh	52,496 MWh	54,150 MWh	53,850 MWh	56,122 MWh	56,971 MWh	57,833 MWh	59,794 MWh
APR	46,644 MWh	47,968 MWh	47,691 MWh	48,937 MWh	48,489 MWh	50,590 MWh	53,050 MWh	52,619 MWh	51,802 MWh	52,903 MWh
MAY	49,186 MWh	49,796 MWh	52,884 MWh	55,069 MWh	56,630 MWh	55,558 MWh	54,035 MWh	55,339 MWh	56,306 MWh	56,229 MWh
JUN	64,599 MWh	56,668 MWh	57,708 MWh	65,632 MWh	66,784 MWh	63,787 MWh	64,623 MWh	62,748 MWh	67,445 MWh	65,163 MWh
JUL	75,713 MWh	75,814 MWh	65,292 MWh	76,314 MWh	77,657 MWh	75,861 MWh	76,582 MWh	70,688 MWh	76,550 MWh	81,118 MWh
AUG	67,373 MWh	72,814 MWh	63,496 MWh	71,712 MWh	71,163 MWh	77,454 MWh	71,321 MWh	69,103 MWh	78,272 MWh	76,384 MWh
SEP	54,314 MWh	52,581 MWh	56,377 MWh	60,114 MWh	52,524 MWh	57,710 MWh	57,637 MWh	55,976 MWh	59,488 MWh	57,864 MWh
OCT	49,274 MWh	50,359 MWh	49,266 MWh	52,738 MWh	53,737 MWh	55,100 MWh	53,983 MWh	55,847 MWh	54,336 MWh	56,189 MWh
NOV	47,409 MWh	48,159 MWh	49,734 MWh	50,969 MWh	52,799 MWh	53,171 MWh	55,128 MWh	53,902 MWh	55,989 MWh	56,462 MWh
DEC	50,692 MWh	52,326 MWh	54,843 MWh	57,647 MWh	56,079 MWh	60,935 MWh	63,430 MWh	64,841 MWh	64,182 MWh	62,575 MWh
TOTAL	650,851 MWh	655,470 MWh	650,950 MWh	697,007 MWh	694,593 MWh	718,974 MWh	724,922 MWh	714,788 MWh	744,672 MWh	749,417 MWh
ANNUAL LF	49%	49%	49%	50%	48%	51%	54%	53%	51%	51%



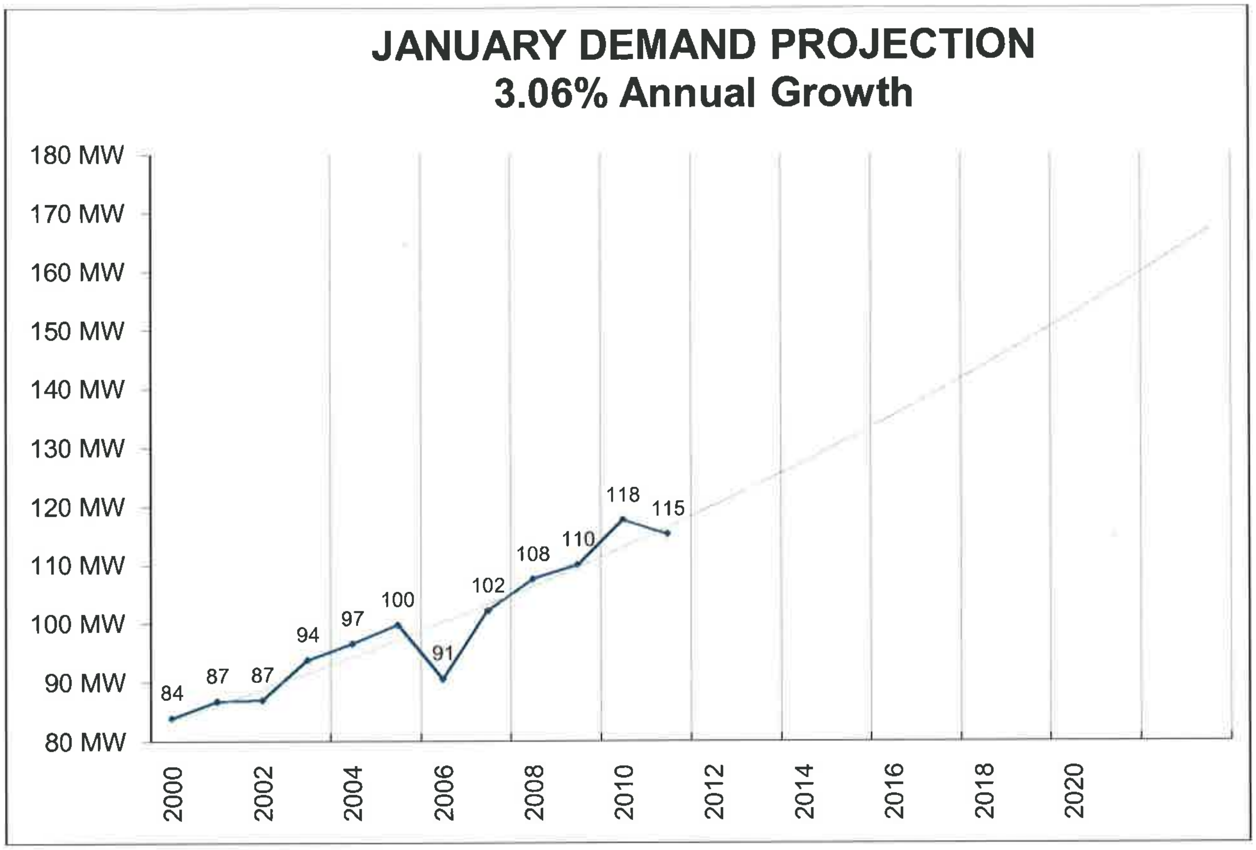
ANNUAL DEMAND PROJECTION
0.95% Annual Growth
200 MW
190 MW
180 MW
170 MW
160 MW
150 MW
140 MW
147
149
152
152
152
158
164
160
152
154
166
168
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020



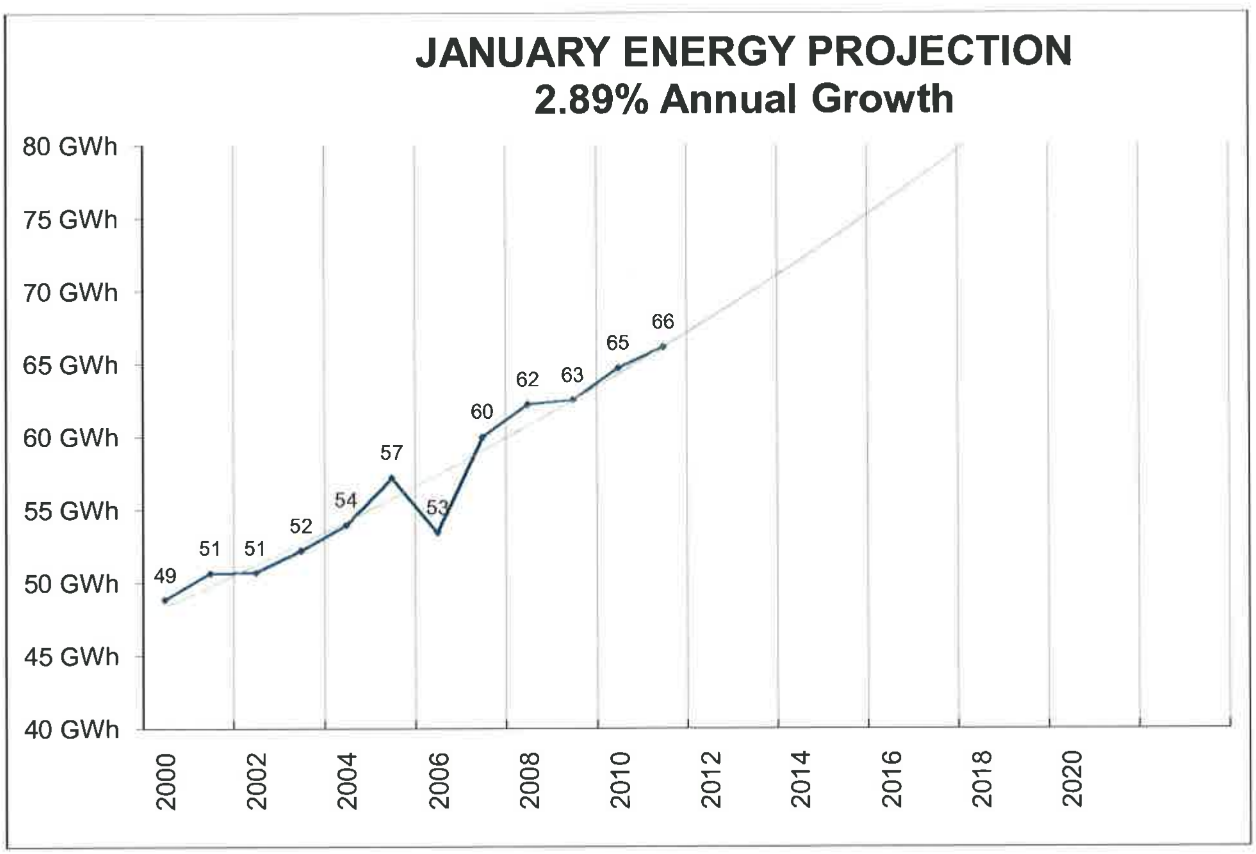
ANNUAL ENERGY PROJECTION
1.68% Annual Growth
900 GWh
800 GWh
700 GWh
600 GWh
633
634
651
655
651
697
695
719
725
715
745
749
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020



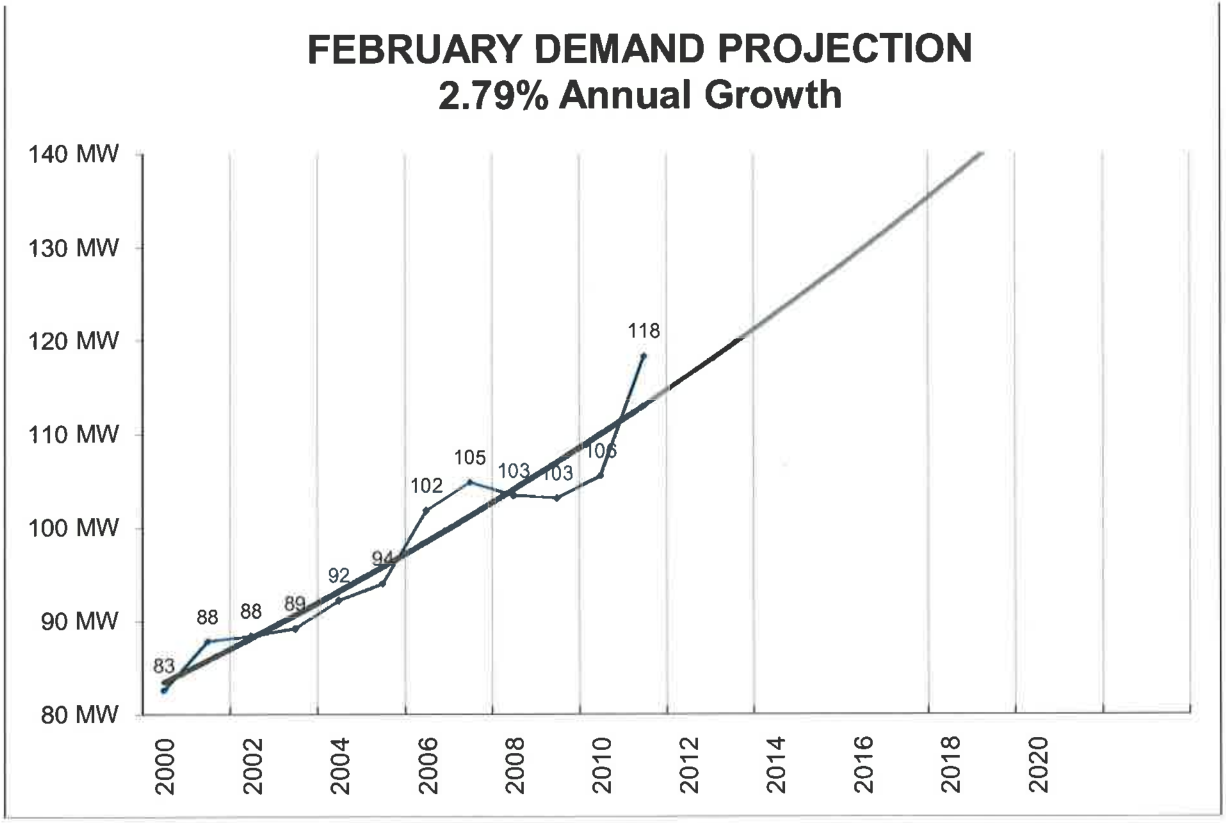
MINIMUM DEMAND PROJECTION
2.56% Annual Growth
70 MW
60 MW
50 MW
40 MW
30 MW
36
37
41
42
42
43
44
47
46
47
47
49
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020

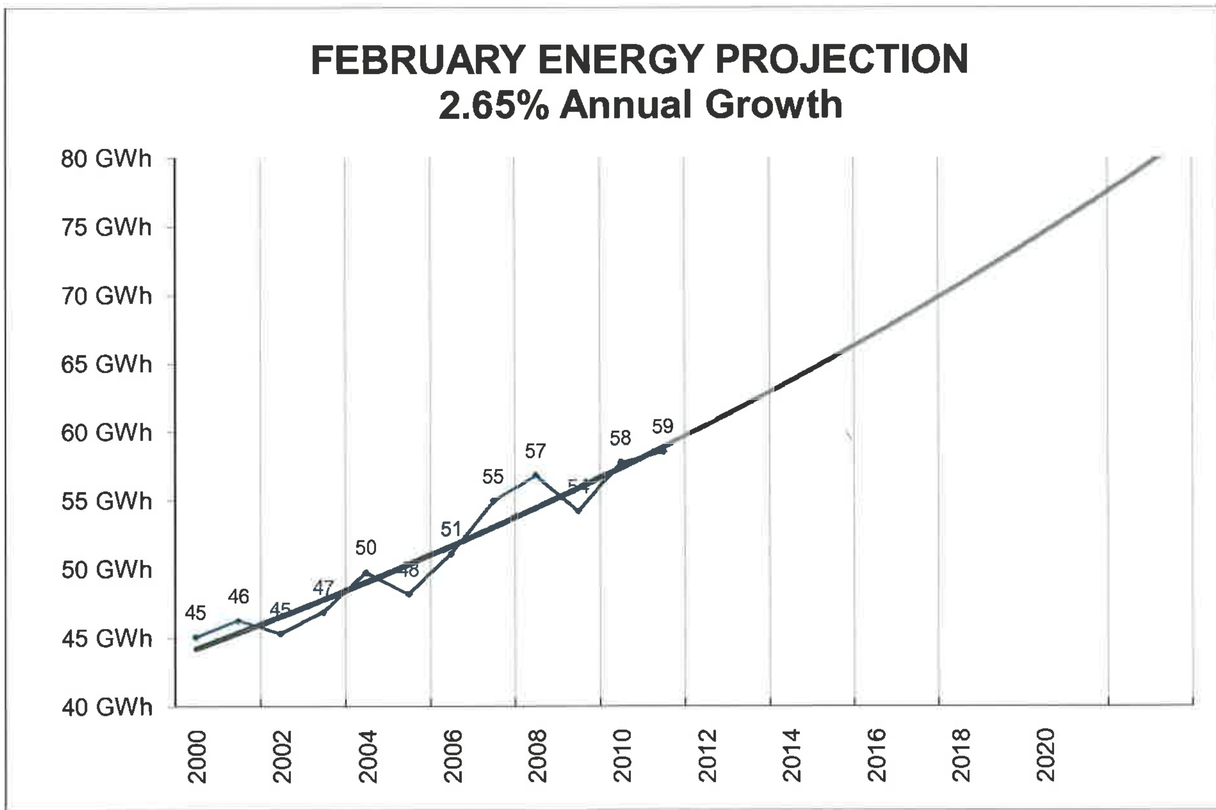


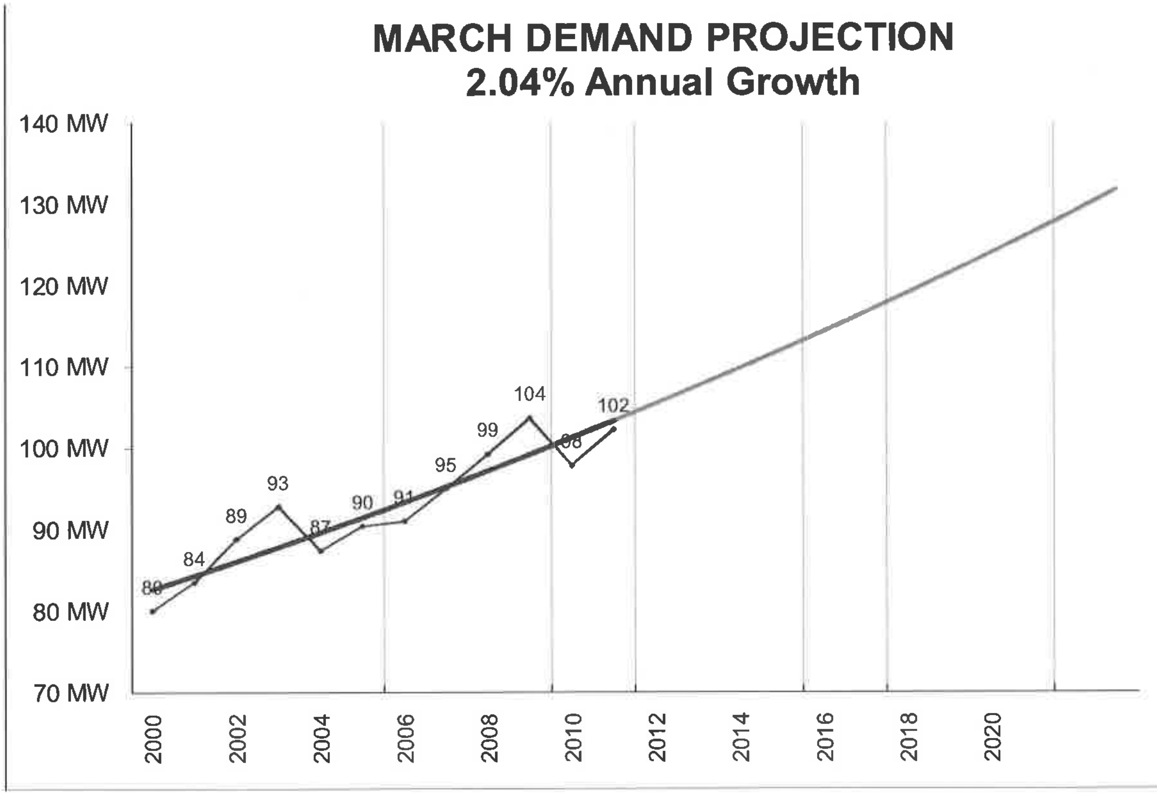
JANUARY DEMAND PROJECTION
3.06% Annual Growth
180 MW
170 MW
160 MW
150 MW
140 MW
130 MW
120 MW
110 MW
100 MW
90 MW
80 MW
84
87
87
94
97
100
91
102
108
110
118
115
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020

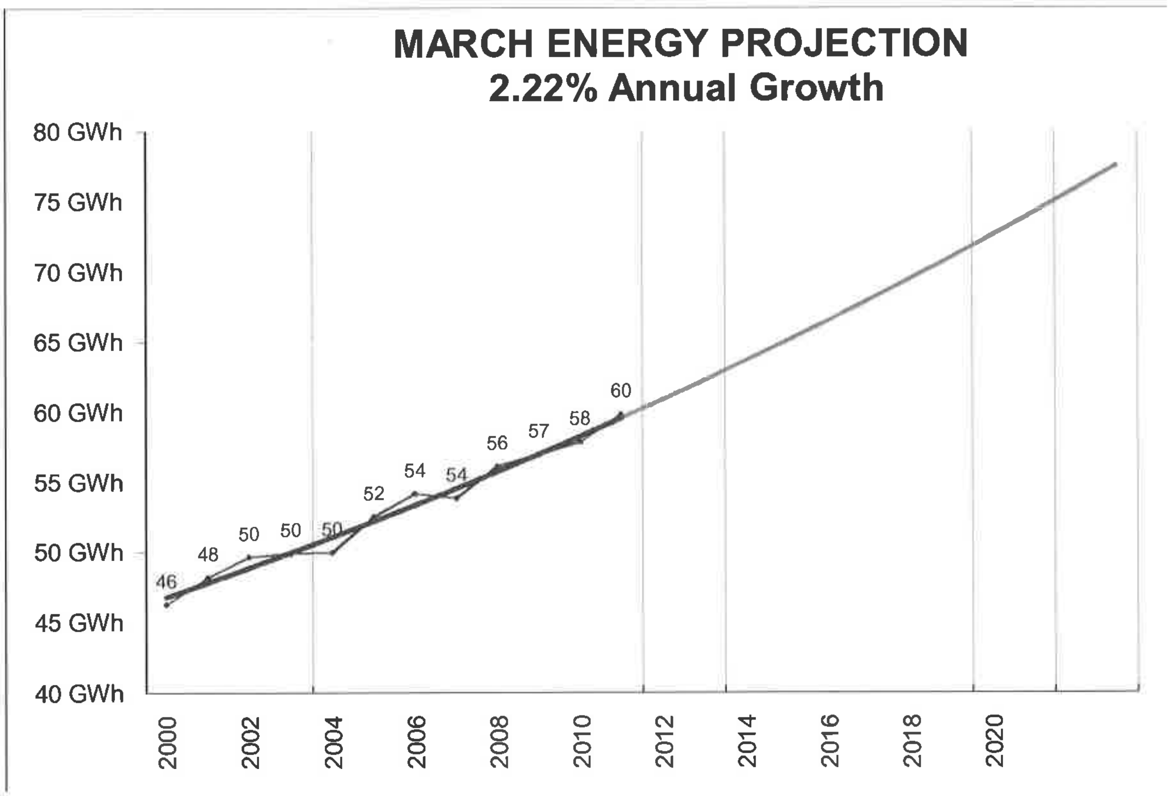


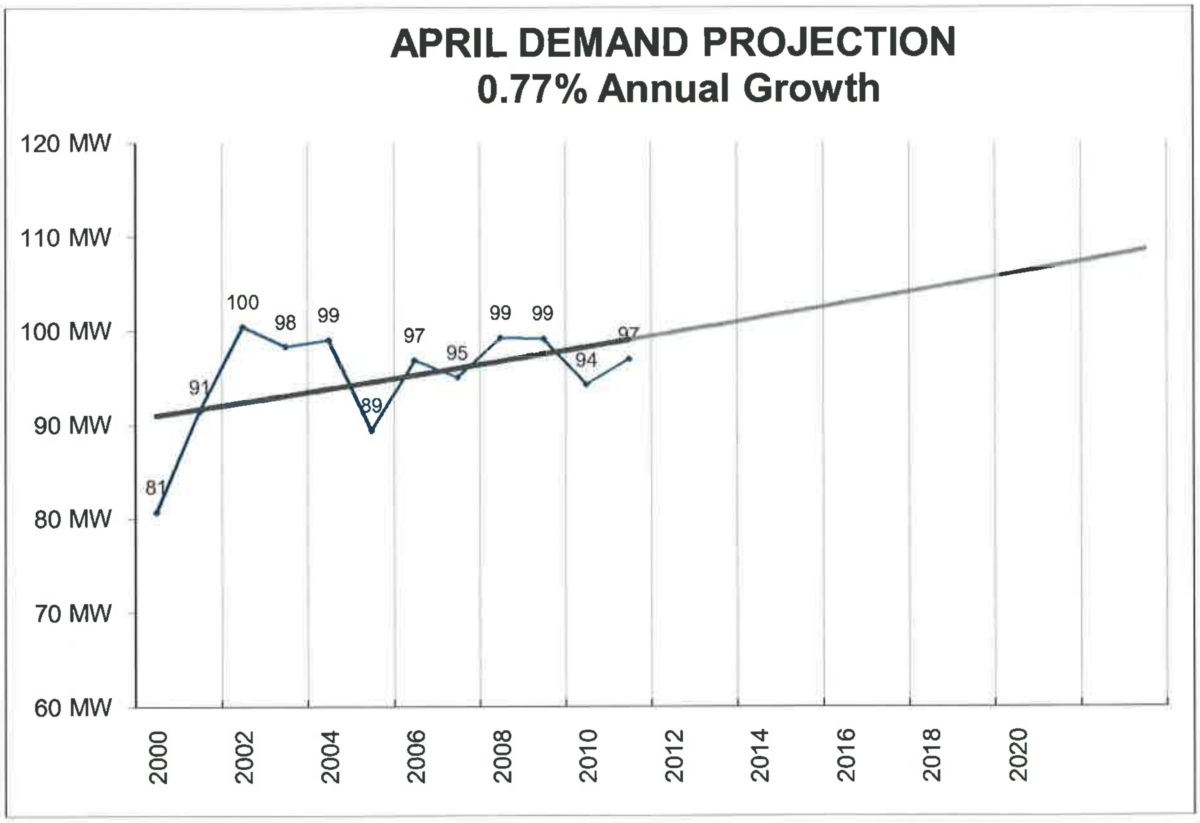
JANUARY ENERGY PROJECTION
2.89% Annual Growth
80 GWh
75 GWh
70 GWh
65 GWh
60 GWh
55 GWh
50 GWh
45 GWh
40 GWh
49
51
51
52
54
57
53
60
62
63
65
66
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020

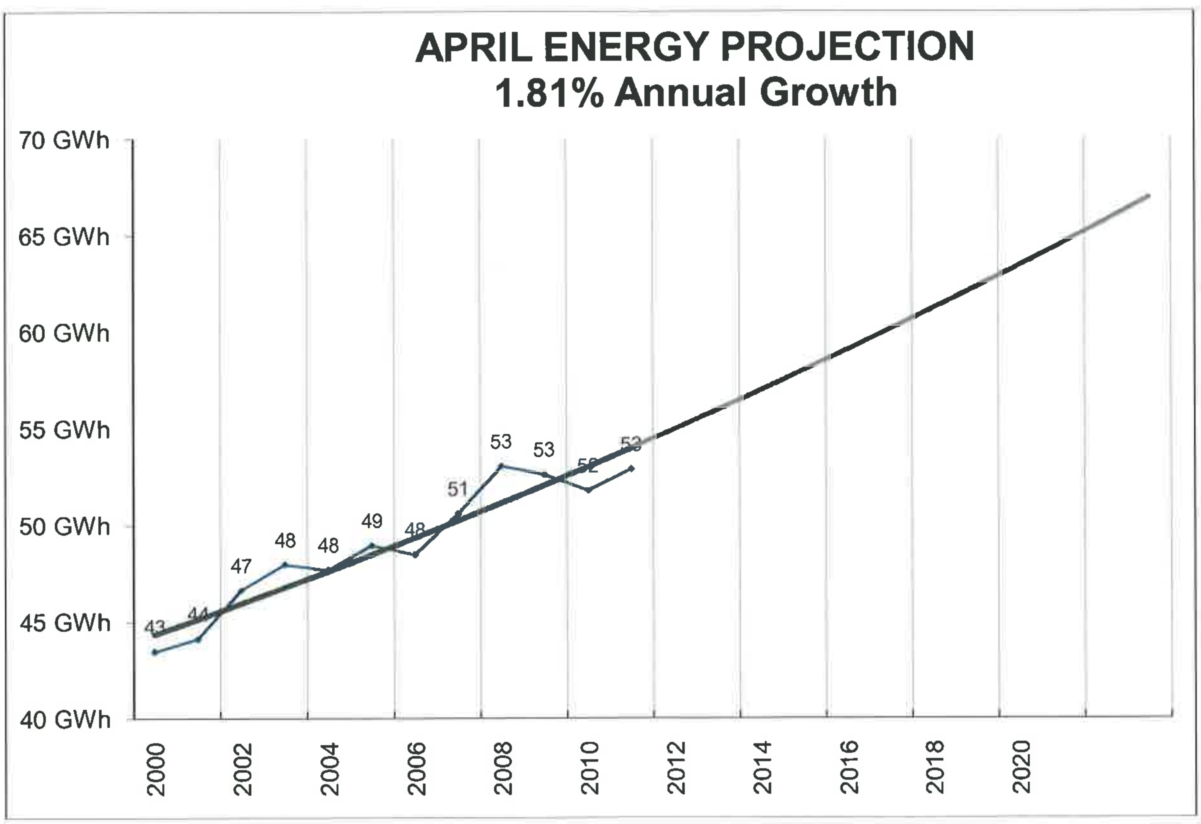

FEBRUARY DEMAND PROJECTION
2.79% Annual Growth
140 MW
130 MW
120 MW
110 MW
100 MW
90 MW
80 MW
83
88
88
89
92
94
102
105
103
103
106
118
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


FEBRUARY ENERGY PROJECTION
2.65% Annual Growth
80 GWh
75 GWh
70 GWh
65 GWh
60 GWh
55 GWh
50 GWh
45 GWh
40 GWh
45
46
45
47
50
48
51
55
57
58
59
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


MARCH DEMAND PROJECTION
2.04% Annual Growth
140 MW
130 MW
120 MW
110 MW
100 MW
90 MW
80 MW
70 MW
80
84
89
93
87
90
91
95
99
104
98
102
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


MARCH ENERGY PROJECTION
2.22% Annual Growth
80 GWh
75 GWh
70 GWh
65 GWh
60 GWh
55 GWh
50 GWh
45 GWh
40 GWh
46
48
50
50
50
52
54
54
56
57
58
60
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


APRIL DEMAND PROJECTION
0.77% Annual Growth
120 MW
110 MW
100 MW
90 MW
80 MW
70 MW
60 MW
81
91
100
98
99
89
97
95
99
99
94
97
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


APRIL ENERGY PROJECTION
1.81% Annual Growth
70 GWh
65 GWh
60 GWh
55 GWh
50 GWh
45 GWh
40 GWh
43
44
47
48
48
49
48
51
53
53
52
53
2000
2002
2004
2006
2008
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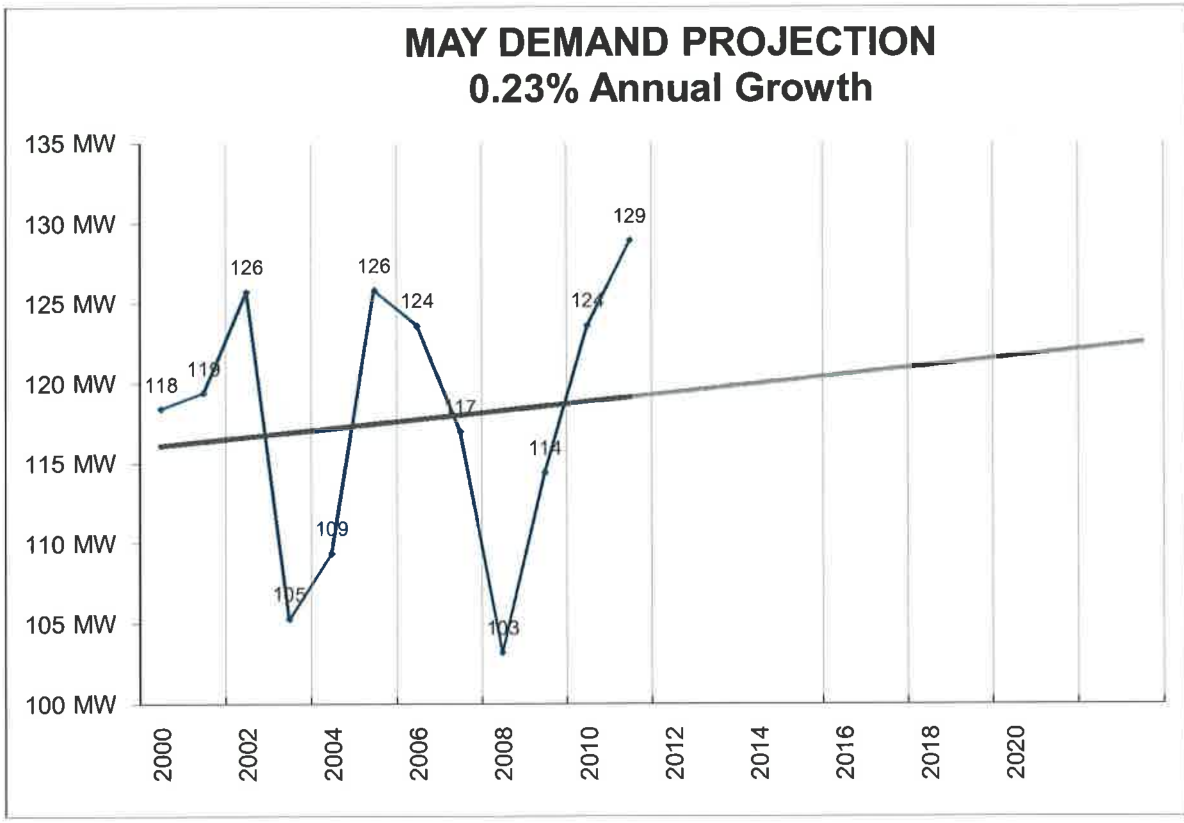
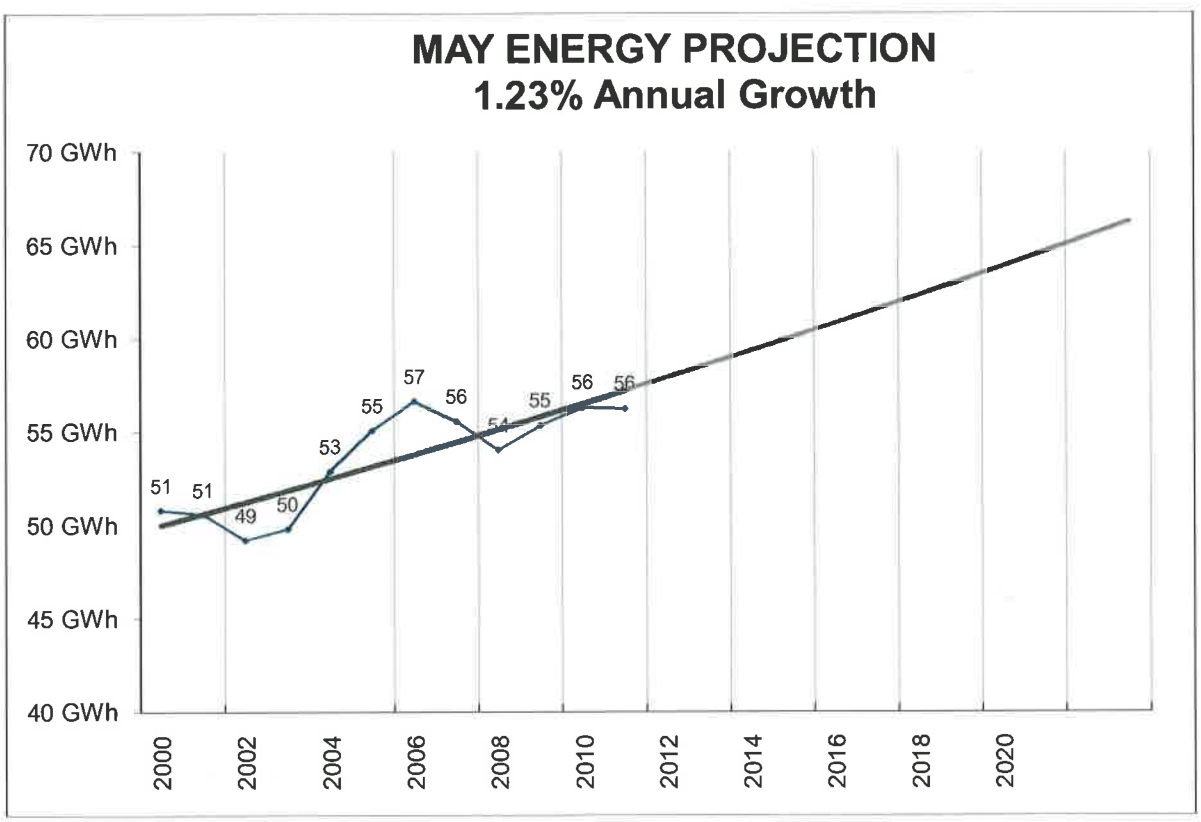
2012
2014
2016
2018
2020


MAY DEMAND PROJECTION
0.23% Annual Growth
135 MW
130 MW
125 MW
120 MW
115 MW
110 MW
105 MW
100 MW
118
119
126
105
109
126
124
117
103
114
124
129
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


MAY ENERGY PROJECTION
1.23% Annual Growth
70 GWh
65 GWh
60 GWh
55 GWh
50 GWh
45 GWh
40 GWh
51
51
49
50
53
55
57
56
54
55
56
56
2000
2002
2004
2006
2008
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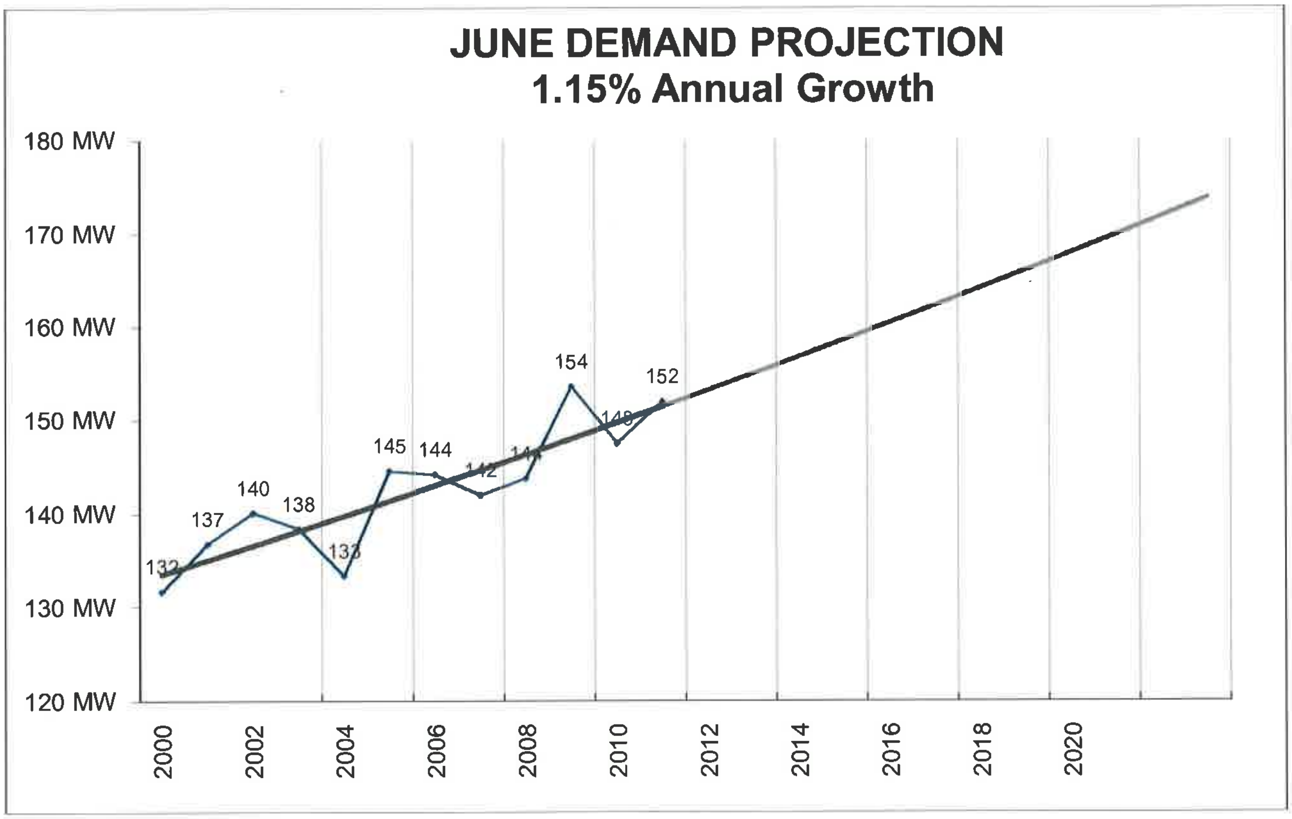
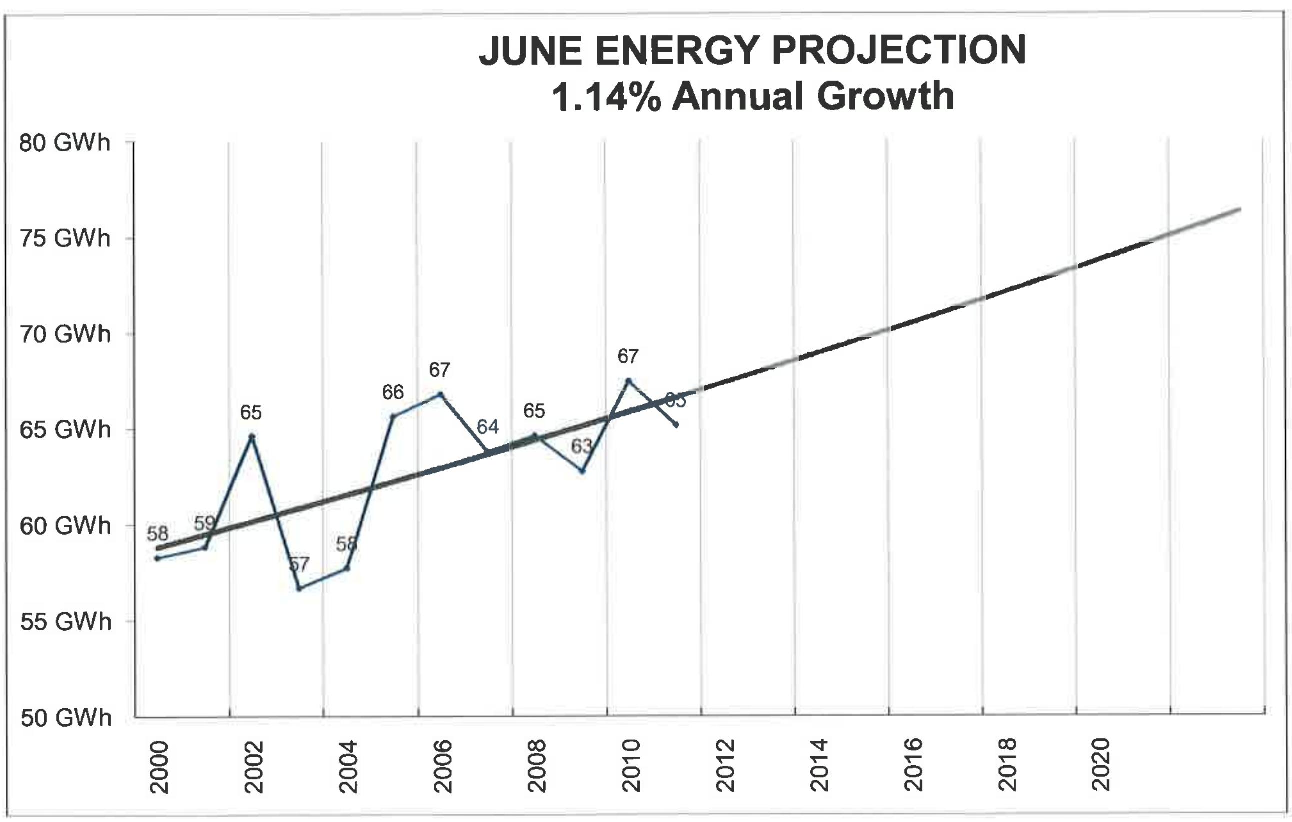
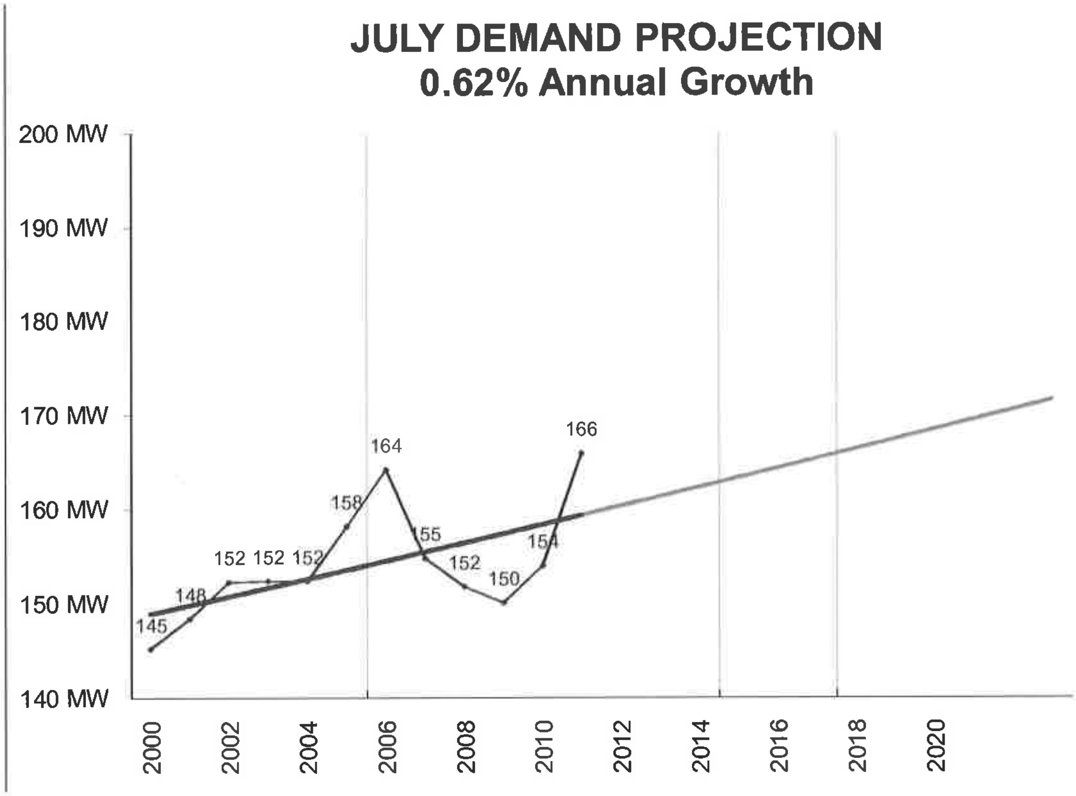
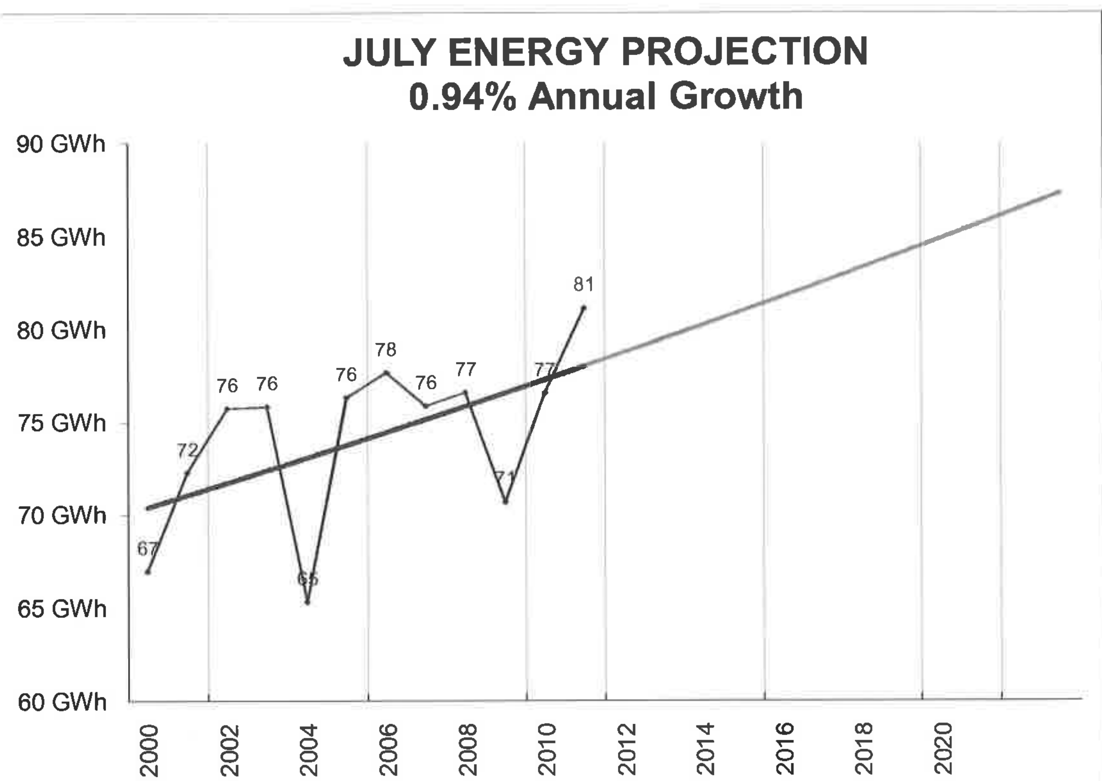
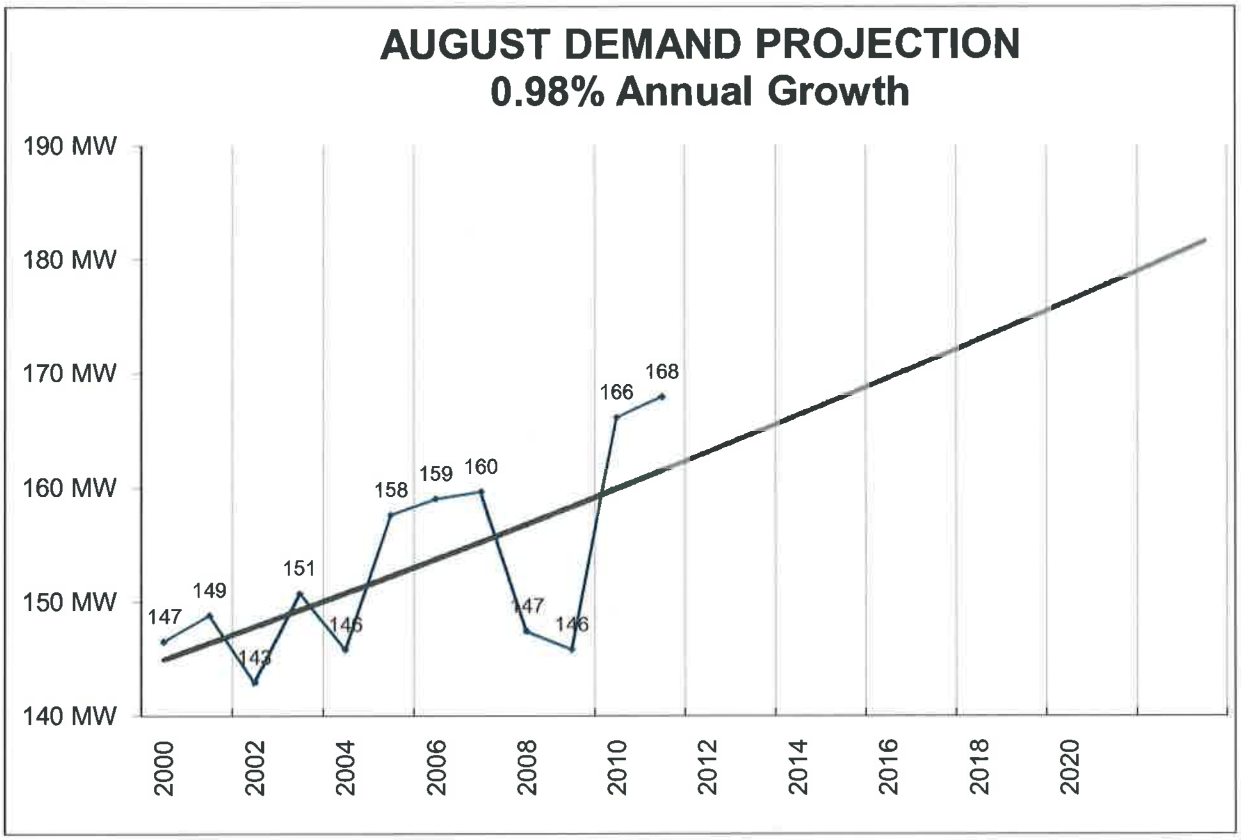
2012
2014
2016
2018
2020

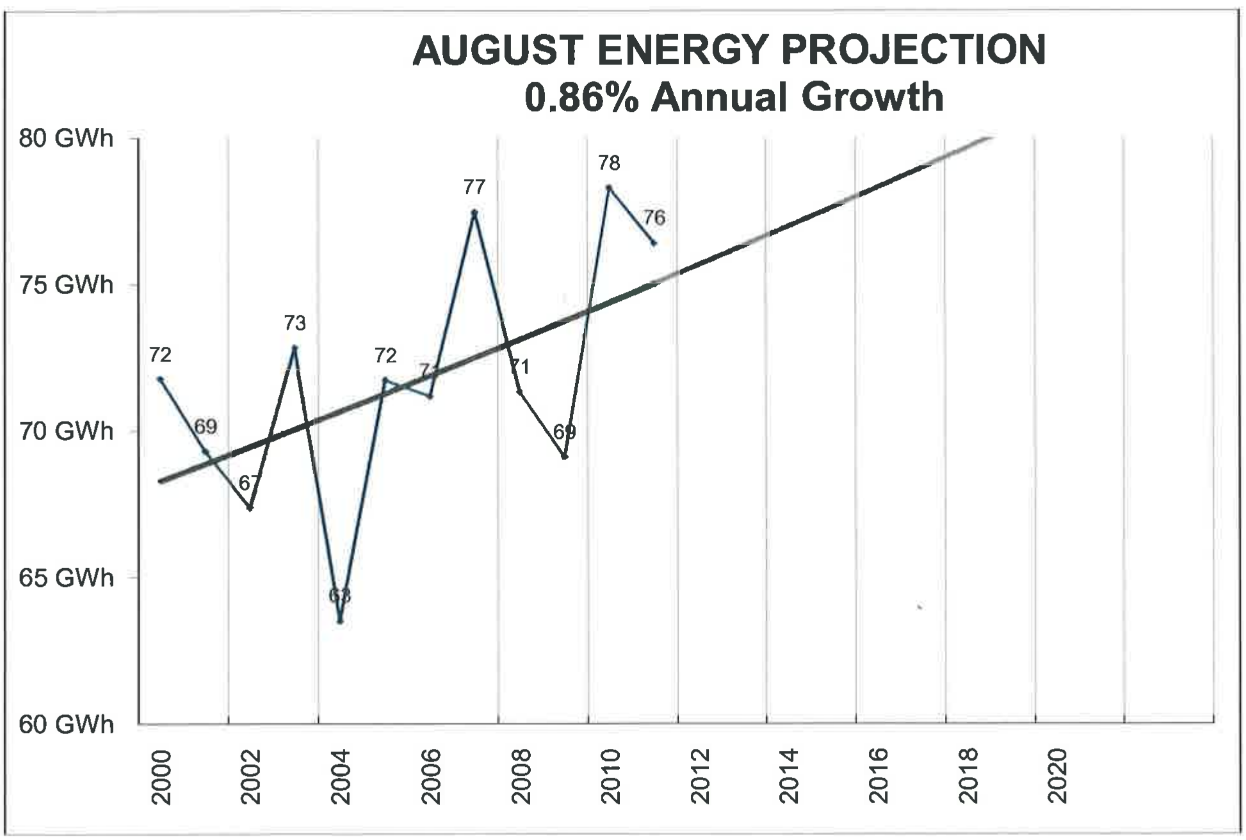

JUNE DEMAND PROJECTION
1.15% Annual Growth
180 MW
170 MW
160 MW
150 MW
140 MW
130 MW
120 MW
132
137
140
138
133
145
144
142
154
148
152
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020

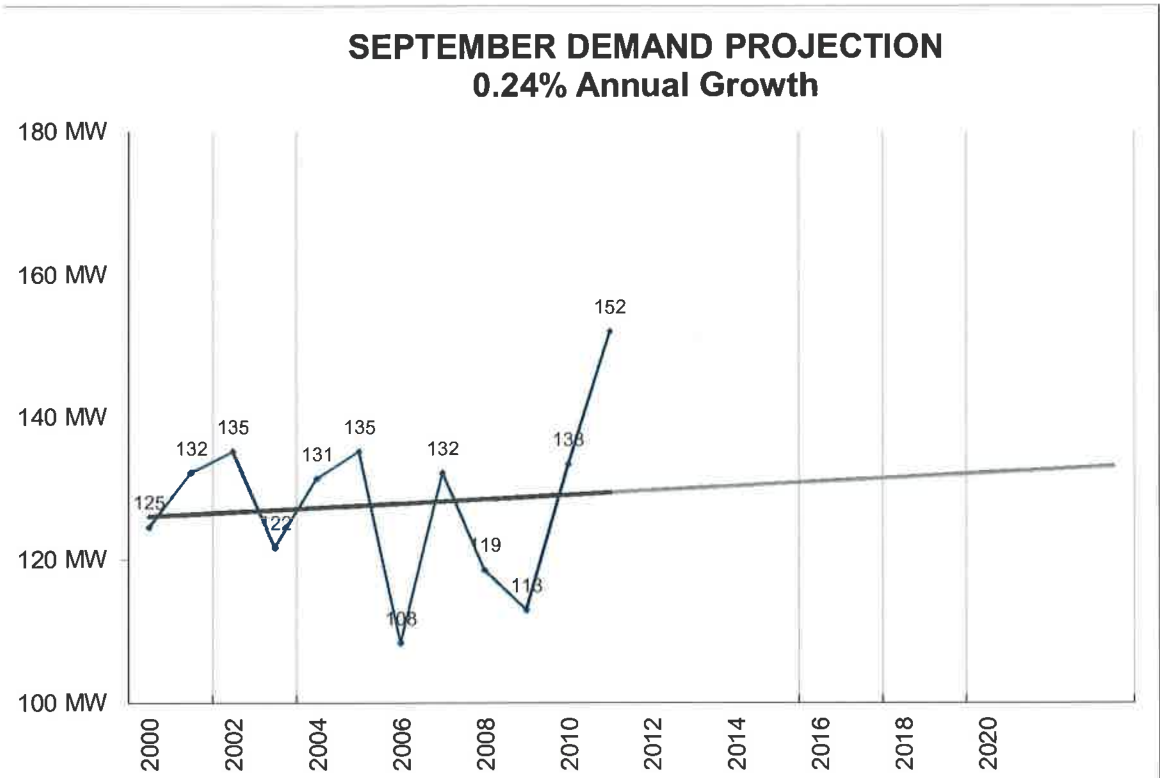

JUNE ENERGY PROJECTION
1.14% Annual Growth
80 GWh
75 GWh
70 GWh
65 GWh
60 GWh
55 GWh
50 GWh
58
59
65
57
58
66
67
64
65
63
67
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020

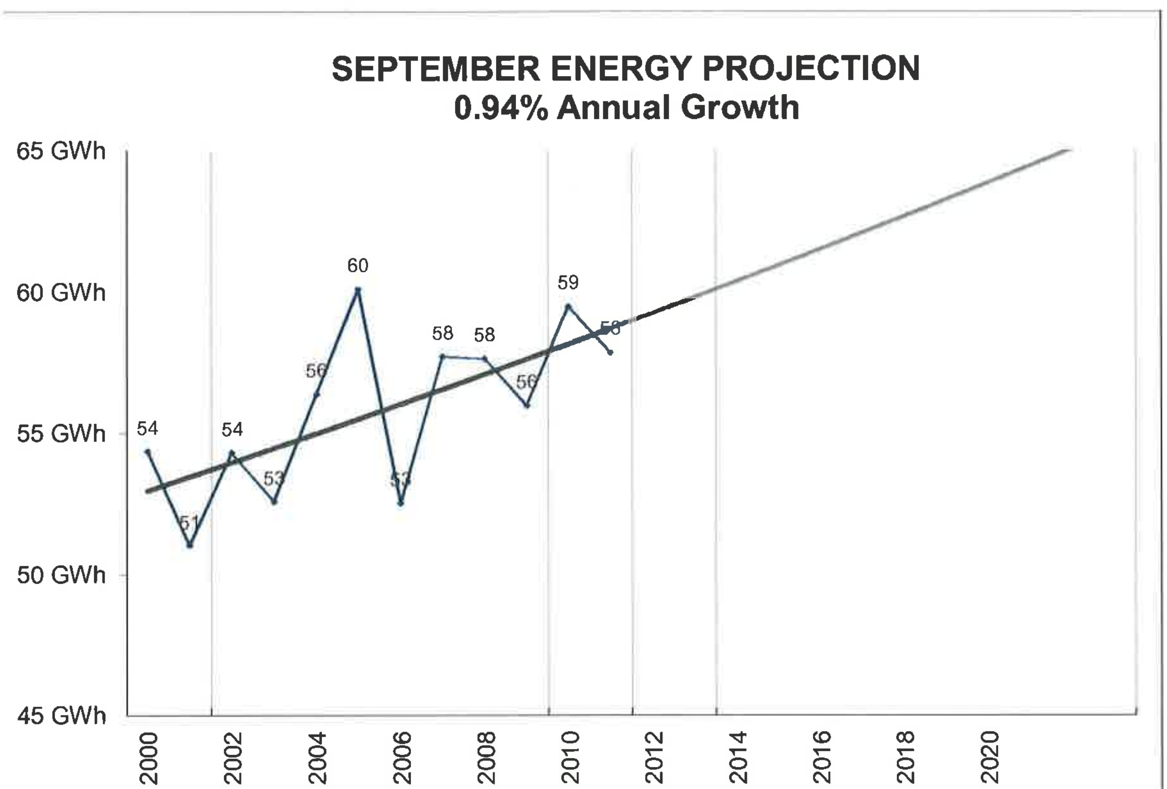

JULY DEMAND PROJECTION
0.62% Annual Growth
200 MW
190 MW
180 MW
170 MW
160 MW
150 MW
140 MW
145
148
152 152 152
158
164
155
152
150
154
166
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


JULY ENERGY PROJECTION
0.94% Annual Growth
90 GWh
85 GWh
80 GWh
75 GWh
70 GWh
65 GWh
60 GWh
67
72
76 76
65
76
78
76
77
71
77
81
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


AUGUST DEMAND PROJECTION
0.98% Annual Growth
190 MW
180 MW
170 MW
160 MW
150 MW
140 MW
147
149
143
151
146
158
159
160
147
146
166
168
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


AUGUST ENERGY PROJECTION
0.86% Annual Growth
80 GWh
75 GWh
70 GWh
65 GWh
60 GWh
72
69
67
73
63
72
71
77
71
69
78
76
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


SEPTEMBER DEMAND PROJECTION
0.24% Annual Growth
180 MW
160 MW
140 MW
120 MW
100 MW
125
132
135
122
131
135
108
132
119
113
133
152
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


SEPTEMBER ENERGY PROJECTION
0.94% Annual Growth
65 GWh
60 GWh
55 GWh
50 GWh
45 GWh
54
51
54
53
56
60
53
58
58
56
59
58
2000
2002
2004
2006
2008
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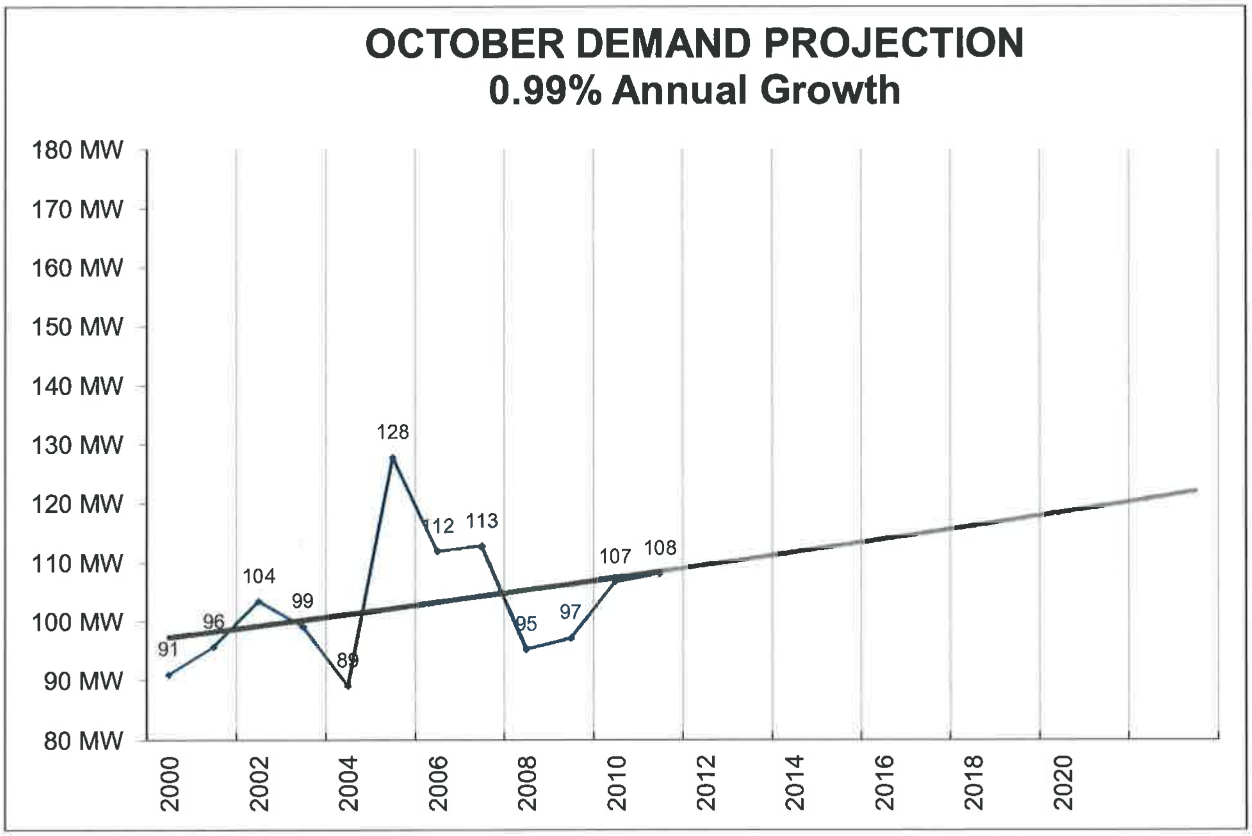
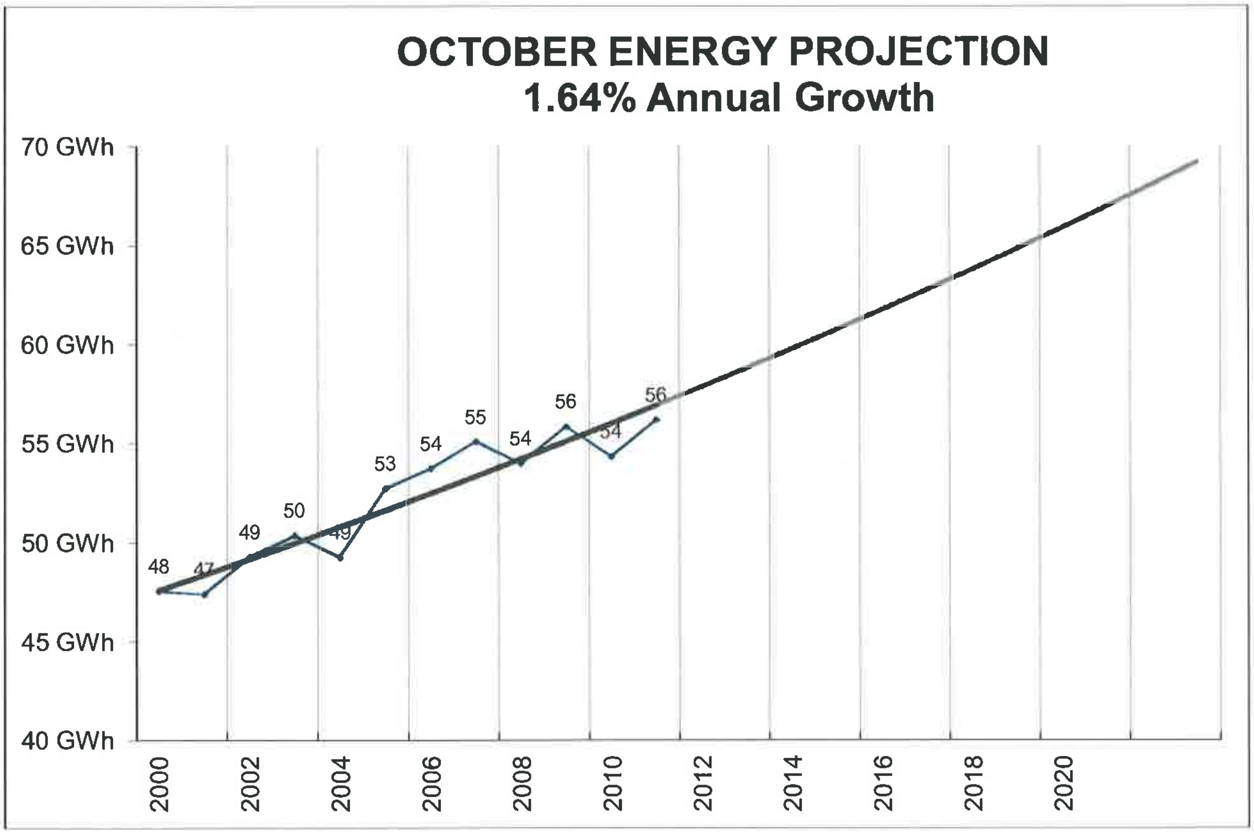
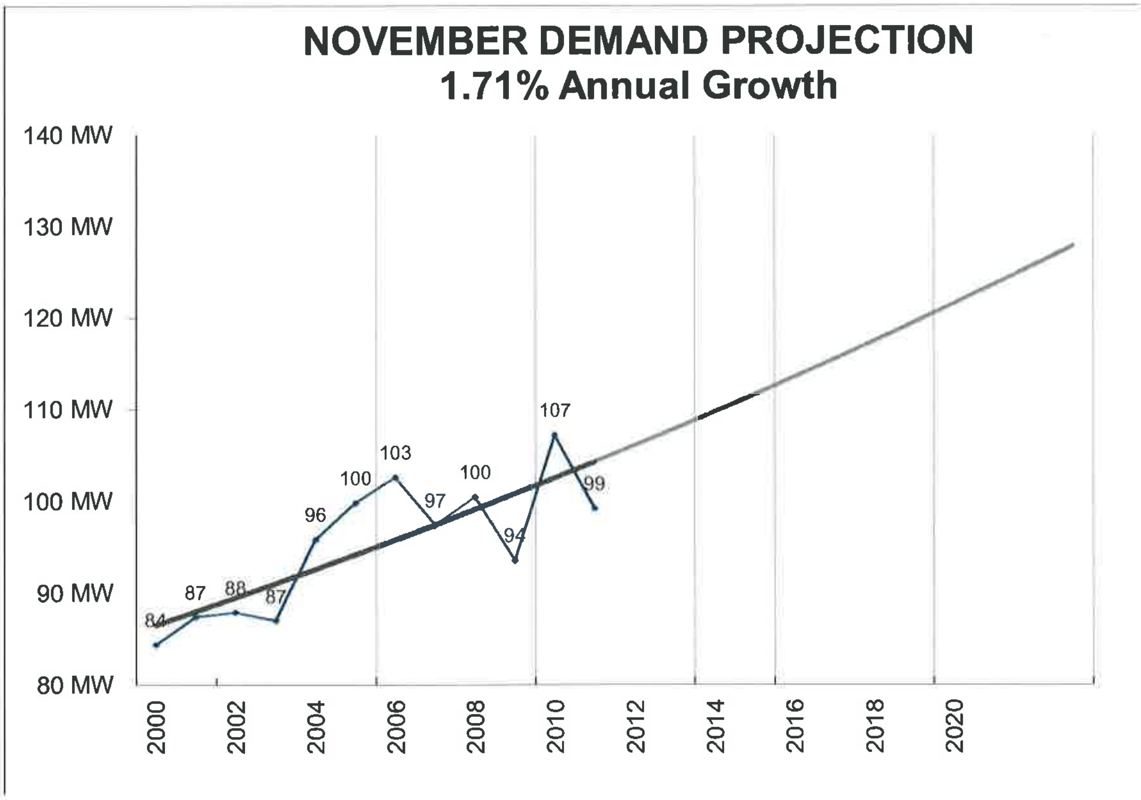
2012
2014
2016
2018
2020

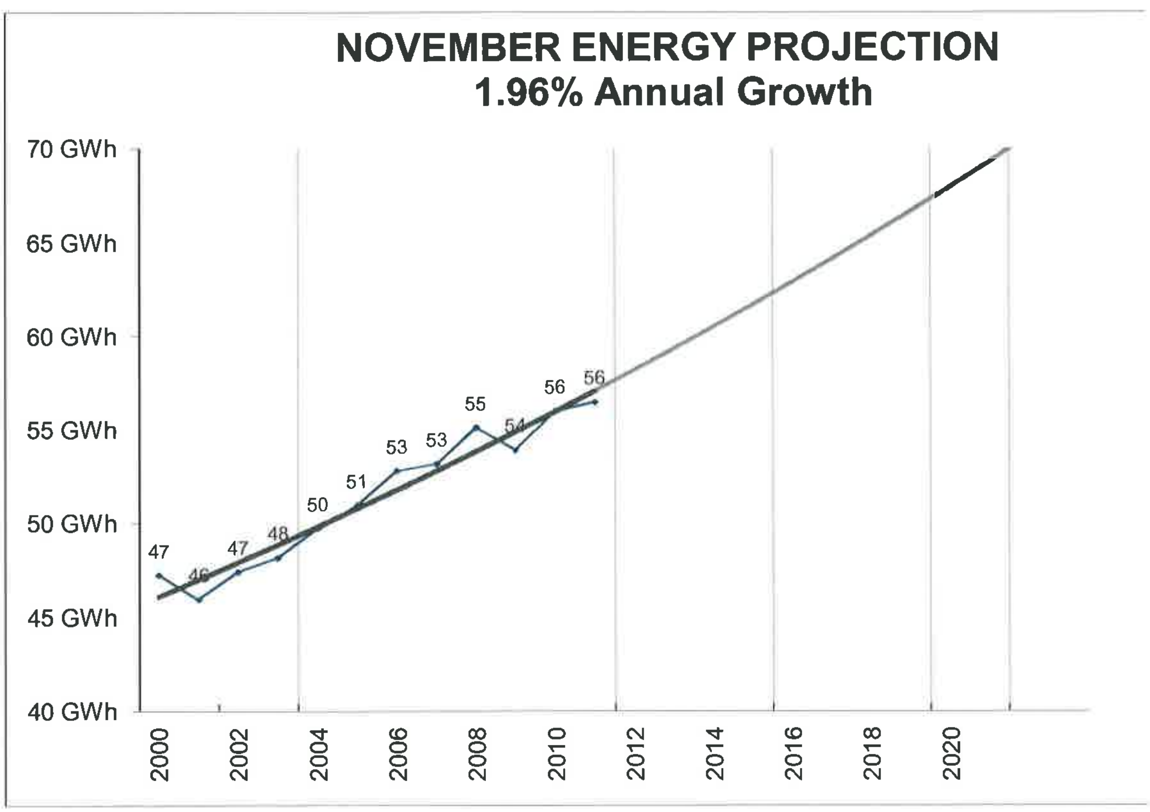


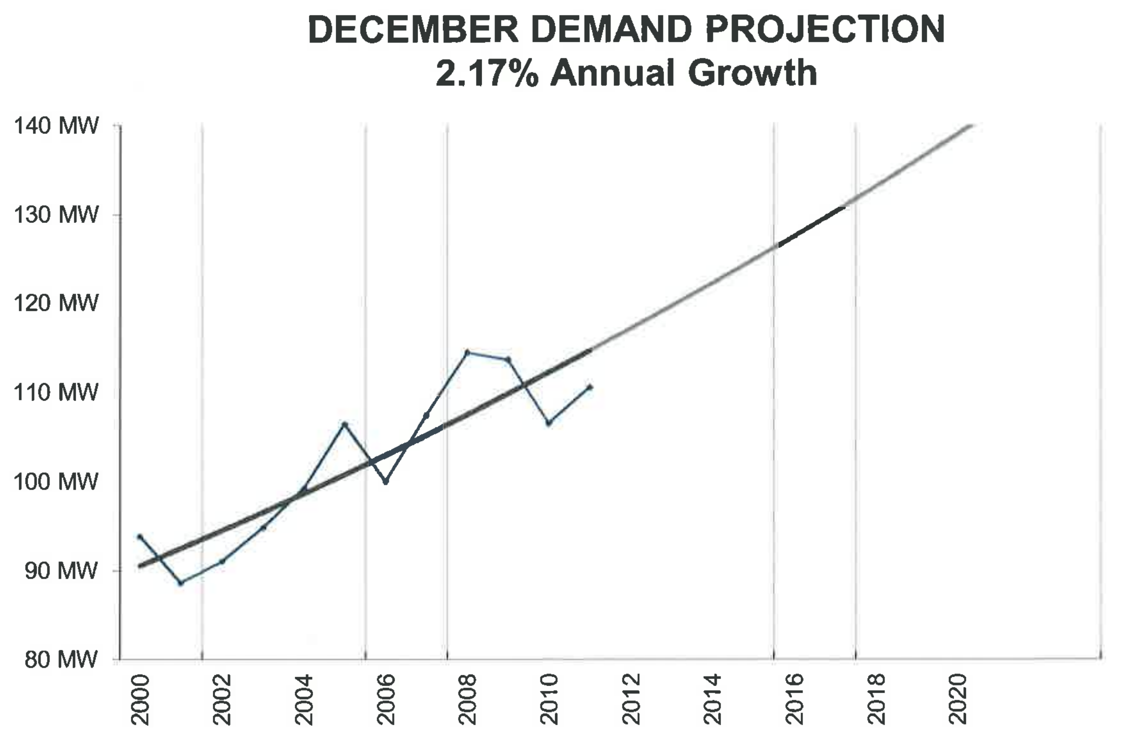
OCTOBER DEMAND PROJECTION
0.99% Annual Growth
180 MW
170 MW
160 MW
150 MW
140 MW
130 MW
120 MW
110 MW
100 MW
90 MW
80 MW
91
96
104
99
89
128
112
113
95
97
107
108
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020

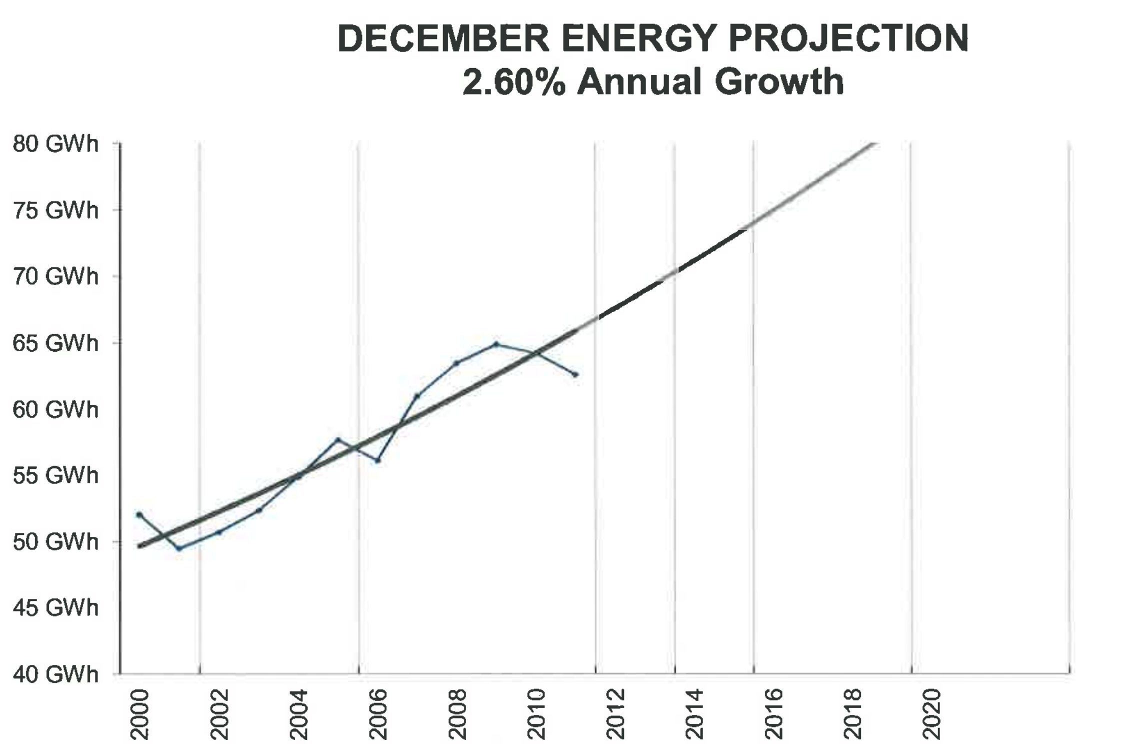


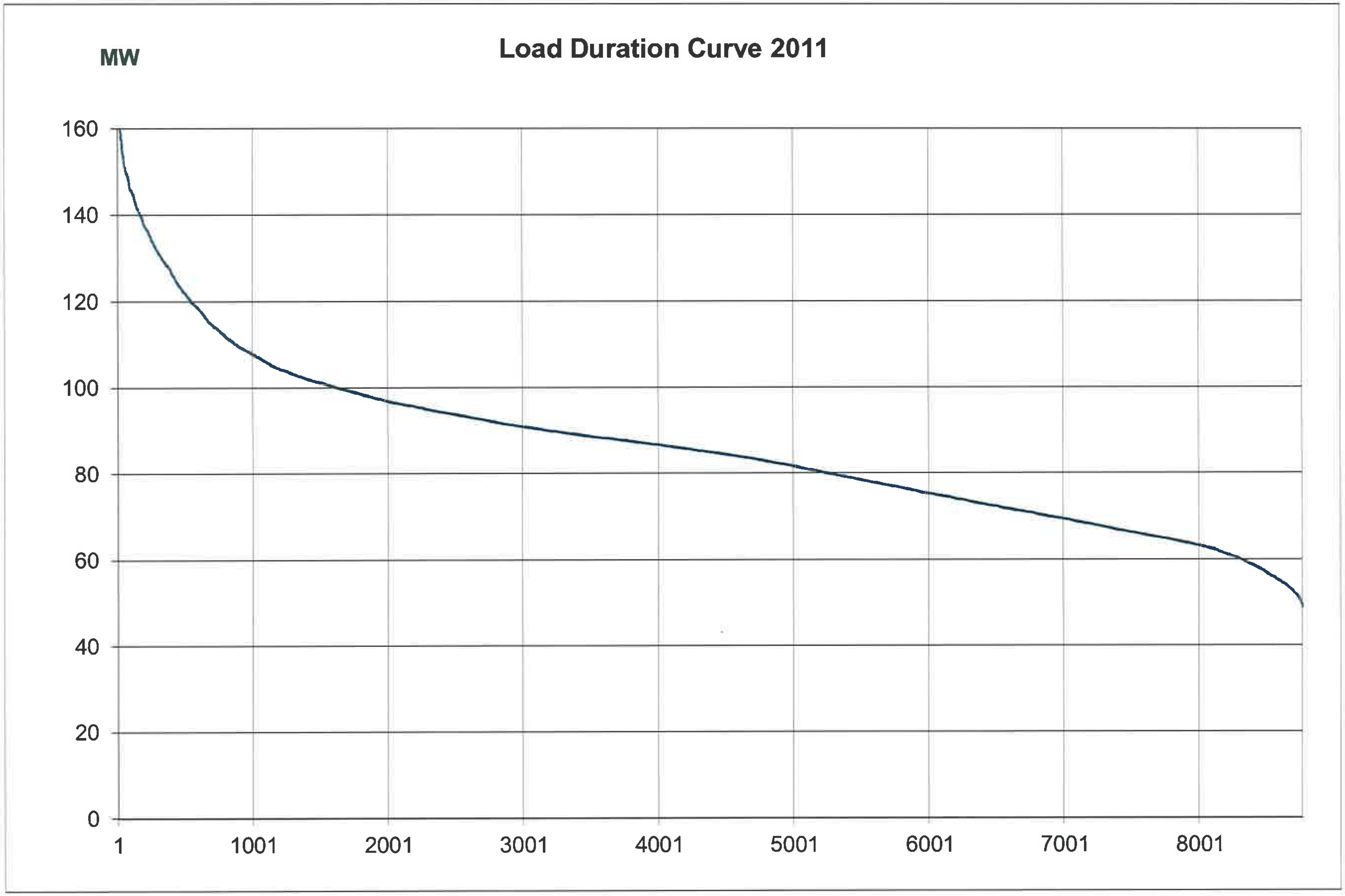
OCTOBER ENERGY PROJECTION
1.64% Annual Growth
70 GWh
65 GWh
60 GWh
55 GWh
50 GWh
45 GWh
40 GWh
48
47
49
50
49
53
54
55
54
56
54
56
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


NOVEMBER DEMAND PROJECTION
1.71% Annual Growth
140 MW
130 MW
120 MW
110 MW
100 MW
90 MW
80 MW
84
87
88
87
96
100
103
97
100
94
107
99
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


NOVEMBER ENERGY PROJECTION
1.96% Annual Growth
70 GWh
65 GWh
60 GWh
55 GWh
50 GWh
45 GWh
40 GWh
47
46
47
48
50
51
53
53
55
54
56
56
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


DECEMBER DEMAND PROJECTION
2.17% Annual Growth
140 MW
130 MW
120 MW
110 MW
100 MW
90 MW
80 MW
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


DECEMBER ENERGY PROJECTION
2.60% Annual Growth
80 GWh
75 GWh
70 GWh
65 GWh
60 GWh
55 GWh
50 GWh
45 GWh
40 GWh
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020


MW
Load Duration Curve 2011
160
140
120
100
80
60
40
20
0
1
1001
2001
3001
4001
5001
6001
7001
8001

APPENDIX "B"

Grand Island Electric Department Reliability Statistics

2011

SAIDI

The **System Average Interruption Duration Index (SAIDI)** is commonly used as a reliability indicator by electric power utilities. SAIDI is the average unscheduled outage duration for each customer served, and is calculated as:

$$\text{SAIDI} = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customers served}}$$

SAIDI is measured in units of time per customer. It is usually measured over the course of a year. According to 2003 EPRI report entitled "Distribution Reliability Indices Tracking Within the United States", the national ten year average between 1992 and 2001 was 107 minutes per customer per year, ***excluding*** major events.

The City of Grand Island has a SAIDI value of approximately 18.44 minutes per year per customer, including all events.

SAIFI

The System Average Interruption Frequency Index (SAIFI) is commonly used as a reliability indicator by electric power utilities. SAIFI is the average number of unscheduled interruptions that customers experience, and is calculated as:

$$\text{SAIFI} = \frac{\text{Total number of customer interruptions}}{\text{Total number of customers served}}$$

SAIFI is measured in units of interruptions per customer. It is usually measured over the course of a year. According to the 2003 EPRI report entitled "Distribution Reliability Indices Tracking Within the United States", the national ten year average between 1992 and 2001 was 1.1 interruptions per customer per year, ***excluding*** major events.

The City of Grand Island has a year to date SAIFI value of approximately 0.56 interruptions per customer per year, with no major event exclusions.

CAIDI

The Customer Average Interruption Duration Index (CAIDI) is commonly used as a reliability indicator by electric power utilities. CAIDI represents the average time required to restore service to the average customer per sustained interruption, and is calculated as:

$$\text{CAIDI} = \frac{\text{Sum of customer interruption durations}}{\text{Total number of customer interruptions}}$$

CAIDI is measured in units of time per customer. It is usually measured over the course of a year. According to the 2003 EPRI report entitled "Distribution Reliability Indices Tracking Within the United States", the national ten year average between 1992 and 2001 was 97.27 minutes per customer per year, ***excluding*** major events.

The City of Grand Island has a year to date CAIDI value of approximately 32.8 minutes per customer per year, with no major event exclusions.