Integrated Resource Plan

Five-Year Plan

(FY2013 to FY2017)

Prepared By:

Utah Municipal Power Agency

Approval Date: APRIL 24, 2013

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Executive Summary

This Integrated Resource Plan (IRP) was prepared by Utah Municipal Power Agency (UMPA or Agency) to guide the future in providing reliable and least-cost electricity to its member cities of Levan, Manti, Nephi, Provo, Salem and Spanish Fork. The IRP was prepared in accordance to the requirements of Western Area Power Administration (Western), an agency within the U.S. Department of Energy, and submitted as required by Energy Policy Act of 1992. The IRP is a tool for guiding the process in evaluating, investigating and making decisions regarding power supply resources and demand-side management programs according to the system requirements, economic viability, plant capability, and environmental sustainability.

The IRP examines four key elements:

> First, UMPA prepared a forecast of the energy and power requirements for the next twenty years. After examining the historical loads and considering the growth patterns of the member cities, UMPA estimates that energy and power requirements will continue to grow at 2.02% and 2.04%, respectively. In addition to the base growth scenario, further consideration was given to a low growth (1.64%) and a high growth (2.46%) projections for planning purposes as presented in the IRP. The forecast is critical in the defining any shortfalls in planning and delivering the energy needs of its member cities.
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> Second, with the forecast completed, UMPA performed an in depth examination into the operating performance and accessibility of both owned and contracted power supply resources. UMPA must ensure the availability and economic performance in the future. UMPA has 308 mw of capacity or 121% percent of the current requirements. There are two major power purchase contracts that expire in the coming years which accounted for 38% of the energy requirements last year. The PacifiCorp long-term contract with its flexible scheduling and 75 MW of capacity expires in June 30, 2017. The Deseret contract with its 80 MW of capacity and favorable pricing expires a few years later in December 31, 2019. The replacement of these supply-side resources along with the ongoing growth among the member cities requires a plan of action by UMPA. In the replacement of these expiring contracts and to meet future growth, UMPA needs a base load supply with immediate peaking capabilities. Coal is not an option. Renewable power supplies may have a role in supplementing the future growth of UMPA and portfolio goals as an intermittent energy resource. The initial assessment indicates that a combined cycle gas turbine (CCGT) may best meet the future power supply criteria. Based on this IRP assessment, UMPA is pursuing a strategy in developing a CCGT resource with a priority for ownership. Although not preferred, UMPA may consider a power purchase agreement with favorable terms and pricing.
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> Third, UMPA reviewed the current demand-side management (DSM) programs and the benefits implemented by the member cities. The assessment from the past five-years indicates UMPA exceeded its DSM goals. DSM plays a vital role by affecting the system growth in equal balance with supply-side requirements. After examining DSM options, UMPA is opting to develop and implement new DSM programs to be added to its current DSM portfolio. Many of the DSM programs are customer based and success is dependent

upon their participation through the member cities. UMPA will actively promote the DSM programs with the member cities and document the level of participation, successes, progress and achievements. As shown in this IRP, the new cumulative DSM goal for the coming five years is approximately 2,970,000 kwhs. As new DSM technology is created and become commercially available, UMPA is committed to implement viable DSM programs in accordance with the IRP criteria.

And Fourth, UMPA has prepared a plan of action as described within the IRP. The decision making process in securing supply-side power resources and implementing demand-side management programs are described within the IRP criteria. UMPA must replace existing supply power supply contracts that expire in the coming years, meet the new growth of the member cities and implement viable DSM programs. These actions are done with the support and approval of the UMPA governing board after involving a public process.

The IRP was prepared to meets the guidelines of Western, including public participation through a public comment period as part of the IRP final process. The draft of IRP was present to public for their review and they were invited to offer comments within a thirty (30) day public comment period. The public comments are found in Appendix F. After the public comment period, the UMPA Board of Directors reviewed the comments, considered appropriate changes, and approved the final IRP.

Purpose of the Integrated Resource Plan

Introduction

The Integrated Resource Plan (IRP) is a comprehensive decision tool and road map for Utah Municipal Power Agency's (UMPA or Agency) objective of providing reliable and least-cost electric service to all of the member cities while addressing risks and uncertainties that are inherent in the electric industry. The member cities are Levan, Manti, Nephi, Provo, Salem and Spanish Fork. The IRP will evaluate demand and supply-side resource options and the relevant economic factors to determine the best fit for future energy goals.

The four key elements of this IRP include:

- The forecast of resource needs;
- The supply-side options;
- The demand-side options; and
- The action plan with specific steps and timeframe.

This IRP is a guiding document to encompass four primary goals:

1. Identify sufficient resources to reliably serve the growing demands of the member cities for the next 5 to 20 year planning period.
2. Ensure the selected resource portfolio balances costs, risk, reliability and environmental concerns.
3. Give equal treatment to supply-side resources and demand-side measures.
4. Involve the board, the member cities and the public in planning and setting the future energy policy.

The actions taken by UMPA in accordance with the IRP will determine the diversity of energy resources to meet the obligations to the member cities. The IRP becomes a viable tool for both long-term and short-term planning. In the short-term, it provides monitoring and evaluation methods for the cost effectiveness of programs and resources. In the long-term, it forces the in-depth look and study of the resources and programs to meet the obligations of the Agency. It puts planning into a living document that is reviewed and updated to reflect the changes in the energy surroundings.

UMPA's member cities have enjoyed low electric rates because of the Federal hydroelectric and coal resources developed throughout most of the last century. However, opportunities to develop new large hydroelectric projects no longer exist, and climate change concerns make it impractical to develop new coal resources. The resources available today that meets future customer demand, focuses primarily on natural gas resources for the base load needs, and where feasible, adding renewable resources such as wind and solar technologies.

As UMPA adds new resources to meet growing customer demand, costs are going to increase; either from participation in new generation construction, or power purchase contracts using natural gas resources. Through the integrated resource planning process, UMPA is responsibly planning the addition of new resources to minimize the cost impact to customers.

UMPA's Mission Statement

UMPA, a separate political subdivision of the State of Utah, was established in 1980 for the purpose of developing a reliable and economic power supply program to meet the "all-requirement-obligation" of electric power and energy needs of its member municipalities in Utah. UMPA is a joint action agency whose services include power supply and control area support, scheduling, joint financing, energy load forecasting, wheeling arrangements, limited political action, demand-side management, engineering, legal assistance and Federal Energy Regulatory Commission (FERC) case support.

The Agency is governed by a six (6) member Board of Directors, consisting of the Mayors, Council Members, and/or appointed city representatives from each member city. In addition, an advisory Technical Committee with an appointee from each of the member cities, usually the city's electric utility manager, provides in depth technical studies, recommendations and detailed analysis to assist the Board of Directors.

UMPA's long standing goals are to; (1) develop a reliable and economical power supply program to meet the electrical power and energy needs as required by the members and their customers; (2) provide the benefits of economies of scale through joint endeavors relating to generation, transmission and distribution of electric power and energy; and (3) involve each member in the planning, operation and developing stages it undertakes.

UMPA's History and IRP

UMPA was created pursuant to the Interlocal Co-operation Act, Title 11, Chapter 13, Utah Code Annotated 1953. UMPA was established on September 18, 1980, for the purpose of developing a reliable and economical power supply program to meet the electric power and energy needs of its member municipalities by acquiring, constructing, operating, maintaining, repairing, and administering power resources.

UMPA conducted reconnaissance power supply investigations in 1981 and prepared and adopted a plan of development and obtained a $6 million loan for the Agency's development activities in 1982. These activities included acquiring water rights for a steam generation unit then under consideration and initiating engineering feasibility studies, legal investigations and power pooling operations. Power supply screening studies, econometric load forecasts and a refined plan of development were accomplished in 1983. Pooling of existing member resources commenced in 1984. In November of 1985, UMPA developed into an All Requirements Supplier for its member cities pursuant with the acquisition of the Bonanza project.

The Agency is governed by a Board of Directors represented by one director/representative from each member city. Each Director has one vote and decisions of the Board are made by majority vote with public input. This governing body is assisted by UMPA's General Manager and staff, and UMPA's Technical Committee. The technical committee was organized to be an advisory body to the Board of Directors.

As a purchaser of power from the Western Area Power Administration (Western), a Federal agency within the U.S. Department of Energy, UMPA is required to submit an IRP to Western under a provision of the Energy Policy Act of 1992. The Agency has had a least-cost plan since

1983, and is currently submitting this IRP for approval by Board of Director who regulates the actions and decision of UMPA in evaluating and obtaining all available supply-side and demand-side options.

The purpose of the IRP is to help UMPA identify which resources to acquire, what amounts of resources to acquire, when to acquire them, and to acquire them at the lowest cost consistent with the guidelines the Agency has established relative to reliability, flexibility, economics, and other significant determinants discussed in the executive summary of this report. The initial IRP process included:

1. Examination of the power and energy requirements for the future.

2. Opened and balanced consideration of a wide variety of supply-side and demand-side options within the existing resource mix.

3. Consideration of environmental impacts of providing energy services.

4. Involvement with the public and stakeholders through the member cities with the invitation to review and comment on the IRP, and its applicable criteria for supply resources and demand-side programs.

Review of UMPA Goals, Strategies and Objectives
The goals of UMPA are to:

1. Develop a reliable and economical power supply program to meet the electric power and energy needs as required by the members and their customers.

2. Provide the benefits of economies of scale through joint endeavors relating to generation, transmission, and distribution of electric power and energy.

3. Involve each member in the planning, operating, and developing stages it undertakes.

In order to reach these goals, several objectives and strategies must be properly accomplished.

a. UMPA must maintain an updated short-term and long-term load forecast and must monitor its load and load shape to assure that the basis for resource selection is well-grounded in terms of peaking, intermediate and base resource needs.

b. The performance of existing resources that provide the framework within which a new resource is introduced must be monitored and optimized to deliver the full amount of power intended by economic dispatch procedures. This will assure the new resource will occupy a position appropriate to its characteristics which formed a major portion of the basis for its selection.

c. UMPA must continue to analyze potential demand-side and supply-side resources to determine that attractive options are fully considered as the IRP evolves in a dynamic process designed to continually enhance the economics, reliability and appropriateness of UMPA's resource mix. UMPA plans to provide a forum in its meetings where public participation plays a role in determining the preferred and economical resource.

d. The uncertainty in any scheme impacts UMPA load and resource plan as well. Therefore, an appropriate level of redundancy, or flexibility, should ideally be present among our resources so that a failure in one resource can be supported by increased performance from another. Conversely, loss of load can be addressed by the absence of a minimum requirement provision with our resources. For shorter term impacts, UMPA can rely on the availability of internal or contracted resources, spinning reserves, or the open market for energy.

e. If the economics can be justified, UMPA must continue to consider environmental impacts with carbon-free, less regulated, cleaner energy resources, as a priority. In FY2012, thirty-five percent (35%) of the Agency's supply-side resources came from renewable resources, primarily from the hydroelectric generation from Western. UMPA is keenly aware of the need and related expenses for clean air and water, and protecting sensitive surroundings, and has as a goal to be a minimal contributor to environmental degradation.

The types of demand-side programs depend on how much electricity the customers use and when they use it. UMPA’s criteria for evaluation of demand-side options include the following attributes:

- Ease of Implementation
- Customer preference
- Costs
- Environmental impact
- Market potential and penetration ability
- Record keeping and documentation
- Reliability, durability and commercial availability
- Capacity shaving and energy efficiency
- Credible operating statistics and measureable results
- Balance of load and resource integration

If a demand-side program scores well against the criteria listed above, and is recommended by the Technical Committee, then the program is evaluated by the staff in more detail. The priority in implementing any program is determined by the least-cost and greatest benefit.

The criteria used for the supply-side options are similar to the criteria used in the demand-side evaluation. UMPA’s criteria for the supply-side options include the following elements:

- Reliability
- Location
- Costs

- Diversity
- Dispatchability
- Capacity and energy capabilities
- Durability
- Credibility of developer, contractor and operator, and their statistics and references
- Ability to meet the demand, follow the load and timely shape according to need
- Other risk factors

If the supply-side or demand-side options meet the respective criteria listed above, then UMPA will evaluate the project/program on the second level which includes:

- Economic considerations
- Environmental considerations
- Governance and control considerations

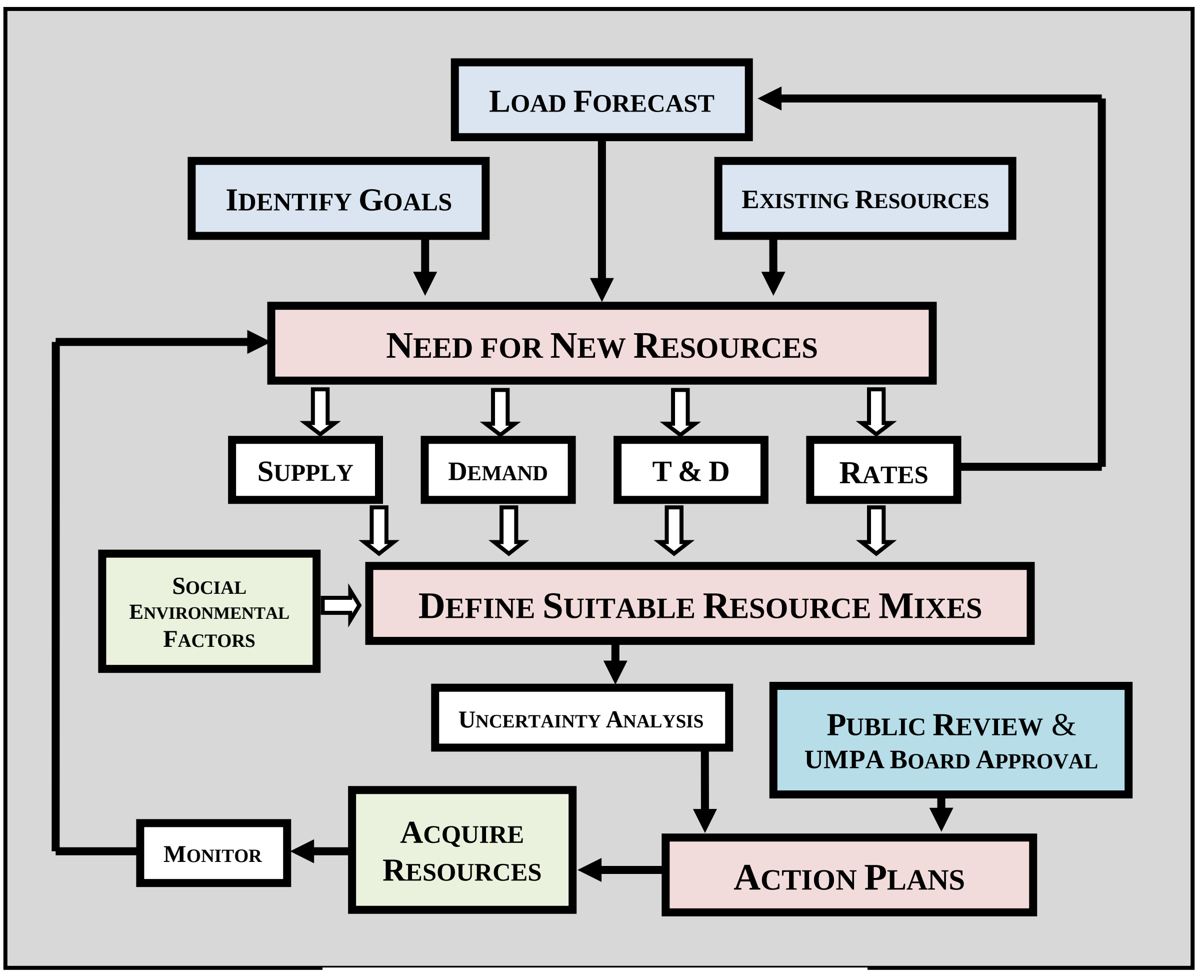
The intent of this IRP is to be a guide for evaluating, studying and making power supply decisions according to the system requirements, economic viability, unit availability and environmental sustainability. If the assumptions and inputs of the IRP are set up incorrectly; it will likely produce erroneous and inaccurate results.

IRP Process

Description

The steps in preparing and updating the IRP are similar to any long-term planning strategy. The initial step begins with identifying member cities' energy and power requirements in the future. In general, history is a good predictor of the future. Historical load patterns of monthly, weekly and daily energy usage are studied and analyzed to determine predictors for the future. In addition to using the system history to forecast the future, other factors, such as specific load points being considered for future developments and member cities' general plan information, are considered in the study.

The flowchart below describes the typical IRP process and key steps in making critical decisions for supply and demand resources. UMPA is governed solely by a Board of Directors that regulates and approves the course of action for the Agency. The Board of Director meetings are open to the public, and are noticed and advertised in accordance with State law. UMPA is not subject to the jurisdiction and oversight of the Utah Public Service Commission.



FLOWCHART OF THE IRP PROCESS

There are common risks throughout the process that are examined and addressed by offering multiple scenarios after analyzing the sensitivity of the variables in preparing IRPs. Those variables which are examined in greater detail in the report include fuel prices (coal, diesel, and natural gas), load growth, electricity spot prices, operation limits, availability, market structure, environmental regulations, transmission constraints, political objectives, compliance mandates, and timing.

The future load requirements of UMPA are studied and analyzed with the first consideration given to the current power resource portfolio and their operating attributes for the purpose of determining if there are any deficits or shortfall. Any shortfall requires action by UMPA to add power resources and/or implement demand-side management activities to meet the energy requirements and maintain system reliability.

Adoption and Approval

The IRP process was reviewed by UMPA Board of Directors. Upon completion of the document "Draft IRP", then the proposed Draft IRP was presented to the public for their review and invited to submit comments during the thirty (30) day comment period. After the public comment period, the staff compiled the public comments and offer recommendations to the UMPA Board in Appendix F. The Board may elect to modify and change the IRP to reflect information and comments offered by the public, or it may choose not to make changes. In the end, the UMPA Board will have final approval of the IRP by resolution.

Over the past several months, public meetings between the staff, Technical Committee and the Board of Directors have provided a transparent process in the development of this IRP, with a comprehensive approach to the study of both supply-side and demand-side options. The review process took place in public meetings and involved the staff and management of the Agency, and also member cities' staff.

In summary, the public process for finalizing the IRP in preparation for submission to Western, comprised of (1) several public meetings with UMPA's Technical Committee and Board of Directors, (2) the posting of the IRP on UMPA's website for public input and review, (3) an invitation to the member cities to review the IRP with their constituents and interested parties, and (4) the final approval by the Board at a public hearing. Public input is important to UMPA by offering several opportunities for the public and interested parties to participate and comment on the IRP.

Electric System Load Forecast

Introduction

UMPA is obligated to serve the electrical growth of its member cities under all conditions including severe cold in the winter months and extreme heat during the summer. The timing of adding new supply resources depends on the rate of growth, and required operating reserves and targeted surpluses for adequate coverage. For the purpose of the IRP analysis, there is an assumption of no new conservation programs to equally evaluate the benefits of supply-side resources and demand-side programs.

UMPA has a long history in projecting and evaluating its actual power and energy loads on a regular basis. First, UMPA prepares its system load forecast by analyzing historical loads from its member cities. Second, UMPA reviews the forecast methodologies and key assumptions used in developing the original load forecast study. It determines through statistical testing and investigations whether the methodologies and assumptions previously used are currently relevant. Forecast updates are prepared of UMPA's demand and energy requirements using monthly data with cross checking for reasonable load factors. And third, UMPA considers any new known point-loads resulting from projects under construction, or any planned development of large electric users. In consultation with its member cities, UMPA reviews the planning, timing, and probability in factoring any new point-loads into the final forecasts.

To accomplish this purpose, annual forecasts of peak demand and energy requirements for the next twenty (20) year period were developed for each of the six member cities within UMPA. The forecast and graphs for each city is shown in Appendix A, Member City Information. The combination of these projections and results are presented herein for the Agency as a whole. These annual forecasts are represented by the 12 month period beginning July 1st and ending June 30th. Based on historical monthly load patterns, the annual forecasts were converted to monthly forecasts for planning purposes.

Forecast Methodologies and Key Assumptions

In developing the annual forecasts for the member cities, several forecasting methodologies were used and a number of assumptions were made. The annual forecasts were developed by projecting total annual energy requirements by either trending techniques, or econometric modeling. Annual load factors were projected based on history, any new known large point-loads, and anticipated system maintenance. Annual peak demands were calculated using the annual energy requirements and load factor projections.

In general, the forecast methodologies used prior to presenting this report, considered historical growth patterns, service area demographics, and service area economics. As a result, the annual forecasts reflect growth that is similar to that experienced historically. The forecasts also show what is anticipated to occur with the demographics and economies of the members' service areas.

The forecasts developed annually reflect normal weather and the projection of electricity consumption for existing large commercial/industrial customers. The forecasts do isolate very large customers (Owens-Corning, BYU, etc.) on the member systems and examines their usage and contribution to growth independent of the normal system growth. In this manner, relevant operating factors unique to the major customers will not be impacted by the system growth factor.

This base growth forecast does not include any new or unusual, large load additions except known point-loads under construction, or highly probable to be constructed. Any new and significant large loads, or so called point-loads, would be evaluated and considered independently of the planning in this study. UMPA wants to encourage the development of economic growth by its member cities, and yet note that new and significantly-sized electrical users may have a negative financial impact to UMPA if not properly anticipated and impact mitigated.

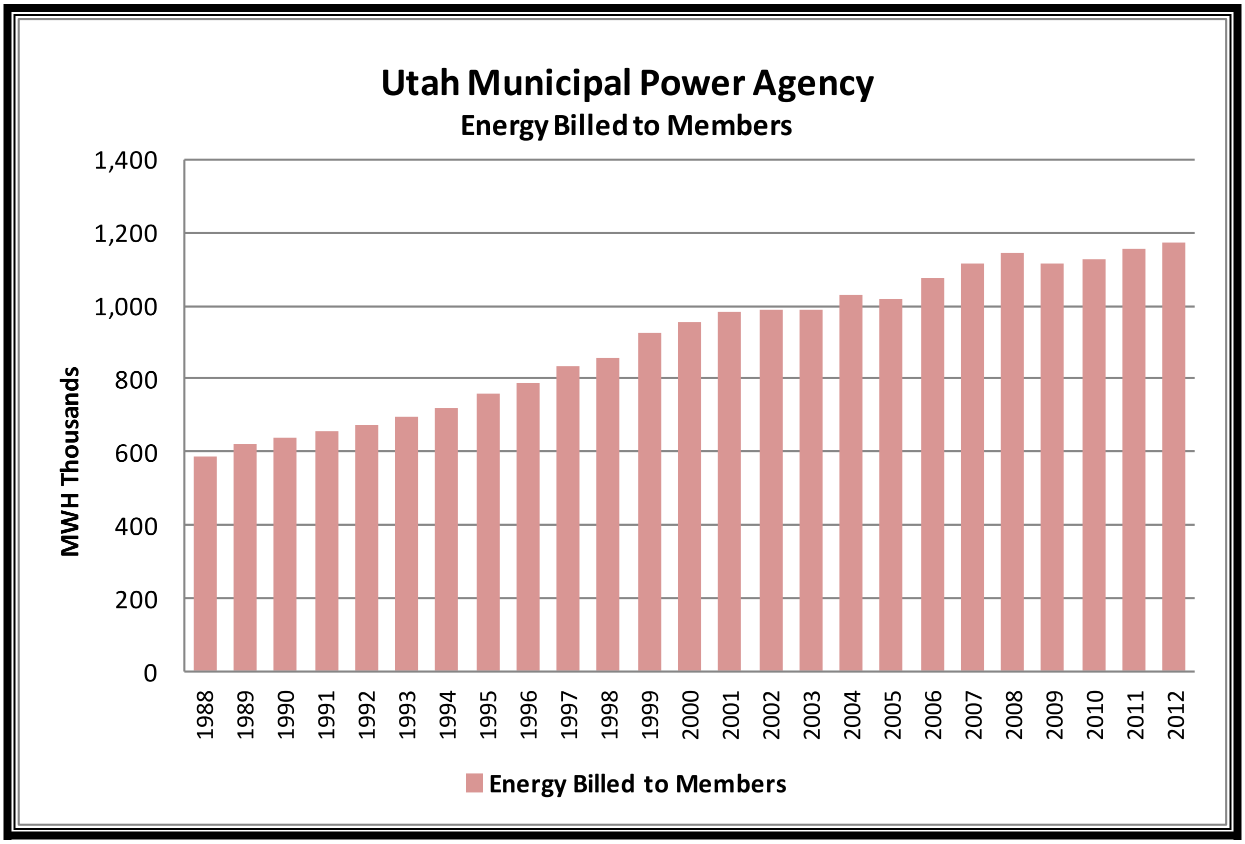
Summary

The projections for the next twenty year period from FY2013 to FY2033 were compared to actual member data over the past 25 years. It was determined that some of member cities' growth should continue to be forecasted using linear and/or logarithmic regression techniques while reflecting recent growth trends.

The following table shows the composite historical fiscal year peak demand and energy requirements for UMPA. From FY1988 to FY2012, UMPA load has experienced growth in energy requirements and peak demand at average annual compound growth rates of 2.91% and 3.78%, respectively.

	Historical Non-Coincidental Load Growth Fiscal Years 1988-2012			
Year	Annual Peak (MW)	% Growth	Energy Requirements (MWH)	% Growth
1988	104.628	-	588,270.227	
1989	112.903	7.91%	621,315.560	5.62%
1990	124.746	10.49%	636,588.517	2.46%
1991	125.979	0.99%	656,360.011	3.11%
1992	127.665	1.34%	672,154.680	2.41%
1993	134.396	5.27%	695,422.621	3.46%
1994	142.386	5.95%	717,998.175	3.25%
1995	147.189	3.37%	757,888.076	5.56%
1996	148.945	1.19%	791,108.207	4.38%
1997	159.732	7.24%	832,771.898	5.27%
1998	168.163	5.28%	858,979.090	3.15%
1999	182.572	8.57%	924,695.535	7.65%
2000	183.861	0.71%	952,323.518	2.99%
2001	203.968	10.94%	986,321.523	3.57%
2002	203.854	-0.06%	991,633.716	0.54%
2003	212.118	4.05%	987,844.631	-0.38%
2004	224.805	5.98%	1,027,698.249	4.03%
2005	217.583	-3.21%	1,019,957.240	-0.75%
2006	231.884	6.57%	1,073,122.597	5.21%
2007	241.418	4.11%	1,117,062.852	4.09%
2008	252.771	4.70%	1,144,740.437	2.48%
2009	243.434	-3.69%	1,114,706.234	-2.62%
2010	241.680	-0.72%	1,125,612.319	0.98%
2011	250.896	3.81%	1,155,514.483	2.66%
2012	254.843	1.57%	1,170,595.819	1.31%
Compounded Rate		3.78%		2.91%

The following is graph of the historical energy loads for UMPA based on the energy requirements billed to the member cities:



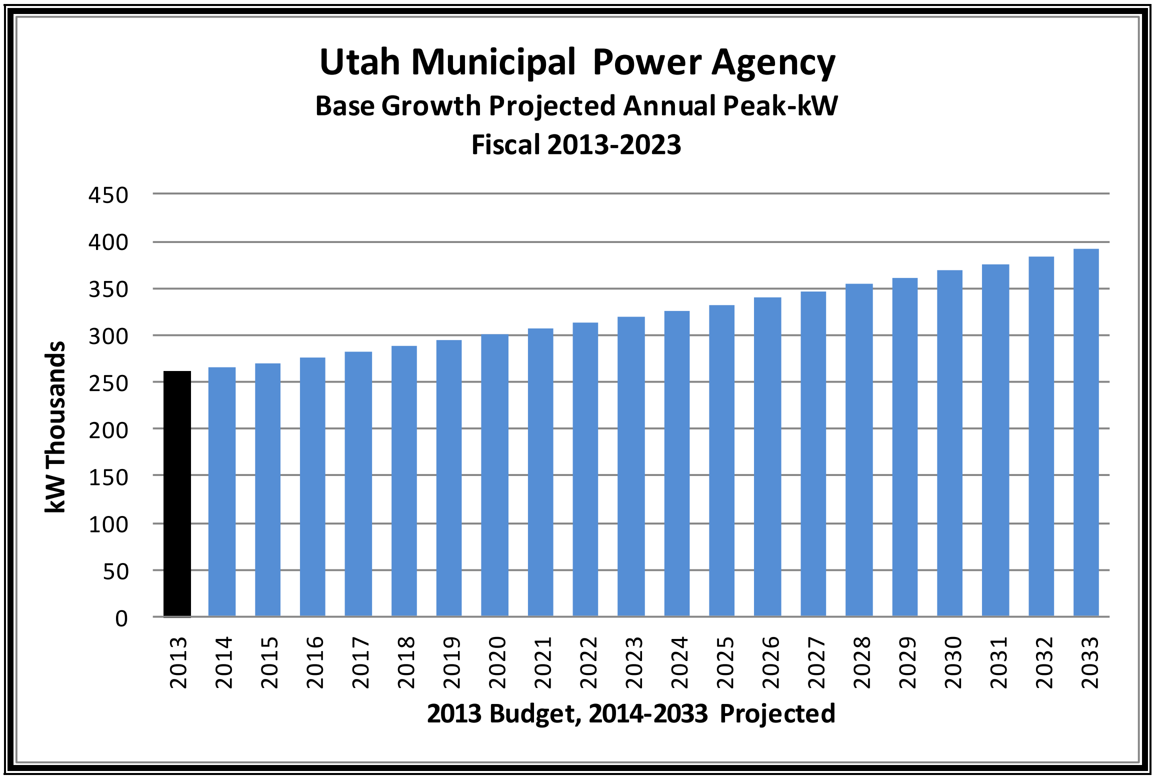
<u>20-Year Electric System Load Forecast</u>
Using the methods described, UMPA forecasts the "base-growth scenario" for peak demand and energy requirements to increase at an average annual compound growth rate of 2.04% for demand, and 2.02% for energy, throughout fiscal years 2013 to 2033 as shown on the following table:

UMPA 20 Year Load Forecast				
Year	Annual Peak kW	% Growth	Energy Requirement (MWh)	% Growth
2013	261,113		1,188,444,331	
2014	265,400	1.64%	1,207,428,447	1.60%
2015	270,879	2.06%	1,231,740,325	2.01%
2016	276,481	2.07%	1,256,586,952	2.02%
2017	282,207	2.07%	1,281,980,775	2.02%
2018	288,061	2.07%	1,307,934,546	2.02%
2019	294,046	2.08%	1,334,461,333	2.03%
2020	300,165	2.08%	1,361,574,524	2.03%
2021	306,421	2.08%	1,389,287,839	2.04%
2022	312,818	2.09%	1,417,615,336	2.04%
2023	319,359	2.09%	1,446,571,422	2.04%
2024	326,046	2.09%	1,476,170,860	2.05%
2025	332,794	2.07%	1,506,375,955	2.05%
2026	339,681	2.07%	1,537,199,101	2.05%
2027	346,710	2.07%	1,568,652,943	2.05%
2028	353,885	2.07%	1,600,750,388	2.05%
2029	361,208	2.07%	1,633,504,603	2.05%
2030	368,683	2.07%	1,666,929,028	2.05%
2031	376,313	2.07%	1,701,037,377	2.05%
2032	384,101	2.07%	1,735,843,643	2.05%
2033	392,049	2.07%	1,771,362,108	2.05%

Peak Demand	
5 Year Compound Growth Rate:	1.96%
10 Year Compound Growth Rate:	2.01%
20 Year Compound Growth Rate:	2.04%

Energy Requirements	
5 Year Compound Growth Rate:	1.93%
10 Year Compound Growth Rate:	1.98%
20 Year Compound Growth Rate:	2.02%

Applying the assumption in forecasting collected from the member cities; the following three graphs show the forecasted power and energy requirements for UMPA using the base-growth scenario:


Utah Municipal Power Agency
Base Growth Projected Annual Peak-kW
Fiscal 2013-2023
kW Thousands
0
50
100
150
200
250
300
350
400
450
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
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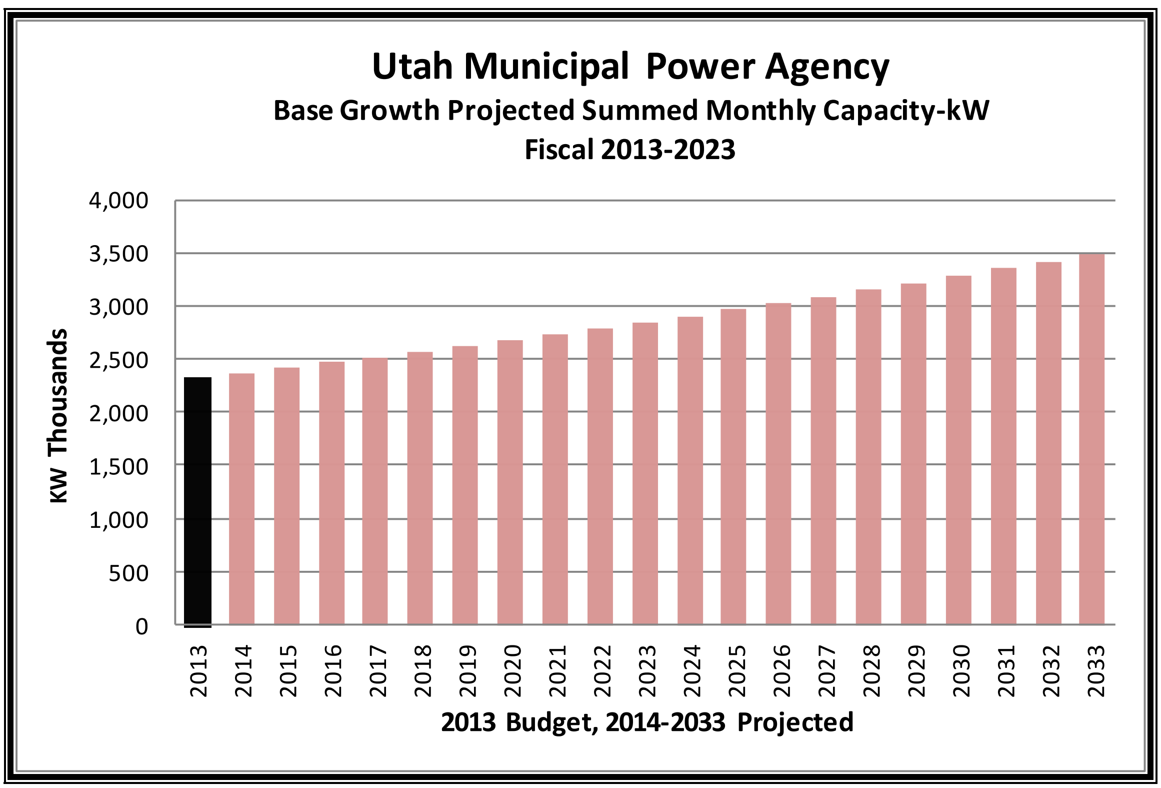
2031
2032
2033
2013 Budget, 2014-2033 Projected


Utah Municipal Power Agency
Base Growth Projected Summed Monthly Capacity-kW
Fiscal 2013-2023
KW Thousands
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
2013
2014
2015
2016
2017
2018
2019
2020
2021
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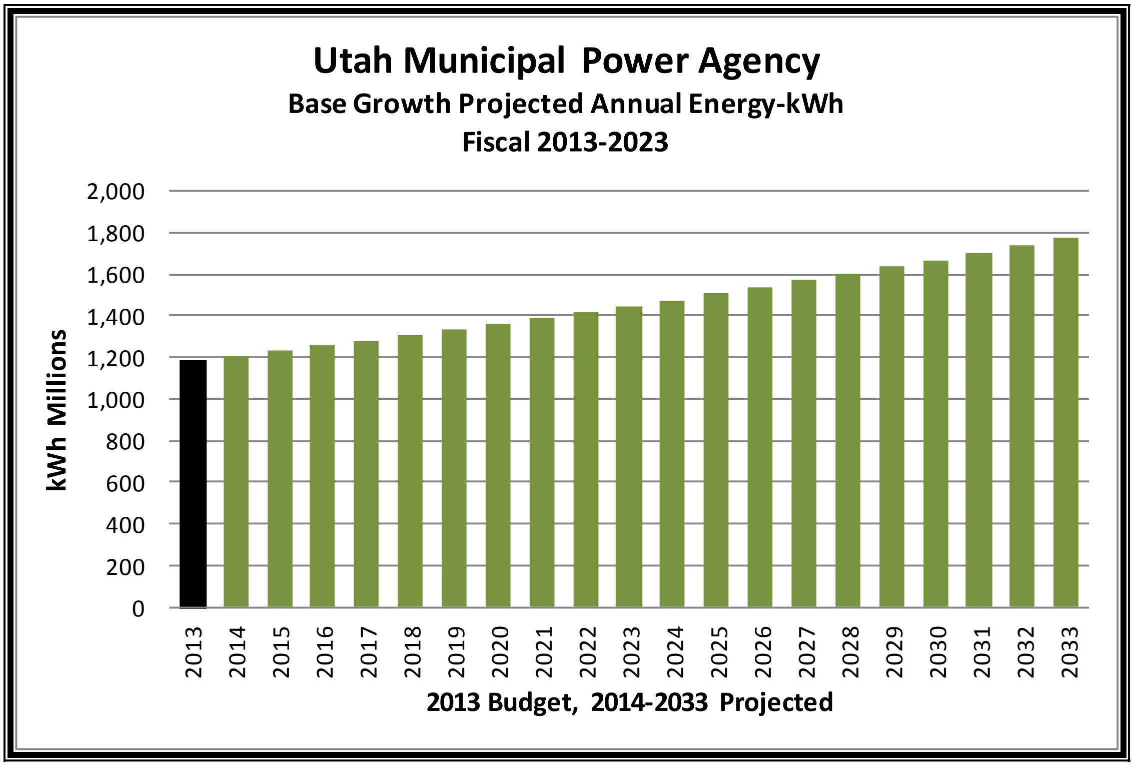
2033
2013 Budget, 2014-2033 Projected

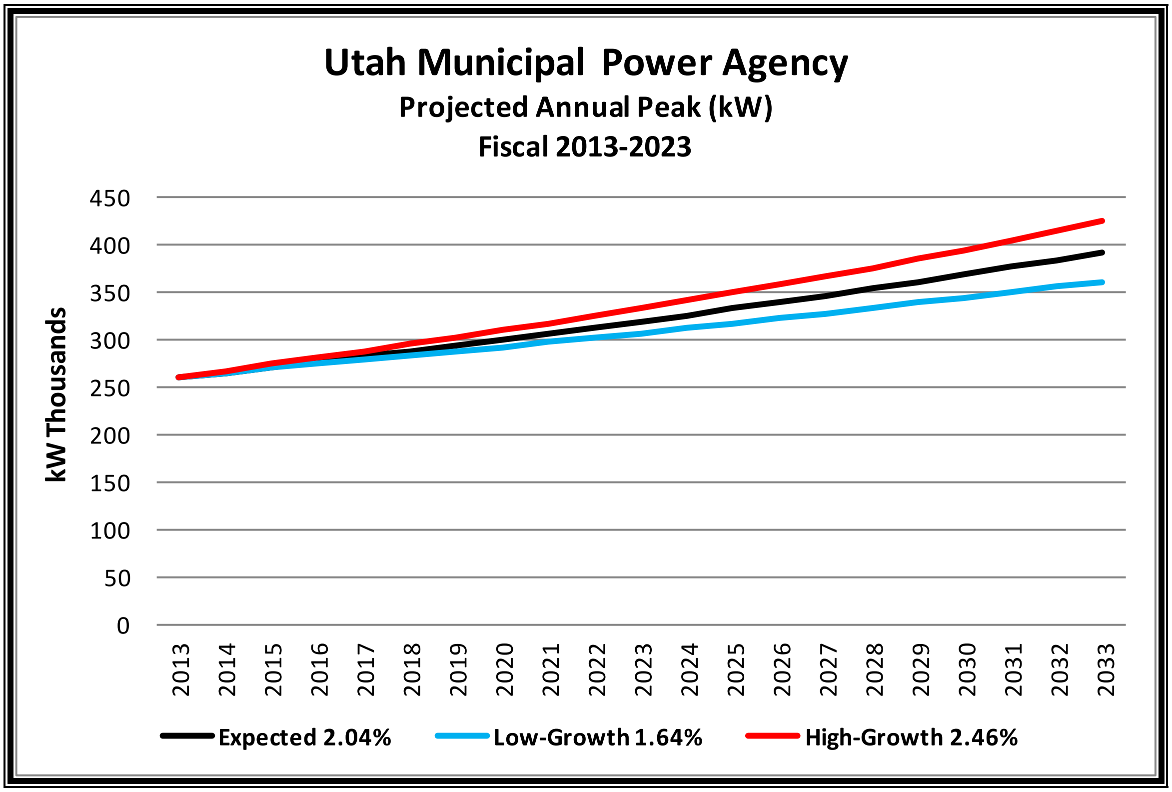


Forecast Scenarios

The "base-growth scenario" represents the projected electrical load growth for UMPA with the most likely probability. In addition to the "base-growth scenario", UMPA examined and projected two other sensitivity scenarios: (1) a slower growth rate of 1.64% called the "low-growth scenario", and (2) a higher growth rate of 2.46% called the "high-growth scenario". The following shows the average annual compound growth rates:

Forecast Scenario	Peak Demand	Energy Requirements
Base-Growth	2.04%	2.02%
Low-Growth	1.64%	1.64%
High-Growth	2.46%	2.46%

The following three-line graphs for annual peak, monthly capacity and energy requirements show the forecasted power and energy requirements for UMPA considering the three different growth scenarios as described:


Utah Municipal Power Agency
Projected Annual Peak (kW)
Fiscal 2013-2023
kW Thousands
450
400
350
300
250
200
150
100
50
0
2013
2014
2015
2016
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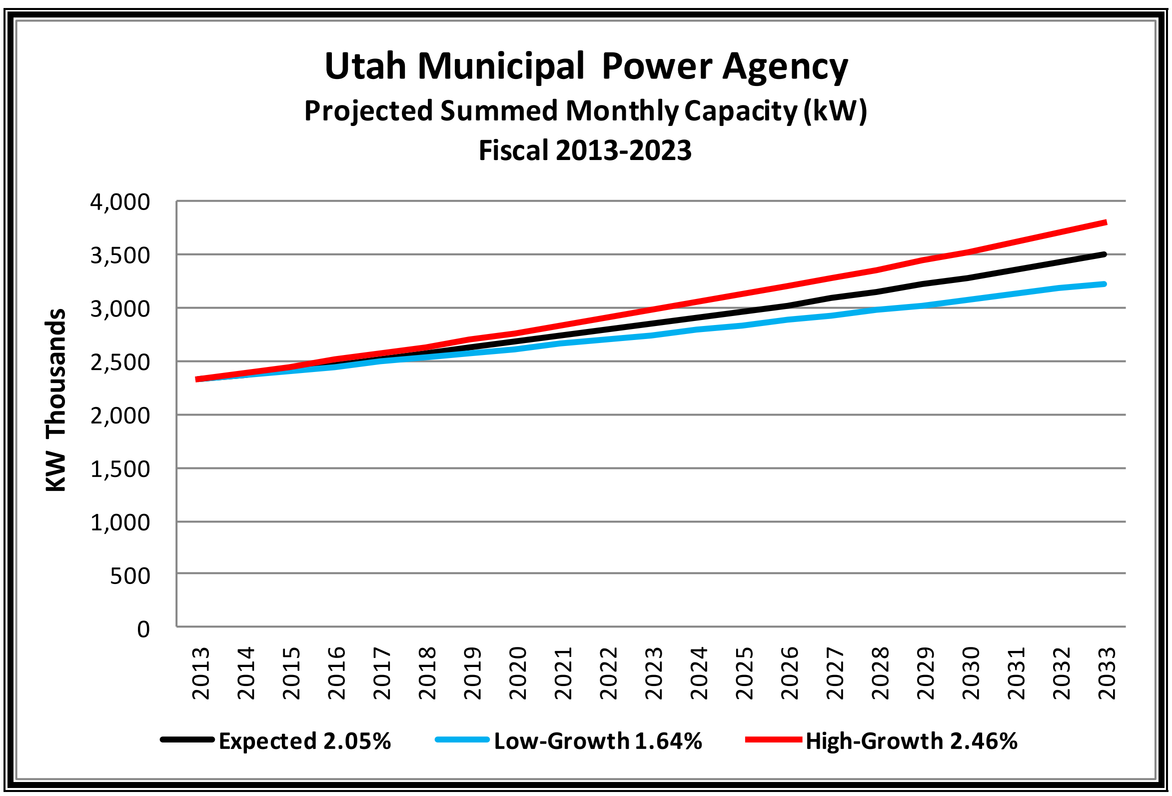
2033
Expected 2.04%
Low-Growth 1.64%
High-Growth 2.46%


Utah Municipal Power Agency
Projected Summed Monthly Capacity (kW)
Fiscal 2013-2023
KW Thousands
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
2013
2014
2015
2016
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2018
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2020
2021
2022
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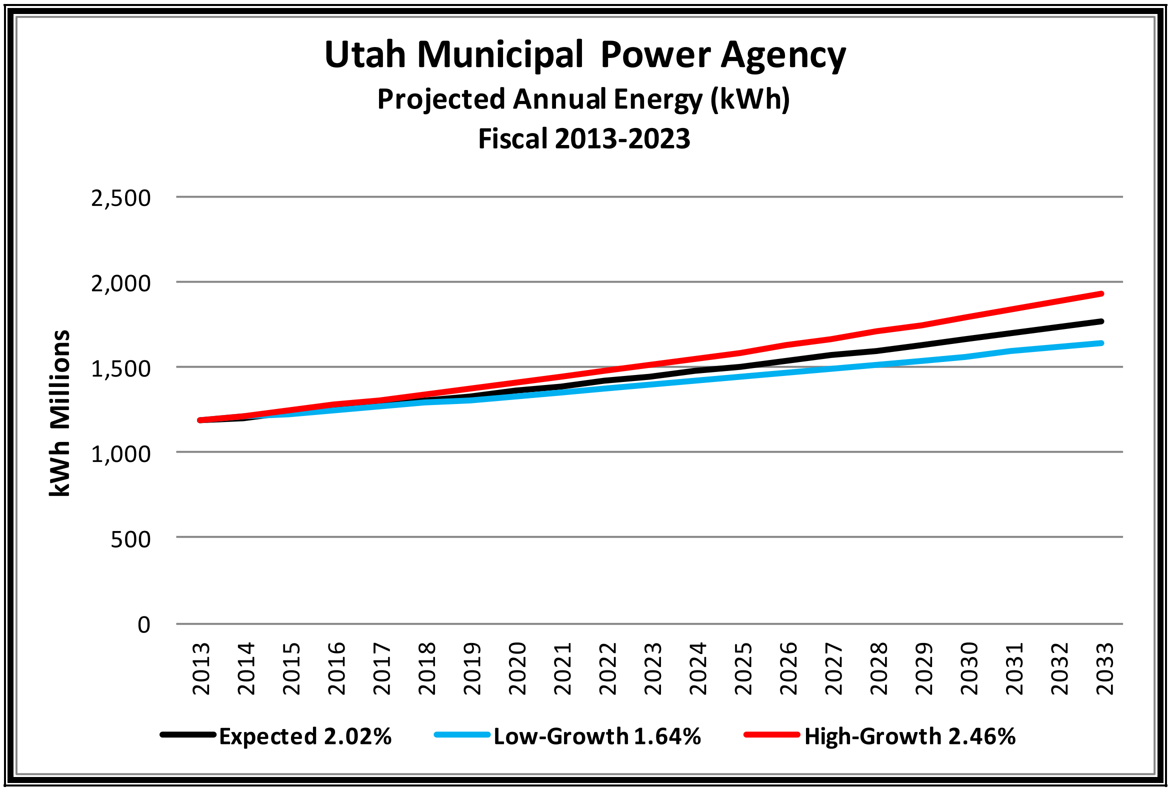
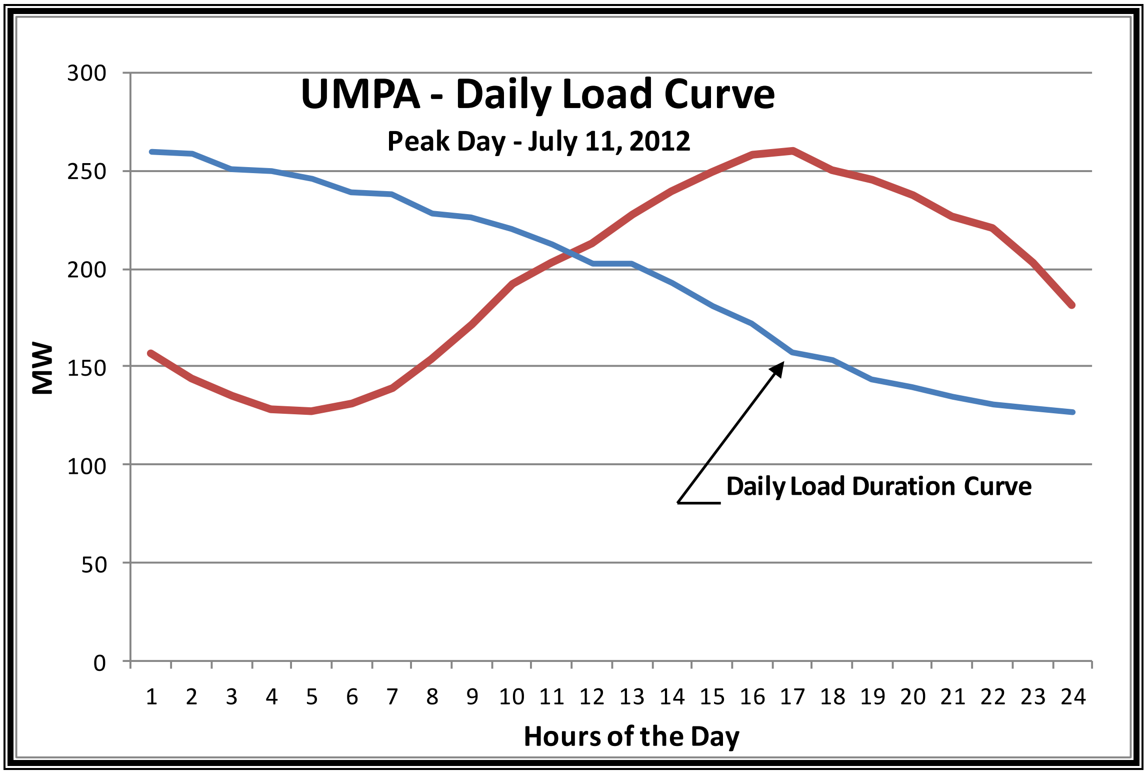
Expected 2.05%
Low-Growth 1.64%
High-Growth 2.46%



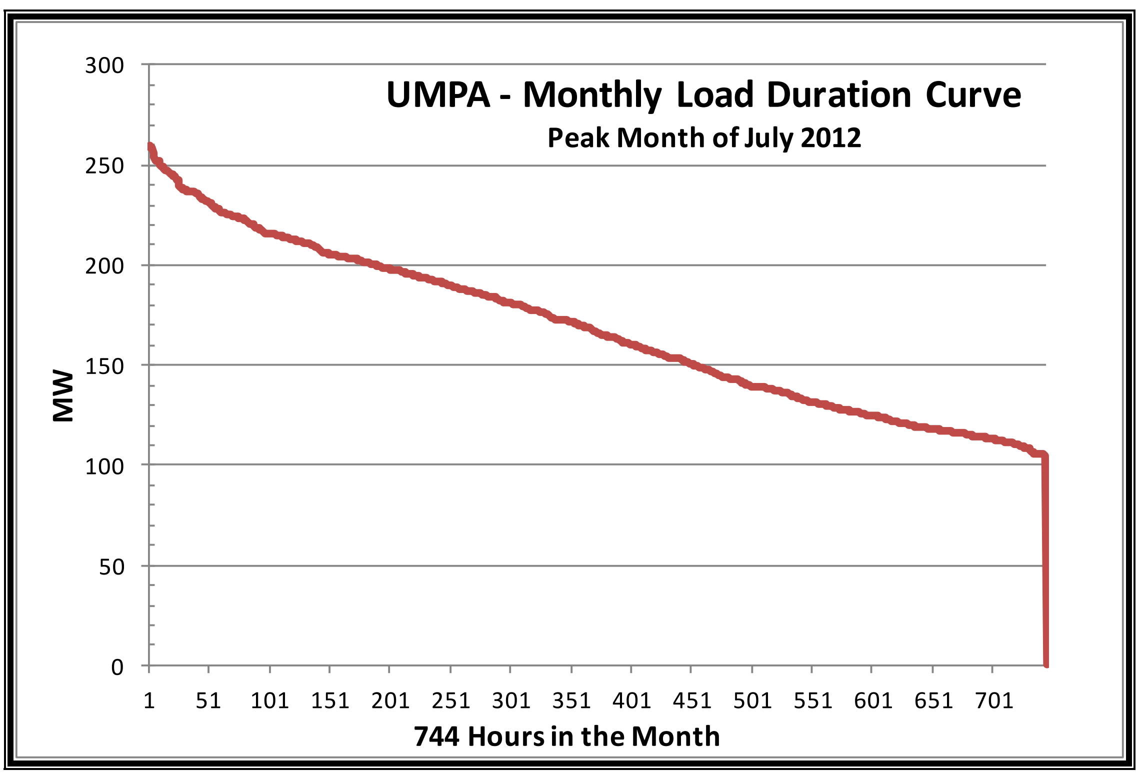
The study period for this IRP is 20 years, thus providing a long-term horizon for UMPA to the upcoming challenges in planning. However, in meeting the submittal requirements for Western, a specific five-year forecast has been prepared. There are additional graphs showing the five-year forecasts for power and energy requirements in Appendix B, UMPA Information.

As shown, UMPA's load will continue to grow as cities expand with new housing starts and economic development along with increases in consumer's usage. The expansion and growth will be different for each member city and UMPA will monitor closely the development patterns and types of construction to respond appropriately to the planning function in this IRP. In forecasting the next 20 year horizon, UMPA does not expect a robust economic period and growth as it experienced in the past 20 years. The system expansion is not only affected by the slow growth in the economy, retail rate increases due to higher production costs and more energy efficient products are likely contributors.

UMPA expects the daily load curves and duration statistics to grow in a comparable fashion as in the past with no major change in the consumer requirements. The impact from demand side management programs in reshaping load curves are considered insignificant for planning purposes. UMPA's current 24 hour energy requirements and daily load curve is shown in the following graph for the peak period day of July 11, 2012:



The monthly load duration curve for the peak month of July 2012 shows the requirement for base load resources as follows:



As shown, UMPA needs to identify, secure, supply and schedule the most economical energy in sufficient quantities to meet the needs of the member cities considering the type of power supply defined as:

> <u>Base Load Generation</u> – Plants are designed to a maximum operating efficiency at continuous operation such as coal and nuclear. Typically the plant investment is higher but through continuously running of the units, the overall economics are lower. Base load units operate at plant availability factor greater than 65% in order to achieve optimal efficiency.
>
> <u>Immediate Load Generation</u> – An intermediate unit is designed to operate a maximum load through the day and easily adjust to minimum load at night, or when there is little to no demand for electricity. Generation cost from immediate units, such as a combined cycle gas turbine, is between that of a peaking and base load generation. Intermediate units operate efficiently at a plant availability factor between 20% and 65%.
>
> <u>Peak Load Generation</u> – A peaking unit is designed to operate infrequently and typically the initial capital costs are greatly reduced. A peaking unit cycles on and off daily, and even on an hourly basis, with a design for quick start up and a wide range for performance. An example of a peaking unit is simple cycle gas turbine or reciprocating engine. Fuel and operating costs are the most expensive. A peaking unit typically has a designed annual plant availability factor of less than 20%.
>
> <u>Intermittent Generation</u> – This is any source of energy that is not continuously available due to some factor outside direct control. The intermittent source may be somewhat unpredictable. For example, solar power or wind generation cannot be controlled nor dispatched to meet the hourly demand of a power system, and solely relies on the forces of nature. Effective use of intermittent sources in meeting electrical load usually relies on the intermittent sources to displace fuel that would otherwise be consumed in generating power to the grid. The use of small amounts of intermittent power has little effect on grid operations; however, larger amounts may require a redesign of the grid infrastructure. Intermittent units operate at a plant availability factor in 20% to 35%.

Although UMPA will be aggressive in the promotion and implementation of demand-side management programs, no significant impact is expected in reshaping or changing the current daily and load duration curves under the current and proposed DSM programs. If there are changes to the power and energy requirements, UMPA will make the appropriate changes and shifts in the implementation phase to appropriately respond.

Description of Existing Supply Resources

Introduction

To quantify future resource requirements, UMPA first determines how much power it can produce from its existing resources. In this section, the term "existing resources" refers to those UMPA resources that are already on-line through ownership, joint participation or through a power sale agreement within the IRP study period.

In evaluating the fit, or economic dispatch of a particular resource, UMPA considers the cost, amount of resources available relative to need, lead time needed to acquire the resource, ability to adjust the timing for acquiring the resource, and operating considerations, such as the resource's flexibility and dispatchability. UMPA also considers the fit of each resource to the existing system, fuel type, location, and its ability to enhance the value of the system. UMPA has a number of alternatives to meet future power needs. These alternatives include options on both the demand-side and supply-side. With the existing system, the supply and demand-side options constitute the agency's portfolio of resources for the future. However, the demand-side alternatives alone will not be sufficient to satisfy UMPA's future load requirements.

This section discusses UMPA's diversified mix of existing resources, firm and non-firm contracts, and existing transmission agreements. It also compares the forecasted loads with our existing generation resources at the 138 kV bus-bar delivery and interconnection.

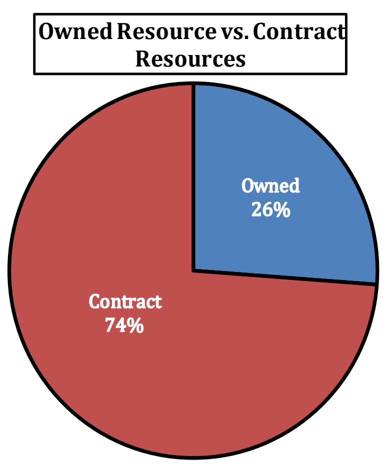
There are significant differences in resource ownership versus power purchase agreements, or contracts for existing resources.

Ownership

- Capital costs
- Operating costs
- Financing – bonding 30 years
- Environmental challenges
- Operating flexibility

Contract

- Length – term (5 to 15 years)
- Pricing
- Operating flexibility
- Little or no control



Both approaches have many benefits and challenges in best managing and scheduling the resources to meet the demands of the utility. This requires managing the risks and rewards to determine the appropriate ratio mix of the two approaches.

Currently, the existing energy resource portfolio is divided as shown in the pie graph. Since 1991, all load growth has been met with power purchase agreements increasing the overall percentage of power supply to contract type resources. The Agency would prefer a balanced equity position between contract and owned resources, and with reasonable efforts, UMPA aims to secure more ownership in future resources to achieve an appropriate balance.

Ownership of Existing Supply Resources

The following are the existing supply-side resources owned by UMPA including member city-owned resources:

Hunter Unit 1

Hunter Unit No.1 is a coal-fired generating plant with a rated capacity of 446,000 kW located near Castle Dale, in Emery County, Utah. In 1980, prior to forming UMPA, Provo purchased a 6.25% undivided ownership interest in the plant and common facilities from Utah Power and Light (PacifiCorp). Provo's capacity from this plant is dedicated to the Agency under a capacity purchase agreement.

Hunter Unit 1 was constructed by Utah Power and Light in the mid-1970's. PacifiCorp is responsible for the administration, construction, operation and maintenance of the Hunter Unit 1. Operation and maintenance costs and capital additions, repairs, improvements and replacements for Hunter Unit 1 are shared by PacifiCorp and the Agency according to ownership interest. Also, the costs related to production of energy are shared in accordance with the percentage of scheduled generation.

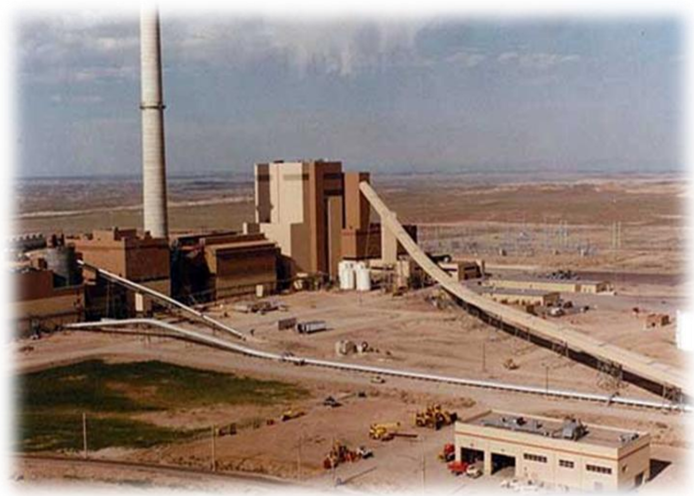
Because of the percentage ownership, increases in generation levels by modernization, upgrades, and replacement of certain plant equipment have enabled UMPA to receive an additional 3,000 kW of capacity. This realized a savings of $5,250,000 by monitoring and challenging PacifiCorp's method of operation. In the 1999, there was an upgrade in the unit resulting in 2000 kW of additional capacity to UMPA. In November 2000, the generator failed which caused the unit to be taken out of service. The generator was rebuilt and placed back into service in May 2001.

At the 138 kV substation level, Hunter provides 32,000 kW of capacity at UMPA's system peak in July and August. The other ten months of the year, Hunter provides 27,000 kW of capacity. The monthly capacity difference in the year is due to the last turbine upgrade; where UMPA is required to schedule in whole megawatts and elected to take its fractional output over the peak months. In 2012, the operating costs for, including debt service, were under 42 mills and operated at a 91.4% availability factor with scheduled maintenance. Currently the plant is being upgraded with new emission control devices to meet new environmental regulations.

Hunter Unit 1 is expected to be operational for the next 20 years under the current maintenance and repair program.

Bonanza Unit 1

The Bonanza Unit No.1 is a 458,000 kW coal-fired generating plant located south of Vernal in Uintah County, Utah. UMPA owns a 3.75% undivided ownership interest and a 1.875% undivided ownership interest in common facilities, plus a contract that expires in 2025 for an additional 3.5% from Deseret Generation and Transmission (Deseret). The power contract mirrors the terms of ownership including actual fuel costs. By acquiring the contract plus ownership, UMPA is able to receive the benefits of resource maximization. In 1992, UMPA received a total of 6,000 kW of capacity at no additional cost which realized a savings of $10,500,000 by monitoring and challenging Deseret's method of operation. Additionally, in 2000, UMPA received 3,000 kW of capacity through a unit upgrade. With the upgrade and all of the systems in top working order, the unit is now available to produce and schedule up to 465,000 kW. Applying UMPA's 7.25% share to total capacity, UMPA is able to schedule 34,000 kW of Bonanza.



At the 138 kV substation level, Bonanza provides a combined total of 34,000 kW of capacity year round. In 2012, the operating cost, including debt service, was approximately 56 mills and operated at an 88.1% availability factor. The lower availability was due to a major planned outage of 4 weeks.

As an element in the acquisition of the Bonanza resource, UMPA acquired a 6.25% ownership to capacity on the Bonanza Project Transmission System. This line allows UMPA to move its Bonanza resource to PacifiCorp or Western at the Mona Substation for delivery to load, as well as for off-system sales to the West.

Bonanza Unit 1 is expected to be operational for the next 20 years under the current maintenance and repair program.

Provo Downtown Power Plant

The Downtown Plant consists of four internal combustion engines and a steam turbine generating unit. There are four (4) duel-fuel reciprocating engine units installed in 1978 and provides a total 10,910 kW capacity. These units are used for reserve and peaking purposes, and operate primarily on natural gas and diesel fuel. The rated capacity of the steam turbine is 9,200 kW and has been placed in cold-standby status with the ability to operate as the future plans dictate. In September 2000, this unit was brought back on-line with remarkable success. The unit was used through

August 2001 until an economic decision necessitated placing it back in cold-standby. The boiler for the steam unit is heated with natural gas.

The overall cost for the reciprocating engines is high when including all of the overhead expenses. These units are not available for base load. They serve to meet the peaking and reserves at near 100% operating factor. Due to the emergency standby source, the engines are available all times, except for scheduled maintenance periods. Currently, new emission control devices (catalytic converters) are being installed to meet future EPA regulations. The steam turbine has been placed in cold-standby and there are no plans to operate it in the near future due for economy reasons.

Although the Provo Plant has the capacity to produce 20,110 kW of generation capacity, only 10,910 kW is planned to be available to meet future loads. The engines are expected to be operational for another 15 years with scheduled maintenance.

Member Hydroelectric Plants

Three of UMPA's member cities have run-of-the-river hydroelectric generation units which output is committed to UMPA. These cities maintain and operate the generating units.

Levan - The town of Levan has two hydroelectric generating units, Pigeon Creek and Cobble Rock. Together these units consist of 320 kW of rated capacity. For the study purposes, we have determined that during the month of August, these units provide an average generation of 50 kW of capacity. The estimated retirement date of these resources is 2027.

Manti - Manti City has two hydroelectric plants which consist of both a new and old generating unit in the Upper Plant, and two new generators in the Lower Plant. These units combined consist of 2,200 kW of rated capacity. For the study purposes, we have determined that during the month of August, these units provide an average generation of 800 kW of capacity. The estimated retirement date of the Upper Hydro is 2025 and the Lower Hydro is 2029.

Nephi - Nephi City has two hydroelectric generating plants named the Bradley Plant and the Salt Creek Plant. The combined units consist of 900 kW of rated capacity. For the study purposes, we have determined that during the month of August, these units provide an average generation of 300 kW of capacity. The estimated retirement date of these units is 2025.

In 2012, the operating cost for the combined units was about 26 mills per kwh, and the units were operated at maximum run-of-the-river conditions for base load. The hydroelectric units are maintained and operated in good condition. All units are operated to meet their regulatory obligations.

Summary of Ownership Resources

A summary table shows the resources owned by UMPA and its member cities and the rated capacity for supply- side operations:

Owned- Supply Resources		Capacity (kW)		Actual FY2012		
	Fuel	Winter	Summer	Peak	Energy	Price/Mills
Hunter Unit 1	Coal	27,000	32,000	32,000	214,900,000	41.60
Bonanza Unit 1	Coal	34,000	34,000	34,000	232,545,000	56.65
Provo Power Plant						
Engines	NG/Diesel	10,910	10,910	10,910	999,571	n/a
Steam Turbine	Natural Gas	9,200	9,200			
Small Hydros						25.97
Levan	Hydro	320	320	189	788,968	
Manti	Hydro	2,200	2,200	1,393	7,228,546	
Nephi	Hydro	900	900	485	1,988,840	

Power Purchase Contracts for Existing Supply Resources

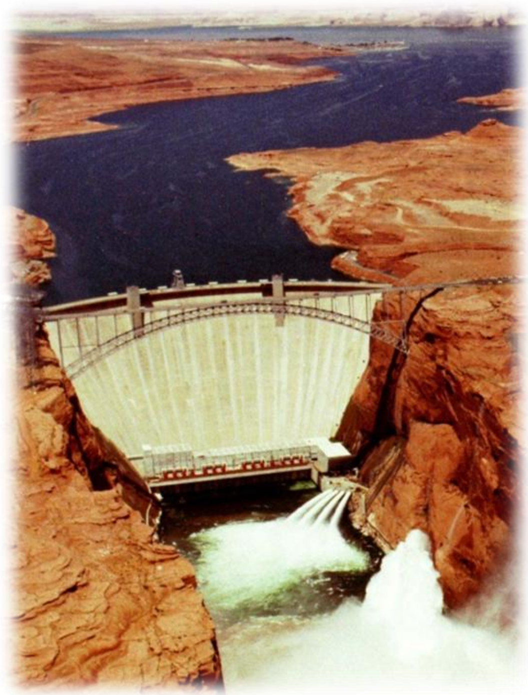
The following are the Existing Resources with UMPA under contract with a power purchase agreement:

Colorado River Storage Project

A significant portion of the Agency's power and energy comes from hydroelectric generation by the Colorado River Storage Project (CRSP) which is owned and operated by the United States government and marketed by Western Area Power Administration (Western). CRSP has been, and continues to be a low cost power and energy resource for the Agency. The amounts of CRSP power and energy available for purchase are subject to seasonal and annual hydrologic variations in the watershed of the Colorado River Basin. Western is responsible for the marketing and transmission of Federal power in 15 western and central states, generated by fifty-five hydropower plants operated by the Bureau of Reclamation and Corp of Engineers.

UMPA entered into a firm allocation of CRSP capacity and energy pursuant to a contract which has been amended from time to time. The current contract extends through September 30, 2024. The Western contract will renew automatically after 2024 with a reduction in the contract amount and allocation that has yet to be determined by Western. In the past, UMPA has received similar reductions. Under the current contract, Western is obligated to furnish firm electric service as set forth in the following table:

Summer Season		Winter Season	
Capacity (kW)	Energy (MWh)	Capacity (kW)	Energy (MWh)
73,587	174,385	87,016	204,880



UMPA received 33.2% of its energy needs from CRSP in FY2012, or 388,184,845 kwh from CRSP at 25.58 mills per kwh. Western is obligated to review annually its rates for CRSP energy to ensure such rates generate sufficient revenues to cover operating and other expenses of CRSP.

In recent years the availability of CRSP power has been affected by prevailing hydrology, environmental impact studies, Federal policies and the Grand Canyon Protection Act of 1992. This Act, environmental studies, and other Federal mandates have given rise to modifications in the flow regime all of which have imposed costs on CRSP customers and the availability of CRSP power. Future modifications to the availability of CRSP energy and power generation due to new flow regimes may continue to impact the benefit and value of this resource.

For Utah customers, CRSP electricity is wheeled on behalf of Western over transmission facilities owned by PacifiCorp, pursuant to a wheeling contract between the Western and PacifiCorp for the life of the CRSP contract.

Deer Creek Hydro

UMPA has executed a purchase contract for electric service with Western to purchase power and energy from the Deer Creek Power Plant of the Provo River Project. Western indicated its intent in a Federal Register Notice dated November 21, 1994, that available power and energy for each month of the summer season would be estimated 60 days before the start of the power season. Any differences between the amounts estimated to be available and the amounts delivered will be reconciled in future schedules.

Winter season energy is available during periods when there is no diversion between the Weber and Provo Rivers, negating the requirement to deliver Deer Creek generation to PacifiCorp. Winter energy is impacted by the joint operation of Deer Creek and Jordanelle hydroelectric plants. The capacity of the Deer Creek plant is 4,950 kW and UMPA purchases 70% of the output of the Project.

In FY 2012, Deer Creek represented 1.51% of UMPA's annual energy needs; 18,500,000 kwhs and costs 14.7 mills per kwh. The term of the contract will continue through 2024 with an extension provision to 2030.

PacifiCorp – Long-Term Contract

PACIFICORP

UMPA has a unique contract with PacifiCorp (formerly Utah Power and Light) that contains flexibility for UMPA to schedule the necessary capacity and energy to meet its future load growth needs. The contract commenced July 1, 1997 and it terminates June 30, 2017. The contract provides for 5-year price re-openers, the most recent of which was completed in December, 2012. Capacity nominations for each month of the 5-year period covered by the IRP are set forth in the agreement and the nominations total 408 MW months. UMPA has flexibility in scheduling energy within a load factor range each month of 45% to 75%. It is important to note that the likelihood for another contract beyond 2017 with PacifiCorp is very remote. Thus, UMPA must plan to replace this 75 MW contract with an alternative supply resource.

In 2012, this contract provided 16.8% percent of the energy needs for the Agency at a blended rate of just over 45 mills per kwh.

Deseret Power Contract

In May 2003, UMPA entered into a wholesale power contract with Deseret Generation and Transmission (Deseret) for purchases of power and energy. The term of the Deseret contract extends to December 31, 2019. Eighty (80) MW of capacity and energy are to be provided from Deseret's interest in the Bonanza Unit No. 1 and Hunter Unit No. 2 power plants offering greater reliability by splitting the output between two units. Deseret may interrupt or curtail capacity and energy made available to the Agency whenever the available output from Hunter Unit 2, Bonanza Unit 1, or both is less than the normal capacity of each unit, to the extent of such reduction in capacity.

For planning purposes, this 80 MW contract ends in 2019. It is uncertain whether UMPA will be able to enter into another contract with Deseret, or be required to find an alternative supply resource to replace this contract.

DESERET POWER
ELECTRIC COOPERATIVE

UMPA is required to pay the monthly capacity charges without regard to the amount of associated scheduled energy delivered to UMPA. In 2012, this contract provided 9.7% percent of the energy needs for the Agency at a blended rate of 123 mills per kwh. The costs were higher than prior years due to the fact that more economical energy was purchased on the spot market and this resource was used for its peak capacity over a shorter duration.

Spanish Fork Wind Test Site

Another renewable resource which UMPA has been involved in is wind generation. Spanish Fork City has a wind test site at the base of Spanish Fork Canyon and over the years several prototype wind turbines have been tested at this site. Currently, there are 9 small operating wind turbines with various turbine capacities operated by Windward Engineering LLC for testing and production. The purpose for these tests is to assist in the design of small wind turbines that may be used in more isolated areas where large wind turbines are not practical. Since the primary purpose is for testing and design work, and with the performance being unpredictable, UMPA receives the energy output without payment.

In FY 2012 the generation from this wind turbine test site was 186,609 kWh at no cost to UMPA.

Spot Market Sales and Purchases
UMPA currently has 40 trading contracts or interchange agreements with other utilities and energy trading entities for the purchase and marketing of energy. The majority of these marketing entities are located in the West and span from the state of Washington to New Mexico. Other marketing entities that UMPA is contracted with are located in New York, Indiana, and Texas. Of the 40 marketing entities, UMPA most often purchases from those that provide the most reliable delivery of energy at the smallest presented risk. When market pricing is favorable for off-system sales, UMPA markets surplus energy to those contracted entities that are most reliable and offer the largest profit margins.

Summary of Contract Resources
A summary table shows the resources contracted by UMPA and the rated capacity for supply side operations:

Contract- Supply Resources		Capacity (kW)		Actual FY2012		
	Fuel	Winter	Summer	Peak	Energy	Price/Mills
C.R.S.P (Western)	Hydro	87,016	73,587	73,587	449,506,959	25.58
PacifiCorp Contract	Coal	25,000	75,000	75,000	198,130,000	45.35
Deseret Contract	Coal	80,000	80,000	80,000	114,750,000	123.28
Deer Creek Contract	Hydro	n/a	n/a		18,500,000	14.74
Spanish Fork Wind	Wind	n/a	n/a	29	186,609	0
Market Purchases	Variety	n/a	n/a		112,175,000	22.78

With two major power supply contracts totaling 155 MW of generating capacity that expire in the next few years, and the challenge of building and replacing supply resources with limited alternatives, it is imperative now for UMPA to begin the process of replacing, or negotiating future power resources. In addition to the replacement supply resources, UMPA must plan for meeting future power and energy growth on the system. The plan for action for supply-side resources is to investigate, and find a replacement for the expiring contracts and the added requirements from growth in the most economical manner.

Transmission Facilities and Contracts
The Agency's acquisition of the Bonanza Project include a 6.25% interest in Deseret's transmission system which enables the Agency to deliver power to the Mona Substation in Utah and the Rangely Substation in Colorado. This provides access to Western's transmission system in Utah and in other Western states.

CRSP electricity is wheeled on behalf of Western over transmission facilities owned by PacifiCorp, pursuant to a transmission wheeling contract between Western and PacifiCorp for the life of the CRSP contract. UMPA has a transmission service agreement with PacifiCorp whereby PacifiCorp transmits UMPA's power across PacifiCorp's transmission system to member cities loads and contract loads. The contract has an indefinite life such that it cannot be cancelled by PacifiCorp unless a replacement contract has been negotiated. The Federal Energy Regulatory Commission (FERC) regulates the rates charged for transmission and ancillary services. Monthly, UMPA pays for its usage of the transmission system on the amount of UMPA power being transmitted on the system at the time of the maximum hourly peak by all users on PacifiCorp's system. The transmission rate is set annually using an updated cost-of-service formula.

Dispatch Application of Power Resources

Scheduling of UMPA's power resources is done on an economic dispatch basis, i.e. lowest cost to highest priced. Base load resources are utilized first to meet the demands and needs of the member cities; followed by intermediate resources; and finally by the peaking resources. UMPA attempts to market and sell to other utilities all and any surplus power in the power market pool. Operating history has shown that UMPA has been very successful in managing and dispatching the power resources.

A historical resource analysis showing the production and operational costs for the variety of supply resources discussed in this section is shown in Appendix D.

Description of Available New Supply Resources

Introduction
This section of the IRP examines the supply-side resources and energy alternatives of possible future power resources to meet the needs and growing demands of UMPA. All of the standard power resources and their typical attributes are described for their consideration.

There are many energy technologies that are developing and maturing, but are not fully ready for commercial deployment due to high costs and lengthy research processes. Fuel cells, hydrogen, wireless electricity, plasma gasification, biofuels, organic photovoltaics, and various forms of nanotechnology, may likely play a role in filling future energy needs. Although the Agency will continue to monitor the developments of these future sources, we have limited the scope to those that are proven and established as mature power supplies.

Fossil Fuel Generation
There are predominantly two options: coal fired generation and natural gas fired generation. Each technology has advantages and disadvantages. Issues associated with natural gas and coal fired generation include environmental concerns, fuel cost volatility, fuel availability, changing regulations and taxes associated with carbon dioxide (CO_2) emissions and other global warming precursors.

Coal Fired Generation
Pulverized Coal Combustion System
The use of electricity has been an essential part of the U.S. economy since the turn of the century. Coal power provides vast quantities of inexpensive, reliable electricity. In 2012, Coal burning produced about 38% of the electricity generated in the U.S. In addition, known coal reserves are expected to last for centuries at current rate of usage.

The traditional coal power plant is a rather simple process. In most coal fired power plants, chunks of coal are crushed into fine powder and fed into a combustion unit where it is burned. Heat from the burning coal is used to generate steam that is used to spin one or more turbines to generate electricity.

Coal is first milled to a fine powder, which increases the surface area and allows it to burn more quickly. In these pulverized coal combustion systems, the powdered coal is blown into the combustion chamber of a boiler where it is burned at high temperatures (see diagram below). The hot gases and heat converts water in tubes lining the boiler into steam.

The high pressure steam is passed into a turbine containing thousands of propeller-like blades. The steam pushes these blades causing the turbine shaft to rotate at high speed. A generator is mounted at one end of the turbine shaft and consists of carefully wound wire coils. Electricity is generated when these are rapidly rotated in a strong magnetic field. After passing through the turbine, the steam is condensed to water and returned to the boiler to be heated once again.

Improvements continue to be made in conventional coal power station design and new combustion technologies are being developed. These allow more electricity to be produced from less coal by improving the thermal efficiency of the power station. Efficiency gains in electricity generation from coal fired power stations will play a crucial part in reducing CO_2 emissions at a global level. Not only do higher efficiency coal fired power plants emit less carbon dioxide per megawatt, they are also more suited to future retrofitting with carbon capture systems.

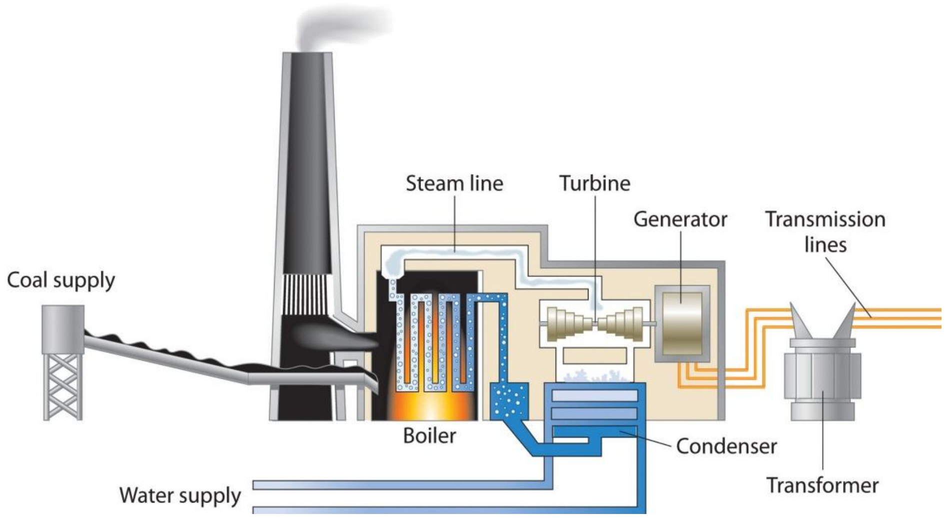


Diagram of a Coal Fired Generation Plan

Improving the efficiency of pulverized coal-fired power plants and reducing emissions have been the focus of considerable efforts by the power industry. Clean coal technology calls for achieving significant efficiency improvements with new, higher efficiency supercritical and ultra-supercritical plants and through the wider use of Integrated Gasification Combined Cycle (IGCC) systems for power generation. A one percentage point improvement in the efficiency of a conventional pulverized coal combustion plant results in a 2-3% reduction in CO_2 emissions.

Fluidized Bed

In a fluidized bed coal plant, pressurized air is injected under a grate in the bottom of the coal-fired boiler. Crushed coal particles float inside the boiler, suspended on upward-blowing jets of air and are fluidized. Limestone is mixed with this fluidized coal. The result is a more thorough burn of the coal, especially for lower quality coal, and removal of 90% plus of the sulfur and nitrogen pollutants. Typically, the boiler is also able to burn other fuels such as wood or waste tires. The boiler then transfers the heat into the steam tubes for circulation through a steam turbine.

This technology was selected for the Deseret Waste Coal Plant located next to the existing Bonanza Power Plant. UMPA is participating in this proposed project. The 90 MW plant would burn waste coal which is coal already mined but not suited, or of the quality needed, for the Bonanza Plant. The capital costs for the plant were expected to be higher than other options; however, the operating fuel was inexpensive making the plant competitive in the market. With new emission control technology, the plant could satisfy the EPA requirements. There is a risk that further EPA rules may apply and CO_2 sequestering would be required, creating uncertainty in the development of the project. The project is on indefinite hold status.

Integrated Gasification Combined Cycle (IGCC)

This new technology uses a gasifier to turn coal and other carbon based fuels into synthetic gas or syngas. It then removes impurities from the syngas before it is combusted. Some of these pollutants, such as sulfur, can be turned into re-usable byproducts. This results in lower emissions of sulfur dioxide, particulates, and mercury. With additional process equipment, the carbon in the syngas can be shifted to hydrogen via the water-gas shift reaction, resulting in nearly carbon free fuel. The resulting carbon dioxide from the shift reaction can be compressed and permanently sequestered. Excess heat from the primary combustion and syngas fired generation is then passed to a steam cycle, similar to a combined cycle gas turbine. This technology results in improved efficiency compared to conventional pulverized coal.

This new technology is considered cutting edge and comes at a very steep price. There are only a few plants operating in the US and a few plants overseas. The main problem for IGCC is its extremely high capital cost, upwards of $3,600 per installed kW. Because of the limited number of plants in operation, there is much uncertainty on the real cost for this technology.

In addition to the costs, there are reported reliability problems in the gasifier section. The gasifier problems have not been fully remedied and continue to challenge the industry in competing with the availability established in traditional coal plants.

Coal Fired Attributes

There is an abundant supply of coal fuel in the western region for this generation. Economically, coal fired generation can provide the lowest costs to customers when compared to other sources. Technology is well advanced.

Coal fired plants are reliable and very cost competitive for base generation. Plants are limited in their dispatchability to follow load curves given the heat rates and efficiency curves. Coal works best as a base load resource and does not integrate well with intermittent wind and solar energy resources.

The environmental impacts of coal fired electrical generation, even when minimized are:

- Coal mining may cause erosion and leaching of toxic chemicals.
- About two-thirds of SO_2, one-third of CO_2, and one-quarter of NO emissions in the U.S. are produced by coal burning.
- Coal burning results in the emission of fine particles matter into the atmosphere.
- Current EPA regulations limit the amount of CO_2 emissions into the atmosphere by mandating new coal plants to the same level as a combined-cycle gas turbine. On an energy basis, coal fired plants emits twice the amount of CO_2 as a gas turbine. Any additional CO_2 must be sequestered underground. Currently, there is no proven commercially available technology to sequester CO_2. In addition, there is no solid body of law dealing with sequestered emissions and questions remain on liability for migrating or leaking sequestered CO_2 emissions. Effectively, coal fired generation cannot comply with current environmental laws; rendering this type of generation impossible to build.

Summary

Although UMPA has enjoyed the benefits of coal-fired generation for many decades, there are no coal fired plants under consideration, or under development in the West for the Agency's consideration due to the political, environmental pressures, and regulation.

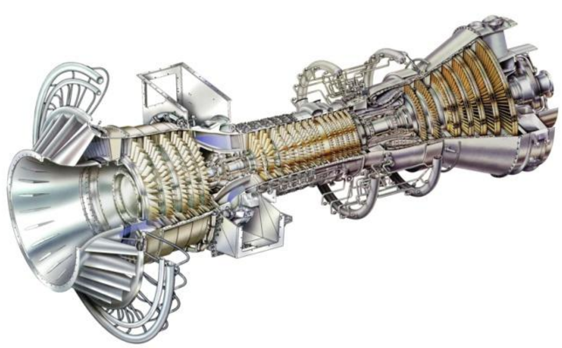
Natural Gas Fired Generation

There are several types of natural gas fired technology as described below:

Simple Cycle Combustion Turbines (SCCT)

This technology is essentially a jet engine turning a generator. It is typically used for peak load service during high price market conditions and for meeting load variations from intermittent resources.

The main advantage of a SCCT is the ability for it to be turned on and off within minutes. Due to its cycling ability, SCCTs are useful for supplying power during peak demand. SCCTs are flexible to be used as peaking power plants, which can operate from several hours per day, up to many hours. They can also meet the shortages and interruptions of base load resources economically and yet operate effectively to meet the load curve. A large simple cycle gas turbine may produce 100 to 300 megawatts of power and have 35–45% thermal efficiency.



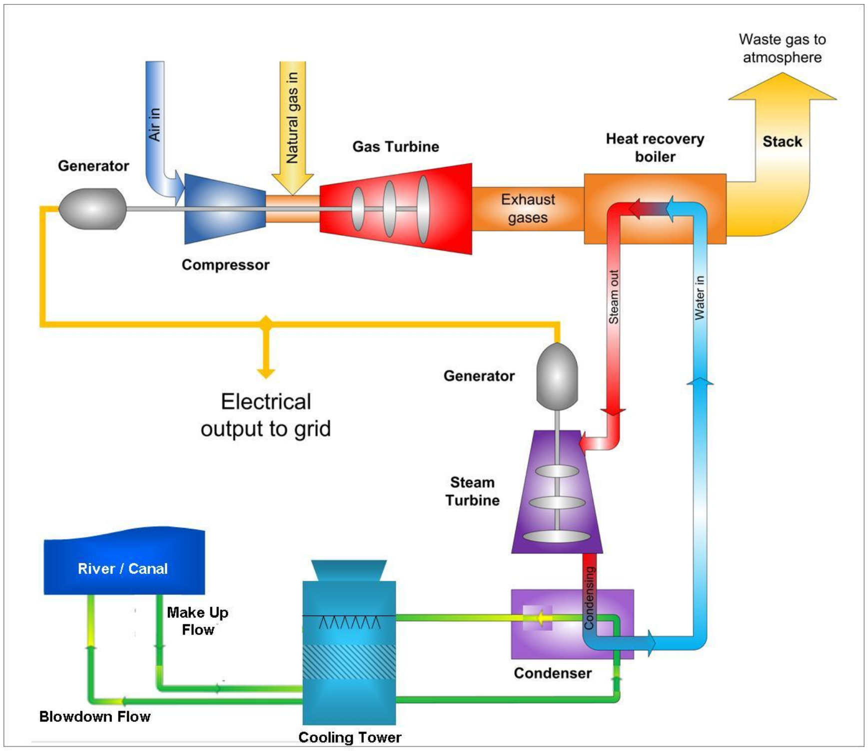
A combustion turbine is a type of internal combustion engine or specifically, a jet engine. It has an upstream rotating compressor coupled to a downstream turbine, and a combustion chamber in-between. Energy is added to the gas stream in the combustor, where fuel is mixed with air and ignited. In the high pressure environment of the combustor, combustion of the fuel increases the temperature. The products of the combustion are forced into the turbine section. There, the high velocity and volume of the gas flow is directed through a nozzle over the turbine's blades, spinning the turbine which powers the compressor and, for some turbines, drives their mechanical output. The energy given up to the turbine comes from the reduction in the temperature and pressure of the exhaust gas. Energy can be extracted in the form of shaft power, compressed air or thrust or any combination of these and used to power aircraft, trains, ships, generators, or even tanks.

Simple cycle units require smaller capital investment than either coal or nuclear power plants, and can be scaled to generate small or large amounts of power. Also, the actual construction process is considerably shorter (months), compared to years for base load power plants.

Combined Cycle Gas Turbines (CCGT)

This plant design adds a boiler system and steam generator unit to the simple cycle gas technology. The jet engine turns a generator and the waste heat from the process is used to generate steam for a turbine/generator set. This generation type has been the technology of choice for meeting base and intermediate loads due to its relatively low capital cost, quick construction lead-time and high fuel efficiency.

More recently, as combustion turbine efficiencies have improved and as natural gas prices have fallen, gas turbines have been more widely adopted for base load power generation, especially in combined cycle mode, where waste heat is recovered to produce additional electricity.



Combined Cycle Gas Turbine System Diagram

A CCGT produces high power outputs at high efficiencies (up to 55%) and with low emissions. A conventional coal-fired power plant converts input energy at 33% efficiency into electricity only and the remaining 67% as waste heat.

<u>Natural Gas-Fired boilers</u>
In this technology, natural gas is used as a boiler fuel to make steam for use by a steam/generator set. These plants were commonly used for base-load applications until the advent of the newer and higher-efficiency combined cycle turbine technology became available.

The Provo Power Plant was built using this boiler technology. The original power plant used coal as the fuel to heat the water in the boiler before running the steam-driven generator. Later the boiler was converted to natural gas to improve efficiencies and lower emissions. Although the gas boiler and turbine unit are operational, with some effort to ready it from its current storage mode, there are many power resources more economical. There are no plans to operate the Provo steam unit. It is kept in a cold-standby condition for potential future use.

Reciprocating Engines (Natural Gas and Diesel Fuel)

Electric generator sets are driven with reciprocating internal combustion engines operated by fuel oil (diesel) or natural gas. These units are available in a wide range of sizes and typically serve as emergency power, or may also be operated in parallel to meet system peak demands. Also these units are frequently used for distribution generation due to the ease of installation, variety of size and elimination of transmission. The capital costs are relatively low for these units while the operating costs are higher due to lower fuel efficiency standards and high maintenance costs.

Examples of this technology are the units located in the Provo Power Plant. The four (4) reciprocating engines and generator sets were installed in the late 70's and continue to run today. Each unit is rated at 2,500 kW with a 10% overload. They are an excellent resource for meeting the super peaks, transmission curtailment, reserves, emergencies, and back up generation. These units are not economical for continuous running due to the high operating costs and poor heat rate.

Natural Gas Fired Attributes

- ◊ Fuel efficiency - A conventional SSCT have a fuel conversion efficiency of 33% which means two thirds of the energy in the fuel burned is lost heat. The turbines in combined cycle power plant have a fuel conversion efficiency of 50% or more, which means they burn about half the amount of fuel as a conventional SSCT plant to generate the same amount of electricity.
- ◊ Low capital costs - The capital cost for building a combined cycle unit is two thirds the capital cost of a comparable coal plant.
- ◊ Commercial availability - Combined cycle units are commercially available from suppliers anywhere in the world. They are easily manufactured, shipped and transported.
- ◊ Abundant fuel sources - The turbines are fueled with natural gas.
- ◊ Reduced emission and fuel consumption - CCGT plants use less fuel per kWh and produce fewer emissions than conventional SSCT and coal fired power plants.
- ◊ Location – There are several sites where natural gas pipelines are located or can be connected for transporting fuel to a CCGT facility making it very cost effective.
- ◊ Dispatchability - CCGT offers reliable and flexible service. It is cost effective as a base and intermediate resource, and the most effective resource in responding to shortages from an intermittent supply-side project.
- ◊ Operating costs - Price of natural gas is subject to wide fluctuations in price. Price volatility is often due to high demands. Electricity prices will fluctuate due to the natural gas market.

Summary

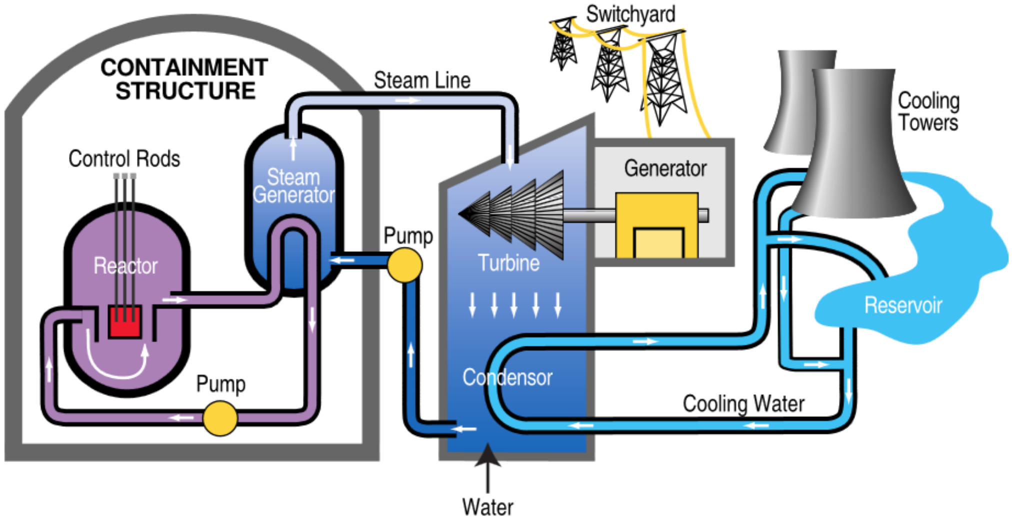
The attributes, economics and viability of CCGT presents the better power supply for future loads and demands. Currently, UMPA is investigating CCGT options for consideration. A preliminary study is being conducted on the NOVI CCGT Project.

Nuclear Generation

Nuclear energy is produced by a controlled atomic chain reaction. When a neutron strikes a relatively large fissionable atomic nucleus, it forms two or more smaller nuclei as fission products, releasing energy and neutrons in a process called nuclear fission. The released neutrons trigger further fission, and so on. The nuclear power plant uses nuclear fission inside the reactor to create heat for generating electricity. The heat is then used to boil water, produce steam and drive a steam turbine.

The difficulties associated with nuclear planning and development; include long lead times for licensing, viable sites, high capital cost, regulatory rate recovery, shortage of trained nuclear technicians, and financing uncertainties.

Diagram of a Nuclear Plant



There is an ongoing debate about the use of nuclear energy. Proponents contend that nuclear power is a sustainable energy source that reduces carbon emissions. Opponents believe that nuclear power poses many threats to people and the environment.

Nuclear power plant accidents include the Three Mile Island accident (1979), the Chernobyl disaster (1986), and the Fukushima Daiichi nuclear disaster (2011). However, the safety record of nuclear power is good when compared with many other energy technologies. Research into safety improvements is continuing and nuclear fusion may be used in the future.

Uranium is a fairly common element in the Earth's crust. Uranium is about 40 times more common than silver. The cost of nuclear power lies for the most part in the construction of the power station. Therefore the fuel's contribution to the overall cost of the electricity produced is relatively small, so even a large fuel price escalation will have relatively little effect on final price. For instance, typically a doubling of the uranium market price would increase the fuel cost for a light water reactor by 26% and the electricity cost about 7%, whereas doubling the price of natural gas would typically add 70% to the price of electricity from that source.

Nuclear power plants have high capital costs for building the plant, but low fuel costs. Therefore, comparison with other power generation methods is strongly dependent on assumptions about construction timescales and capital financing for nuclear plants as well as the future costs of fossil fuels and renewables as well as for energy storage solutions for intermittent power sources. Cost estimates also need to take into account plant decommissioning and nuclear waste storage costs. With the ongoing effort to mitigate global warming, such as a future carbon tax or carbon emissions trading, it may favor the economics of nuclear power.

In nuclear development, there are firms now considering a “modular” design for reactors. This design differs from traditional nuclear plants as the reactors are significantly smaller and several are installed at a single site, depending on need. It would be expected that the investment costs are less for a smaller unit and that the regulatory process and construction timetable would be shortened.

Analysis of the economics of nuclear power must take into account on who bears the risks of future uncertainties. To date, all operating nuclear power plants were developed by state-owned or state-regulated utilities where many of the risks associated with construction costs, operating performance, fuel price, accident liability and other factors were borne by consumers rather than suppliers. In addition, because the potential liability from a nuclear accident is so great, the full cost of liability insurance is generally limited by the government, which the U.S. Nuclear Regulatory Commission concluded constituted a significant subsidy.

<u>Attributes</u>

- ◊ Nuclear power production has recently enjoyed renewed interest because of its lack of green house gas emissions.
- ◊ There are concerns on safety, plant location, skilled staffing, and strong public opposition to nuclear.
- ◊ There is an extensive governmental approval process and long construction timetable creating development risk to the owner.
- ◊ There is a very high capital investment with a low fuel costs.
- ◊ The economics are most favorable when operating as a base load resource.
- ◊ Environmental concerns for nuclear power are radioactive wastes such as uranium mill tailings, spent (used) reactor fuel, and other radioactive wastes. These materials can remain radioactive and dangerous to human health for thousands of years.

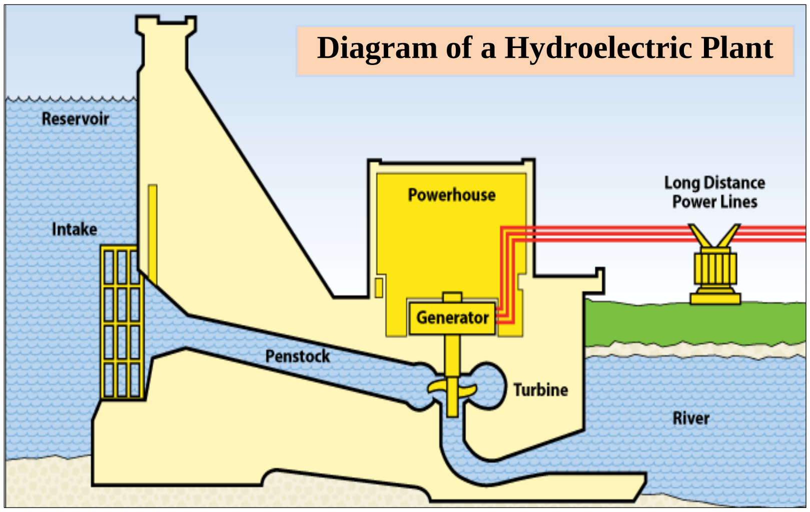
<u>Summary</u>

Although there is new consideration of nuclear power production as a viable supply alternative, more proven developments need to be successfully funded, developed, and operated safely to further mitigate the decision risks. Until such time, the Agency does not consider nuclear power as a near-term option. A more favorable option for the Agency involving nuclear development and associated risk may be to consider a power purchase agreement to minimize operational risks.

Hydroelectric Generation

Hydroelectricity is the term referring to electricity generated by hydropower; the production of electrical power through the use of the gravitational force of flowing water. It is the most widely used form of renewable energy. Once a hydroelectric plant is constructed, the project produces no direct waste, and no air pollutants and carbon dioxide (CO_2).

Mechanical energy is harnessed from moving water. The amount of available energy in moving water is determined by its flow and fall. In either instance, the water flows through a pipe, or penstock, then pushes against, and turns blades in a turbine to spin a generator to produce electricity. In a run-of-the-river system, the force of the current applies the needed pressure, while in a storage system, water is accumulated in reservoirs created by dams, then released as needed to generate electricity.



Currently, UMPA benefits greatly from hydroelectric generation. The power purchase contract with Western is supplied from generation from the Glen Canyon Dam, Flaming Gorge Dam and the Aspinal units in Colorado operated by the Federal government. Also, the Agency receives power from the cities of Manti, Levan, and Nephi produced from the small run-of-the-river hydro units.

There are a few remaining sites available for hydroelectric development in Utah. A list of potential sites is available through the State's energy office. However, most of these sites remain unfeasible based on current market prices. New technology called "micro turbines" is being developed to install on culinary water or irrigation pipe lines in place of pressure reducing systems. This technology is in the early adoption stage and has not been fully proven to be feasible.

Pump Storage

Another type of hydroelectric generation is called a "pumped storage" that can effectively store water for controlled power generation when needed. When power rates are very low during off-peak hours, power is sent from a power grid into the electric generators to act like a pump. The generators/motors spin the turbines backward, which causes the turbines to pump water from a lower reservoir to an upper reservoir, where the water is stored as potential power. During on-peak hours when power rates are very high, the water is released from the upper reservoir back down into the lower reservoir. This spins the turbines forward, activating the generators to produce electricity during on-peak periods. Finding a viable location for a project is very difficult. The feasibility for this project is driven by a wide price difference between on-peak and off-peak electricity.

Attributes

- ◊ Hydroelectric generation is a proven renewable resource and should be developed where feasible.
- ◊ The capital costs are high and the operating costs are very low.
- ◊ Depending on the site and storage, the generation profiles will likely not peak during the summer requirements of the Agency.
- ◊ Run-of-the-river plants are not dispatchable. There is an operational risk due to seasonal droughts causing low or no production periods; requiring an alternative power source.
- ◊ Typically, the projects are environmentally friendly with no pollutants and emissions; but may have fishery and water supply impacts.

Summary

The Agency will continue to examine and monitor any and all potential sites. However, no action will be taken until a feasibility analysis indicates a viable power option.

Wind Turbines

Wind turbines are designed to exploit the wind energy that exists at a location and convert it to electricity. A wind turbine is a device that converts kinetic energy from the wind into mechanical energy through the turbine and then generates electricity.

Turbines used in wind farms for commercial production of electric power are usually three-bladed and pointed into the wind by computer-controlled motors. These have high tip speeds of over 200 mph, high efficiency, and low torque which contribute to good reliability. The blades are usually colored light gray to blend in with the clouds and range in length from 66 to 130 feet. The tubular steel towers range from 200 to 300 feet tall. The blades rotate at 10 to 22 revolutions per minute.

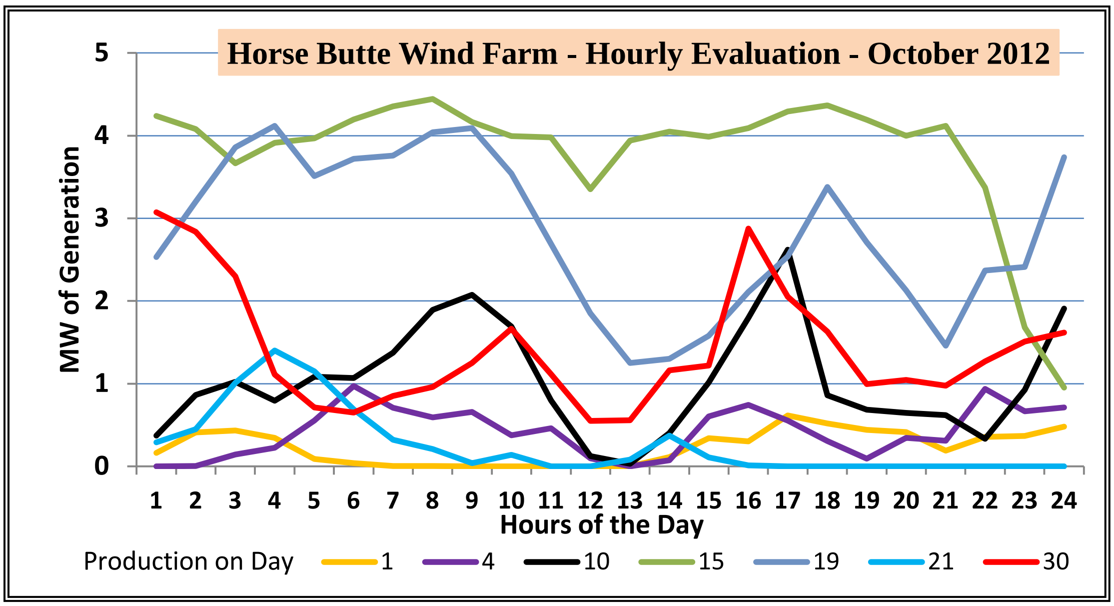
A gear box is commonly used for stepping up the speed of the generator, although designs may also use direct drive of an annular generator. Some models operate at constant speed, but more energy can be collected by variable-speed turbines which use a solid-state power converter to interface to the transmission system. All turbines are equipped with protective features to avoid damage at high wind speeds, by feathering the blades into the wind which ceases their rotation, supplemented by brakes.

The utilization of wind turbines can be a great way to harness the energy of the wind into useable electricity. Harnessing the winds energy with a wind turbine can provide a source of clean and renewable electricity for large or small communities. Wind turbines can be installed as single installation or with multiple installations called a “wind farm”.

The location of a wind turbine or wind farm is of key importance to the performance and generation efficiency, and return on investment of the installation. Utilities spend research and development funds into investigating locations which will be the most beneficial for their venture project.

The intermittent nature of wind generation makes it difficult to predict output from hour to hour and serve the energy demand requirements. To make this generation useful, another controllable generating resource must be available to rapidly ramp up or down its production in the opposite direction in order to balance and stabilize the output of the wind resource. Therefore, wind generation replaces and saves the fuel costs of other controllable supply-side resources.

The following production graph illustrates the actual output from the existing Horse Butte Wind Project located in Idaho as a portion purchased by a contracted customer. The generation varies significantly and unpredictable with only a few days shown for the month; which creates a challenge for scheduling this resource.



Attributes

- ◊ Wind generation is a renewable source and should be developed where feasible. It is one of the least-cost renewable energy sources. It is a proven technology with growing numbers of deployments.
- ◊ The capital costs are high and the operating costs are very low. Capital costs range from $1,600 to $2,500 per kW depending on the site and project size. Estimated operating costs range from $9 to $14 per MWh. However, there is still considerable uncertainty over how these costs may fare over time.
- ◊ Depending on the site, the generation profiles will likely not peak during the daily or seasonal requirements of the Agency.
- ◊ Wind generation is not dispatchable, predictable or controllable. It can only operate within a range under certain windy conditions. It is intermittent and creates an

operational risk. When wind generation is low or non-producing, there must be a controllable power source to replace the wind generation to meet energy requirements. In the design, wind generation is best used to offset the fuel costs of other supply-side resources.

◊ Wind is environmentally friendly with no pollutants and emissions. However, there are other environmental challenges with; (1) certain locations may impact birds and migration paths, (2) certain locations may be unsightly and a visual impact, and (3) the use of significant land for equivalent generation production as compared with other generating sources.

Summary

The Agency will continue to examine and monitor this technology applicable to potential sites. Until a project demonstrates to be feasible and viable as an integrated source within the operating mix of generation, there is no action plan for wind generation.

Solar Generation

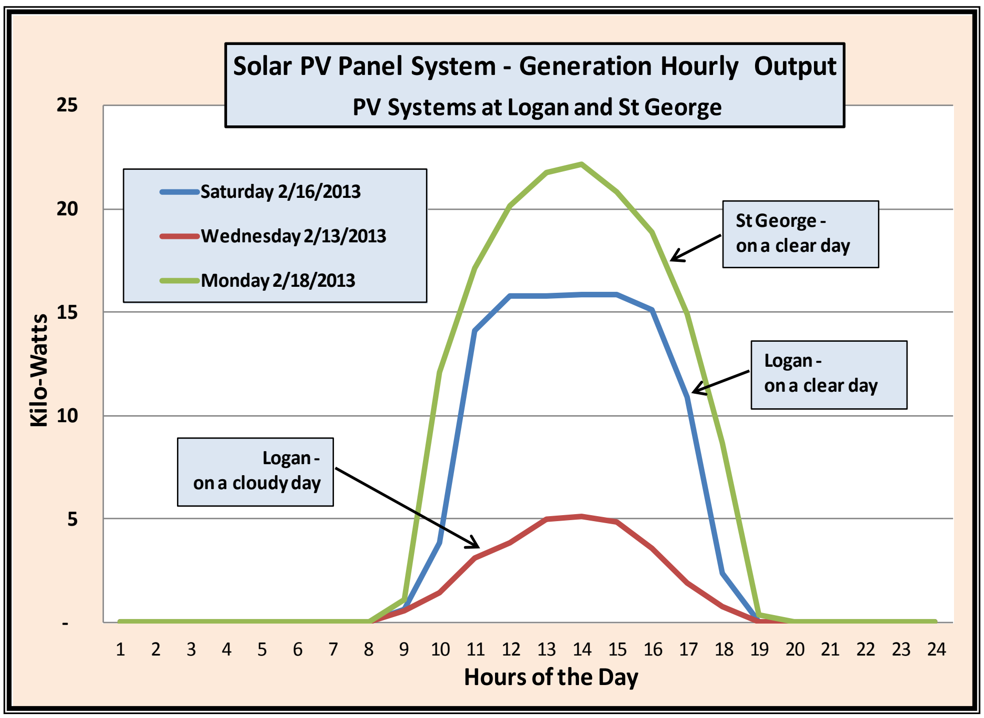
Solar energy is the energy from the sun in the form of solar radiation, which makes the production of solar electricity possible. Solar panels can be used in a variety of different ways in order to harness the sun’s energy. This energy can then be used to provide a renewable source of electricity or even a hot water supply depending on what you require. Solar energy can be converted to electricity in two ways:

Solar cells or photovoltaic (PV) devices change sunlight directly into electricity. Individual PV cells are grouped into panels, and then into arrays of panels that can be used in a variety of applications. These could include a small number of cells to charge a battery, or large numbers of cells grouped into multiple panels to power a single home, or a utility-scale power plant that covers many acres.

Concentrating solar power plants generate electricity by using the heat from solar thermal collectors to heat a fluid that produces steam. The steam is used to power a generator.

Solar PV panels are the most common solution for people interested in harnessing the sun's energy. PV panels can be installed as single devices or as part of what is called an "array". The advantage of installing solar PV panels in an array is the ability to generate more power from one system instead of having to install complete separate solar PV systems for each panel used. The increasing efficiency of solar energy technologies may allow consumers to install PV systems to reduced energy bills under a net metering program. Net metering is an electricity policy for consumers who own renewable energy facilities and receive retail credit for at least a portion of the electricity they generate. The payback for a solar PV system is dependent on the amount of generation, the retail credit for reducing the delivery of electricity by the utility, and the utility's retail rate structure.

The cost of PV has steadily declined since the first solar cells were manufactured, driven in part by advances in technology and increases in manufacturing scale and sophistication. Substantial research and engineering is being applied towards thin-film PV devices that have the potential to be less costly to produce than traditional solar cells. Another developing solar technology uses lenses with mirrored dishes that focus sunlight on solar cells and thermal troughs/dishes. These approaches generally require automated tracking systems to be effective.



The performance of a PV array is dependent upon sunlight. Weather conditions, such as clouds or fog, have a significant effect on the amount of solar energy received by a PV array and its performance. Most modern modules are about 10% efficient in converting sunlight.

Solar is a high cost renewable energy technologies, but a combination of Federal and state incentives make it more attractive for both commercial and residential applications. Currently, Federal tax incentives allow owners of systems to write-off up to 30% of the cost of a PV system. These tax incentives are not available to UMPA.

UMPA has permitted the member cities to offer net metering programs to promote the development of solar energy for those consumers willing to invest in this technology. To date, there are 25 net metering customers within the member cities.

St George City (not a UMPA member) developed and operates a solar farm to provide the opportunity for their customers to elect whether their electricity usage, all or a portion, comes from a renewable source. Although there is much interest and passion for renewable by many consumers, the level of participation is low, when required to invest in higher cost sources of generation.

Attributes

- ◊ Solar generation is an intermittent renewable source and should be considered where feasible. It is a proven technology with improving efficiency.
- ◊ The capital costs are very high and the operating costs are very low. Capital costs range from $3,600 to $5,000 per kW depending on the site and project size. There is still some uncertainty on how these costs may fair over time and their longevity.
- ◊ Depending on the site, the generation profiles will likely not peak during the daily or seasonal requirements of the Agency.
- ◊ The production is not dispatchable or controllable. It operates within a band of certain day light hours and is affected by clouds and inclement weather. It is intermittent and creates an operational risk. When solar generation is low or non-producing, there must be a controllable power source to replace the solar generation to meet energy requirements. In the design, solar generation is best used to offset the fuel costs of other dispatchable supply-side resources.
- ◊ This resource is environmentally friendly with no pollutants and emissions. There are environmental concerns regarding (1) the visual impacts of the panels in conforming neighborhoods, (2) the location may affect wildlife habitat, and (3) the use of significant land for equivalent generation production as compared with other generating sources.

Summary

The Agency will continue to investigate this option for renewable opportunities. However, there remains the requirement for dispatchable generation to meet future demands and loads not found in solar generation.

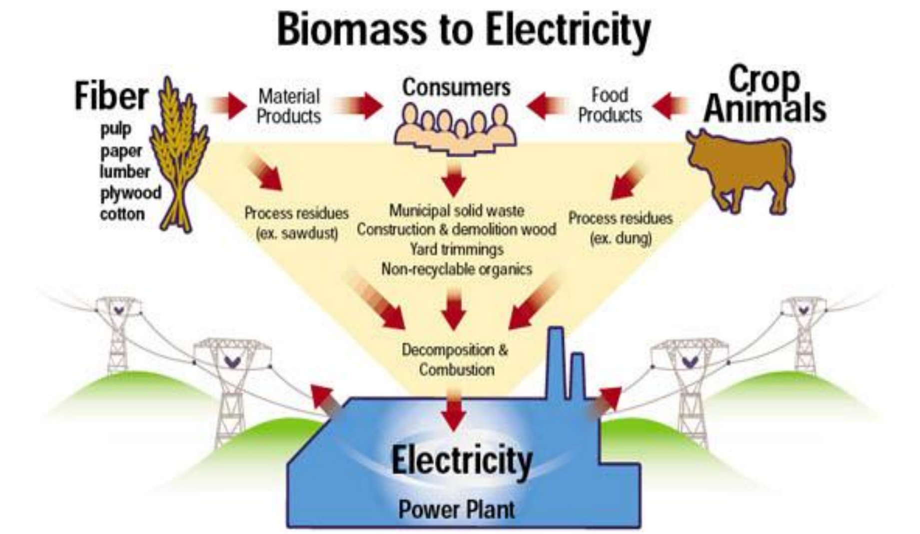
BioMass Generation

When potential energy is stored within materials like plant and animal (organic matter) it is called “biomass”. Biomass is organic matter used in a gasifier to produce heat through a steam turbine to generate electricity or by direct combustion in a gas-fired turbine or reciprocating engine driven-generator. Biomass is renewable because it takes far less time to develop than fossil fuels. Biomass projects are small producers, usually under five megawatts in size.

Renewable biomass may include the use of:

- Agricultural residue
- Animal waste
- Landfill gas
- Pulp/wood waste from wood industry or materials from forests to prevent fires
- Energy crops (corn, sugar, soy, etc)

An example of a biomass project is a landfill gas-to-energy plant that uses organic waste and decomposes to produce methane as a natural by-product. However, methane is considered a potent greenhouse gas with an impact 20 times greater than CO_2. In order to protect the environment and air quality, methane gas from landfills must be flared. Landfill energy production collects the methane gas in a network of wells and perforated pipe buried in the landfill. Blowers create a vacuum system to draw the methane out of the landfill before it is released into the air. Impurities are filtered out, allowing clean, compressed gas to fuel modified reciprocating engines.



For example, the South Utah Valley Solid Waste District (SUVSWD) is considering developing a landfill gas-to-energy plant. Federal regulations require them to capture the methane gas from the landfill. After refinement, the methane gas may be used to generate electricity. With member cities Spanish Fork, Salem and Provo being also members of SUVSWD, it warrants further consideration.

<u>Attributes</u>

- ◊ Biomass generation is a renewable source and should be developed where feasible.
- ◊ Project costs range from \$2,500 to \$4,000 per kW depending on the site and project size, with fuel costs typically low. There still is some uncertainty on the longevity of the units and availability of the fuel source.
- ◊ Depending on the site, the generation may or may not be controllable depending on the biomass fuel source.
- ◊ Typically with biomass generation, the environmental impacts are offset by the ongoing adverse impact and costs of managing the biomass waste. The environmental impacts from converting the waste stream into electricity are an enhancement over the alternative of either storing or destroying the waste by-product.

<u>Summary</u>

The Agency will continue to look for opportunities. The only project under discussion is the landfill gas-to-energy project by SUVSWD. This plant would be small, less than 2 MW. If feasible, this size plant could integrate into UMPA’s resources.

Co-Generation Unit

Combined heat and power plants or cogeneration facilities can consist of several technological configurations for generating electricity. One design involves a combined cycle plant where the boiler also provides steam to a host enterprise such as a hospital or university. Other technologies include use of natural gas or a waste fuel, such as wood chips, in a boiler to provide both steam and power. When appropriately sized for the host thermal load, such an arrangement can result in thermal efficiencies nearing 80 percent. However, it may be difficult to design and allocate capital and operating costs in ways that make these projects cost-effective.

In the history of the downtown Provo Power Plant, waste heat from the plant was to be piped to nearby businesses for heating and chilling purposes. This was called the district heating project. The project was short lived because the Provo Power Plant was removed from base load operations in the early 90's due to its inefficiencies and other power supplies costing much less at the time. Even with the potential for additional revenue from the sale of hot water, the Provo Power Plant was no longer cost effective to run as a base load resource.

Provo's largest customer, Brigham Young University (BYU), is considering the value of co-generation as it plans for replacing its aging heating infrastructure. This plan is still very conceptual. UMPA and Provo will work closely with BYU, and will only pursue this option if and when it becomes feasible to the Agency.

Attributes

- ◊ Typically cogeneration facilities use natural gas to generate electricity and heat. The feasibility lies with the ability to combine the value of generating power and using the waste heat on the surrounding property, thus providing an overall lower cost benefit.
- ◊ Co-generation plants are likely dispatchable to serve the peak period.
- ◊ In most cases, the technology is proven and operations are predictable.
- ◊ The environmental impacts are the same as the other generation method while benefitting by a more useful and efficient fuel conversion.

Summary

The Agency will continue to look for opportunities. The only project under discussion would be located at or near BYU. This plant would likely be between 10 to 15 MW. If feasible, this size plant could integrate into UMPA's resources with proper planning and coordination. There are no other known opportunities being considered.

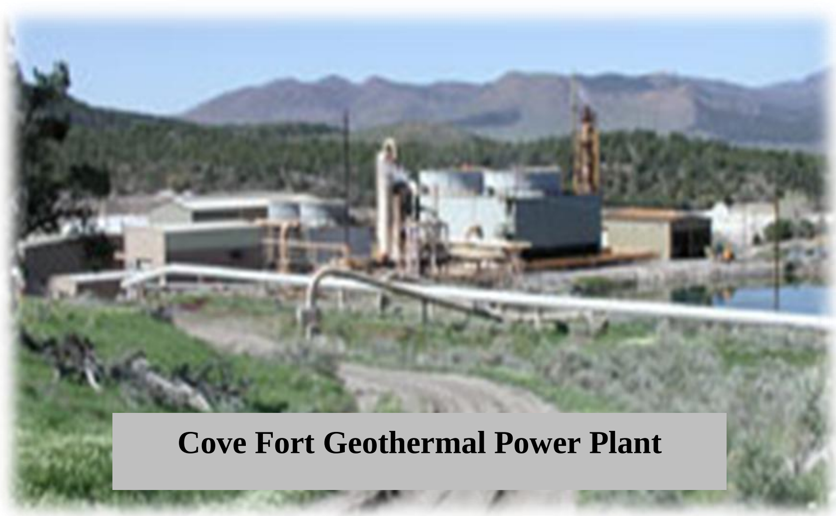
Geothermal Generation

Electricity is generated from geothermal water or steam sources. Technologies in use include dry steam power plants, flash steam power plants and binary cycle power plants. Geothermal power uses steam or hot fluids in underground rock formations to run steam turbine generators. Viable geothermal reservoirs are those that have adequate heat, rock permeability, and hot water or steam, and site accessibility.

Geothermal power plants typically produce power by either flashing hot water into steam or using the hot water to heat a secondary working fluid (such as isobutene, which vaporizes at lower temperature than water). After the water steam or vapor is passed through a turbine, it is condensed and returned back into the reservoir. To prevent resource degradation, geothermal reservoirs must be managed by re-injecting water back into the reservoir. Geothermal power technology has been in use for over 40 years in the U.S., but its application has been limited by the number of commercially viable sites.

The Agency has a history in operating a geothermal project with the Cove Fort Geothermal Project. In1986, Mother Earth Industries (MEI) drilled several hot water wells and built this generating plant. There were many challenges in the early development and operation of the facility. At that time, Provo entered into a power purchase agreement with MEI to take the output. When MEI failed to perform a few years later, Provo bought out MEI's interest and took over the operation.

Beginning in 1994, the Agency started managing and operating the plant on behalf of Provo. The steam resource became more stable, production improved, and costs were better managed. However, even with these improvements, the cost of generation was higher than the market and other sources. It was decided to sell the assets, and allow the private sector to risk and invest in expanding the geothermal source and plant size, thus expecting to lower the overall production cost. The risk to expand and further invest at the site was too great for the Agency. The Agency and Provo sold their assets in 2003. The sale of Cove Fort Plant and its replacement power contract saved the member cities several million. The site was shut down for many years.



Cove Fort Geothermal Power Plant

Recently, Enel Green Power North America, begun construction work on a new geothermal plant with an installed capacity of 25 MW. The plant should enter service by the end of 2013. The total investment is approximately $126 million.

<u>Attributes</u>

- ◊ The location is critical in the development of an efficient geothermal power station. There are few viable geothermal sites for generation.
- ◊ Geothermal plants are capital intensive, in the range of $3,000 to $7,000 per kW, depending on the nature of the site and resource. This high cost is due partly to the cost of drilling exploration wells, which may or may not find a suitable reservoir. Due to the uncertainty of the hot water resource, there is higher risk in the development of geothermal over the alternatives.
- ◊ Geothermal power production is a mature technology.
- ◊ Geothermal generation is a renewable resource for base loads.

Summary

Given the history and experience with the Cove Fort Geothermal Plant, the development of geothermal resources is risky. Being risk adverse, the Agency may elect a favorable power purchase agreement with a potential geothermal plant developer. The Agency will consider future opportunities. However, there are no known projects being considered at this time.

Distributed Generation

Distributed generation is defined as a generating unit(s) located near or at a customer's site that is interconnected to a utility's distribution system. Distributed generators installed by customers may supply electricity alone or the combination of electricity with heat or steam. On-site generators can have several advantages for electricity customers such as:

- If redundant capability is installed, reliability can be higher than grid-supplied electricity.
- Although electricity from distributed generation is generally more costly than grid-supplied power, the waste heat from on-site generation can be captured and used to offset energy requirements and costs for other end uses.
- Distributed generation can reduce the need for energy purchases during periods of peak demand, which can lower energy bills.

Summary

The Agency has the obligation to secure and supply all the electricity needs for the member cities. Permitting distribution generation by member cities may be in conflict with the Agency's contractual obligation unless it meets the net metering policy adopted by the Agency. At this time, there are no known projects. UMPA will work with member cities to consider the feasibility of distribution generation by potential developers to ensure compliance with existing contracts.

Power Purchase Agreement (PPA)

Another option for consideration by UMPA is a long-term power purchase agreement (PPA) to meet the future supply demands. Historically, PPAs have been an effective resource in serving electrical loads. For planning purposes, a long term PPA with contractual terms that range from 5 to 20 years and defined pricing for a buyer to purchase power from a supplier is preferred.

PPA is a contract between two parties, one who generates electricity for the purpose of sale (the seller) and one who is looking to purchase electricity (the buyer). PPA defines all of the commercial terms for the sale of electricity between the two parties, including the plant's availability, schedules for delivery of electricity, performance standards, penalties for under delivery, payment terms, and termination. PPA may be the principal agreement that defines the revenue and credit quality of a generating project and is thus a key instrument of project finance.

Typically, the buyer will require the seller to guarantee that the project will meet certain performance standards. Performance guarantees let the buyer plan accordingly to meet demand schedules and also encourages the seller to maintain the generation facility for peak performance. The seller may be responsible for contractually guarantees on availability and production efficiency.

There are advantages and disadvantages in using a PPA depending on the specific terms and conditions for the supply resource. The buyer has no ownership interest in the power plant and that limits certain risks and responsibilities for the buyer. With no equity, the buyer does not finance the purchase or construction of the generation; freeing the buyer from ongoing debt obligations. The buyer is not responsible for the fuels, labor and other operational challenges. This limits their role and involvement at the generation side of the supply resources. However, it may be in the best interest of the buyer to pre-pay for generation capacity by issuing debt. In addition, the buyer through a PPA may be able to structure the delivery of the power to better fit the system loads.

The buyer may end up paying for the operational risks through higher costs. Just like in any free market transaction, the timing of the contract plays a significant role in setting the terms. If there is a surplus of generation capacity on the market, the buyer is able to ask for more favorable terms of price, flexibility and duration. When the market is favorable to the seller because generation is in demand, this results in higher prices and more favorable terms to the seller. In some cases, when the demand for generation is very high, there are times when no long-term supply contracts are available.

The key elements of a Power Purchase Agreement (PPA) are:

- Length
- Pricing
- Performance standards
- Operating flexibility and production
- Transmission network

<u>Summary</u>
With its past successes, the Agency will consider PPAs as an alternative in meeting the added supply-side resources in the future. However, the Agency should strive for a balanced approach as it considers a PPA. Creating diversity among resources and generation including PPA demonstrate a greater level of redundancy and risk management. The appropriate balance between equity ownership and contracts for power is open for debate. UMPA should solicit proposals from interested sellers and careful analyze the supply-side choices with consideration to the future power market before making its decisions.

Spot Wholesale Electricity Market or Short-Term Purchases
There is a spot wholesale electricity market when utilities their excess capacity and electricity output to other buying utilities or power brokers on an hour-to-hour, day-to-day, or month-to-month basis. The price of fuel, open transmission network, and available generation capacity drive the market between buyers and sellers for these short transactions.

In principle, the system price for the day-ahead market is determined by matching offers from excess generating utilities (seller) through bidding from consuming utilities (buyer) for each transmission region to develop a classic supply and demand equilibrium price, usually on an hourly interval. Energy purchased during the peak periods trades at a much higher cost than off peak periods due to supply and demand needs.

Financial risk management is often a high priority for utilities due to the substantial price and volume risks that the power markets can exhibit. A consequence of the complexity of a wholesale electricity market can be extremely high price volatility at times of peak demand and supply shortages. The particular characteristics of this price risk are highly dependent on the physical fundamentals of the market such as the mix of types of generation plant and relationship between demand and weather patterns. Price risk can be manifest by price spikes which are hard to predict and price steps when the underlying fuel or plant position changes for long periods.

Additionally, there is volume risk which denotes the event whereby electricity market participants have uncertain volumes or quantities of consumption or production. For example, a utility is unable to accurately predict consumer demand for any particular hour more than a few days into the future and a power producer is unable to predict the precise time that they will have plant outages or shortages of fuel. A compounding factor is also the common correlation between extreme price and volume events. For example, price spikes frequently occur when some producers have plant outages or when some consumers are in a period of peak consumption. The introduction of substantial amounts of intermittent power sources such as wind energy will have an impact on market prices.

Electricity utilities that buy and sell from the wholesale market are exposed to these price and volume risks. To protect themselves from uncertainty, the utilities may enter into "hedge contracts" with other utilities. The structure of these contracts varies by regional market due to different conventions and market structures. The two simplest hedge methods are simple fixed price forward contracts for physical delivery and contracts for differences where the parties agree on a strike price for defined time periods.

Buying wholesale electricity is not without its drawbacks (market uncertainty, costs, availability, transmission constraints, and other factors), as electricity would need to be bought and sold on a daily basis. However, the larger the utility's electrical load, the greater the benefit and incentive to utilize and manage the wholesale market.

<u>Summary</u>

The Agency will continue to use the Spot Wholesale Electricity Market to adjust for short periods of uncertainty in resource availability, pricing, or consumers' usage with the ability to manage surpluses and deficits. There are no plans to use the spot market for any other purpose than short-term transactions and to help in maintaining its competitiveness.

Renewable Portfolio Standards

Another applicable factor contributing to Agency's resource planning is the future Renewable Portfolio Standard (RPS). A RPS may created by both state and/or Federal laws and policies designed to increase the utilities' generation of electricity from renewable resources. These policies require or encourage utilities, within a given time line, to supply a certain minimum share of their electricity from designated renewable resources. Generally, these renewable resources include wind, solar, geothermal, biomass, and some types of hydroelectric generation.

Although there has been plenty of public debate in Congress, and extreme lobbying by environmental groups and special interest groups benefiting from renewable power, there is no

Federal RPS or mandate for renewable power. The growing arguments behind climate change legislation have threatened the call for a national RPS and therefore many states and utilities have elected to pursue the development of renewable power in order to prevent strict mandates by the Federal government.

Utah has adopted a target or goal for renewable power. Utah Code 10-19-201states that:

> (1) (a) To the extent that it is cost effective to do so, beginning in 2025 the annual retail electric sales in this state of each municipal electric utility shall consist of qualifying electricity or renewable energy certificates in an amount equal to at least 20% of adjusted retail electric sales.

The state's renewable goal reflects the changing public attitude towards renewable power, and by those key policy-makers for the state. UMPA will be prudent and wise in considering renewable power in its planning to the extent that it is cost effective and in accordance with the law.

Future Resource Criteria and Considerations

UMPA monitors and investigates potential generation resources in the region which may be considered for inclusion in UMPA supply-side portfolio. In reviewing the American Public Power Association's report on "New Generating Capacity for 2013", it indicates that the near term trend continues to favor natural gas as shown below:

Fuel Mix of New Plant - Under Construction

Primary Fuel Type	Capacity (MW)	% of Total
Natural Gas	16,491	40.9%
Wind	7,695	19.1%
Solar	5,121	12.7%
Nuclear	4,620	11.4%
Coal	3,714	9.2%
Wood	835	2.1%
Water (Hydro)	639	1.6%
Other	1,246	3.1%
Total	**40,361**	

With each new supply-side opportunity, UMPA will be prudent and careful in the review and investigation according to the IRP process. Factors to be considered in the selection of any supply-side resources should be:

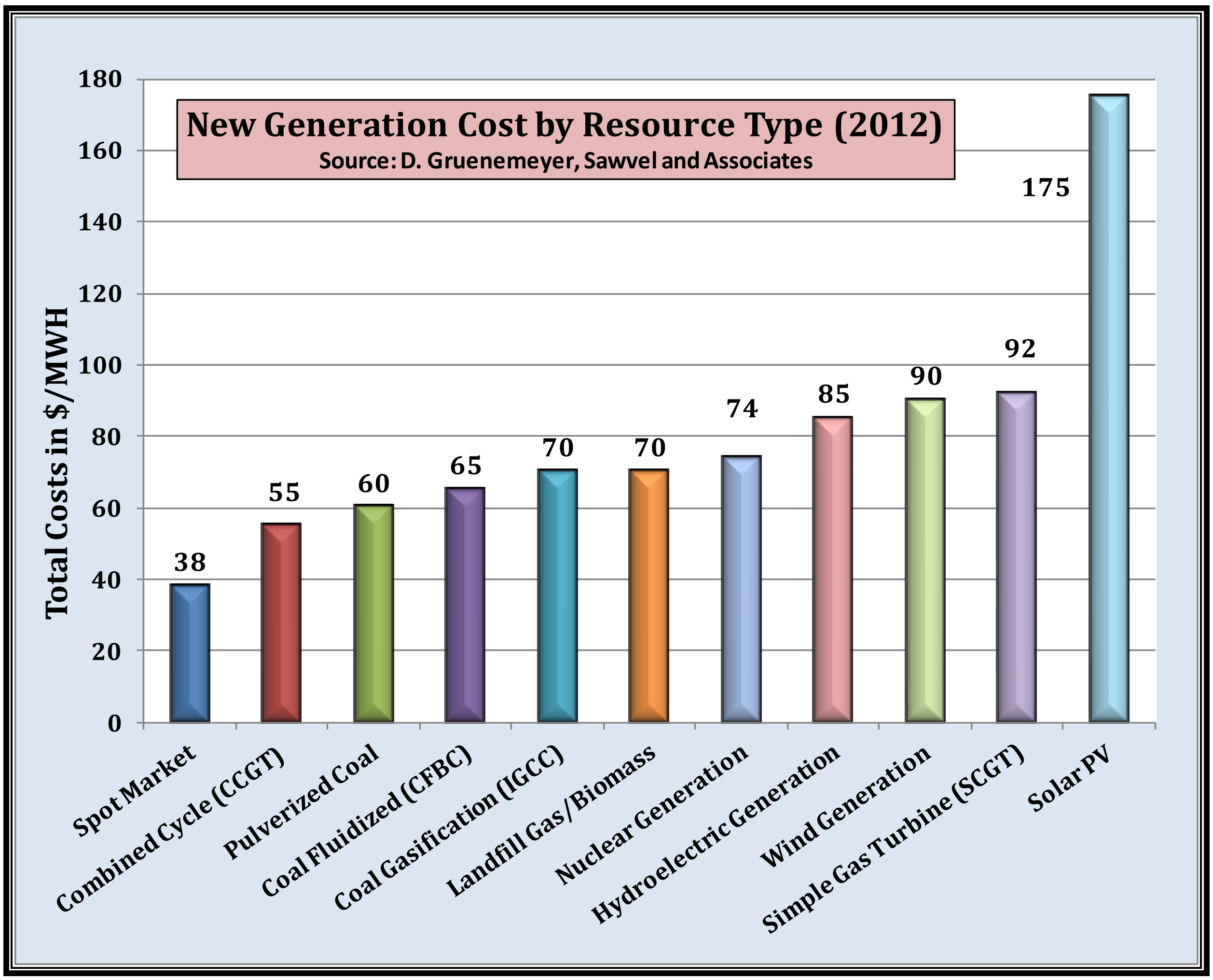
- Balance between ownership and purchase agreement
- Size in capacity and energy output
- Costs
  - Capital
  - Operating
  - Fuel
  - Transmission
  - Financing

- Environmental impacts
- Operating criteria, scheduling flexibility, and ability to dispatch for load
- Reliability, efficiency, and durability
- Location
- Diversity, fuel options and other risk factors
- Transmission network constraints

If the supply-side meets the respective criteria listed above, then UMPA will evaluate it on the second level which includes:

- Economic considerations
- Environmental considerations
- Governance and control considerations

The following graph illustrates the typical generating cost for the different type of supply-side resources under consideration.

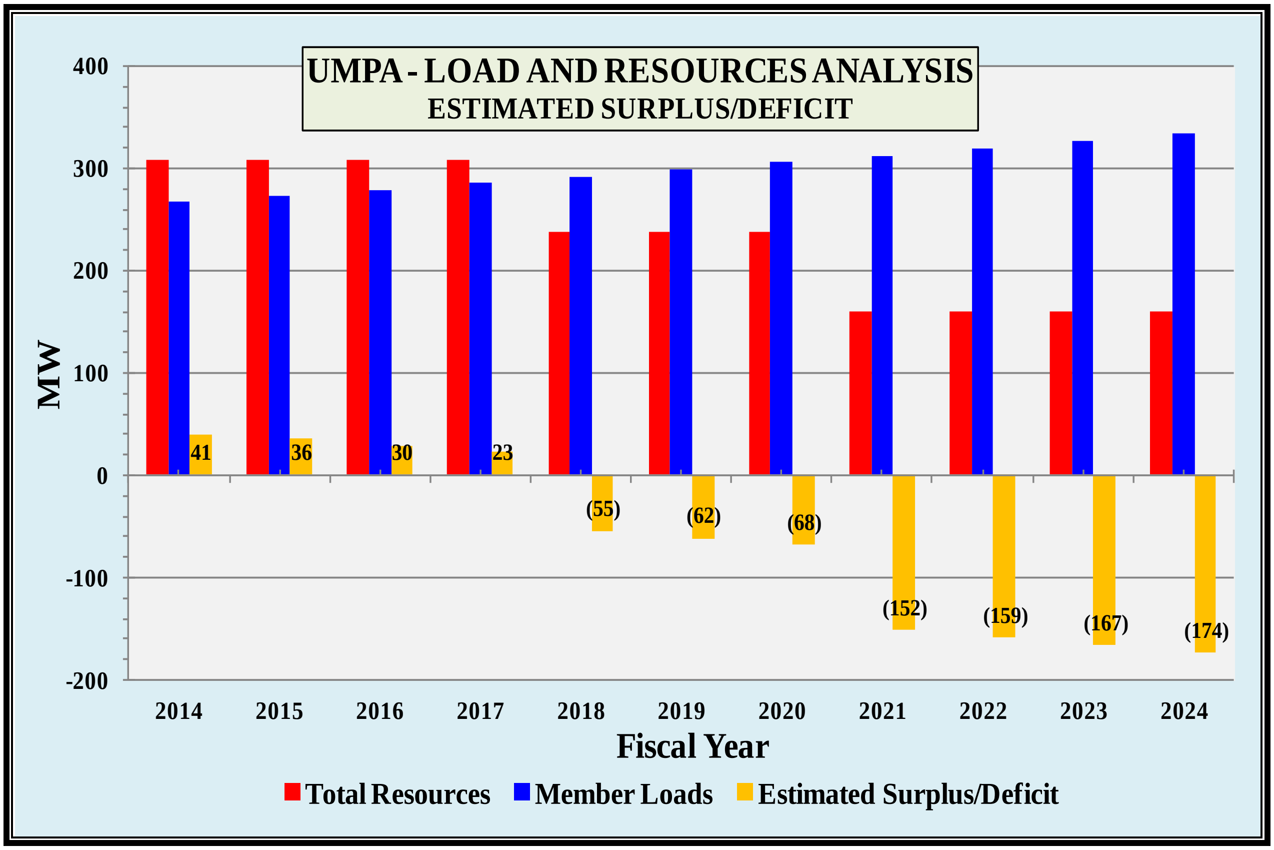


Supply-Side Plan of Action

Supply-side resources for planning and further consideration are as follows:

- Investigate and seek participation via ownership (preferably) or purchase agreement in natural gas combine cycle gas fired turbine power plant.
- Promote renewable power resources where cost effective. Investigate the potential of a land fill gas plant with South Utah Valley Waste District. Support the net metering efforts by the member cities.
- Investigate the potential for co-generation facilities in cooperation with member cities and their customers.

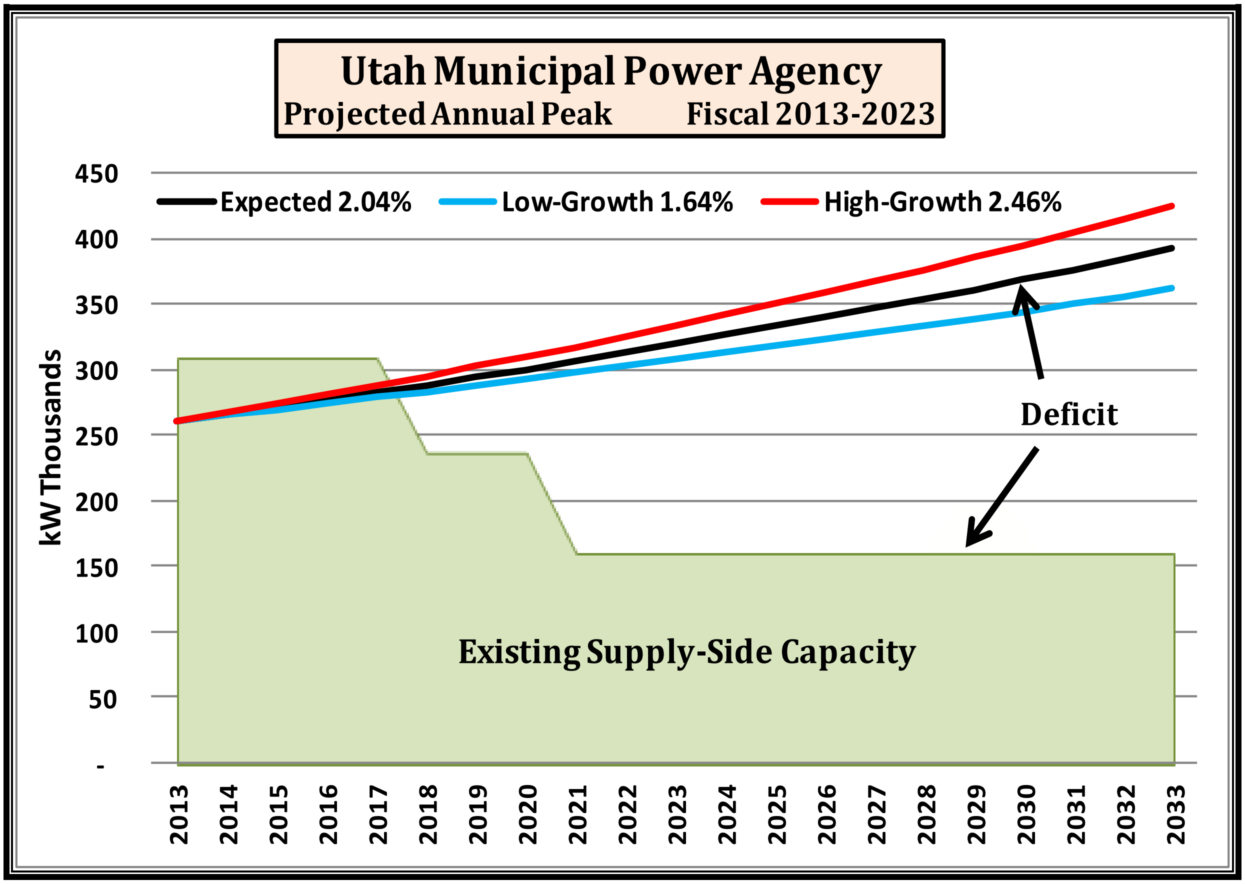
The following graph depicts the forecasted loads, available supply-side resources and the surplus or deficit for the coming years:



In summary, UMPA's members have enjoyed low electric rates because of the coal fired resources developed in the region and the access to Federal developed hydroelectric generation. The opportunity to develop large hydroelectric projects no longer exists. Concerns with climate change and regulatory uncertainty make it impractical to develop new coal resources as a future alternative, even with the abundance of coal supply in the region. Clean coal technology may still be a resource possibility with further advances in design. With the RPS, renewable power will continue to play a significant role in meeting the demands for future resources.

For the future, UMPA must find a base and intermediate load resource to replace the energy deficit left from the expiring power purchase contracts and continued growth on the system. The primary replacement source available today comes from natural gas. UMPA will be exploring the development and participation in a natural gas fired plant.

The following graph shows the deficit in meeting the forecasted loads with the current supply-side resources into the future years:



Description of the Demand-Side Management (DSM) Programs

Introduction

The use of Demand-Side Management (DSM) is an effective tool in reducing and changing the usage patterns of electricity by the consumer. DSM examines how customers use electricity and determines how their usage patterns could be changed to make generation more effective. The current strategy by UMPA calls for continuing to promote conservation and energy efficiency through a variety of DSM programs where the programs are less than the avoided cost of production.

The DSM programs are an essential component of the resource strategy. The member cities are responsible for implementing and managing the DSM programs with their customers. UMPA's role is to develop, encourage, promote, train and assist the member cites with several options for their specific DSM programs. Each city may select which programs best fit their needs of the community, and plan and fund those programs accordingly. UMPA will continue to track and report the results and successes from each member city.

The Agency's goal is to assist the member cities in helping their customers use energy more efficiently and effectively without sacrificing convenience and quality of service. Our demand response programs are focused on reducing peaks; while, the energy efficiency programs target year-round energy and demand reduction.

Over the years, UMPA and its members have attempted to track and report the benefits and savings from the implemented DSM programs as described in this section. The IRP calls for the continued use of some programs, the adoption of others, and additional investigation into other DSM programs. The implementation and continuation of any DSM program will be based on a cost to benefit value.

Description of FY2007 DSM Programs – Consideration and Status

As reported to Western, the active DSM programs provided for in the FY 2007 IRP are enumerated and explained as follows:

Tree Planting

This program was initiated in 1996. Trees are provided to consumers with central air conditioning to plant for shading their homes to reduce energy consumption. DSM-related planting of trees will not account for any capacity and energy savings for the first 15 years in order to allow the planted trees to mature. Once they reach maturity, a savings is estimated of 0.14 kW and 210 kWh per year per tree. Additional trees have been planted for utility purposes and achieve city forestry plans that support the mitigation of greenhouse gases.

Completed
To date, UMPA member cities has planted **9,340** trees under this program. With the first trees planted in 1996 and after maturing for 15 years, there is a estimated reduction of 151 kW and 227,745 kWh for FY2012.

Target
UMPA is committed to continuing this program with the target of 250 trees planted each year. The overall goal is to move towards one tree planted per customer having central (refrigerated) air conditioning.

City/Utility Facilities (In-House) Conservation Program

As stated in previous plans, member cities have implemented this program to promote energy efficiency in their city buildings and facilities. Feasible improvements were made where funding was available. Improvements included efficient lighting, weatherization with windows and insulation, efficient heating and cooling equipment, improved motors, and added energy control devices. Using the latest technology and products, this program will continue to look for ways to improve energy efficiency with city facilities.

Completed
In FY2012, only two members reported reductions. The improvements resulted in a reduction of 1.1 kW and 2,821kWh.

Target
UMPA is committed to continuing this program with the target of further reduction as it is determined to be cost effective. This will be ongoing effort to improve and reduce energy at city buildings and facilities. In addition, there will be a greater effort to collect and report potential reduction likely not captured in prior years.

Energy Efficient Street Lights

Replacing street lighting with more efficient lights has proven to be cost effective. At the adoption of the original plan, the more efficient high pressure sodium (HSP) street lights were installed to replace the older mercury vapor street lights. With LED street lighting being commercially available, UMPA and its member cities will continue to promote energy efficiency by installing new and enhanced LED lighting where feasible. In addition, member cities are making efforts to replace current street lights nearing the end of life with LED technology. Replacing a HPS light fixture with a new LED light saves an additional 50% to 60% energy.

Cities are also retrofitting traffic signals with LED lighting to improve efficiency. Several member cities have already converted many traffic lights to LED in the past few years. These efforts to reduce energy were not documented at the time. However, we plan to document the LED upgrades in the future.

Completed
In FY2012, there were 409 new street lights installed and replaced with the majority being LED lights. These improvements are estimated to have reduced 44.3 kW and 194,056 kWh.

Target
UMPA is committed to reducing energy by replacing older, less-efficient street lamps with more efficient lights. Where feasible and funding is available, cities will install LED lights and efficient HPS lights. There is a target of 100 street light upgrades per year.

Low Loss Distribution Transformers

UMPA member cities will continue to only acquire low loss transformers and will not accept transformers with estimated average no-load and full load losses that exceed 10%. The economic approach governing purchase decisions remains the same as in prior plans. Member cities will investigate and develop new benchmarks in the coming year to further expand this program and set new standards for purchasing.

Completed
In FY2012, there were 180 new low-loss transformers installed and/or replaced on the system. The improvements resulted in a reduction of 63.6 kW and 514,834 kWh.

Target
UMPA is committed to a reduction in energy by using efficient low loss transformers for replacement and new installations. There is a target of 100 new transformers per year. In addition, the standard will be studied in the coming year and improved for better reductions.

Residential Energy Audits

The member cities have been offering residential audits since 1996. Over time the auditing program has improved to identify efficiency in homes by offering information

and infrared images showing the air flow through windows, walls and the overall structure of the home. In addition, the audit examines the efficiency of current appliances and electronics. This information helps a homeowner make a determination if weatherization, new equipment, change in living behavior, or appliance upgrades are necessary to increase the efficiency and reduce consumption in the home. The number of audits varies from year to year, and is determined by the public interest.

Completed

In FY2012, there were162 residential audits performed. Based the education value and home improvements made by the consumers, the residential audits reduced an estimated 8.2 kW.

Target

UMPA is committed to continuing this program with the target of 25 residential audits each year. Since this is a customer voluntary program, participation is not mandated by UMPA members. We plan to encourage and promote for the benefits of energy audits with the consumers.

Education

Since 2002, UMPA has engaged the National Energy Foundation (NEF) to assist in providing formal education in the public school system regarding energy saving ideas and methods. The program offers a variety of energy saving devices to the students along with emphasis on improving the behavior in better utilizing electricity. Each year, the NEF focuses its program at a specific grade (typically 4th, 5th or 6th grade) and teaches their energy conservation program at a number of schools within the UMPA's service territory to complete the training. The results have been very favorable from both the students and teachers by acknowledging the value in teaching energy efficient concepts to future consumers. The students are invited to survey their energy usage at home, involve the participation of the parents, and then discuss the results with the class. They are then encouraged to apply new techniques, use appliances during off-peak periods, and make simple improvements to observe the reduction of energy. For example, students were given a compact fluorescent light bulb to replace an incandescent bulb to demonstrate a reduction in energy to their parents.

Member cities conduct other public meetings and events throughout the year where energy conservation and efficiency are promoted and marketed. Many of the cities' web sites offer conservation tips and advice. Cities use monthly newsletters as another communication tool to educate and inform the public.

Completed

The NEF attempts to quantify the energy savings and reduction of energy from their programs and products provided to the students. For FY2012, NEF conservatively reported and estimated a reduction of 507 kW and 1,230,260 kWh.

Target

UMPA is committed to fund the education of energy efficiency in the schools and plans to use NEF in the coming years. It is expected that similar savings will be targeted in the future as in the past. Member cities will continue to sponsor and host events for promoting the message of conservation and wise energy use. The combination of monthly utility bills and city newsletters will continue to offer energy saving tips.

Assessment of Completed DSM Program
When UMPA prepared and submitted the IRP in 2007, it estimated the benefits from the proposed DSM program as follows:

Summary of the DSM Energy Value (kWh) for Year 2012

Program	**Estimated Savings**	**Actual Savings**
Tree Planting	170,330	227,745
In-House Conservation and others	923,631	787,527
Education	791,895	1,230,260
Total	1,885,856	2,245,532
Total Energy Saving (kWh) Cumulative IRP Period (2007-2012)	5,657,358	12,876,133
Estimated Savings at Retail Pricing		**$1,222,969**

The results of the DSM programs during the IRP reporting period from FY2007 through FY2012 are better than expected. This number is likely understated due to the lack of recording all of the efforts by UMPA and its member cities with new energy efficiency programs being added during this period. The annual DSM measurements and performance report is located in the Appendix C – Member City Demand-Side Management Data.

New FY2013 DSM Programs

In December 2009, UMPA adopted to expand the Demand-Side Management Programs and guidelines for member cities. To date, the existing programs have yielded the desired benefits of reducing load growth by encouraging conservation and wise use of electrical energy by consumers. UMPA believed that additional conservation benefits can be realized by providing a frame work of principles and goals for the member cities to design, implement, operate, monitor and report new programs tailored to meet the demographics, demands, loads and economics for each city. This new direction opened the door for net metering and other programs to be examined, developed and implemented as each city evaluates its own situation.

The new guidelines state that a DSM program includes all activities, policies and processes that:

(a) Encourage retail energy conservation using print, video, audio materials;
(b) Provide rate price signals using time-of-use metering and computer software or systems allowing retail customers to see their current usage and rates;
(c) Utilize electronic systems to temporarily shut-off or restrict retail customers appliances, air conditioning or other electrical energy intensive equipment during peak periods; or
(d) Other programs approved by the board.

In addition to the DSM programs and targets listed above, UMPA member cities are committed to add the following DSM programs and targets for the coming five years to defer and delay the building of additional capacity in the future:

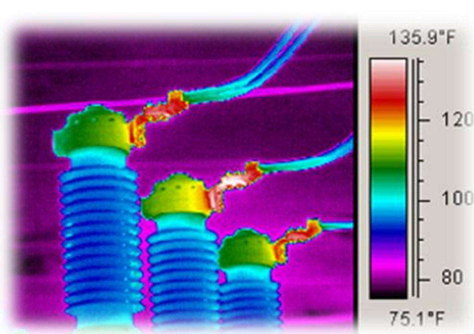
Voltage Regulator Control

This program may allow UMPA and member cities to save as much as 2% of its peak load during critical periods. For those members with remote voltage control, this program could be activated during the monthly system peak and result in significant kW reductions. Over time, the kW reduction and value would likely escalate with load growth. Although this DSM program has been mentioned in prior plans, it has not been implemented. More studies, system improvements and added controls are necessary before the program is ready to deploy. Once the program is active, it may be used during periods of operational or economic necessity when UMPA's loads are the highest.

<u>Target</u>

UMPA is not ready to implement this program and will continue to study for future consideration. The actual use will depend on the operational or economic necessity for reduction in peak demand. There is no targeted kW reduction at this time.

System Infra-red Scanning



The loss of energy through excessive heat in connections and electrical equipment is another area of concern for the member cities. System losses are monitored and are benchmarked against other utilities. In order to reduce losses, regular inspections and infra-red scanning of substations and major equipment identify problems before they become catastrophic and result in outages or system damages. This inspection demonstrates the level of commitment to system efficiency.

Target

UMPA's members plan to use this tool for reducing system losses caused by poor connections and equipment performance. The measuring of energy saved by correcting each trouble spot is difficult to define. UMPA will continue to measure the overall system losses and use this program to supplement its effort for a reliable and efficient system. Comparing and demonstrating lower system losses than the utility standard reflects a commitment to system efficiency. There is no targeted kW reduction at this time. UMPA will track the cost and labor time committed to this program.

Net Metering Program

Although this may not be considered a true DSM program, UMPA's promotion of a net metering program will reduce overall system loads by generating electricity at the point of use, thereby reducing the cost of future generation and system capacity. Most of the UMPA member cities offer a net metering program for consumers that want to install renewable power supplies to generate electricity on their site and offset the delivery of electricity by the utility. This program was started in 2010. To date, there are 25 customers using net metering.

Target

UMPA is committed to continuing this program and promoting the benefits to the consumers through its members. Since this is a customer voluntary program, participation may not be mandated by UMPA and will be encouraged for the benefit of the consumer. There are no targeted energy and demand reductions at this time. UMPA will track and quantify the number and system size in the coming years.

Weatherization Rebates for Residential

UMPA member cities may elect to implement and promote conservation and energy efficiency through a residential weatherization rebate program. The weatherization rebate program offers an incentive on the improvement of energy efficiency in residential buildings through the installation of qualified and more efficient windows, added insulation in walls and ceilings, and installation of more efficient central air conditioning. This program will be similar to other surrounding utilities offering rebates for weatherization for ease of marketing and administration. Provo currently offers this program and other members are considering the option.

<u>Target</u>
UMPA will encourage this program for the consumers through the member cities. Since this is a customer voluntary program, participation may not be mandated by UMPA and will be encouraged for the benefit of the consumer. There are no targeted energy and demand reductions at this time. UMPA will track the cost and weatherization benefits in the coming years.

Energy Efficiency Appliance Rebates – Energy Star

UMPA member cities may elect to implement and promote conservation and energy efficiency through an appliance rebate program. The appliance rebate program offers an incentive on the purchase of new qualified energy-star rated appliances in our customer's homes including refrigerators, dishwashers, clothes washers, lighting fixtures and ceiling fans. This program will be similar to other utilities offering rebates for weatherization for ease of marketing and administration. UMPA encourages members to determine the consumers' interest in these products and the appropriate funding mechanism.

<u>Target</u>
UMPA will encourage these programs for the consumers where feasible. Since this is a customer voluntary program, participation may not be mandated by UMPA and will be encouraged for the benefit of the consumer. There are no targeted energy and demand reductions at this time. UMPA will track and report the costs and participation levels by city.

Refrigerator Disposal

UMPA member cities may elect to implement and promote energy efficiency through a refrigerator/freezer disposal program by contracting with a third party to remove appliances from the customer's homes. The member utility may promote energy conservation through a rebate to incentivize the customers to clean out old, inefficient equipment, and offering them an avenue and resource to properly dispose and recycle the equipment. This program will be similar to other utilities offering rebates for refrigerator disposal for ease of marketing and administration. Currently, Provo offers this program and others are considering it.

<u>Target</u>
UMPA will encourage the promotion of this program for the consumers through the member cities. Since this is a customer voluntary program, participation may not be mandated by UMPA and will be encouraged for the benefit of the consumer. There are no targeted energy and demand reductions at this time. UMPA will track the cost and energy savings in the coming years.

Future DSM Opportunities

UMPA is committed to increase the efficient use of energy and power through other activities, programs, and technology as the systems are commercially available and meets the DSM criteria stated in this IRP. Other DSM programs under further consideration are:

- Power Factor Correction – Members are encouraged to monitor their distribution systems and power factor and take corrective action where needed. This results in reducing the loss of power due to excessive reactive power issues.

- Restructuring of Retail Rates - Members are encouraged to study and evaluate the implementation of new retail rates designs that will promote energy conservation such as an inclining energy block or time of use design.

- Load Control Program for Central Air Conditioning – UMPA will work in the coming years with the members to study and determine the value for this program. This program needs to be compatible with the supply-side resources and costs.

- Smart Grid Programs – It has been stated that a modernization of the national grid system expects to reduce demand by 20% in the nation and enough to eliminate hundreds of power plants. Several members have implemented AMI (automated metering integration) for improved system monitoring and accuracy of system losses. UMPA and its members will continue to investigate new technology and implement it based on the DSM criteria.

Projection of Future Benefits from DMS

Summary of the Projected DSM Energy Value (kWh)
FY2017

Program	Estimated Savings
Tree Planting	750,000
Auditing and Conservation	20,000
Energy Efficient Street Light	250,000
Low Loss Transformers	500,000
Appliances and Weatherization	250,000
Education	1,200,000
Total	**2,970,000**
Total Energy Saving (kWh) 5-Year Cumulative IRP Period (FY2013 to FY2017)	**13,500,000**

Summary of Action Plans for DSM Programs

These activities and resultant efficiencies will assist UMPA in deferring construction of a new power plant or the early purchase of additional supply-side contract(s). In many cases, these DSM programs provide a lower cost option compared to the cost of building new power plants. This Plan recommends the continuation of preferred DSM Programs with emphasis also on newly developed programs since the previous submission of UMPA's IRP. This commitment is made notwithstanding that it has been demonstrated that UMPA has an adequate supply of existing resources to meet its members' future loads during this study period.

Each UMPA member has devised operating procedures for implementing programs as described in the IRP. Each member has internally noted progress reporting since the publication of the previously submitted Plan. In numerous cases, progress is deemed to be ongoing, and in other cases, specific projects have been completed and internally documented.

As demonstrated in its history, UMPA will study, investigate, consider and implement new technology, methods, programs and products that reduce or improve the efficient use of electricity using the criteria offered in this IRP. UMPA considers this a dynamic process and desires to enhance services to its members and consumers. UMPA welcomes demand-side alternative programs to meet the growing needs of its members.

Description on the IRP Approval Process

Overview

This IRP was prepared and drafted by the UMPA staff using operating data and records for the reporting period. Demand-side management activities were reported by the member cities through an annual survey and collection process. The UMPA staff with input from the member cities via participation at various meetings and consultations has played a significant role in developing the IRP. Therefore, the IRP was submitted in draft form for the approval of the UMPA Board of Directors followed by an invitation to the public to review and offer comments.

The Draft IRP was available to the member cities and posted on UMPA's web site at http://www.umpa.cc/. The public was invited to review and submit comments on the Draft IRP. The public comment period was for thirty (30) days from March 5st to April 4th, 2013.

Upon closing of the comment period, it was expected that the UMPA staff would collect, compile and consider all of the public comments. Then, the staff would prepare a report that would analyze each comment, offer suggested changes and recommendations in response to the comment, and seek approval from the UMPA Board on the final IRP report. However, there were no comments submitted by the public requiring a response or modification to the plan.

The final adoption of the IRP is scheduled for April 24, 2013 at the UMPA Board of Directors which is open to the public.

UMPA expresses appreciation to the UMPA Board of Directors and Technical Committee for their participation and support of this effort. The Board consists of the following members:

- Levan – Mayor Russell Mangelson, Chair
- Provo – Mayor John Curtis, Vice Chair
- Nephi – Mayor Mark Jones, Secretary/Treasurer
- Spanish Fork – City Council Member Steve Leifson
- Manti – Mayor Natasha Madsen
- Salem – City Council Member Sterling Rees

The Technical Committee consists of the following members:

- Salem - Clark Crook, Chair
- Nephi – Tony Ferguson, Vice Chair
- Levan – Jason Worwood
- Spanish Fork – Kelly Peterson
- Manti – Gene Rogers
- Provo – Tad Smallcomb (alternate)

The UMPA staff involved in the preparation of the IRP consists of:

- W. Leon Pexton, General Manager and COO
- Layne Burningham, CFO and Future GM
- Kevin Garlick, Power Resource Manager
- Scott Lynsky, Operations Manager

- William Doty, Operations Analyst
- Jacob Chrisman, Resource Scheduler

Timeline
The following represents key dates and the timeline for completing the IRP:

February 20, 2013	Technical Committee reviews draft language on DSM and load forecast for the IRP
February 27, 2013.	Technical Committee reviews the Draft IRP.
February 27, 2013	Board of Directors reviews the Draft IRP.
March 5, 2013	Start of the Public Comment Period
April 4, 2013	End of the Public Comment Period
April 24, 2013	Technical Committee reviews public comment report and findings and recommends approval to the Board of Directors.
April 24, 2013	Board Directors reviews public comment report and findings and considers approval of the IRP by resolution. (See UMPA Resolution adoption of the FY2013 IRP in Appendix D).
April 26, 2013	Post the FY2013 IRP on UMPA's web site.
April 26, 2013	Submit FY2013 IRP to Western.

The final Integrated Resource Plan is available on the UMPA website at http://www.umpa.cc/.

Public Comments
The comments submitted by the public and associated response from the Agency are filed under Appendix F, Public Comments and UMPA Response. The IRP was modified to reflect those comments offered and approved by the UMPA Board of Directors.

Reporting Action Plan and Measurement Process

UMPA will continue to report its findings and data to Western on an annual basis in accordance to the IRP. The report will update Western as to progress, measured success, and decisions made toward both supply-side resources and demand-side management programs. Every year at the end of the fiscal year, UMPA plans to follow the steps in collecting and reporting the data:

- Prepare a detail survey and submit to all the member cities.
- Collect the data including the DSM activities and related energy reductions from member cities.
- Prepare an annual report on DSM Activities with performance measurements on each program described within.
- Submit this DSM report to Western in accordance to guidelines.
- Update the load forecasts.
- Investigate and secure new supply-side resources in accordance to the IRP standards.
- Submit historical energy and power supply data to Western.
- Update the timeline and progress on adding new supply resources to the existing resource mix.
- Post supply resources and DSM progress data on UMPA's website for public review.

List of Appendices

Appendix A - Member City Information

Salem City

For more information - Web site: www.pondtown.org/

Customer Profile (FY 2012)

1 Service Area — 10.17 square miles

2 Geographical Characteristics — 85% urban development with some agriculture areas in current service area. Annexed area to be served in the future (currently rural and agriculture)

3 Customer Mix

	No. of Customers	Kwh Sales	Percentage
Residential	1,808	18,734,988	59%
Commerical	171	11,461,549	36%
Industrial	1	781,200	2%
Agricultural	-		0%
Street Lights	-		0%
Exempt Accounts	-	1,041,990	3%
Total	1,980	32,019,727	

4 Historical Loads — See attachment for Salem's historical loads and graph

5 Projected Loads — See attachment for Salem's projected loads and graph

6 Existing System Data

Peak	9,068	kW
Energy	33,718,322	kWh
Number of Electric Meters	1,980	
Population	6,603	
Miles of Distribution Lines	45	
Number of Substations	2	

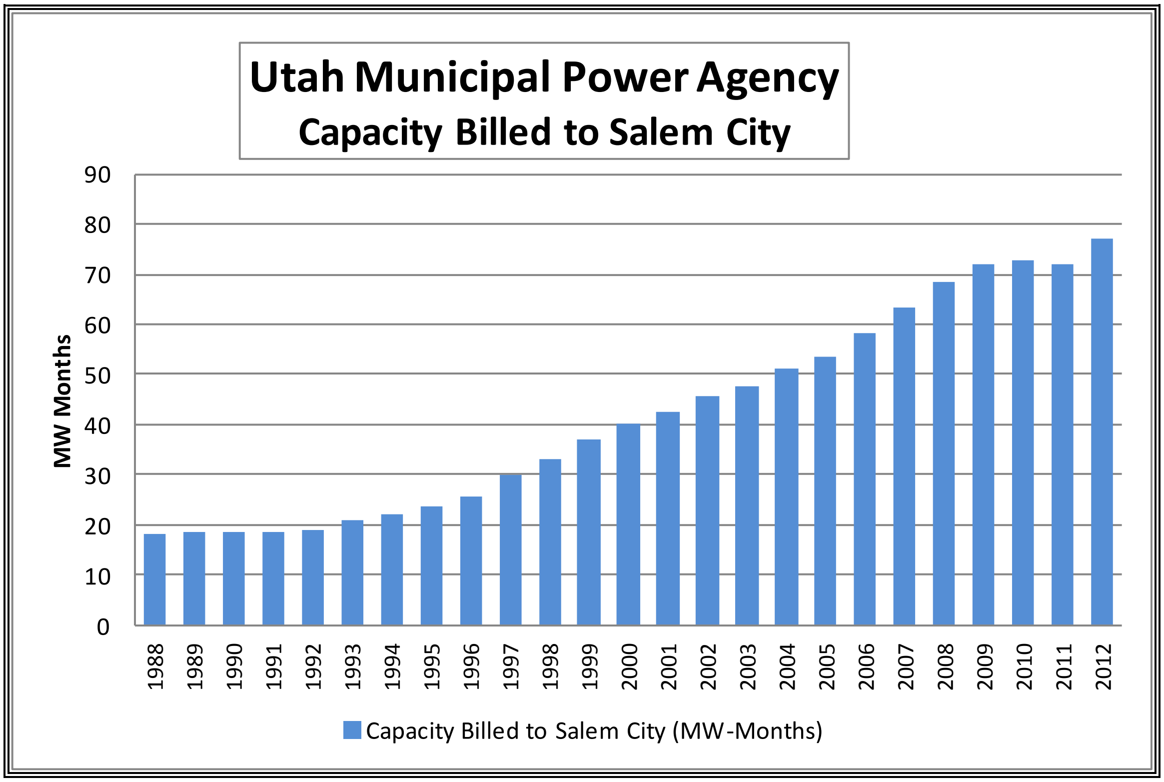
7 Rates - Current Rates (July 2012)

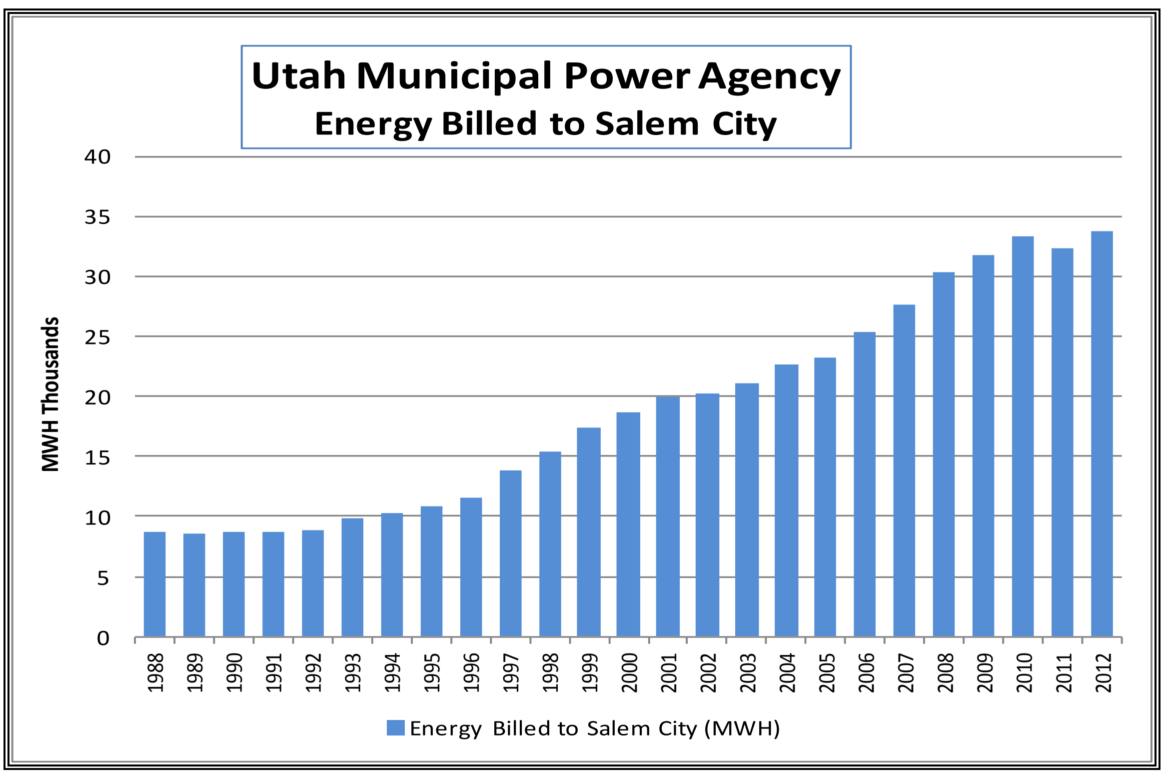
Residential	Base	$11.00
	First 500 kwh	$0.077659 per kwh
	501 to 999 kwh	$0.091650 per kwh
	1,000 kwh	$1.50
	1,001 to 1,499 kwh	$0.110000 per kwh
	1,500 kwh	$2.50
	Over 1,500 kwh	$0.117500 per kwh
Commerical	Base	$49.00
	Demand	$10.99 per kw
	First 3,000 kwh	$0.033718 per kwh
	Over 3,000 kwh	$0.046100 per kwh

8 Financial Information (FY2012)

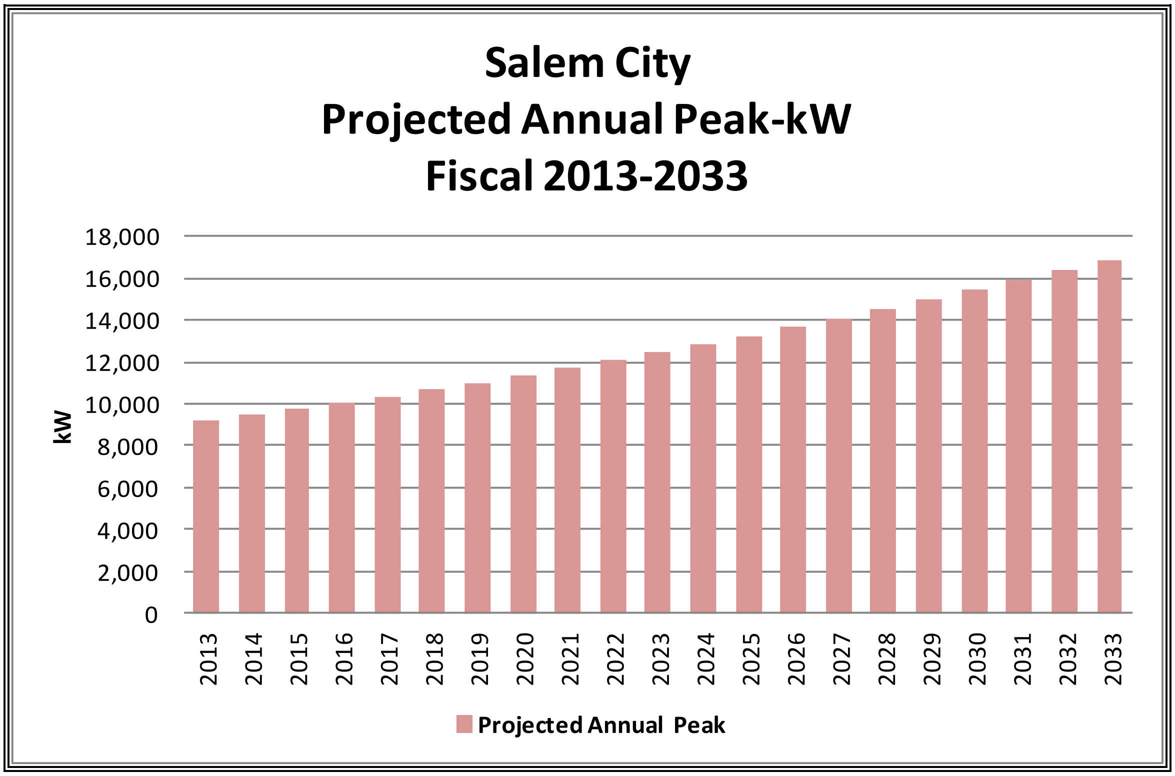
Electric Revenues	$3,027,226
Other Revenues	$14,842
Total Revenues	$3,042,068
Purchased Power Expense	$1,993,344
Other Expenses	$1,045,661
Total Expenditures	$3,039,005

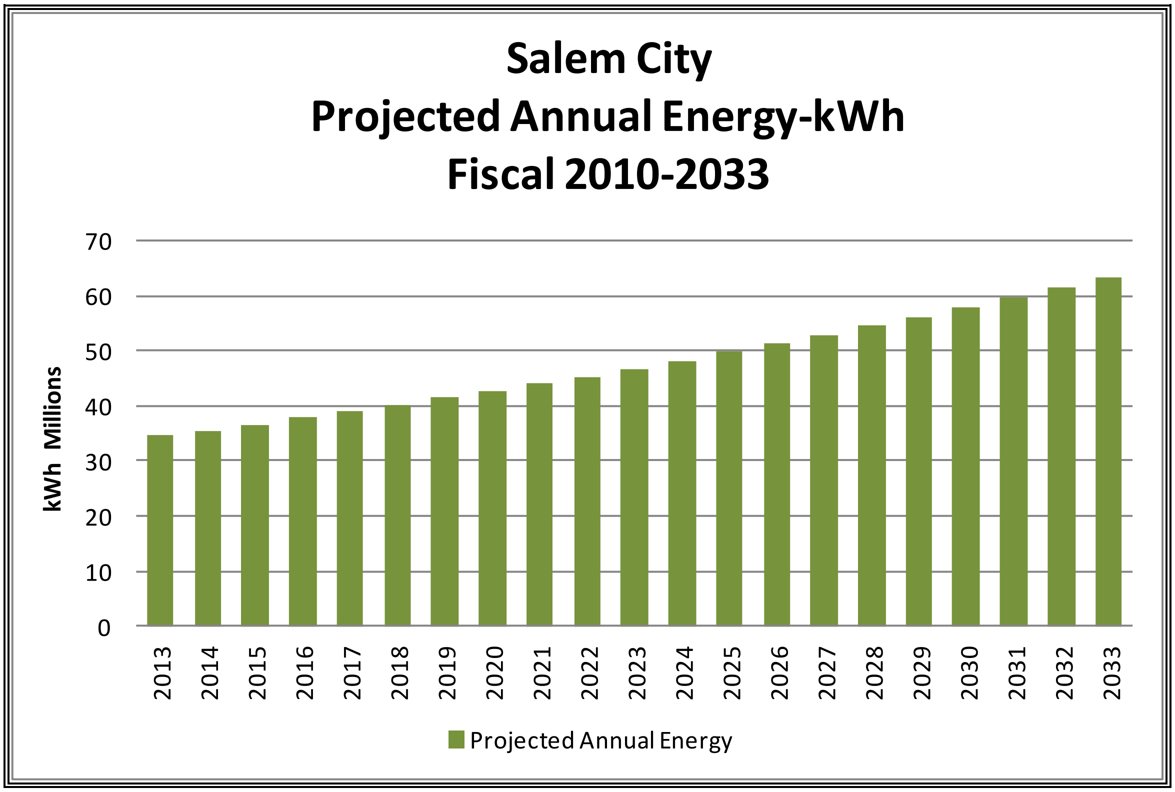
		Utah Municipal Power Agency				
			Salem City			
		Historical Non-Coincidental Load Growth				
		Fiscal Years 1988-2012				
Year	Annual Peak (MW)	% Change Over Prior Year	Capacity Billed to Salem City (MW-Months)	% Change Over Prior Year	Energy Billed to Salem City (MWH)	% Change Over Prior Year
1988	1.753	-	18.141	-	8,654.308	
1989	1.917	9.36%	18.414	1.50%	8,585.090	-0.80%
1990	1.735	-9.49%	18.422	0.04%	8,689.461	1.22%
1991	1.992	14.81%	18.642	1.19%	8,662.340	-0.31%
1992	1.910	-4.12%	19.130	2.62%	8,828.112	1.91%
1993	2.128	11.41%	20.960	9.57%	9,841.883	11.48%
1994	2.190	2.91%	22.022	5.07%	10,312.790	4.78%
1995	2.293	4.70%	23.566	7.01%	10,882.033	5.52%
1996	2.422	5.63%	25.489	8.16%	11,615.602	6.74%
1997	3.003	23.99%	29.970	17.58%	13,775.620	18.60%
1998	3.194	6.36%	33.099	10.44%	15,359.891	11.50%
1999	3.550	11.15%	37.126	12.17%	17,362.732	13.04%
2000	4.036	13.69%	40.157	8.16%	18,702.261	7.71%
2001	4.376	8.42%	42.698	6.33%	19,981.750	6.84%
2002	4.802	9.73%	45.679	6.98%	20,281.005	1.50%
2003	5.247	9.27%	47.579	4.16%	21,043.389	3.76%
2004	5.727	9.15%	51.168	7.54%	22,671.979	7.74%
2005	5.773	0.80%	53.445	4.45%	23,210.113	2.37%
2006	6.567	13.75%	58.351	9.18%	25,417.253	9.51%
2007	7.039	7.19%	63.331	8.53%	27,646.578	8.77%
2008	7.810	10.95%	68.581	8.29%	30,334.055	9.72%
2009	8.681	11.15%	72.009	5.00%	31,745.523	4.65%
2010	8.183	-5.74%	72.613	0.84%	33,303.864	4.91%
2011	8.753	6.97%	72.000	-0.84%	32,341.586	-2.89%
2012	9.068	3.60%	77.203	7.23%	33,718.322	4.26%


Utah Municipal Power Agency
Capacity Billed to Salem City
MW Months
90
80
70
60
50
40
30
20
10
0
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Capacity Billed to Salem City (MW-Months)


Utah Municipal Power Agency
Energy Billed to Salem City
MWH Thousands
40
35
30
25
20
15
10
5
0
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Energy Billed to Salem City (MWH)

20 Year Forecast -Salem City				
Year	Annual Peak kW	% Growth	Energy Requirement (MWh)	% Growth
2013	9,217	0.00%	34,668,221	0.00%
2014	9,456	2.60%	35,569,595	2.60%
2015	9,749	3.10%	36,672,252	3.10%
2016	10,052	3.10%	37,809,092	3.10%
2017	10,363	3.10%	38,981,174	3.10%
2018	10,684	3.10%	40,189,590	3.10%
2019	11,016	3.10%	41,435,468	3.10%
2020	11,357	3.10%	42,719,967	3.10%
2021	11,709	3.10%	44,044,286	3.10%
2022	12,072	3.10%	45,409,659	3.10%
2023	12,446	3.10%	46,817,359	3.10%
2024	12,832	3.10%	48,268,697	3.10%
2025	13,230	3.10%	49,765,026	3.10%
2026	13,640	3.10%	51,307,742	3.10%
2027	14,063	3.10%	52,898,282	3.10%
2028	14,499	3.10%	54,538,129	3.10%
2029	14,949	3.10%	56,228,811	3.10%
2030	15,412	3.10%	57,971,904	3.10%
2031	15,890	3.10%	59,769,033	3.10%
2032	16,382	3.10%	61,621,873	3.10%
2033	16,890	3.10%	63,532,151	3.10%


Salem City
Projected Annual Peak-kW
Fiscal 2013-2033
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
kW
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Projected Annual Peak


Salem City
Projected Annual Energy-kWh
Fiscal 2010-2033
70
60
50
40
30
20
10
0
kWh Millions
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Projected Annual Energy

Levan Town

For more information - Web site: www.levantown.org/

Customer Profile (FY 2012)

1 Service Area 1 square miles

2 Geographical Characteristics 100% rural and agriculture.

3 Customer Mix

	No. of Customers	Kwh Sales	Percentage
Residential	315	2,976,496	60%
Commerical	12	301,679	6%
Industrial	-	-	0%
Agricultural	3	1,528,680	31%
Street Lights	-	40,680	1%
Exempt Accounts	11	126,462	3%
Total	341	4,973,997	

4 Historical Loads See attachment for Levan's historical loads and graph

5 Projected Loads See attachment for Levan's projected loads and graph

6 Existing System Data

Peak	1,248	kW
Energy	5,394,581	kWh
Number of Electric Meters	341	
Population	836	
Miles of Distribution Lines	9	
Number of Substations	1	

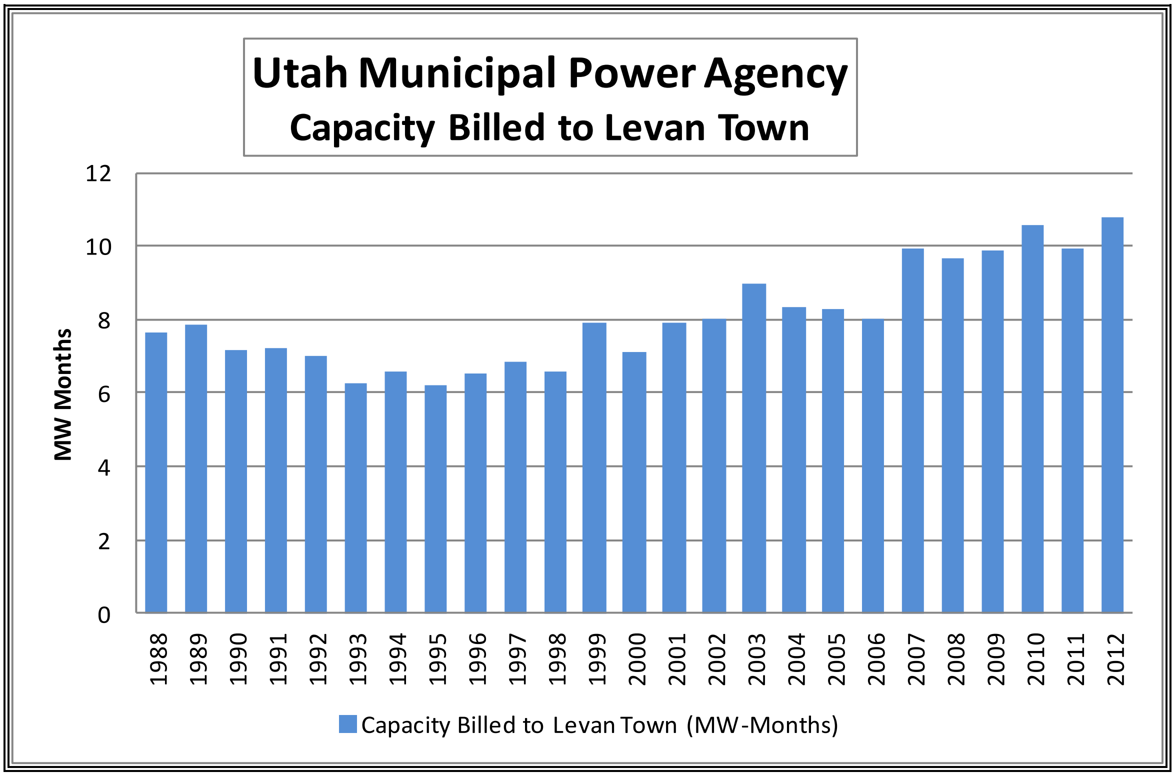
7 Rates - Current Rates (July 2012)

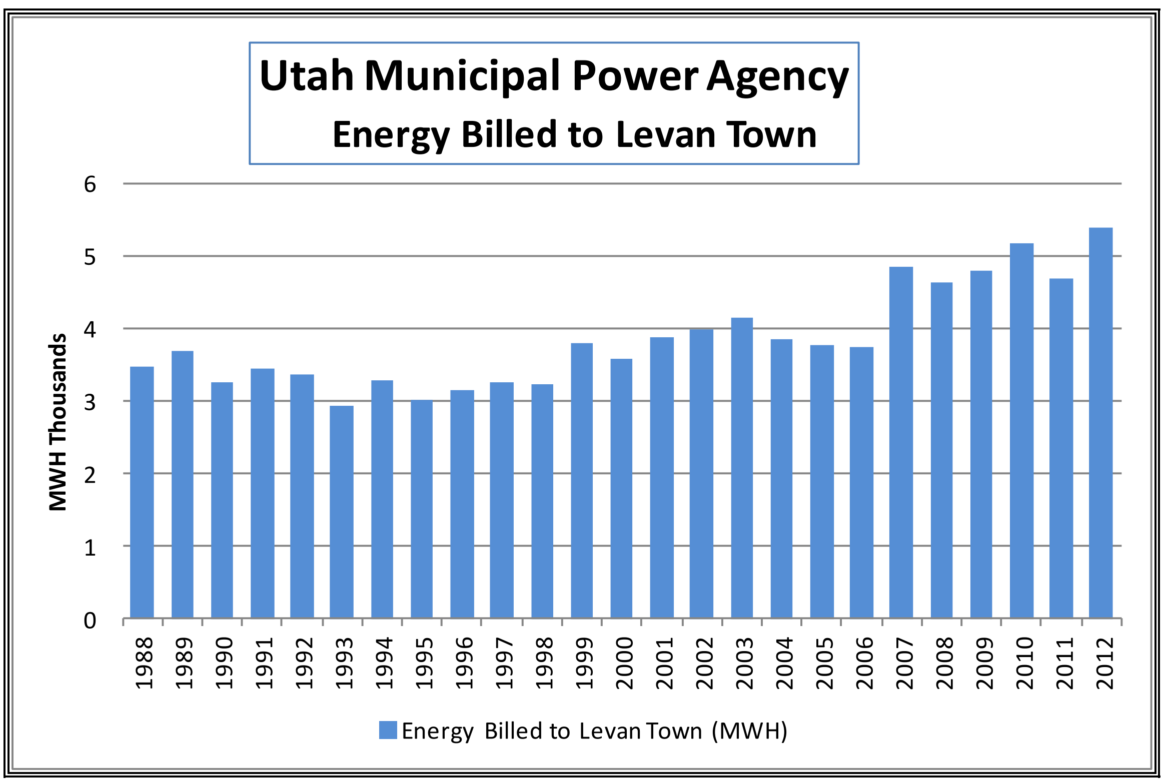
Residential	Base	$5.50 per month
	Energy	$0.0830 per kwh
Commerical	Base	$5.50 per month
	Energy	$0.0283 per kwh
	Demand	$13.69 per kw

8 Financial Information (FY2012)

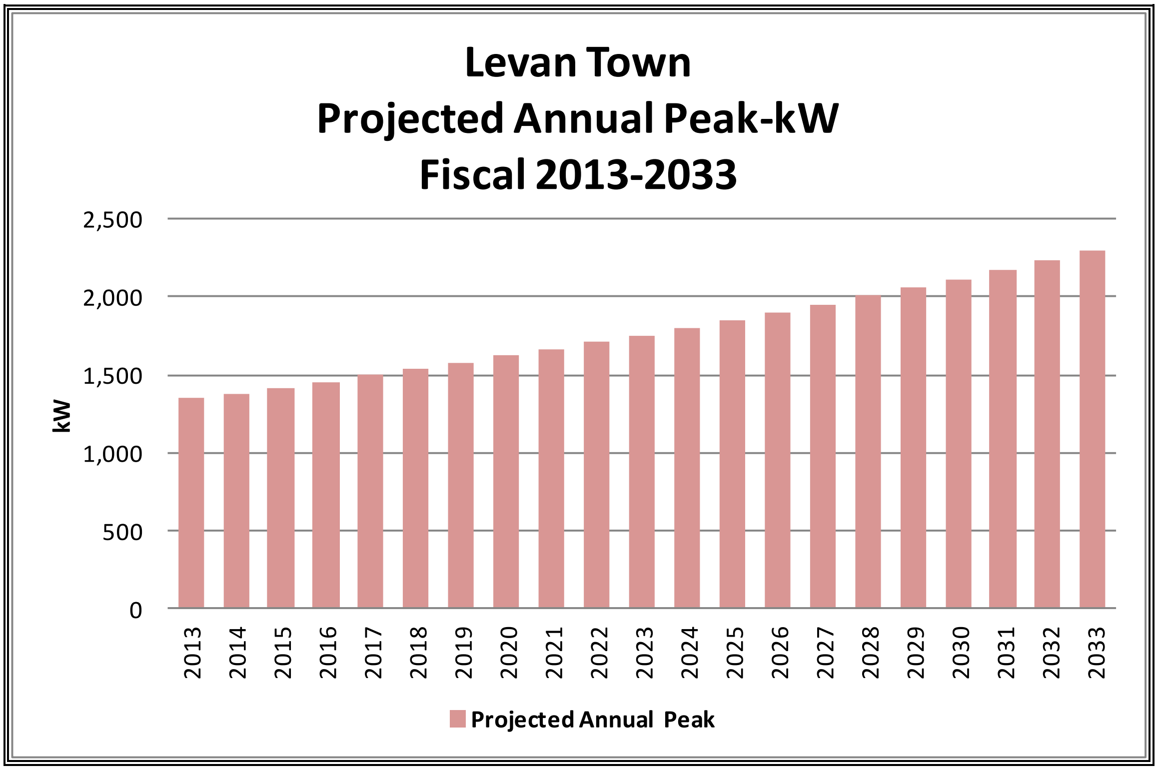
Electric Revenues	$367,555
Expenses - Power Supply	$252,448
Capital Improvement Expenses	$36,436
Other Expenses	$10,389
Total Expenditures	$299,273

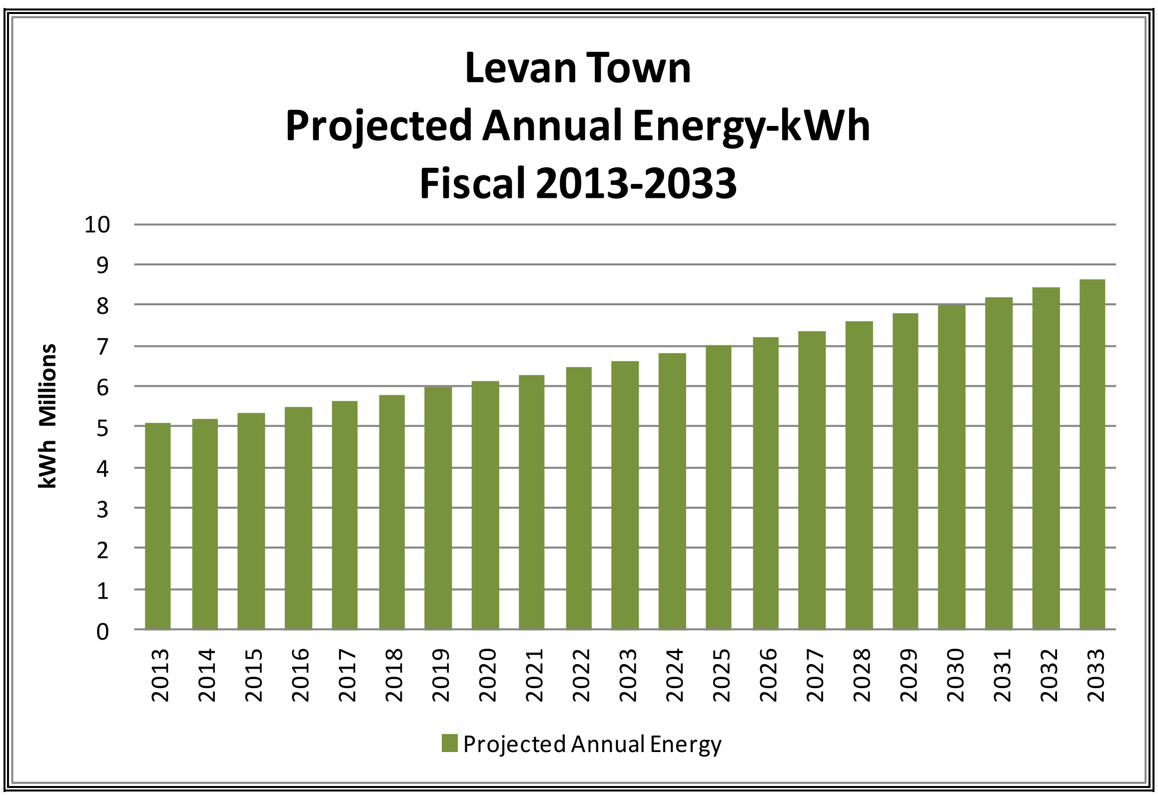
		Utah Municipal Power Agency				
		Levan Town				
		Historical Non-Coincidental Load Growth				
		Fiscal Years 1988-2012				
Year	Annual Peak (MW)	% Change Over Prior Year	Capacity Billed to Levan Town (MW-Months)	% Change Over Prior Year	Energy Billed to Levan Town (MWH)	% Change Over Prior Year
1988	0.795	-	7.639	-	3,472.475	
1989	0.792	-0.38%	7.834	2.55%	3,691.772	6.32%
1990	0.795	0.38%	7.166	-8.53%	3,259.977	-11.70%
1991	0.785	-1.26%	7.207	0.57%	3,437.092	5.43%
1992	0.716	-8.79%	7.028	-2.48%	3,356.701	-2.34%
1993	0.646	-9.78%	6.252	-11.04%	2,924.368	-12.88%
1994	0.647	0.15%	6.574	5.15%	3,286.960	12.40%
1995	0.726	12.21%	6.197	-5.73%	3,008.534	-8.47%
1996	0.679	-6.47%	6.503	4.94%	3,163.019	5.13%
1997	0.736	8.39%	6.824	4.94%	3,245.208	2.60%
1998	0.724	-1.63%	6.591	-3.41%	3,228.176	-0.52%
1999	0.795	9.81%	7.889	19.69%	3,796.875	17.62%
2000	0.748	-5.91%	7.127	-9.66%	3,594.391	-5.33%
2001	0.871	16.44%	7.925	11.20%	3,884.791	8.08%
2002	0.951	9.18%	8.020	1.20%	3,978.142	2.40%
2003	1.006	5.78%	8.996	12.17%	4,139.182	4.05%
2004	1.065	5.86%	8.338	-7.31%	3,856.907	-6.82%
2005	0.980	-7.98%	8.260	-0.94%	3,767.626	-2.31%
2006	0.964	-1.63%	8.012	-3.00%	3,734.180	-0.89%
2007	1.100	14.11%	9.935	24.00%	4,852.732	29.95%
2008	1.163	5.73%	9.662	-2.75%	4,639.428	-4.40%
2009	1.213	4.30%	9.866	2.11%	4,789.020	3.22%
2010	1.262	4.04%	10.569	7.13%	5,184.982	8.27%
2011	1.290	2.22%	9.958	-5.78%	4,683.626	-9.67%
2012	1.248	-3.26%	10.795	8.41%	5,394.581	15.18%


Utah Municipal Power Agency
Capacity Billed to Levan Town
MW Months
0
2
4
6
8
10
12
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Capacity Billed to Levan Town (MW-Months)


Utah Municipal Power Agency
Energy Billed to Levan Town
MWH Thousands
0
1
2
3
4
5
6
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Energy Billed to Levan Town (MWH)

20 Year Forecast - Levan Town				
Year	Annual Peak kW	% Growth	Energy Requirement (MWh)	% Growth
2013	1,348		5,087,365	
2014	1,382	2.50%	5,214,549	2.50%
2015	1,419	2.70%	5,355,342	2.70%
2016	1,457	2.70%	5,499,936	2.70%
2017	1,496	2.70%	5,648,435	2.70%
2018	1,537	2.70%	5,800,942	2.70%
2019	1,578	2.70%	5,957,568	2.70%
2020	1,621	2.70%	6,118,422	2.70%
2021	1,665	2.70%	6,283,619	2.70%
2022	1,710	2.70%	6,453,277	2.70%
2023	1,756	2.70%	6,627,516	2.70%
2024	1,803	2.70%	6,806,459	2.70%
2025	1,852	2.70%	6,990,233	2.70%
2026	1,902	2.70%	7,178,969	2.70%
2027	1,953	2.70%	7,372,801	2.70%
2028	2,006	2.70%	7,571,867	2.70%
2029	2,060	2.70%	7,776,308	2.70%
2030	2,116	2.70%	7,986,268	2.70%
2031	2,173	2.70%	8,201,897	2.70%
2032	2,232	2.70%	8,423,348	2.70%
2033	2,292	2.70%	8,650,779	2.70%


Levan Town
Projected Annual Peak-kW
Fiscal 2013-2033
2,500
2,000
1,500
1,000
500
0
kW
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Projected Annual Peak


Levan Town
Projected Annual Energy-kWh
Fiscal 2013-2033
10
9
8
7
6
5
4
3
2
1
0
kWh Millions
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Projected Annual Energy

Spanish Fork City

For more information - Web site: www.spanishfork.org/

Customer Profile (FY 2012)

1 Service Area 15.36 square miles

2 Geographical Characteristics 76% developed in urban and suburban with 24% rural and agriculture.

3 Customer Mix

	No. of Customers	Kwh Sales	Percentage
Residential	9,730	86,982,036	37%
Commerical	1,088	95,404,599	40%
Industrial	8	45,641,620	19%
Agricultural	5	1,152,440	0%
Street Lights		40,218	0%
Exempt Accounts	212	8,260,642	3%
Total	11,043	237,481,555	

4 Historical Loads See attachment for Spanish Fork's historical loads and graph

5 Projected Loads See attachment for Spanish Fork's projected loads and grap

6 Existing System Data

Peak	54,736	kW
Energy	237,500,842	kWh
Number of Electric Meters	11,043	
Population	34,691	
Miles of Distribution Lines	148	
Number of Substations	7	

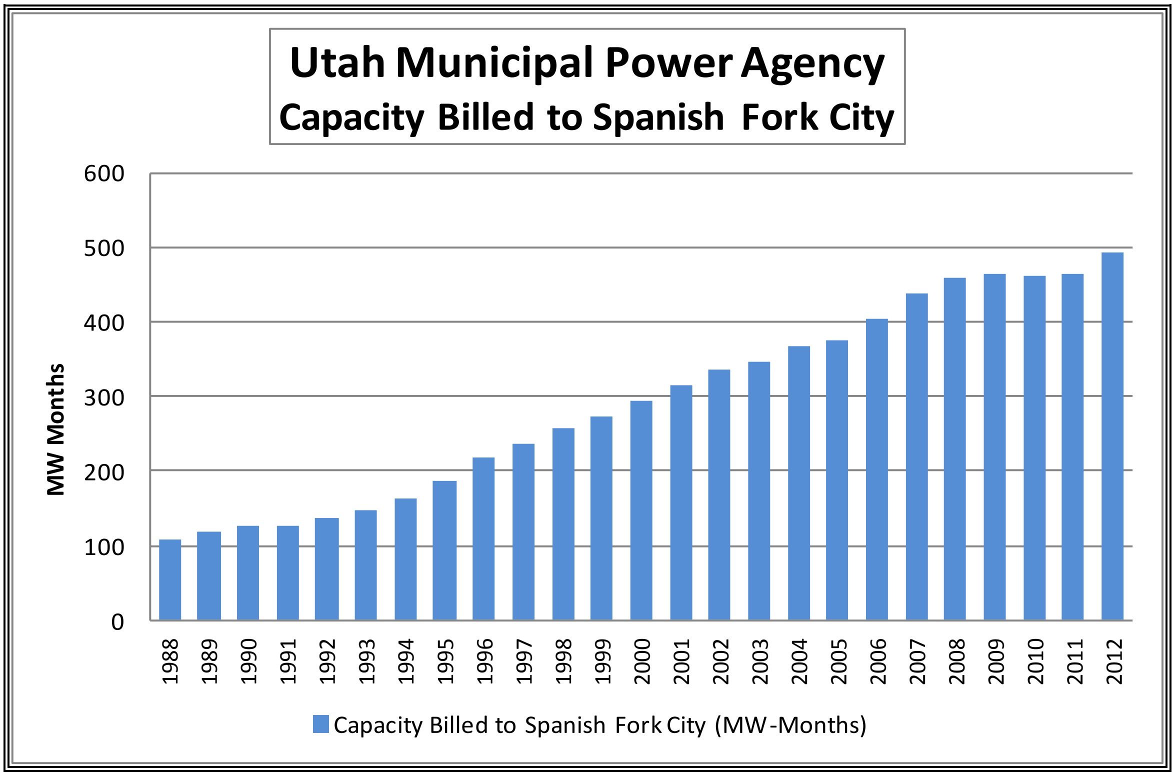
7 Rates - Current Rates (July 2012)

Residential	Customer Charge	$3.50	per month
	Energy	$0.08484	per kwh
	Fuel Adjuster	varies	per kwh
Commerical	Customer Charge	$6.50	per month
	Demand	$6.00	per kw
	First 1,000 kwh	$0.12150	per kwh
	1,001 to 5,000	$0.07979	per kwh
	Over 5,000	$0.05147	per kwh
	Fuel Adjuster	varies	per kwh

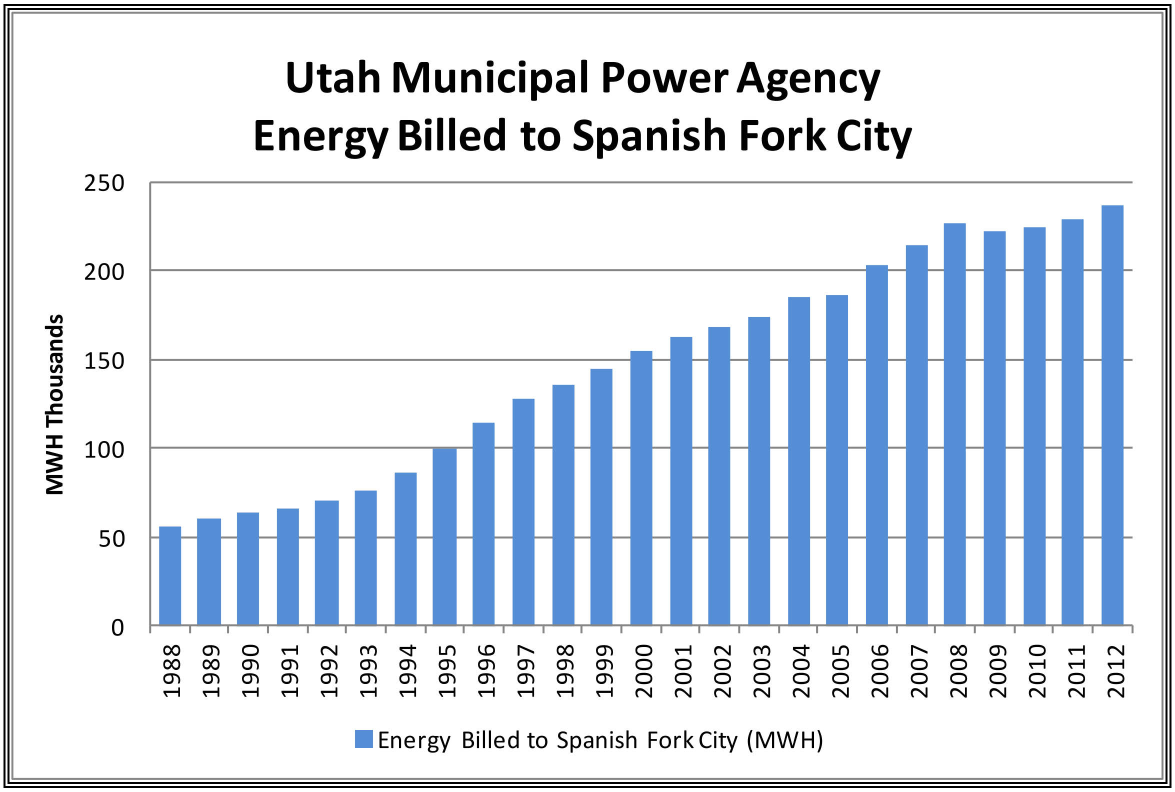
8 Financial Information (FY2012)

Electric Revenues	$	24,874,771
Other Revenues	$	1,841,633
Total Revenues	$	26,716,404
Expenses - Power Supply	$	12,338,655
Capital Improvement Expenses	$	866,683
Other Expenses	$	9,052,333
Total Expenditures	$	22,257,671

		Utah Municipal Power Agency				
		Spanish Fork City				
		Historical Non-Coincidental Load Growth				
		Fiscal Years 1988-2012				
Year	Annual Peak (MW)	% Change Over Prior Year	Capacity Billed to Spanish Fork City (MW-Months)	% Change Over Prior Year	Energy Billed to Spanish Fork City (MWH)	% Change Over Prior Year
1988	9.606	-	109.024	-	55,949.289	
1989	10.383	8.09%	118.203	8.42%	60,375.990	7.91%
1990	11.483	10.59%	125.174	5.90%	63,436.914	5.07%
1991	11.399	-0.73%	127.140	1.57%	65,963.060	3.98%
1992	12.652	10.99%	137.590	8.22%	70,730.962	7.23%
1993	13.276	4.93%	148.478	7.91%	76,408.561	8.03%
1994	15.735	18.52%	163.422	10.06%	86,436.560	13.12%
1995	17.396	10.56%	187.795	14.91%	100,127.167	15.84%
1996	19.315	11.03%	218.000	16.08%	114,934.065	14.79%
1997	21.783	12.78%	237.386	8.89%	127,551.091	10.98%
1998	24.168	10.95%	258.316	8.82%	135,877.636	6.53%
1999	26.556	9.88%	273.225	5.77%	144,852.983	6.61%
2000	27.962	5.29%	292.945	7.22%	154,318.397	6.53%
2001	32.102	14.81%	315.172	7.59%	163,187.289	5.75%
2002	33.600	4.67%	335.019	6.30%	168,363.322	3.17%
2003	36.069	7.35%	345.170	3.03%	173,814.499	3.24%
2004	41.190	14.20%	368.588	6.78%	185,073.742	6.48%
2005	38.793	-5.82%	376.231	2.07%	186,690.869	0.87%
2006	43.152	11.24%	402.997	7.11%	203,364.528	8.93%
2007	47.755	10.67%	438.322	8.77%	214,924.944	5.68%
2008	52.673	10.30%	459.135	4.75%	227,085.740	5.66%
2009	52.300	-0.71%	463.104	0.86%	221,992.272	-2.24%
2010	53.012	1.36%	462.793	-0.07%	224,525.003	1.14%
2011	53.793	1.47%	463.583	0.17%	228,656.598	1.84%
2012	54.736	1.75%	491.810	6.09%	237,500.842	3.87%

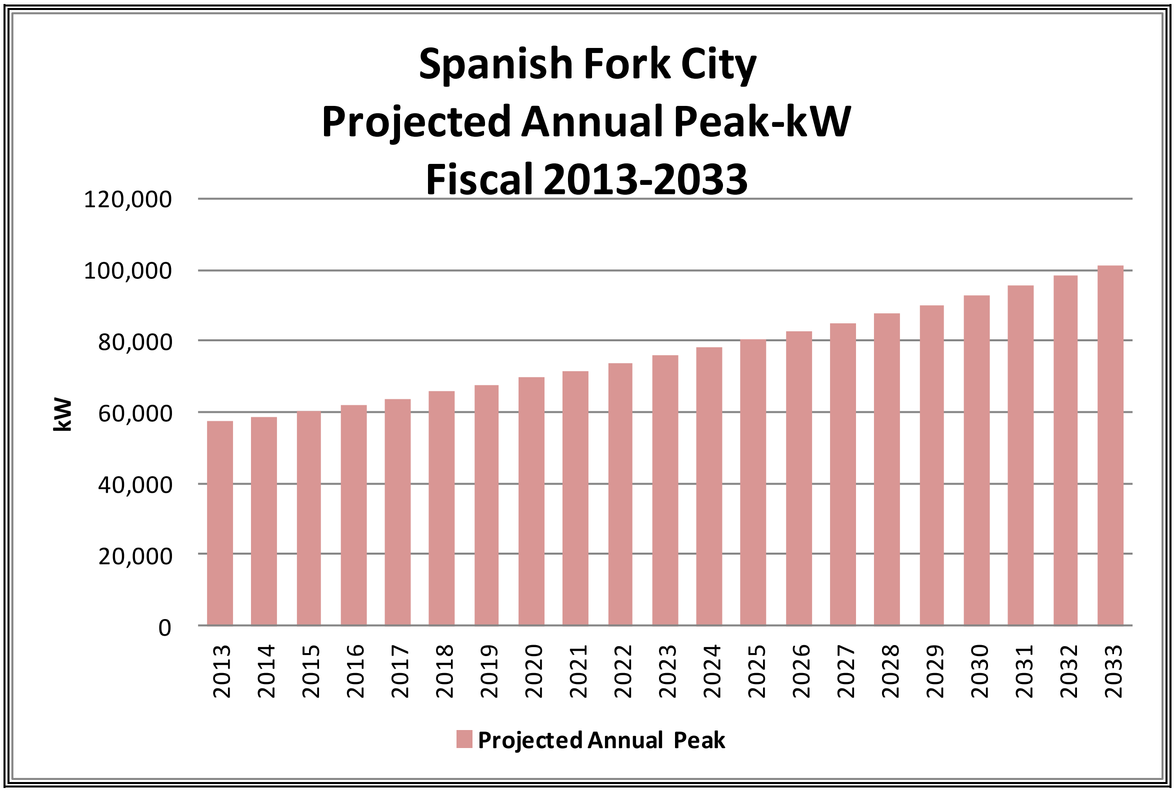


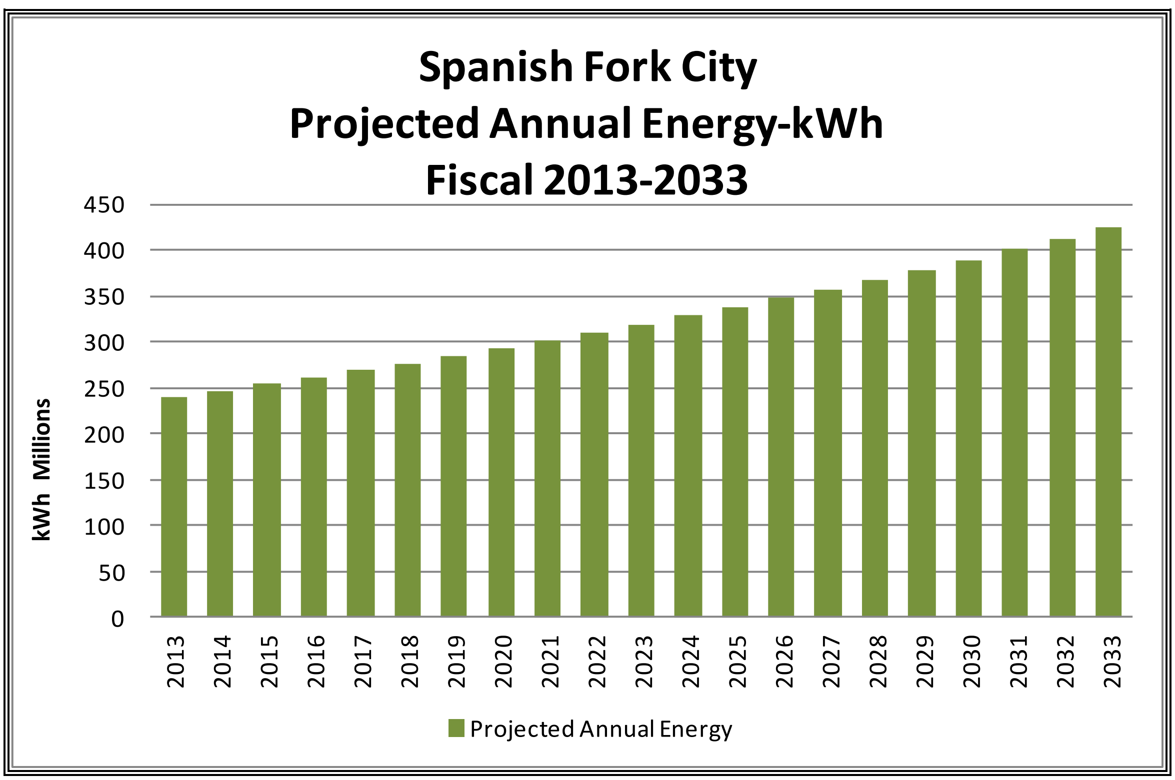
Utah Municipal Power Agency
Capacity Billed to Spanish Fork City
MW Months
600
500
400
300
200
100
0
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Capacity Billed to Spanish Fork City (MW-Months)



Utah Municipal Power Agency
Energy Billed to Spanish Fork City
MWH Thousands
250
200
150
100
50
0
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Energy Billed to Spanish Fork City (MWH)

20 Year Forecast -Spanish Fork				
Year	Annual Peak kW	% Growth	Energy Requirement (MWh)	% Growth
2013	57,300	0.00%	240,576,676	0.00%
2014	58,675	2.40%	246,350,516	2.40%
2015	60,377	2.90%	253,494,681	2.90%
2016	62,128	2.90%	260,846,027	2.90%
2017	63,929	2.90%	268,410,562	2.90%
2018	65,783	2.90%	276,194,468	2.90%
2019	67,691	2.90%	284,204,108	2.90%
2020	69,654	2.90%	292,446,027	2.90%
2021	71,674	2.90%	300,926,962	2.90%
2022	73,753	2.90%	309,653,844	2.90%
2023	75,891	2.90%	318,633,805	2.90%
2024	78,092	2.90%	327,874,185	2.90%
2025	80,357	2.90%	337,382,537	2.90%
2026	82,687	2.90%	347,166,630	2.90%
2027	85,085	2.90%	357,234,463	2.90%
2028	87,553	2.90%	367,594,262	2.90%
2029	90,092	2.90%	378,254,496	2.90%
2030	92,704	2.90%	389,223,876	2.90%
2031	95,393	2.90%	400,511,369	2.90%
2032	98,159	2.90%	412,126,198	2.90%
2033	101,006	2.90%	424,077,858	2.90%


Spanish Fork City
Projected Annual Peak-kW
Fiscal 2013-2033
kW
120,000
100,000
80,000
60,000
40,000
20,000
0
2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033
Projected Annual Peak


Spanish Fork City
Projected Annual Energy-kWh
Fiscal 2013-2033
kWh Millions
450
400
350
300
250
200
150
100
50
0
2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033
Projected Annual Energy

Manti City

For more information - Web site: www.manticity.com/

Customer Profile (FY 2012)

1 Service Area — 1 square mile

2 Geographical Characteristics — 99% development with homes and businesses in current service area.

3 Customer Mix	No. of Customers	Kwh Sales	Percentage
Residential	1,235	10,553,968	58%
Commerical	130	6,069,456	34%
Industrial	-	-	0%
Agricultural	35	1,438,267	8%
Total	1,400	18,061,691	

4 Historical Loads — See attachment for Manti's historical loads and graph

5 Projected Loads — See attachment for Manti's projected loads and graph

6 Existing System Data

Peak	4,288	kW
Energy	20,177,800	kWh
Number of Electric Meters	1,400	
Population	3,005	
Miles of Distribution Lines	120	
Number of Substations	4	

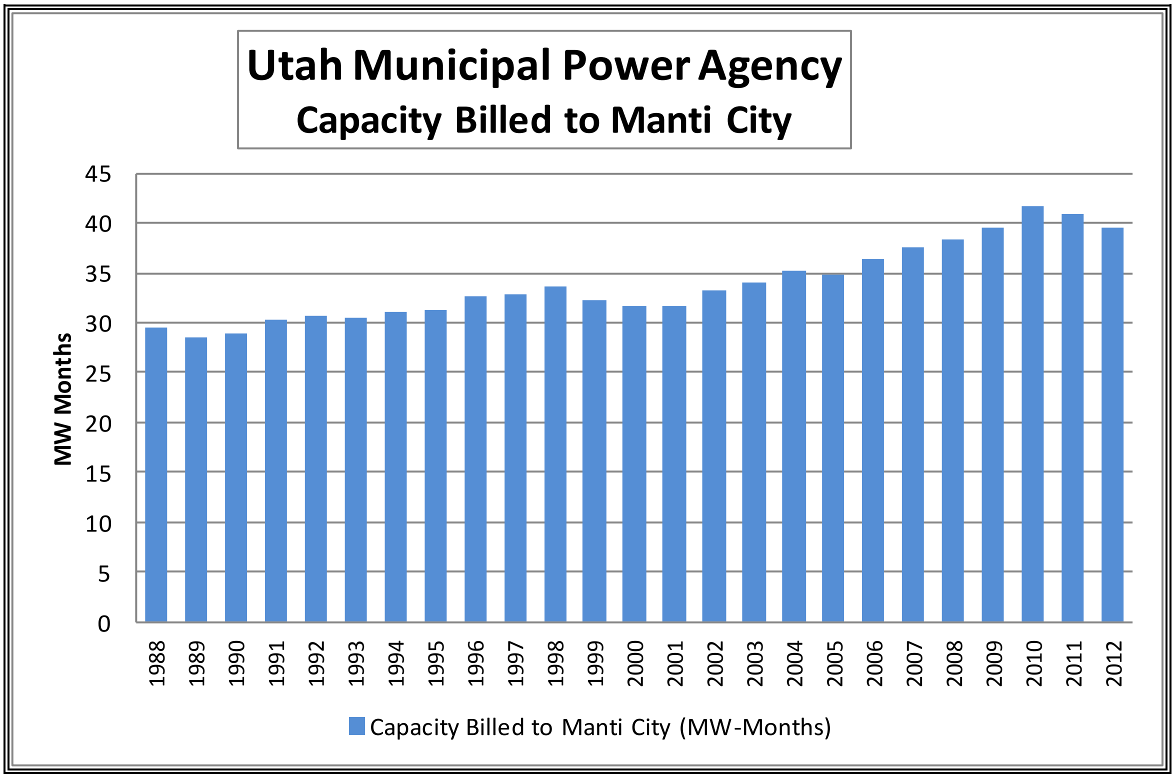
7 Rates - Current Rates (July 2012)

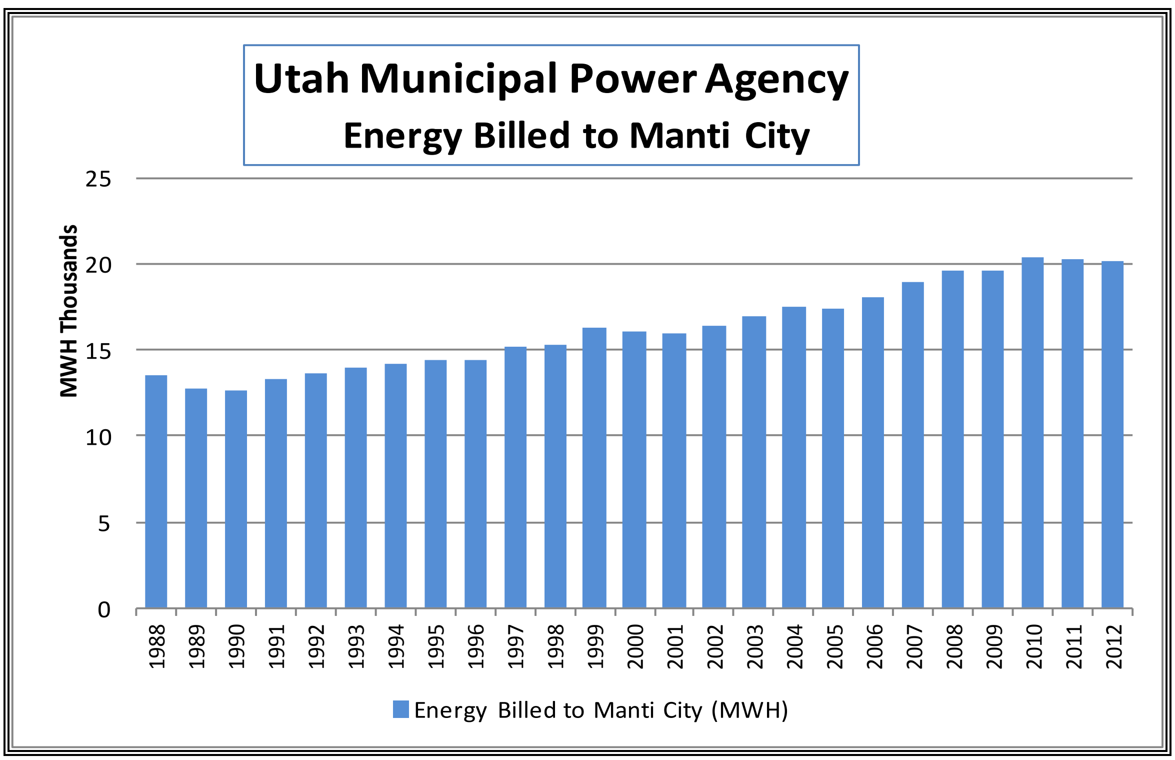
All Customers	Base	$5.00 per month
	Energy	$0.0775 per kwh

8 Financial Information (FY2012)

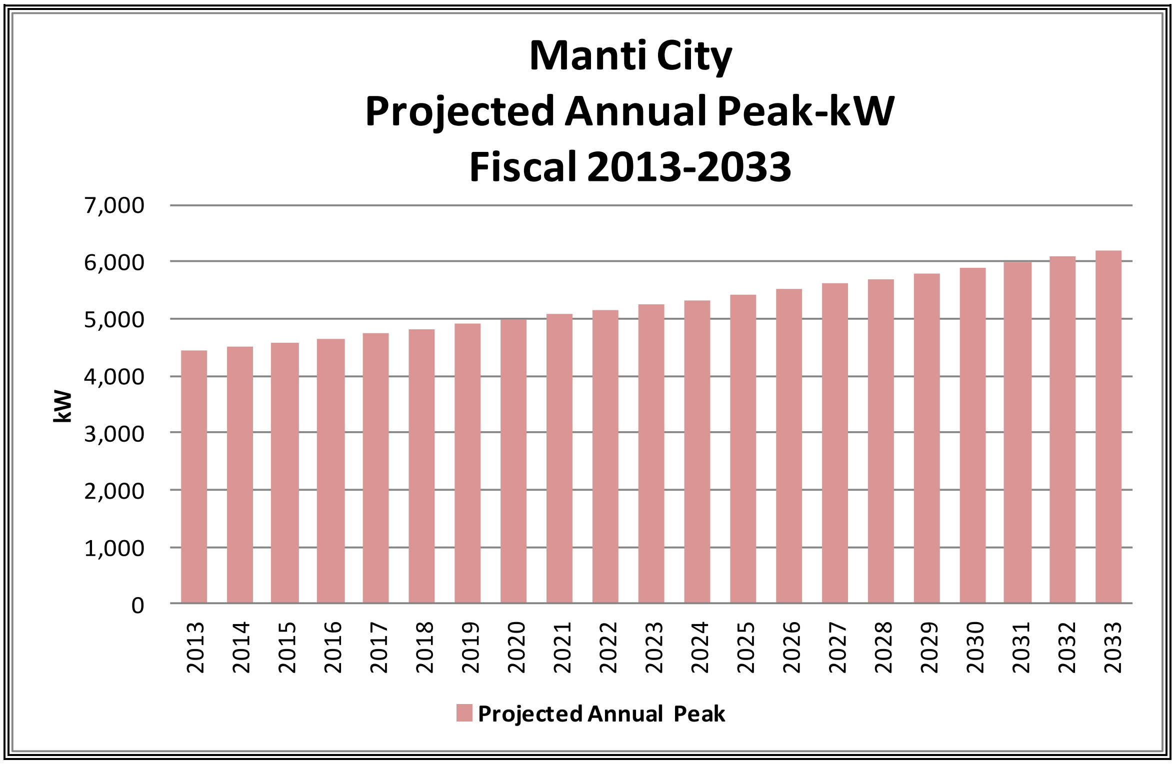
Electric Revenues	$1,703,381
Other Revenues	$132,727
Total Revenues	$1,836,108
Expenses - Power Supply	$834,812
Other Expenses	$573,257
Total Expenditures	$1,408,069

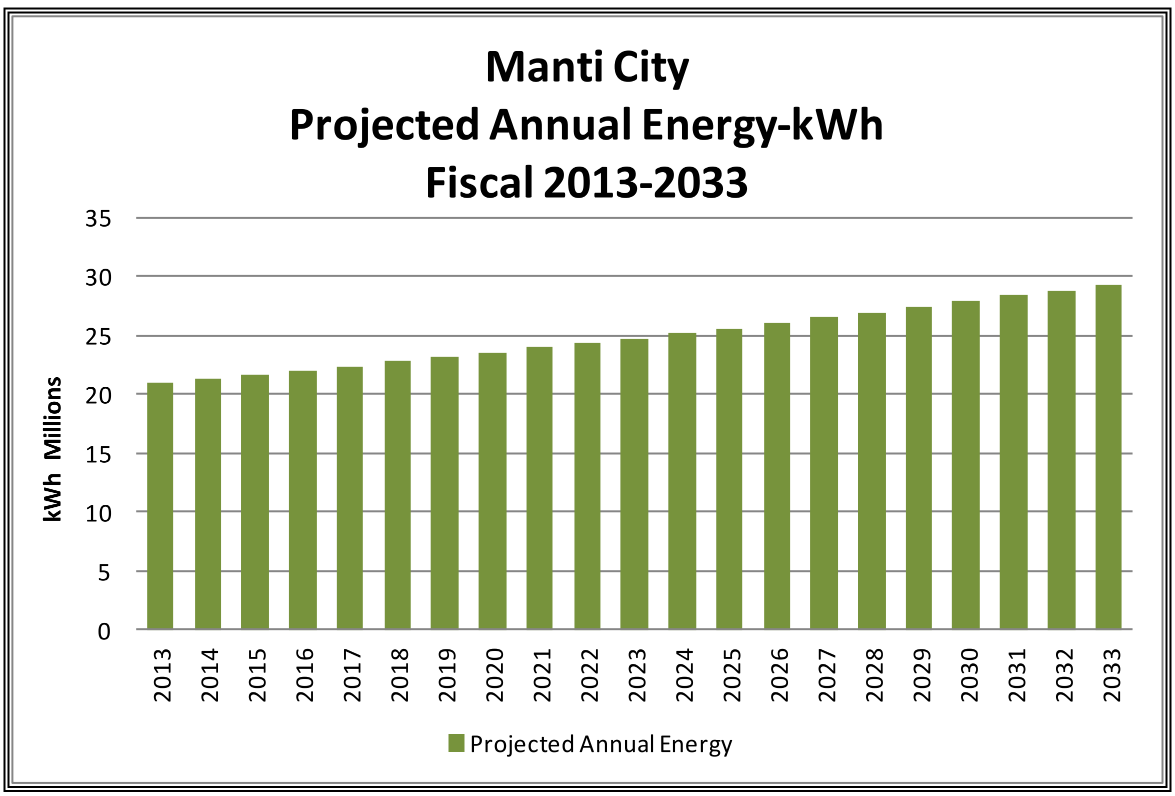
		Utah Municipal Power Agency				
		Manti City				
		Historical Non-Coincidental Load Growth				
		Fiscal Years 1988-2012				
Year	Annual Peak (MW)	% Change Over Prior Year	Capacity Billed to Manti City (MW-Months)	% Change Over Prior Year	Energy Billed to Manti City (MWH)	% Change Over Prior Year
1988	2.959	-	29.483	-	13,496.278	
1989	2.929	-1.01%	28.619	-2.93%	12,774.668	-5.35%
1990	2.722	-7.07%	28.973	1.24%	12,688.105	-0.68%
1991	3.057	12.31%	30.210	4.27%	13,319.939	4.98%
1992	3.218	5.27%	30.670	1.52%	13,609.445	2.17%
1993	2.920	-9.26%	30.436	-0.76%	13,933.669	2.38%
1994	2.938	0.62%	31.041	1.99%	14,160.125	1.63%
1995	2.891	-1.60%	31.312	0.87%	14,425.802	1.88%
1996	3.425	18.47%	32.607	4.14%	14,436.868	0.08%
1997	3.279	-4.26%	32.835	0.70%	15,214.888	5.39%
1998	3.443	5.00%	33.649	2.48%	15,359.388	0.95%
1999	3.347	-2.79%	32.334	-3.91%	16,277.917	5.98%
2000	3.152	-5.83%	31.755	-1.79%	16,051.380	-1.39%
2001	3.126	-0.82%	31.645	-0.35%	15,935.831	-0.72%
2002	3.136	0.32%	33.328	5.32%	16,381.221	2.79%
2003	3.371	7.49%	34.101	2.32%	16,924.026	3.31%
2004	3.760	11.54%	35.141	3.05%	17,554.388	3.72%
2005	3.516	-6.49%	34.874	-0.76%	17,371.494	-1.04%
2006	3.465	-1.45%	36.298	4.08%	18,082.775	4.09%
2007	3.682	6.26%	37.489	3.28%	18,909.769	4.57%
2008	3.677	-0.14%	38.359	2.32%	19,674.069	4.04%
2009	3.760	2.26%	39.465	2.88%	19,566.586	-0.55%
2010	4.745	26.20%	41.666	5.58%	20,391.809	4.22%
2011	4.326	-8.83%	40.882	-1.88%	20,331.266	-0.30%
2012	4.288	-0.88%	39.582	-3.18%	20,177.800	-0.75%


Utah Municipal Power Agency
Capacity Billed to Manti City
MW Months
45
40
35
30
25
20
15
10
5
0
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Capacity Billed to Manti City (MW-Months)


Utah Municipal Power Agency
Energy Billed to Manti City
MWH Thousands
25
20
15
10
5
0
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Energy Billed to Manti City (MWH)

20 Year Forecast -Manti City				
Year	Annual Peak kW	% Growth	Energy Requirement (MWh)	% Growth
2013	4,438	0.00%	20,992,673	
2014	4,504	1.50%	21,307,563	1.50%
2015	4,581	1.70%	21,669,792	1.70%
2016	4,659	1.70%	22,038,178	1.70%
2017	4,738	1.70%	22,412,827	1.70%
2018	4,818	1.70%	22,793,845	1.70%
2019	4,900	1.70%	23,181,341	1.70%
2020	4,984	1.70%	23,575,423	1.70%
2021	5,068	1.70%	23,976,206	1.70%
2022	5,154	1.70%	24,383,801	1.70%
2023	5,242	1.70%	24,798,326	1.70%
2024	5,331	1.70%	25,219,897	1.70%
2025	5,422	1.70%	25,648,636	1.70%
2026	5,514	1.70%	26,084,662	1.70%
2027	5,608	1.70%	26,528,102	1.70%
2028	5,703	1.70%	26,979,079	1.70%
2029	5,800	1.70%	27,437,724	1.70%
2030	5,899	1.70%	27,904,165	1.70%
2031	5,999	1.70%	28,378,536	1.70%
2032	6,101	1.70%	28,860,971	1.70%
2033	6,205	1.70%	29,351,607	1.70%


Manti City
Projected Annual Peak-kW
Fiscal 2013-2033
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
kW
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Projected Annual Peak


Manti City
Projected Annual Energy-kWh
Fiscal 2013-2033
35
30
25
20
15
10
5
0
kWh Millions
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Projected Annual Energy

Nephi City

For more information - Web site: www.nephi.utah.gov/

Customer Profile (FY 2012)

1 Service Area — 4.34 square miles

2 Geographical Characteristics — 100% suburban development surrounded with rural and agriculture.

3 Customer Mix

	No. of Customers	Kwh Sales	Percentage
Residential	-	19,668	27%
Commerical	-	25,734	36%
Industrial	-	24,547	34%
Agricultural	-	1,025	1%
Street Lights	-	284	0%
Exempt Accounts	-	753	1%
Total	-	72,011	

4 Historical Loads — See attachment for Nephi's historical loads and graph

5 Projected Loads — See attachment for Nephi's projected loads and graph

6 Existing System Data

Peak	15,891	kW
Energy	73,777,024	kWh
Number of Electric Meters	2,221	
Population	5,436	
Miles of Distribution Lines	90	
Number of Substations	2	

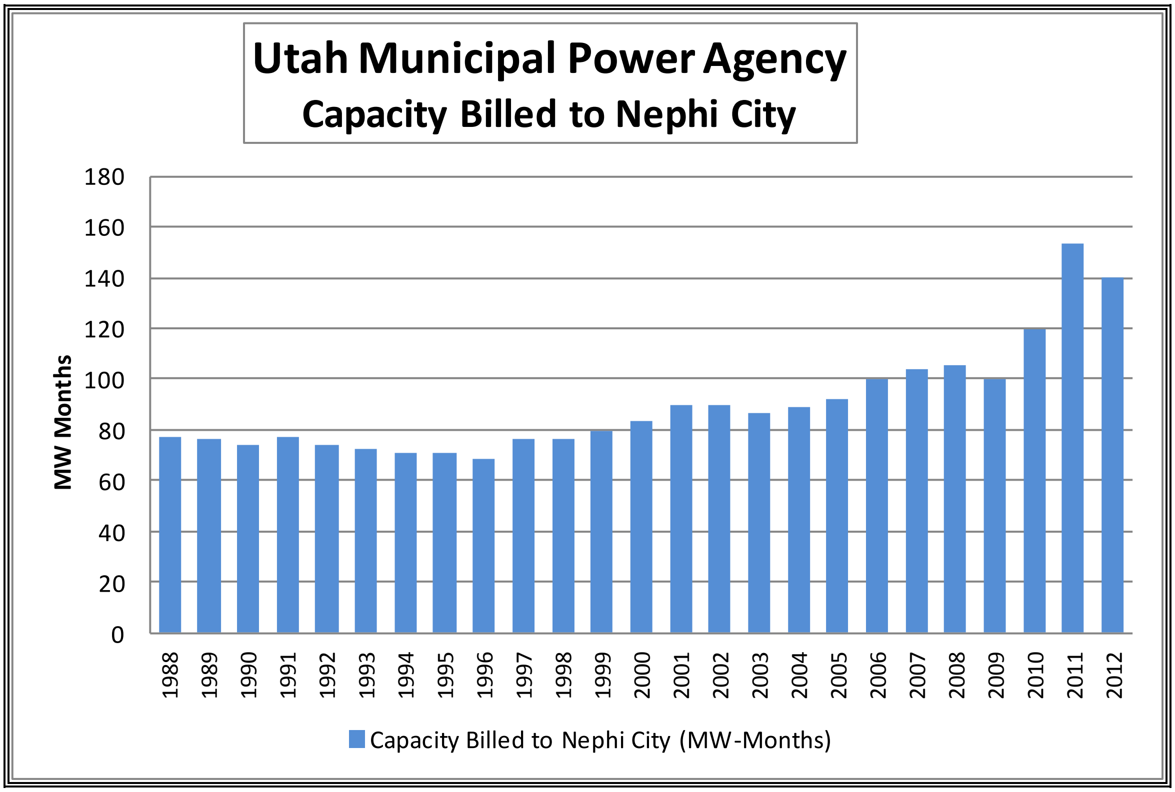
7 Rates - Current Rates (July 2012)

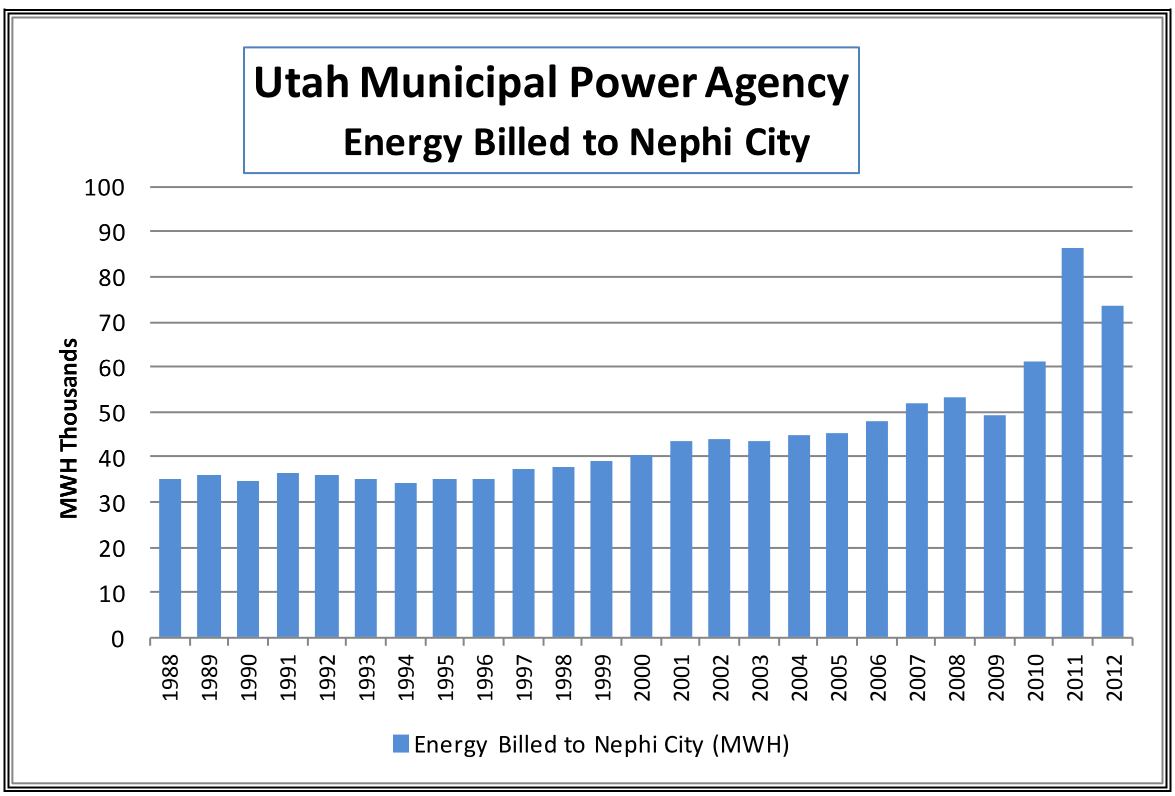
Residential	Customer Charge	$5.50	per month
	Energy	$0.0800	per kwh
Commerical	Customer Charge	$8.00	per month
	First 500	$0.1204	per kwh
	501 to 10,000	$0.0573	per kwh
	Over 10,000	$0.0424	per kwh
	Demand	$9.71	per kw over 5 kw

8 Financial Information (FY2012)

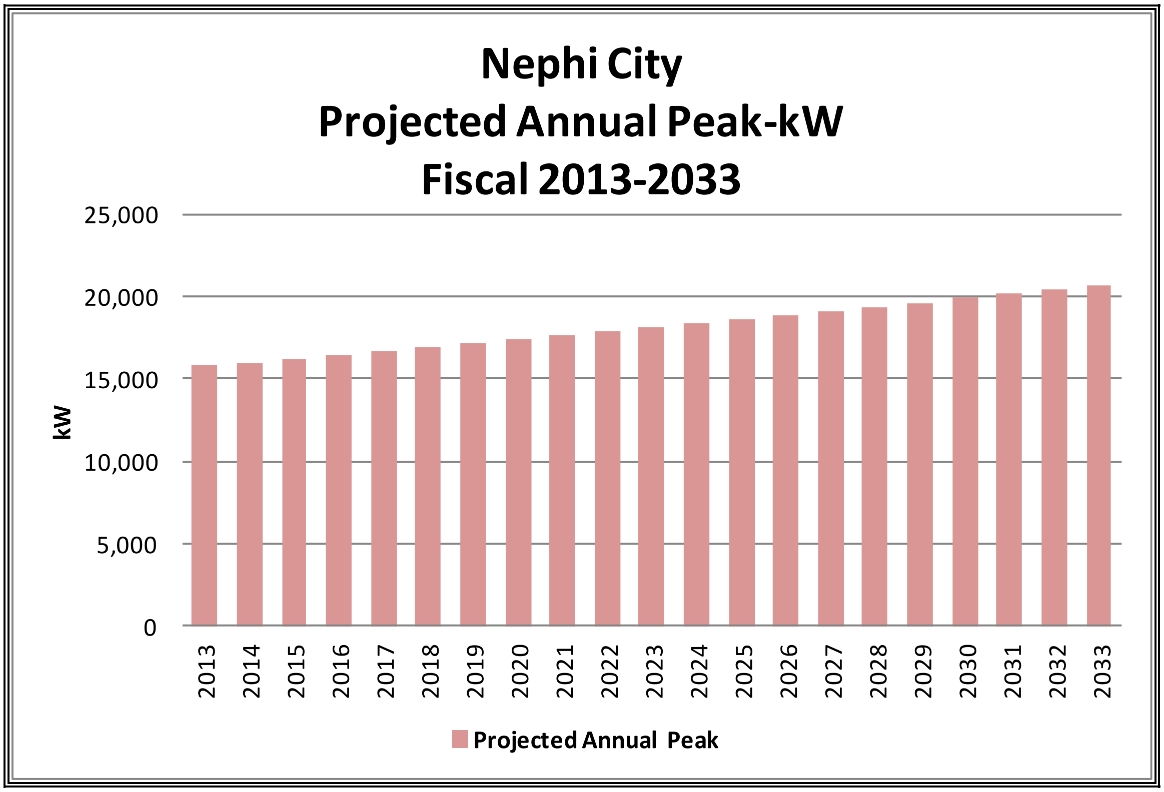
Electric Revenues	$5,014,625
Other Revenues	$32,869
Total Revenues	$5,047,494
Expenses - Power Supply	$3,690,970
Capital Improvement Expenses	$260,678
Other Expenses	$938,514

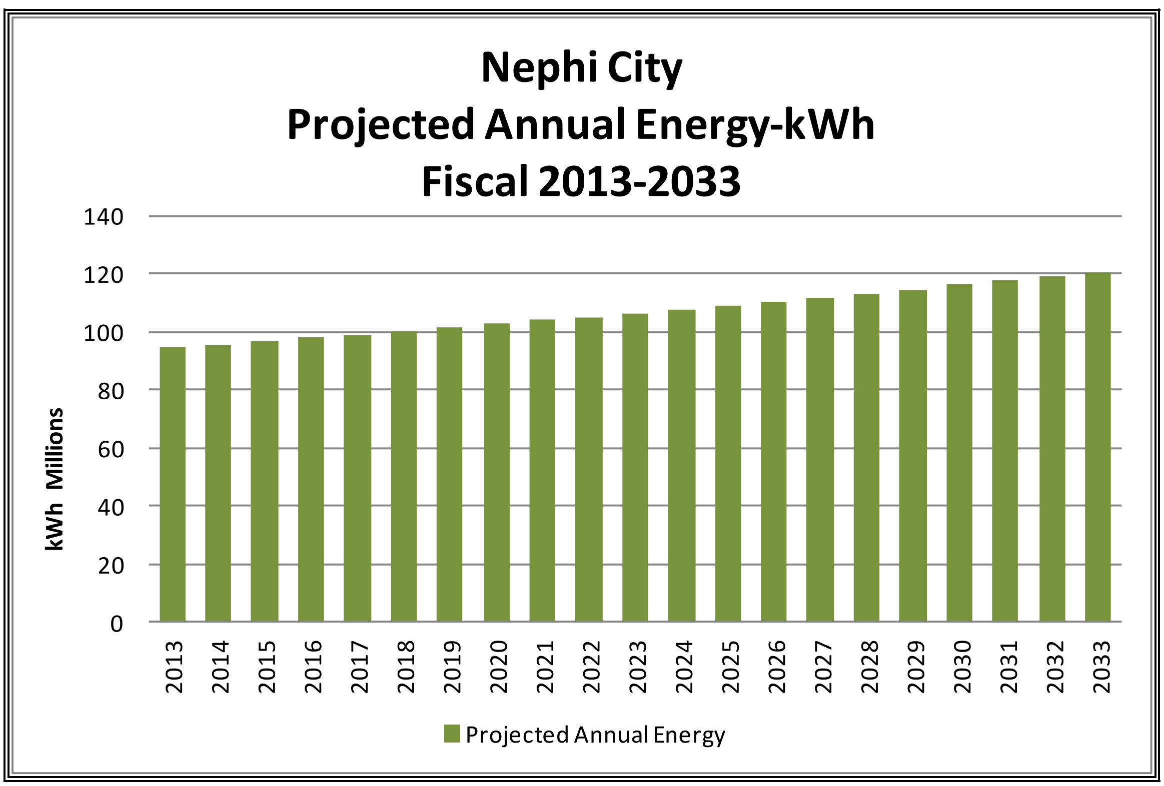
		Utah Municipal Power Agency				
			Nephi City			
		Historical Non-Coincidental Load Growth				
		Fiscal Years 1988-2012				
Year	Annual Peak (MW)	% Change Over Prior Year	Capacity Billed to Nephi City (MW-Months)	% Change Over Prior Year	Energy Billed to Nephi City (MWH)	% Change Over Prior Year
1988	7.748	-	77.042	-	35,210.610	
1989	7.958	2.71%	76.782	-0.34%	36,119.940	2.58%
1990	7.269	-8.66%	74.173	-3.40%	34,858.560	-3.49%
1991	7.955	9.44%	77.013	3.83%	36,274.980	4.06%
1992	7.361	-7.47%	73.852	-4.10%	35,892.760	-1.05%
1993	7.320	-0.56%	72.460	-1.88%	34,952.040	-2.62%
1994	6.944	-5.14%	70.732	-2.38%	34,164.840	-2.25%
1995	6.960	0.23%	71.072	0.48%	35,056.620	2.61%
1996	6.734	-3.25%	68.684	-3.36%	34,887.780	-0.48%
1997	7.463	10.83%	76.791	11.80%	37,528.340	7.57%
1998	7.453	-0.13%	76.377	-0.54%	37,953.527	1.13%
1999	7.937	6.49%	79.609	4.23%	38,967.156	2.67%
2000	7.729	-2.62%	83.541	4.94%	40,353.781	3.56%
2001	8.343	7.94%	90.023	7.76%	43,294.948	7.29%
2002	8.486	1.71%	89.983	-0.04%	43,854.121	1.29%
2003	8.720	2.76%	86.932	-3.39%	43,618.239	-0.54%
2004	9.088	4.22%	88.975	2.35%	44,770.667	2.64%
2005	8.937	-1.66%	91.965	3.36%	45,366.978	1.33%
2006	9.466	5.92%	99.848	8.57%	48,116.342	6.06%
2007	10.264	8.43%	103.757	3.91%	52,038.489	8.15%
2008	10.587	3.15%	105.256	1.44%	53,282.039	2.39%
2009	10.188	-3.77%	100.257	-4.75%	49,211.451	-7.64%
2010	10.912	7.11%	119.281	18.98%	61,270.140	24.50%
2011	14.269	30.76%	153.405	28.61%	86,391.068	41.00%
2012	15.891	11.37%	139.670	-8.95%	73,777.024	-14.60%


Utah Municipal Power Agency
Capacity Billed to Nephi City
MW Months
180
160
140
120
100
80
60
40
20
0
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Capacity Billed to Nephi City (MW-Months)


Utah Municipal Power Agency
Energy Billed to Nephi City
MWH Thousands
100
90
80
70
60
50
40
30
20
10
0
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Energy Billed to Nephi City (MWH)

20 Year Forecast - Nephi City				
Year	Annual Peak kW	% Growth	Energy Requirement (MWh)	% Growth
2013	15,858	0.00%	94,958,204	0.00%
2014	16,009	0.89%	95,734,775	0.82%
2015	16,223	1.25%	96,838,283	1.15%
2016	16,442	1.26%	97,964,964	1.16%
2017	16,666	1.27%	99,115,305	1.17%
2018	16,894	1.28%	100,289,804	1.18%
2019	17,127	1.29%	101,488,967	1.20%
2020	17,365	1.30%	102,713,312	1.21%
2021	17,608	1.31%	103,963,369	1.22%
2022	17,856	1.32%	105,239,677	1.23%
2023	18,109	1.33%	106,542,787	1.24%
2024	18,367	1.34%	107,873,263	1.25%
2025	18,614	1.34%	109,220,353	1.25%
2026	18,864	1.34%	110,584,266	1.25%
2027	19,118	1.34%	111,965,210	1.25%
2028	19,375	1.34%	113,363,400	1.25%
2029	19,635	1.34%	114,779,049	1.25%
2030	19,899	1.34%	116,212,377	1.25%
2031	20,167	1.34%	117,663,604	1.25%
2032	20,438	1.34%	119,132,953	1.25%
2033	20,712	1.34%	120,620,651	1.25%


Nephi City
Projected Annual Peak-kW
Fiscal 2013-2033
25,000
20,000
15,000
10,000
5,000
0
kW
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Projected Annual Peak


Nephi City
Projected Annual Energy-kWh
Fiscal 2013-2033
140
120
100
80
60
40
20
0
kWh Millions
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Projected Annual Energy

Provo City

For more information - Web site: www.provo.org/

Customer Profile (FY 2012)

1 Service Area — 43 square miles

2 Geographical Characteristics — 85% urban development and 12% suburban development with 3% rural and agriculture.

3 Customer Mix

	No. of Customers	Kwh Sales	Percentage
Residential	30,986	236,269,116	31%
Commerical	4,261	391,600,615	51%
Industrial	1	137,472,000	18%
Agricultural	-		0%
Street Lights	-	3,798,870	0%
Exempt Accounts	315	953,281	0%
Total	35,563	770,093,882	

4 Historical Loads — See attachment for Provo's historical loads and graph

5 Projected Loads — See attachment for Provo's projected loads and graph

6 Existing System Data

Peak	172,285	kW
Energy	800,027,250	kWh
Number of Electric Meters	35,563	
Population	112,488	
Miles of Distribution Lines	357	
Miles of Transmission Lines	41	
Number of Substations	12	

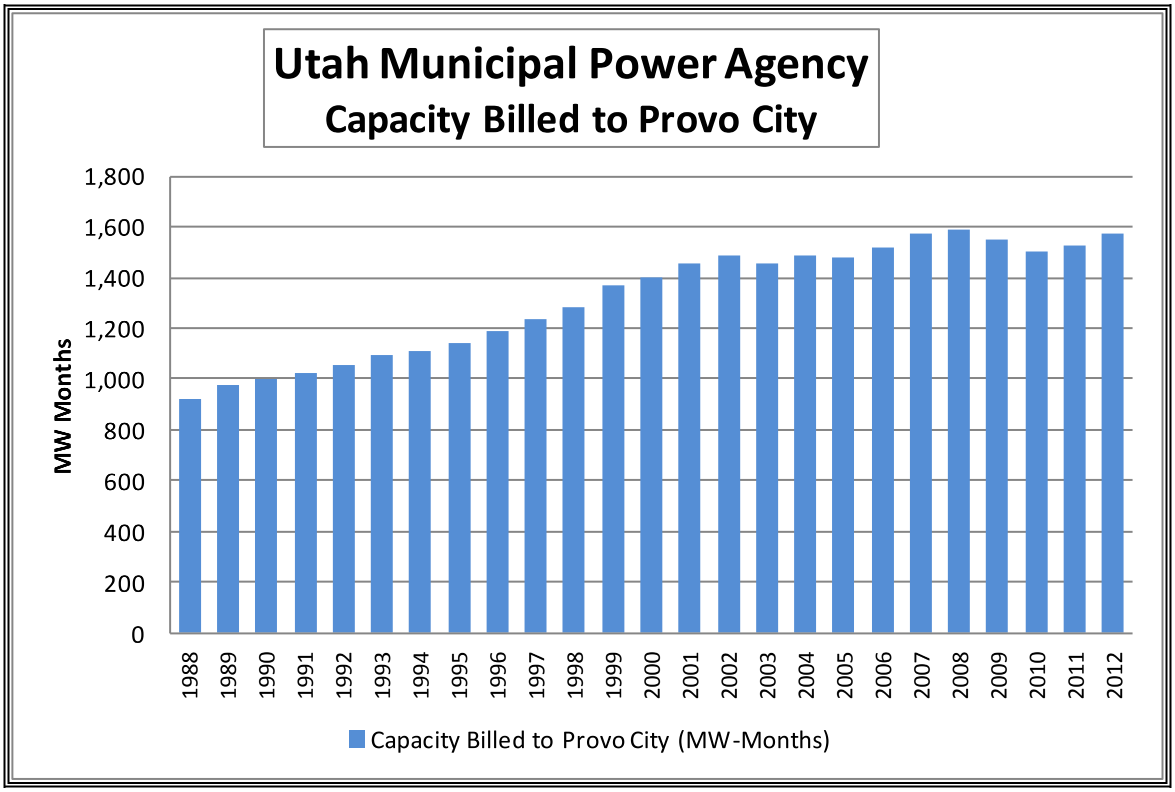
7 Rates - Current Rates (July 2012)

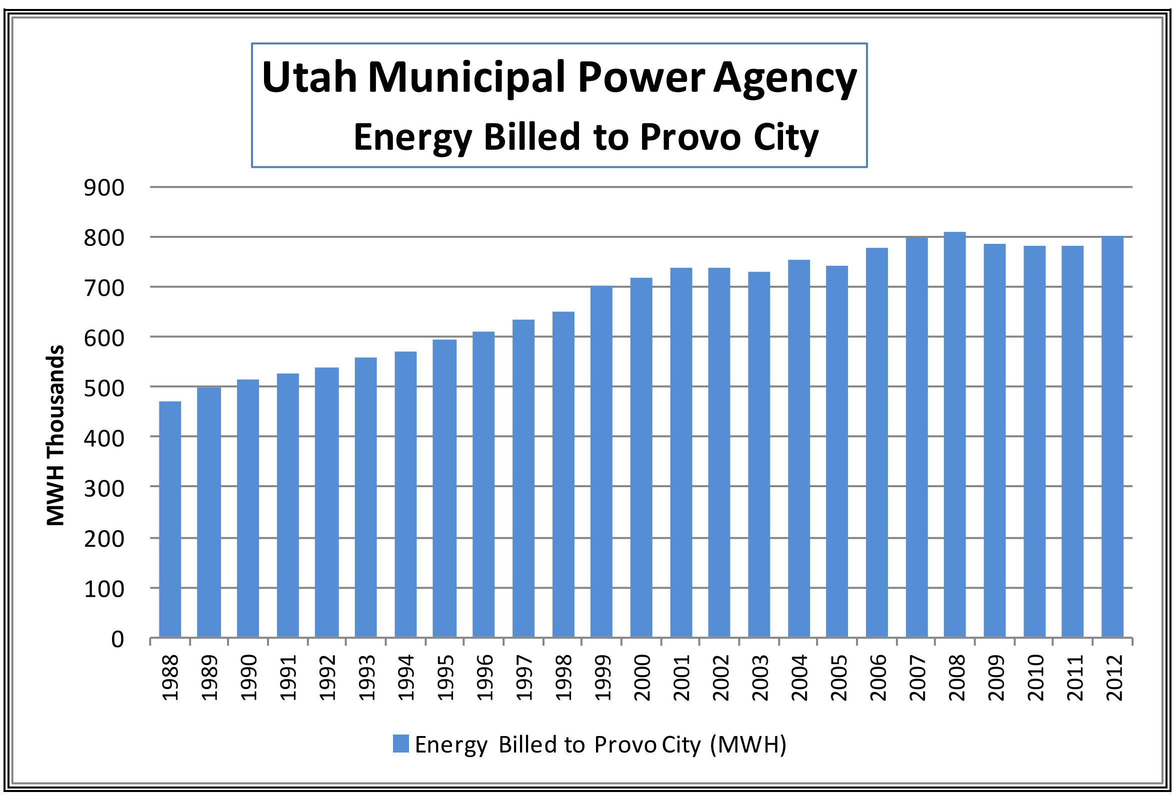
Residential	Customer Charge	$6.25	per month
	First 500	$0.0835	per kwh
	501 to 1,000	$0.0970	per kwh
	Over 1,000	$0.1075	per kwh
Commerical	Customer Charge	$28.15	per month
	Energy	$0.0416	per kwh
	Demand	$12.40	per kw

8 Financial Information (FY2012)

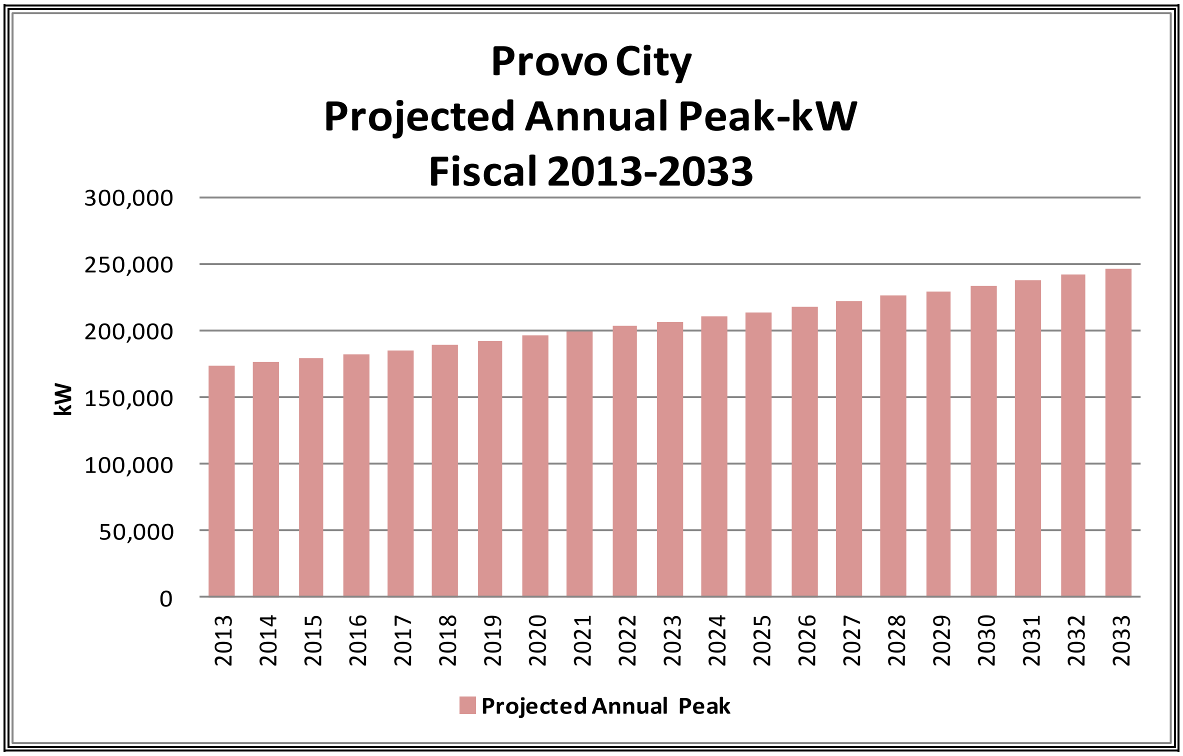
Electric Revenues	$60,682,707
Other Revenues	$6,132,843
Total Revenues	$66,815,550
Expenses and Power Supply	$45,633,520
Capital Improvement Expenses	$4,865,252
Other Expenses	$13,013,137
Total Expenditures	$63,511,909

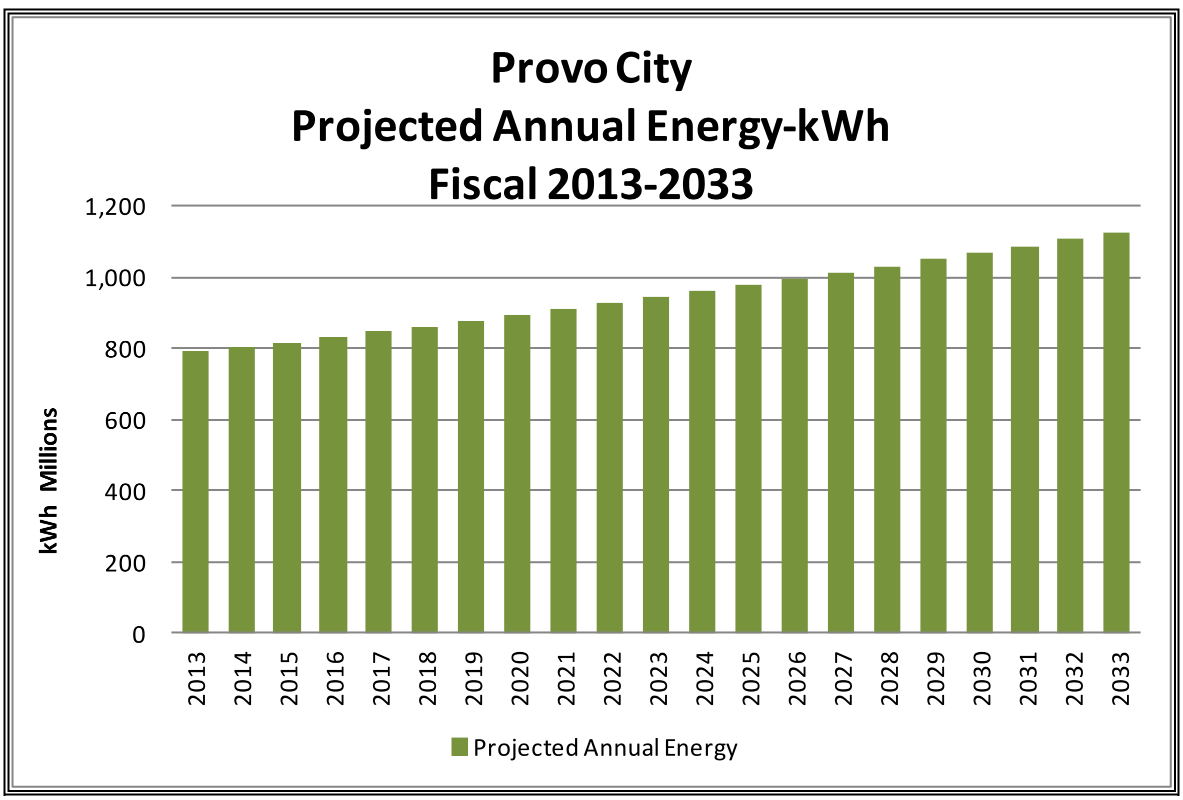
		Utah Municipal Power Agency				
		Provo City				
		Historical Non-Coincidental Load Growth				
		Fiscal Years 1988-2012				
Year	Annual Peak (MW)	% Change Over Prior Year	Capacity Billed to Provo City (MW-Months)	% Change Over Prior Year	Energy Billed to Provo City (MWH)	% Change Over Prior Year
1988	92.500	-	924.600	-	471,486.766	
1989	92.600	0.11%	976.180	5.58%	499,768.100	6.00%
1990	103.270	11.52%	999.365	2.38%	513,655.500	2.78%
1991	103.673	0.39%	1,020.417	2.11%	528,702.600	2.93%
1992	103.713	0.04%	1,058.058	3.69%	539,736.700	2.09%
1993	110.433	6.48%	1,092.566	3.26%	557,362.100	3.27%
1994	115.529	4.61%	1,112.426	1.82%	569,636.900	2.20%
1995	119.172	3.15%	1,143.946	2.83%	594,387.920	4.35%
1996	117.836	-1.12%	1,191.735	4.18%	612,070.873	2.97%
1997	125.336	6.36%	1,237.895	3.87%	635,456.751	3.82%
1998	130.973	4.50%	1,283.713	3.70%	651,200.472	2.48%
1999	142.874	9.09%	1,369.830	6.71%	703,437.872	8.02%
2000	141.246	-1.14%	1,400.708	2.25%	719,303.308	2.26%
2001	156.050	10.48%	1,454.894	3.87%	740,036.914	2.88%
2002	153.601	-1.57%	1,486.003	2.14%	738,775.905	-0.17%
2003	157.912	2.81%	1,452.249	-2.27%	728,305.029	-1.42%
2004	164.208	3.99%	1,489.876	2.59%	753,770.566	3.50%
2005	160.272	-2.40%	1,481.200	-0.58%	743,550.160	-1.36%
2006	168.350	5.04%	1,519.384	2.58%	776,406.821	4.42%
2007	171.578	1.92%	1,574.860	3.65%	798,690.340	2.87%
2008	177.278	3.32%	1,592.648	1.13%	809,725.160	1.38%
2009	169.022	-4.66%	1,548.119	-2.80%	787,401.382	-2.76%
2010	164.204	-2.85%	1,504.982	-2.79%	780,936.521	-0.82%
2011	169.217	3.05%	1,525.841	1.39%	783,110.339	0.28%
2012	172.285	1.81%	1,575.500	3.25%	800,027.250	2.16%


Utah Municipal Power Agency
Capacity Billed to Provo City
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
MW Months
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Capacity Billed to Provo City (MW-Months)


Utah Municipal Power Agency
Energy Billed to Provo City
900
800
700
600
500
400
300
200
100
0
MWH Thousands
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Energy Billed to Provo City (MWH)

20 Year Forecast - Provo City				
Year	Annual Peak kW	% Growth	Energy Requirement (MWh)	% Growth
2013	173,477	0.00%	792,161,192	0.00%
2014	175,906	1.40%	803,251,448	1.40%
2015	179,072	1.80%	817,709,974	1.80%
2016	182,296	1.80%	832,428,754	1.80%
2017	185,577	1.80%	847,412,472	1.80%
2018	188,917	1.80%	862,665,896	1.80%
2019	192,318	1.80%	878,193,882	1.80%
2020	195,780	1.80%	894,001,372	1.80%
2021	199,304	1.80%	910,093,397	1.80%
2022	202,891	1.80%	926,475,078	1.80%
2023	206,543	1.80%	943,151,629	1.80%
2024	210,261	1.80%	960,128,359	1.80%
2025	214,046	1.80%	977,410,669	1.80%
2026	217,899	1.80%	995,004,061	1.80%
2027	221,821	1.80%	1,012,914,134	1.80%
2028	225,813	1.80%	1,031,146,589	1.80%
2029	229,878	1.80%	1,049,707,227	1.80%
2030	234,016	1.80%	1,068,601,957	1.80%
2031	238,228	1.80%	1,087,836,793	1.80%
2032	242,516	1.80%	1,107,417,855	1.80%
2033	246,882	1.80%	1,127,351,376	1.80%


Provo City
Projected Annual Peak-kW
Fiscal 2013-2033
300,000
250,000
200,000
150,000
100,000
50,000
0
kW
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Projected Annual Peak


Provo City
Projected Annual Energy-kWh
Fiscal 2013-2033
1,200
1,000
800
600
400
200
0
kWh Millions
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Projected Annual Energy

Appendix B - UMPA Information

Utah Municipal Power Agency

Customer Profile (FY 2012) **For more information - Web site: www.umpa.cc/**

1 Service Area 74.87 square miles

2 Geographical Characteristics 90% urban and suburban development with the remaining in rural and agriculture.

3 Customer Mix See Appendix A - Member Information

4 Historical Loads See attachment for historical loads and graph

5 Projected Loads See attachment for projected loads and graph

6 Existing System Data

Peak	254,843	kW
Energy	1,170,595,819	kWh
Number of Retail Electric Meters	52,548	Sum of the member meters

7 Rates - Current Rates (July 2012)

Member City Rates	Energy	$0.0210	per kwh
	Demand	$13.69	per kw
	Energy Cost Adjuster	varies by month	per kwh

8 Financial Information	**FY2012**	**FY2011**
Total Operating Revenues	$68,159,908	$66,801,832
Total Operating Expenses	$64,512,428	$63,833,628
Income (loss) from Operations	$3,647,480	$2,968,204
Utility Plant and Equipment	$13,935,319	$14,775,477
Current Assets	$27,961,617	$26,952,367
Long-Term Liabilities	$21,707,607	$25,553,331
Current Liabilities	$9,518,833	$8,268,977
Rate Stabilization Fund Balance	$1,607,654	$1,803,767
Debt Service Coverage	1.18	1.00

Utah Municipal Power Agency

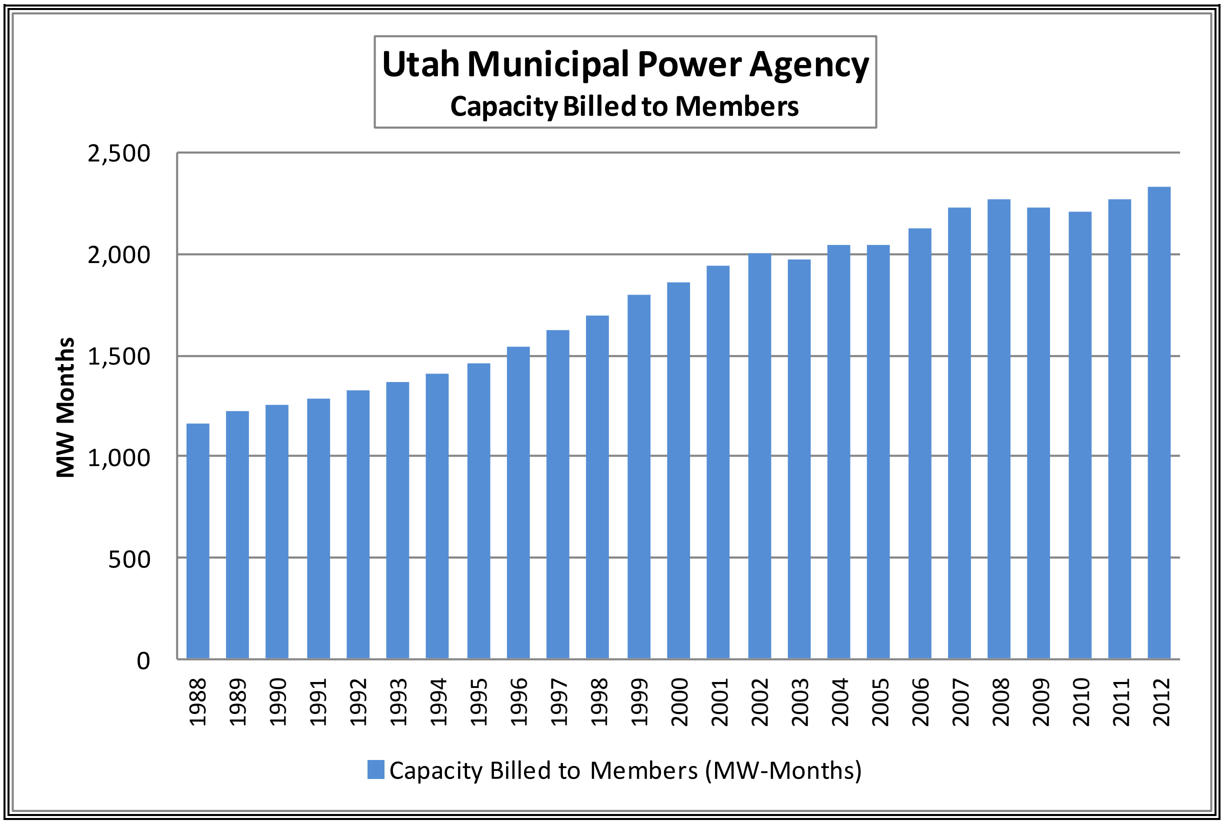
Historical Non-Coincidental Load Growth

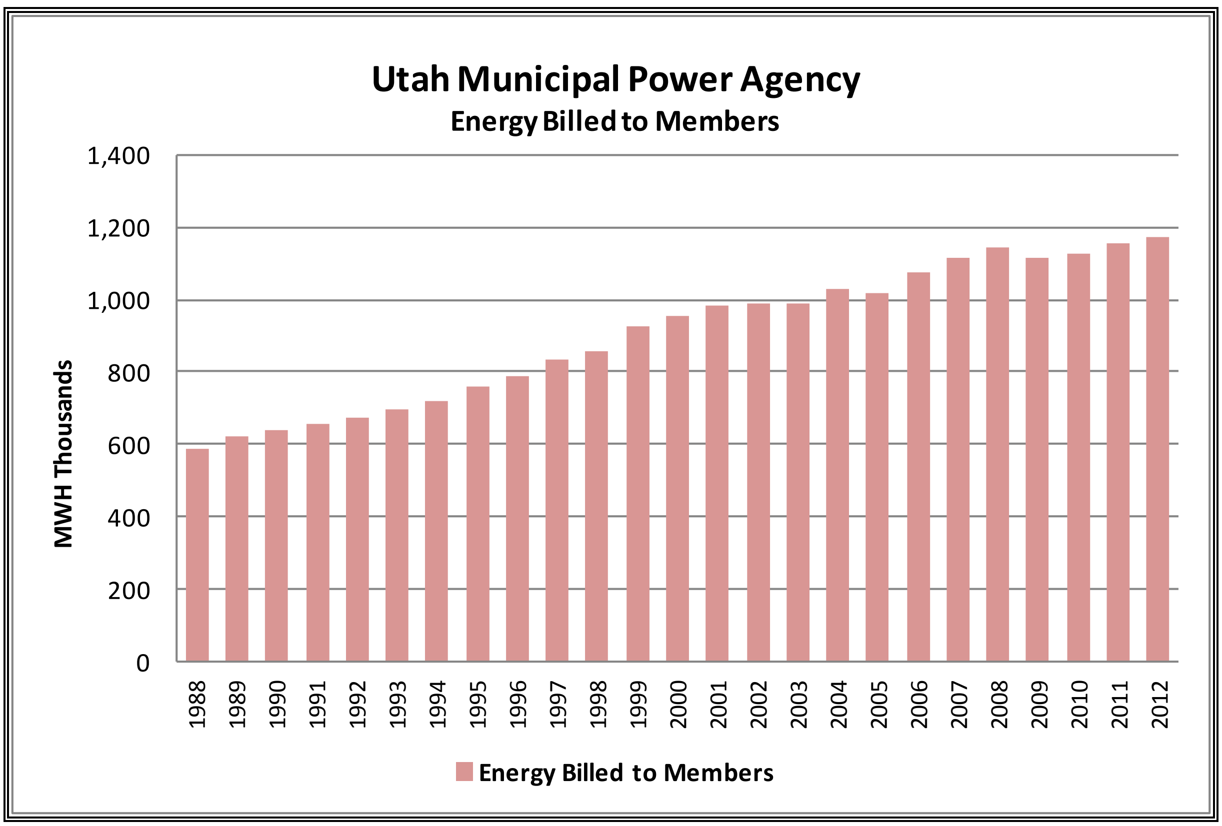
Fiscal Years 1988-2012

Year	Annual Peak (MW)	% Change Over Prior Year	Capacity Billed to Members (MW-Months)	% Change Over Prior Year	Energy Billed to Members (MWH)	% Change Over Prior Year
1988	104.628	-	1,165.929	-	588,270.227	
1989	112.903	7.91%	1,226.032	5.15%	621,315.560	5.62%
1990	124.746	10.49%	1,253.273	2.22%	636,588.517	2.46%
1991	125.979	0.99%	1,280.629	2.18%	656,360.011	3.11%
1992	127.665	1.34%	1,326.328	3.57%	672,154.680	2.41%
1993	134.396	5.27%	1,371.152	3.38%	695,422.621	3.46%
1994	142.386	5.95%	1,406.217	2.56%	717,998.175	3.25%
1995	147.189	3.37%	1,463.888	4.10%	757,888.076	5.56%
1996	148.945	1.19%	1,543.018	5.41%	791,108.207	4.38%
1997	159.732	7.24%	1,621.701	5.10%	832,771.898	5.27%
1998	168.163	5.28%	1,691.745	4.32%	858,979.090	3.15%
1999	182.572	8.57%	1,800.013	6.40%	924,695.535	7.65%
2000	183.861	0.71%	1,856.233	3.12%	952,323.518	2.99%
2001	203.968	10.94%	1,942.357	4.64%	986,321.523	3.57%
2002	203.854	-0.06%	1,998.032	2.87%	991,633.716	0.54%
2003	212.118	4.05%	1,975.027	-1.15%	987,844.631	-0.38%
2004	224.805	5.98%	2,042.087	3.40%	1,027,698.249	4.03%
2005	217.583	-3.21%	2,045.975	0.19%	1,019,957.240	-0.75%
2006	231.884	6.57%	2,125.666	3.90%	1,073,122.597	5.21%
2007	241.418	4.11%	2,227.694	4.80%	1,117,062.852	4.09%
2008	252.771	4.70%	2,273.641	2.06%	1,144,740.437	2.48%
2009	243.434	-3.69%	2,232.820	-1.80%	1,114,706.234	-2.62%
2010	241.680	-0.72%	2,211.904	-0.94%	1,125,612.319	0.98%
2011	250.896	3.81%	2,265.669	2.43%	1,155,514.483	2.66%
2012	254.843	1.57%	2,334.560	3.04%	1,170,595.819	1.31%
*	3.78%		2.94%		2.91%	
**	0.20%		0.66%		0.56%	

* Compound Growth Rate: 1988-2012

** Compound Growth Rate: 2008-2012

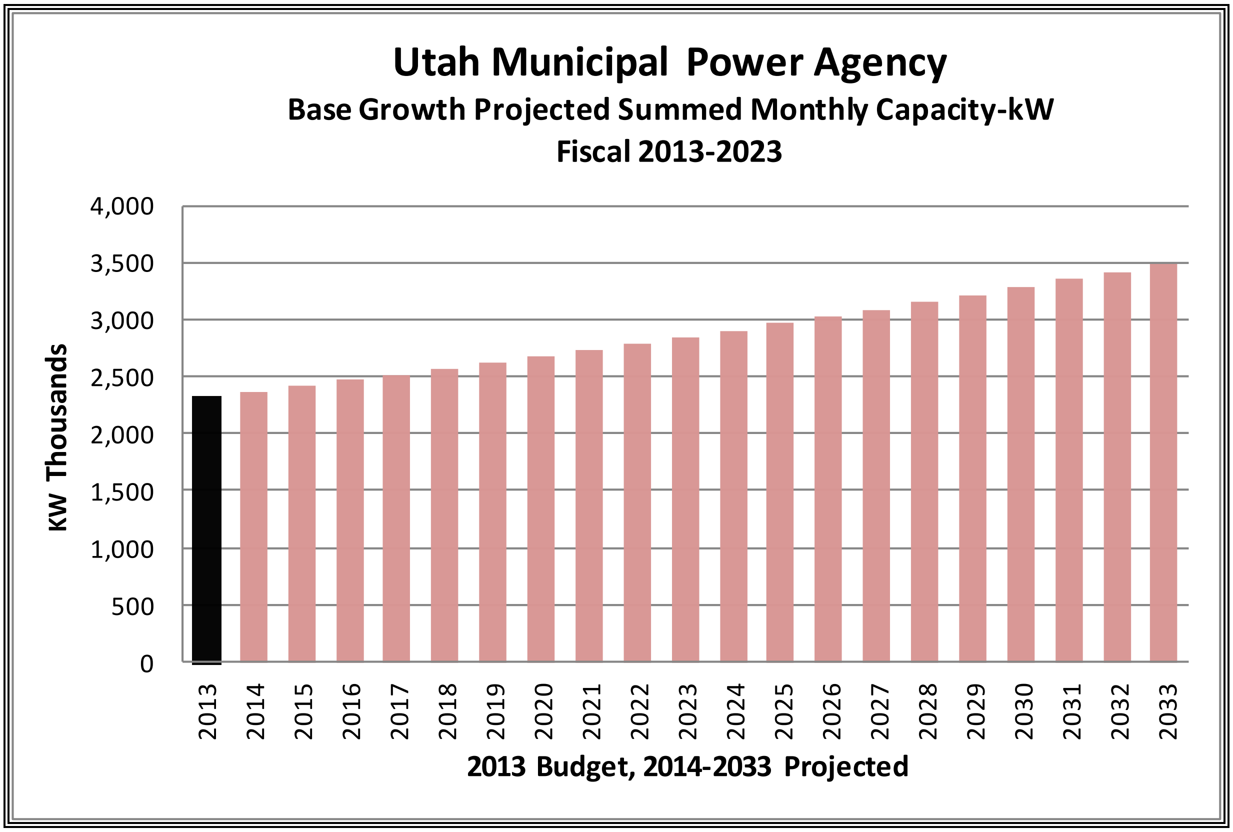

Utah Municipal Power Agency
Capacity Billed to Members
MW Months
2,500
2,000
1,500
1,000
500
0
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Capacity Billed to Members (MW-Months)

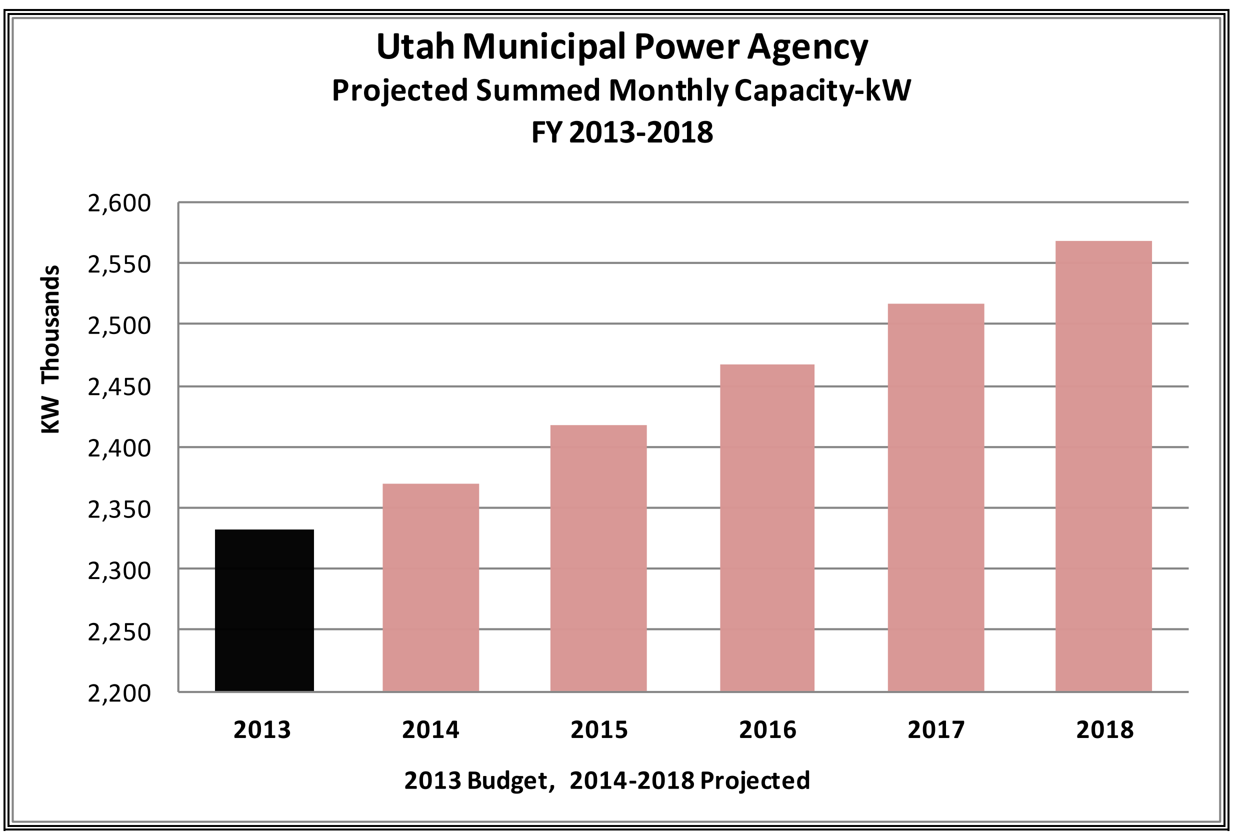

Utah Municipal Power Agency
Energy Billed to Members
MWH Thousands
1,400
1,200
1,000
800
600
400
200
0
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Energy Billed to Members

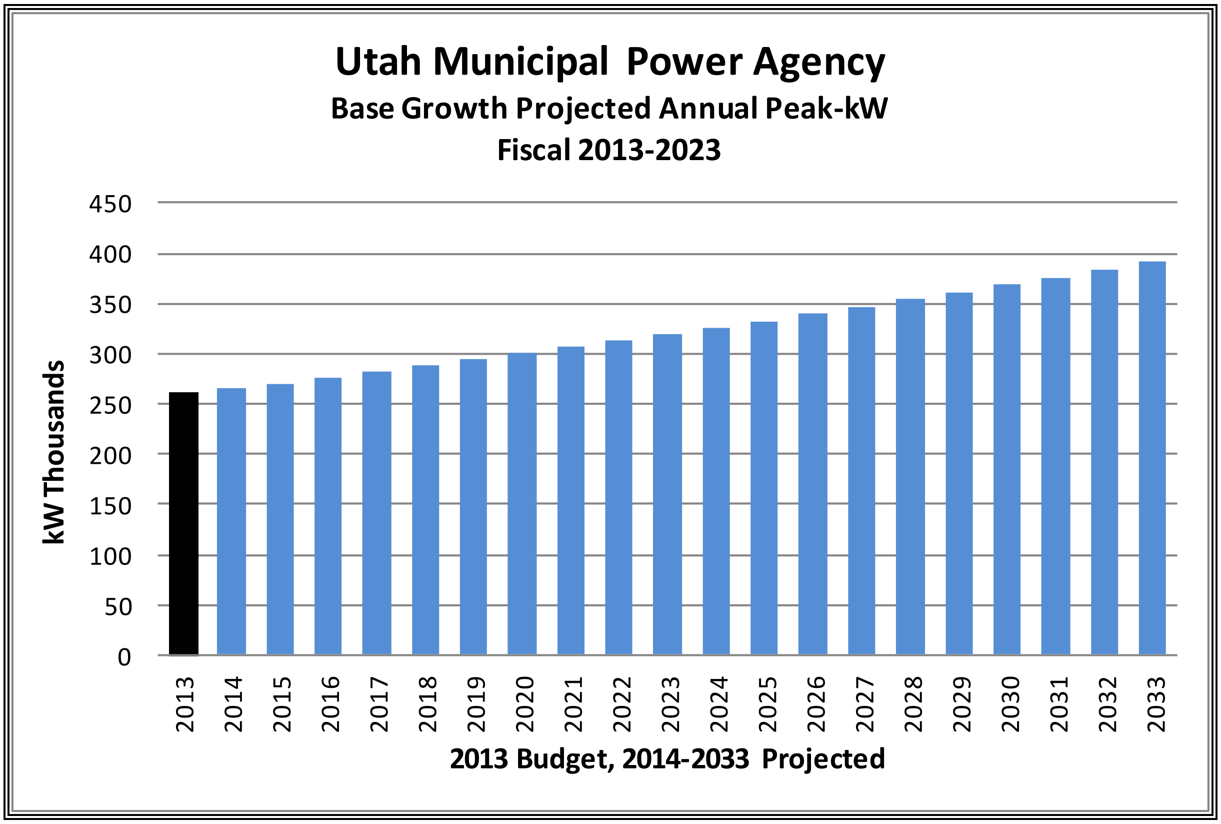
UMPA 20 Year Load Forecast				
Year	Annual Peak kW	% Growth	Energy Requirement (MWh)	% Growth
2013	261,113		1,188,444,331	
2014	265,400	1.64%	1,207,428,447	1.60%
2015	270,879	2.06%	1,231,740,325	2.01%
2016	276,481	2.07%	1,256,586,952	2.02%
2017	282,207	2.07%	1,281,980,775	2.02%
2018	288,061	2.07%	1,307,934,546	2.02%
2019	294,046	2.08%	1,334,461,333	2.03%
2020	300,165	2.08%	1,361,574,524	2.03%
2021	306,421	2.08%	1,389,287,839	2.04%
2022	312,818	2.09%	1,417,615,336	2.04%
2023	319,359	2.09%	1,446,571,422	2.04%
2024	326,046	2.09%	1,476,170,860	2.05%
2025	332,794	2.07%	1,506,375,955	2.05%
2026	339,681	2.07%	1,537,199,101	2.05%
2027	346,710	2.07%	1,568,652,943	2.05%
2028	353,885	2.07%	1,600,750,388	2.05%
2029	361,208	2.07%	1,633,504,603	2.05%
2030	368,683	2.07%	1,666,929,028	2.05%
2031	376,313	2.07%	1,701,037,377	2.05%
2032	384,101	2.07%	1,735,843,643	2.05%
2033	392,049	2.07%	1,771,362,108	2.05%

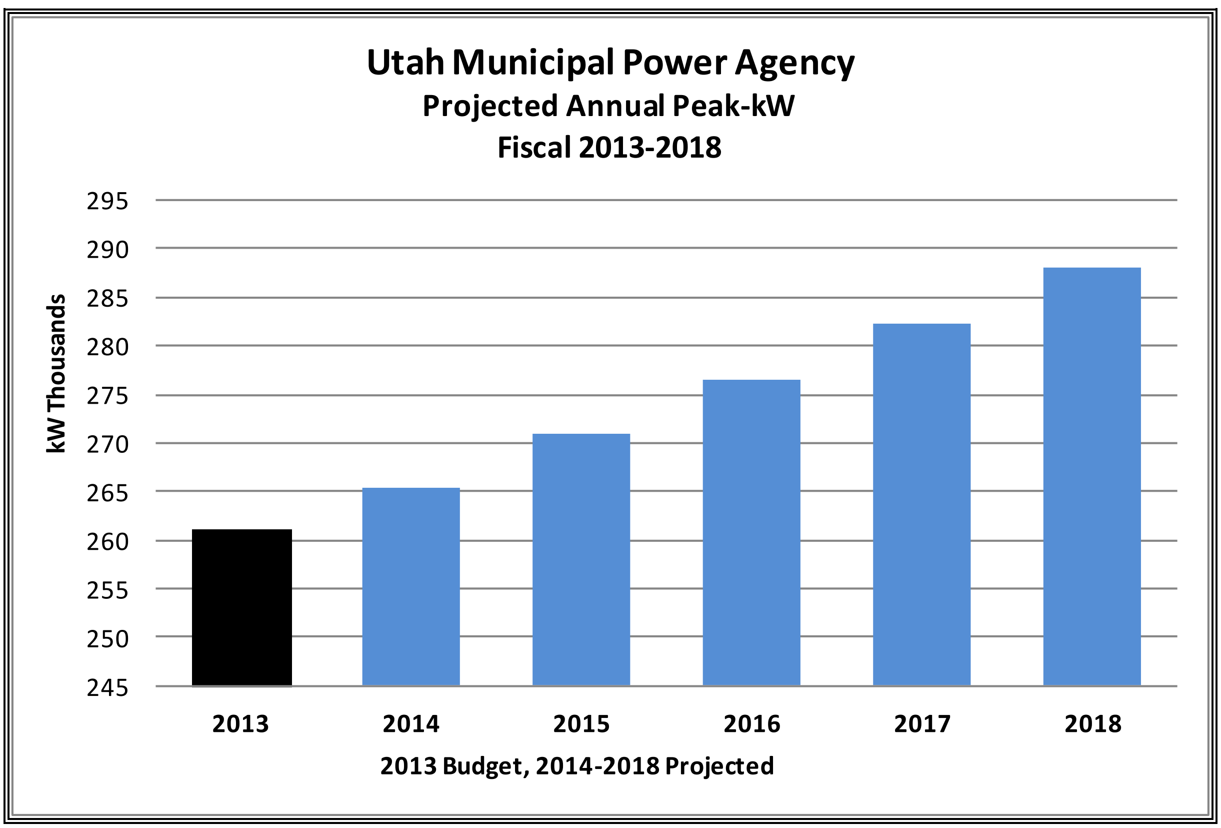
Peak Demand	
5 Year Compound Growth Rate:	1.96%
10 Year Compound Growth Rate:	2.01%
20 Year Compound Growth Rate:	2.04%

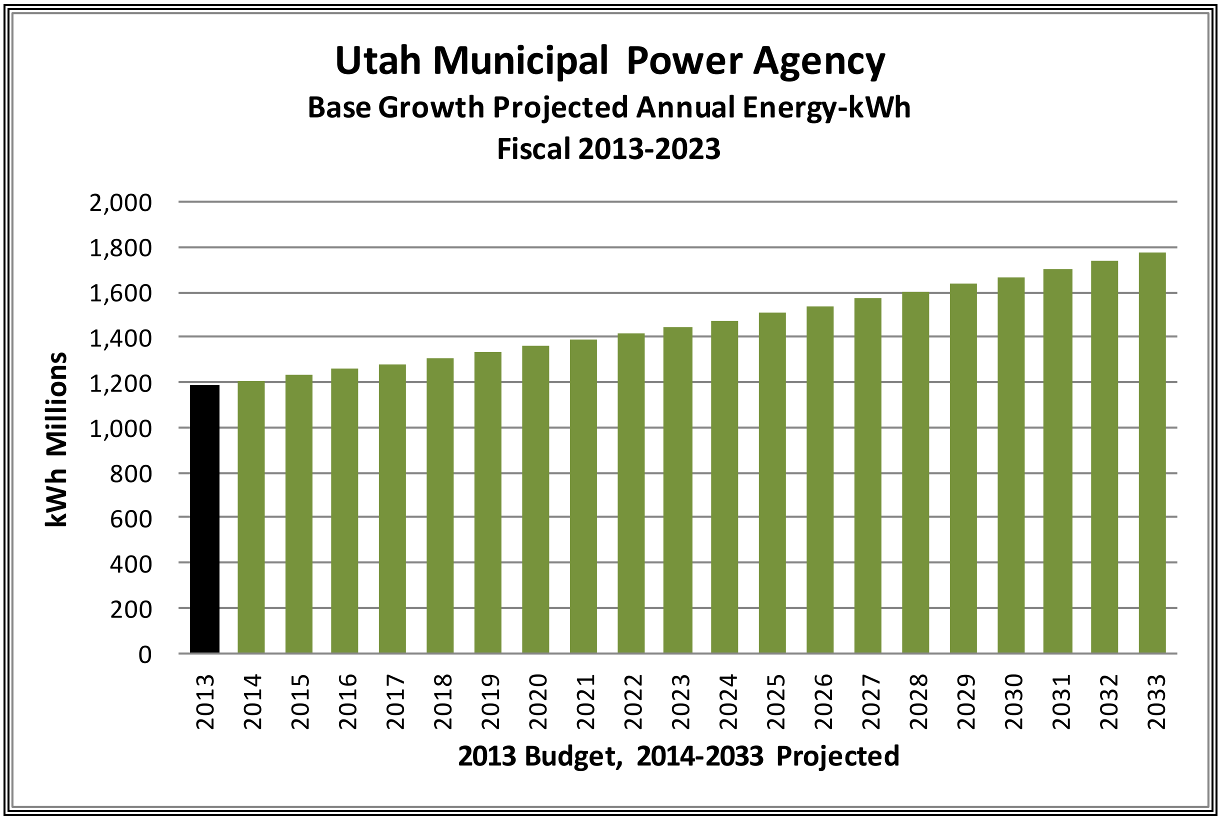
Energy Requirements	
5 Year Compound Growth Rate:	1.93%
10 Year Compound Growth Rate:	1.98%
20 Year Compound Growth Rate:	2.02%

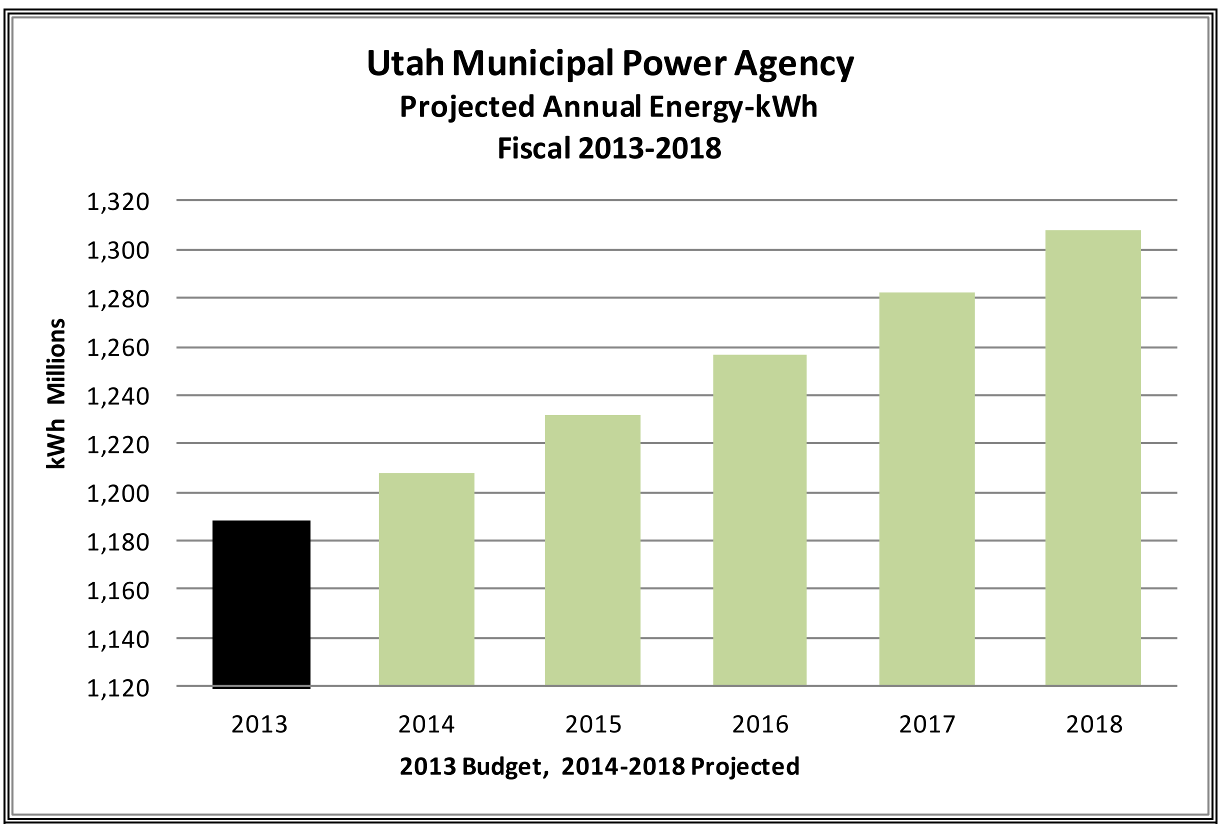

Utah Municipal Power Agency
Base Growth Projected Summed Monthly Capacity-kW
Fiscal 2013-2023
KW Thousands
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2013 Budget, 2014-2033 Projected

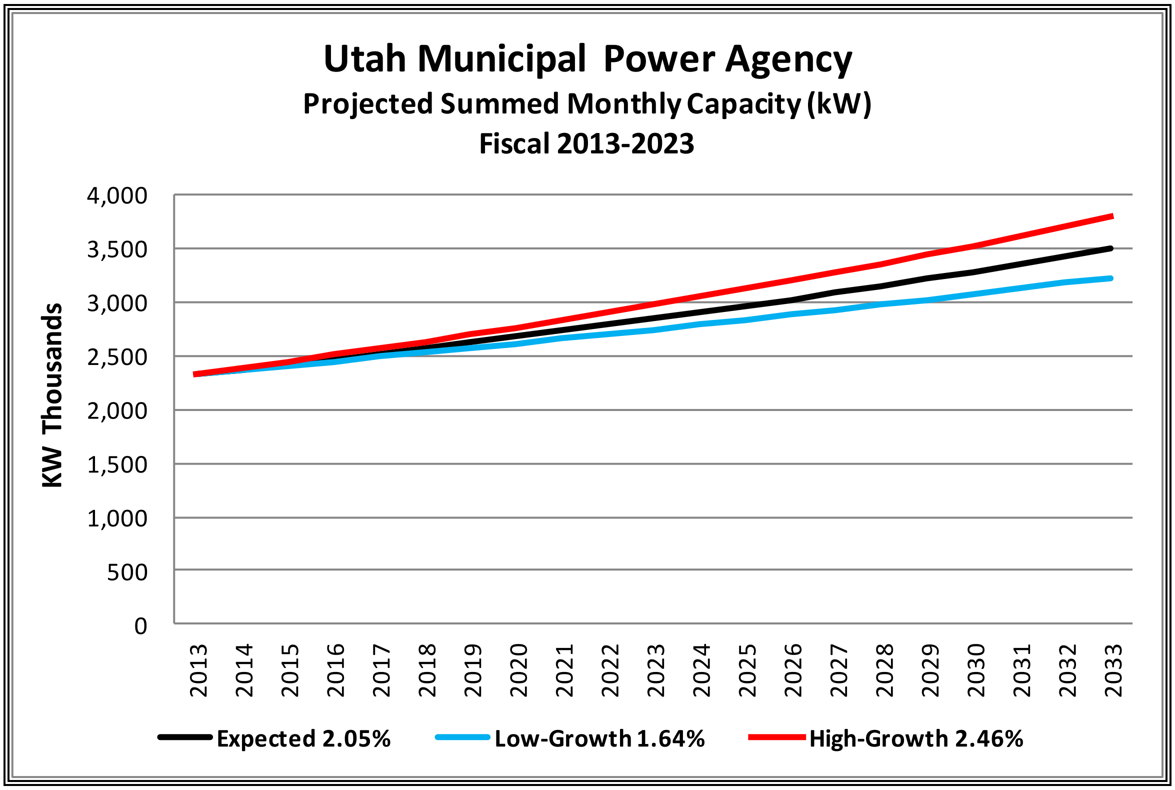

Utah Municipal Power Agency
Projected Summed Monthly Capacity-kW
FY 2013-2018
KW Thousands
2,600
2,550
2,500
2,450
2,400
2,350
2,300
2,250
2,200
2013
2014
2015
2016
2017
2018
2013 Budget, 2014-2018 Projected

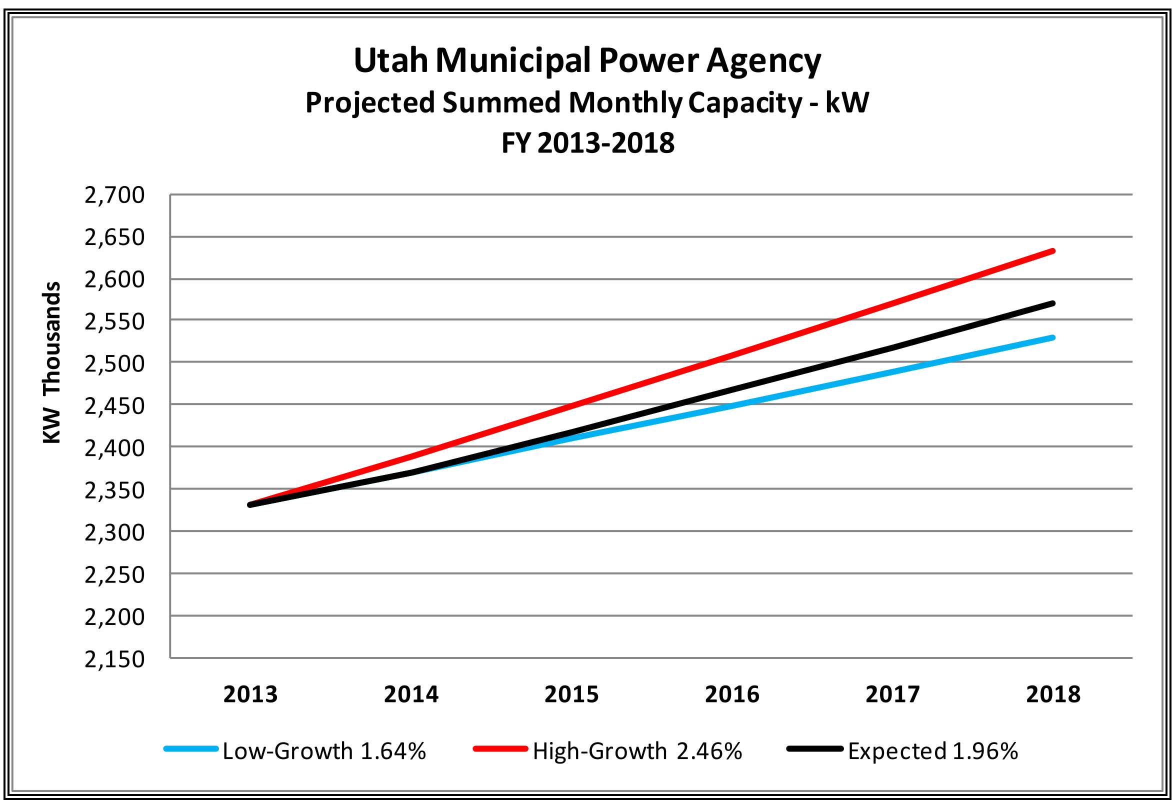

Utah Municipal Power Agency
Base Growth Projected Annual Peak-kW
Fiscal 2013-2023
kW Thousands
450
400
350
300
250
200
150
100
50
0
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2013 Budget, 2014-2033 Projected

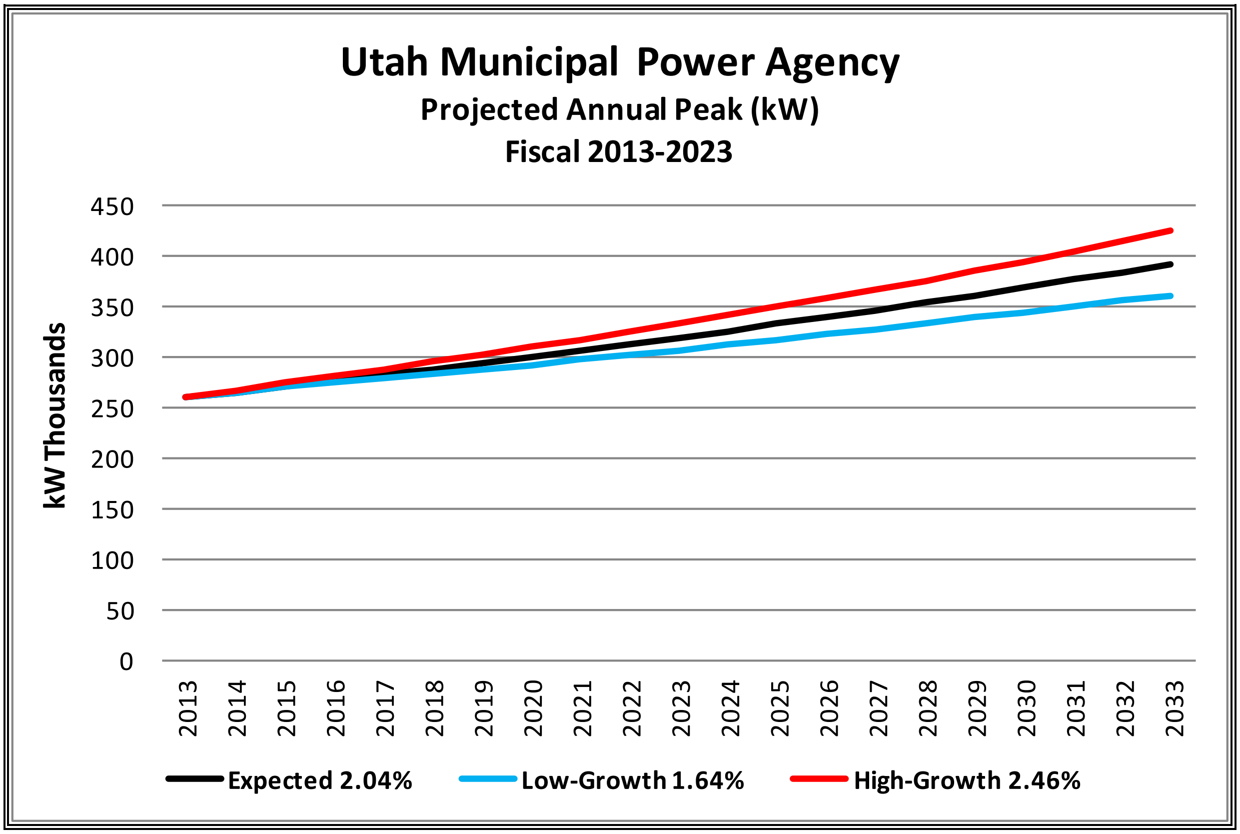

Utah Municipal Power Agency
Projected Annual Peak-kW
Fiscal 2013-2018
kW Thousands
295
290
285
280
275
270
265
260
255
250
245
2013
2014
2015
2016
2017
2018
2013 Budget, 2014-2018 Projected

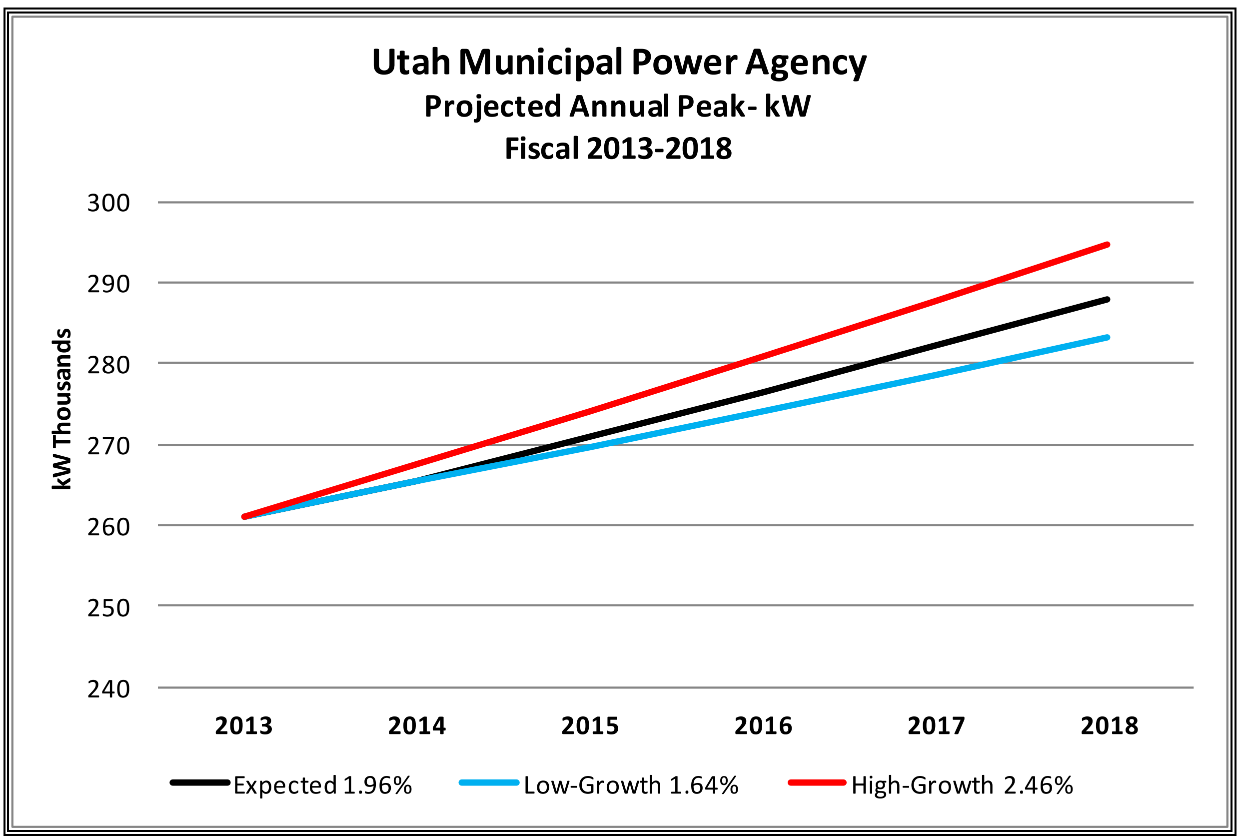

Utah Municipal Power Agency
Base Growth Projected Annual Energy-kWh
Fiscal 2013-2023
kWh Millions
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2013 Budget, 2014-2033 Projected

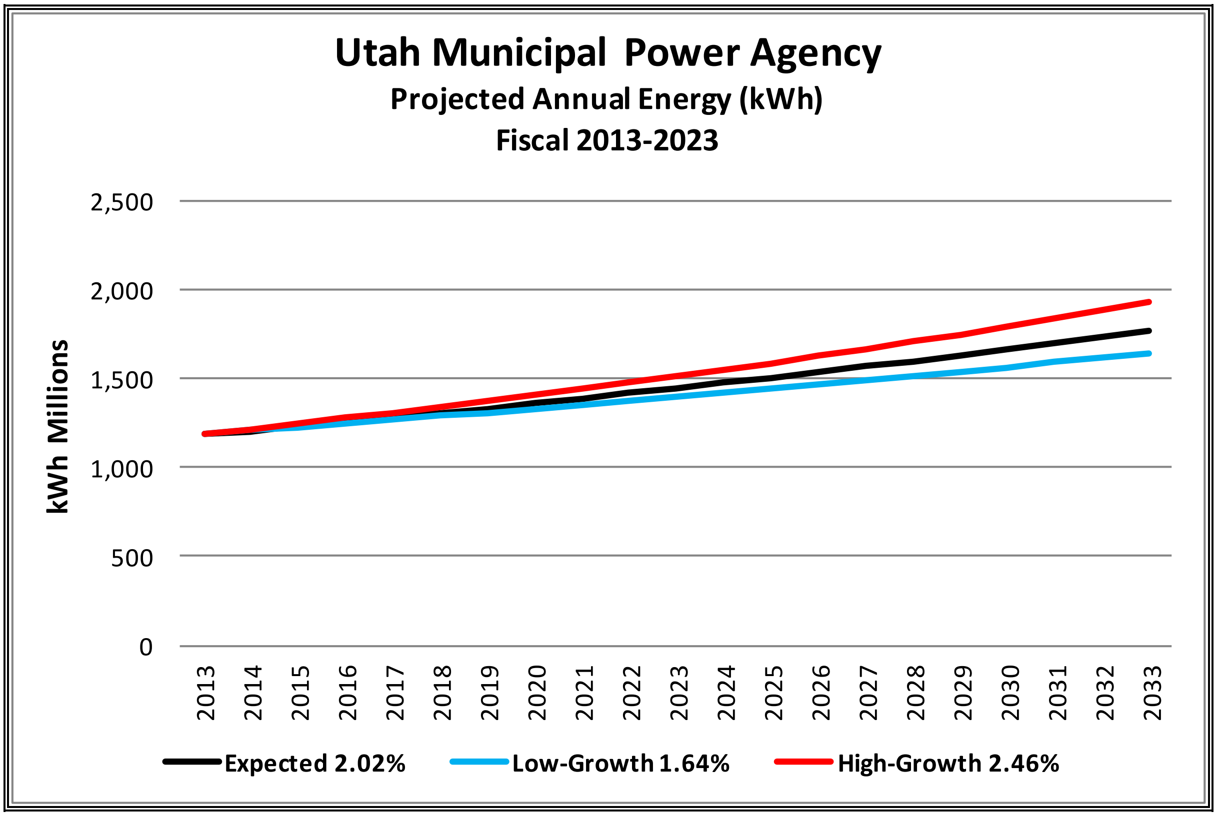

Utah Municipal Power Agency
Projected Annual Energy-kWh
Fiscal 2013-2018
kWh Millions
1,320
1,300
1,280
1,260
1,240
1,220
1,200
1,180
1,160
1,140
1,120
2013
2014
2015
2016
2017
2018
2013 Budget, 2014-2018 Projected

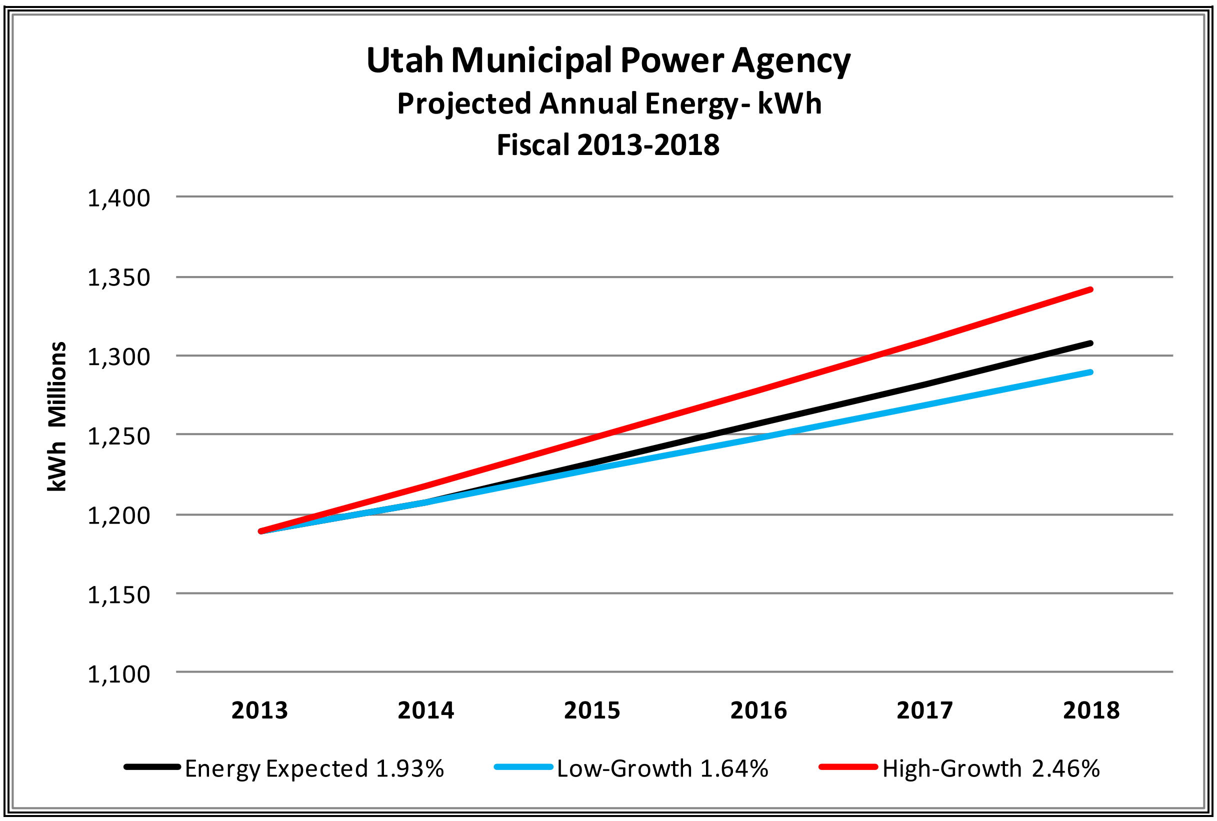

Utah Municipal Power Agency
Projected Summed Monthly Capacity (kW)
Fiscal 2013-2023
KW Thousands
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033
Expected 2.05%
Low-Growth 1.64%
High-Growth 2.46%


Utah Municipal Power Agency
Projected Summed Monthly Capacity - kW
FY 2013-2018
KW Thousands
2,700
2,650
2,600
2,550
2,500
2,450
2,400
2,350
2,300
2,250
2,200
2,150
2013 2014 2015 2016 2017 2018
Low-Growth 1.64%
High-Growth 2.46%
Expected 1.96%


Utah Municipal Power Agency
Projected Annual Peak (kW)
Fiscal 2013-2023
kW Thousands
450
400
350
300
250
200
150
100
50
0
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Expected 2.04%
Low-Growth 1.64%
High-Growth 2.46%


Utah Municipal Power Agency
Projected Annual Peak- kW
Fiscal 2013-2018
kW Thousands
300
290
280
270
260
250
240
2013
2014
2015
2016
2017
2018
Expected 1.96%
Low-Growth 1.64%
High-Growth 2.46%


Utah Municipal Power Agency
Projected Annual Energy (kWh)
Fiscal 2013-2023
kWh Millions
2,500
2,000
1,500
1,000
500
0
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Expected 2.02%
Low-Growth 1.64%
High-Growth 2.46%


Utah Municipal Power Agency
Projected Annual Energy- kWh
Fiscal 2013-2018
kWh Millions
1,400
1,350
1,300
1,250
1,200
1,150
1,100
2013
2014
2015
2016
2017
2018
Energy Expected 1.93%
Low-Growth 1.64%
High-Growth 2.46%

Appendix C - Demand-Side Management Data

SUMMARY of DSM Program from FY2007 to FY2012								
Utah Municipal Power Agency		**Fiscal Year**						
		2007	**2008**	**2009**	**2010**	**2011**	**2012**	**Total**
DSM Tree Planting								
	Number of Planted Trees*	0	0	0	318.6	720.9	1084.5	2,124
	Estimated kW Reduction	0.0	0.0	0.0	44.6	100.9	151.8	297.4
	Estimated kWh Reduction	-	-	-	66,906	151,389	227,745	446,040
In-House Conservation Program								
	Estimated kW Reduction	0.3	0.0	0.0	2.1	1.7	1.1	5.2
	Estimated kWh Reduction	780	0	0	5,527	4,526	2,821	13,654
Residential Energy Audits								
	Number of Audits	7	19	-	6	393	162	587
	Estimated kW Reduction	0.4	1.0	-	0.3	19.7	8.2	29.6
	Estimated kWh Reduction	3,276	8,892	-	2,808	183,924	75,816	274,716
Low Loss Transformer Program								
	Number of Transformers	395	315	186	185	158	180	1,419
	Estimated kW Reduction	86.3	92.2	63.4	63.1	60.8	63.6	429.4
	Estimated kWh Reduction	698,395	962,865	513,143	510,384	490,534	514,834	3,690,155
Energy Efficient Street Lights								
	Number of Lights	231	106	74	302	349	409	1,471
	Estimated kW Reduction	23.7	9.6	8.6	35.0	39.0	44.3	160.2
	Estimated kWh Reduction	103,937	42,245	37,526	153,147	170,820	194,056	701,731
Energy Efficiency Education Program								
	Number of Participants	1,803	2,030	2,045	2,063	2,284	2,054	12,279
	Estimated kW Reduction	355.0	467.0	549.5	632.0	693.0	507.0	3,203.5
	Estimated kWh Reduction	1,075,613	1,075,613	1,283,672	1,491,730	1,592,950	1,230,260	7,749,838
Totals								
	Estimated kW Reduction	465.7	569.8	621.5	777.1	915.1	776.0	4,125.3
	Estimated kWh Reduction	1,882,001	2,089,615	1,834,340	2,230,502	2,594,143	2,245,532	12,876,133
	Estimated Savings	$157,339	$182,921	$179,502	$221,601	$259,496	$222,110	$1,222,969
	Notes:							
	*	Only trees that have matured for 15 years are counted here.						

Appendix D - UMPA Historical Resource Analysis

UTAH MUNICIPAL POWER AGENCY
HISTORICAL RESOURCE ANALYSIS
Detail

RESOURCE	03-04	04-05	05-06	06-07	07-08	08-09	09-10	10-11	11-12
BONANZA									
Debt service	2,463,246.00	2,460,566.00	2,461,954.00	2,458,365.00	2,459,382.00	2,459,816.00	2,459,527.00	2,461,262.00	2,458,948.00
Fixed costs	3,080,522.96	2,888,632.83	2,953,802.32	3,227,845.15	2,898,709.12	3,646,044.91	3,464,409.28	3,356,506.63	4,663,954.50
Fuel costs	4,889,037.04	4,697,116.24	4,925,964.56	5,299,851.19	6,175,360.98	5,993,313.41	5,914,740.00	6,339,390.16	6,049,963.27
Other									
Total Costs	10,432,806.00	10,046,315.07	10,341,720.88	10,986,061.34	11,533,452.10	12,099,174.32	11,838,676.28	12,157,158.79	13,172,865.77
kwh produced	275,646,340	284,990,400	273,818,000	251,814,000	281,813,000	272,804,000	280,924,000	248,849,000	232,545,000
mills/kwh	37.85	35.25	37.77	43.63	40.93	44.35	42.14	48.85	56.65
CRSP									
AHP Cost	7,034,444.13	6,588,048.43	6,959,021.65	7,165,596.93	7,345,063.46	7,769,112.53	8,348,304.65	9,115,752.02	9,733,162.50
AHP kWh	292,586,634	276,602,004	271,972,775	277,717,085	294,923,845	302,965,383	290,603,524	338,312,614	388,184,845
AHP Mills/kwh	24.04	23.82	25.59	25.80	24.90	25.64	28.73	26.94	25.07
WRP/CDP Cost	195,932.09	235,312.33	552,740.74	1,154,623.43	1,282,059.32	770,019.69	327,635.20	398,576.37	1,764,843.99
WRP/CDP kWh	3,696,000	4,213,001	9,302,999	18,477,447	19,545,005	15,507,297	8,790,000	8,109,086	61,322,114
WRP/CDP Mills/kwh	53.01	55.85	59.42	62.49	65.60	49.66	37.27	49.15	28.78
Combined Cost	7,230,376.22	6,823,360.76	7,511,762.39	8,320,220.36	8,627,122.78	8,539,132.22	8,675,939.85	9,514,328.39	11,498,006.49
Combined kWh	296,282,634	280,815,005	281,275,774	296,194,532	314,468,850	318,472,680	299,393,524	346,421,700	449,506,959
Combined Mills/kwh	24.40	24.30	26.71	28.09	27.43	26.81	28.98	27.46	25.58
HUNTER									
Debt service	3,165,953.00	3,187,741.00	3,195,378.00	3,163,429.00	3,172,469.00	3,156,288.00	3,150,880.00	2,967,285.00	3,142,323.00
Fixed costs	1,299,908.54	2,888,063.93	1,383,200.07	1,345,630.33	1,392,586.62	2,464,029.05	5,235,846.80	2,908,334.02	2,957,701.27
Fuel costs	1,534,839.76	1,597,151.32	1,994,118.70	2,056,829.10	2,074,194.61	2,479,571.79	2,115,897.80	2,680,150.09	2,839,577.21
Other									
Total Costs	6,000,701.30	7,672,956.25	6,572,696.77	6,565,888.43	6,639,250.23	8,099,888.84	10,502,624.60	8,555,769.11	8,939,601.48
kwh produced	203,378,000	186,898,000	221,253,000	210,455,000	203,005,000	208,933,000	173,490,000	205,027,000	214,900,000
mills/kwh	29.51	41.05	29.71	31.20	32.70	38.77	60.54	41.73	41.60
COVE FORT									
Debt service	755,186.04	755,782.00	755,813.00	755,091.00	755,904.00	755,888.00	755,700.00	755,746.92	755,045.04
Fixed costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Resource Maint. & Royalties	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other									
Total Costs	755,186.04	755,782.00	755,813.00	755,091.00	755,904.00	755,888.00	755,700.00	755,746.92	755,045.04
kwh produced	0	0	0	0	0	0	0	0	0
mills/kwh	ERR	ERR	ERR	ERR	ERR	ERR	ERR	ERR	ERR
DOWNTOWN PLANT									
Debt service									
Fixed costs	542,308.45	452,530.70	569,433.68	631,471.89	772,887.18	832,791.51	844,762.28	1,037,678.49	869,789.90
Fuel costs	142,581.37	151,161.79	129,163.45	190,317.15	275,049.25	187,837.52	90,417.38	72,121.10	89,055.75
Other									
Total Costs	684,889.82	603,692.49	698,597.13	821,789.04	1,047,936.43	1,020,629.03	935,179.66	1,109,799.59	958,845.65
kwh produced	2,107,834	1,608,947	1,482,480	3,399,994	3,123,858	2,089,837	1,576,039	936,421	999,571
mills/kwh	324.93	375.21	471.24	241.70	335.46	488.38	593.37	1,185.15	959.26
HYDROS									
Debt service									
Fixed costs	358,656.00	355,461.81	358,536.02	320,364.00	351,881.00	287,919.47	256,101.35	260,052.00	259,896.00
Fuel costs									
Other									
Total Costs	358,656.00	355,461.81	358,536.02	320,364.00	351,881.00	287,919.47	256,101.35	260,052.00	259,896.00
kwh produced	8,256,577	8,203,253	10,939,262	10,277,025	6,749,938	7,897,572	7,837,180	8,175,234	10,006,354
mills/kwh	43.44	43.33	32.78	31.17	52.13	36.46	32.68	31.81	25.97

UTAH MUNICIPAL POWER AGENCY
HISTORICAL RESOURCE ANALYSIS
Detail

RESOURCE	03-04	04-05	05-06	06-07	07-08	08-09	09-10	10-11	11-12
UP&L FIRM									
Debt service									
Fixed costs	2,839,853.20	2,683,309.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel costs									
Other									
Total Costs	2,839,853.20	2,683,309.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00
kwh produced	52,666,000	52,511,000	0	0	0	0	0	0	0
mills/kwh	53.92	51.10	ERR	ERR	ERR	ERR	ERR	ERR	ERR
PACIFICORP LONG-TERM FIRM									
Debt service									
Fixed costs	9,422,059.16	9,255,916.40	9,505,188.64	9,546,974.16	9,549,158.72	9,370,233.96	9,239,904.00	9,163,421.20	8,985,781.49
Fuel costs									
Other									
Total Costs	9,422,059.16	9,255,916.40	9,505,188.64	9,546,974.16	9,549,158.72	9,370,233.96	9,239,904.00	9,163,421.20	8,985,781.49
kwh produced	216,259,000	209,110,000	219,836,000	221,634,000	221,728,000	214,029,000	208,421,000	205,130,000	198,130,000
mills/kwh	43.57	44.26	43.24	43.08	43.07	43.78	44.33	44.67	45.35
DEER CREEK - FIRM CONTRACT									
Debt service									
Fixed costs									
Fuel costs									
Other	305,882.66	304,454.66	261,788.66	242,582.66	234,272.66	247,214.00	297,032.00	291,381.14	272,716.82
Total Costs	305,882.66	304,454.66	261,788.66	242,582.66	234,272.66	247,214.00	297,032.00	291,381.14	272,716.82
kwh produced	6,697,000	5,382,000	12,763,000	18,146,000	12,708,000	11,612,000	13,863,000	10,495,000	18,500,000
mills/kwh	45.67	56.57	20.51	13.37	18.44	21.29	21.43	27.76	14.74
OTHER - Primarily Marketing									
Debt service									
Fixed costs									
Fuel costs									
Other	3,790,977.64	3,306,282.04	3,609,073.34	2,998,347.00	1,224,380.50	3,152,851.15	3,968,897.00	2,613,127.00	2,555,016.26
Total Costs	3,790,977.64	3,306,282.04	3,609,073.34	2,998,347.00	1,224,380.50	3,152,851.15	3,968,897.00	2,613,127.00	2,555,016.26
kwh produced	108,428,000	88,164,000	71,393,000	62,050,000	20,750,000	108,358,000	155,884,000	134,769,000	112,175,000
mills/kwh	34.96	37.50	50.55	48.32	59.01	29.10	25.46	19.39	22.78
DG&T CONTRACT									
Debt service									
Fixed costs									
Fuel costs									
Other	6,643,023.85	10,532,542.02	16,592,322.34	25,164,132.96	27,087,158.43	24,056,843.63	20,380,781.47	17,792,559.33	14,146,657.36
Total Costs	6,643,023.85	10,532,542.02	16,592,322.34	25,164,132.96	27,087,158.43	24,056,843.63	20,380,781.47	17,792,559.33	14,146,657.36
kwh produced	183,974,000	299,078,000	438,518,000	617,009,000	649,057,000	503,207,000	358,929,000	237,528,000	114,750,000
mills/kwh	36.11	35.22	37.84	40.78	41.73	47.81	56.78	74.91	123.28

Appendix E - UMPA Resolution Approving the IRP

Resolution 13-04-24

A Resolution Approving the Five-Year Integrated Resource Plan (FY2013-FY2017)

WHEREAS, Utah Municipal Power Agency (UMPA) has been organized under the Utah Interlocal Cooperation Act (Act) for the purpose of accomplishing the joint and cooperative action of its member cities – Levan, Manti, Nephi, Provo, Salem and Spanish Fork (Member Cities) in securing reliable and economic supplies of electric power and energy, and has previously entered into all-requirements power supply agreements with each of its Member Cities requiring UMPA to provide, and the Member Cities to buy, all of their electric power and energy requirements; and

WHEREAS, UMPA's Member Cities load growth for power and energy continues to increase, thereby requiring UMPA to plan for the supply-side and demand-side resources in meeting the Member Cities future power and energy needs; and

WHEREAS, UMPA's planning for new supply-side resources becomes more challenging with the costs for new generation increasing, environmental regulations being added and more complex, and the viability of generation options being limited and reduced; and

WHEREAS, UMPA's existing programs to promote energy conservation and reduce retail load growth and energy demands (Demand Side Management or DSM) have yielded the desired benefits of reducing load growth by encouraging conservation and wise use of electrical energy by the Member Cities and their consumers; and

WHEREAS, UMPA, as a customer, has a an obligation to submit an five-year Integrated Resource Plan to Western Area Power Administration;

NOW THEREFORE, be it hereby resolved by the UMPA Board of Directors (Board):

A. UMPA has prepared an Integrated Resource Plan (IRP) for the next five years, FY2013 to FY2017, in accordance with the requirements set by Western Area Power Administration (Western). Both UMPA Technical Committee and UMPA Board of Directors participated and offered input in the development and review of the IRP.

B. UMPA desired to invite and gather comments from the public and Member Cities. The IRP was posted on the web and made available in the office for public review for a 30-day comment period in March 2013. At the conclusion of the comment period, there were no material comments submitted by the public.

C. UMPA's Member Cities, at their discretion, may adopt and implement a Demand-Side Management (DSM) program that meets UMPA's criteria. Member Cities will periodically report to UMPA (a) the status of each approved DSM program, (b) the benefits derived including its best estimate energy saved and, if applicable, avoided demand, and (c) number of customers participating.

D. UMPA Board of Directors reviewed and approved the IRP at the April 24, 2013 Board of Directors Meeting open to the public.

E. UMPA submits the IRP to Western in compliance with 10 CFR Part 905 – Energy Planning and Management Program for its approval.

Dated this 24th day of April, 2013

RUSSELL MANGELSON, Chair
Utah Municipal Power Agency
Board of Directors

MARK JONES, Secretary-Treasurer
Utah Municipal Power Agency
Board of Directors

Appendix F - Public Comments and UMPA Response

IRP Public Comments
The following 3 comments were filed along UMPA's response to the comments:

Subject: Comment
Date: 2013-03-23 07:12
To: irp@umpa.cc

From: John Curtis <john@provo.org>
Subject: Comment
Physical Address: 351 W Center St
Provo, UT 84604

Comments:
Nice work!. Thanks for making this happen.

PS Now you have a comment.
--
This mail is sent via contact form on UMPA - Utah Municipal Power Agency
http://www.umpa.cc

Response:
Thank you for the comment.

Subject: IRP
Date: 2013-04-04 16:07
To: irp@umpa.cc

From: Wayne Parker <wparker@provo.org>
Subject: IRP
Physical Address: 351 W. Center Street
Provo, UT 84601

Comments:
The Energy Department staff has taken an initial and admittedly cursory review of the draft Integrated Resource Plan (IRP) proposed by UMPA. We would offer the following comments that may help with discussions by the Energy Board and our elected officials at the UMPA meetings this week in St. George.

While these are preliminary comments, we are reviewing the document in more detail and may offer additional and more specific comments as part of the overall public comment process.

1. We applaud UMPA for taking on the important task of preparing a very specific IRP for the Agency and the member utilities. We can tell that it has been a significant task and express our thanks for getting so much on paper than helps define terms, identify options, quantify challenges and begin to chart a course for the future.

Response:
Thank you for recognizing the efforts in the IRP to chart a future energy course.

2. While the IRP makes great strides in these areas, we feel that some of the assumptions involved in drafting the IRP might be worth further discussion. For example, UMPA has always operated on the assumption that owned resources for base load is best, and that assumption served us well for many years. The fact that we have 121% of capacity in current owned or contracted resources currently provides a hedge in difficult times and provided a revenue stream when the market allowed us to sell surplus power. We know as well that given current expiring contracts in the coming years, that coverage will drop below 100%. We would encourage UMPA to consider as part of the IRP some reconsideration of what portion of base load should involved owned resource. We don’t know what the right proportion should be, but we think the IRP should include a discussion about such underlying philosophies.

Response:
We agree that further discussions are necessary in deciding the future supply-side options for the Agency. The intent of the IRP is to define and set the process in analyzing and assessing those energy resource options. We agree that there will be a time in the future to evaluate the best approach for acquiring new resources when the existing resources (owned or contracted) are insufficient or “drop below 100%”.

The discussion and selection for the right type of resource(s) with its attributes including availability and dispatchability to meet the future loads will be essential in the IRP process. At this time, we believe that the member cities are better served to define a working process in the IRP for accessing all the variables in making these decisions, then trying to determine and set a specific operating philosophy using only today’s conditions. We are concern that setting a defined philosophy now may not be valid and supported in the future due to changes with the makeup of the board members, the resources choices at the time, the future environmental rules, the wishes of the communities for renewable, risks and costs, and the many other variables in the supply-side planning. In summary, we welcome a <u>timely discussion on the underlying philosophies</u> in making the next power supply decision with the member cities.

3. As the IRP discusses the Agency’s current resources, the cost per KwH of the Provo Plant is not specifically discussed. The future of the Provo Plant, particularly in light of less expensive peaking options currently being considered should be addressed with greater clarity in the IRP.

Response:
The intent of the IRP is to provide a basic overview of all of the operating resources for the public. The IRP is not intended to discuss in detail, all of the operating attributes and costs in scheduling and dispatching the resources. There is a monthly strike price set by estimating the fuel cost for the plant operations. Hourly, the dispatcher determines the better value in buying on the spot market or running the engines to meet the load and supply reserves. The strike price is available to member cities and discussed in the operations report with the Technical Committee.

Currently, we are not aware of lower cost resources for peaking and reserves available to UMPA. The Provo Plant has no debt and the operating costs are the fuel, maintenance, and capital improvements (overhauls and environmental upgrades). The plant is the most favorable fixed pricing option for peaking and reserves. The annual average cost per Kwh is located in Appendix D. The cost varies significantly from month to month with all the valuable costs being expense monthly against the energy output.

Regarding the future of the Provo Plant, UMPA plans to operate the plant in accordance with the agreement with Provo. We recognize that this is an asset belonging to Provo. We welcome the opportunity <u>to discuss the future plans of the plant with Provo</u> to best prepare for any impact it may have in resource planning.

4. The forecasting models included in the IRP should be disclosed in more detail in the IRP. We are concerned that the IRP is essentially silent on issues that relate to future power consumption trends and that it appears that projected population growth is the primary factor used in the projections. For example, have we considered the impact of such elements as (1) the proliferation of electric powered vehicles, (2) a growing conservation ethic, (3) technology tools that would allow better management of energy consumption, (4) the changing demographics in our communities that will result in greater residential densities?

Response:
The intent of the IRP is to provide a basic overview to the public in the methods and factors used in forecasting the loads for the member cities. The member cities vary significantly in size and demographic complexity. The IRP did not intent to address the suggested elements due to the uncertainty and complexity within the parameters of forecasting future loads.

Several times in the past, the Agency has paid for expert consultants to perform forecasts using the most complex and sophisticated models. These reports are available. History has shown that these past forecasts when compared to actual loads have only a few short years of accuracy. The last IRP used forecast information provided by a professional consultant. However, that forecast did predict the downturn in the economy three years ago and the impact to member cities loads.

Forecasting is complex with many variables affecting the accuracy for long term forecasts. At this time, the Agency has elected to be conservative in its methods and approach while trying to better understand the critical elements that may affect its future power supply decision. By using historical data with a subjective weighted method in forecasting, the Agency has achieved favorable and proven results.

In summary, <u>if member cities have a better approach, they are invited to offer their own load forecasts</u> for consideration in the resource planning. In addition, the Board may elect to fund and hire a professional consultant to consider the suggested elements and any other appropriate factors in forecasting the member cities loads.

5. In terms of Demand Side Management discussed in the IRP, the document tries to estimate the savings impact of some elements like tree planting and energy services initiatives. But member utilities' efforts at AMI deployments in Spanish

Fork and Nephi have not been estimated, nor is there any future projections of the impact of such initiatives on future electricity demand.

Response:
We are not aware of any direct energy saving as a result of a AMI deployment in those cities as part of smart grid program. We welcome your suggestions or input that may show energy savings for AMI deployment. Certain programs and products of smart grid may yield energy savings in the future. If and when those products are deployed, we would expect to quantify specifically those benefits at that time.

6. The IRP has not made a serious attempt at quantifying some of the impacts of political efforts to make traditional carbon-based energy sources more expensive. It would seem that the Agency should consider a greater effort at estimating those costs as we explore our future challenges with resources mixes.

Response:
We agree that the IRP does not address or attempt to predict the outcome of any political efforts regarding climate change legislation and possible carbon taxes. There are simple too many variables and possible directions for the IRP to address without developing any reasonable conclusion. Although we recognize that there will likely be future legislation, we chose not to speculate, promote or politicize any specific position within the IRP. Such an approach may limit or harm UMPA's ability to participate in future political discussions in representing UMPA's best interests.

7. Finally, we hope that the IRP would not be finalized without a section that includes a definitive plan about what to do about the issues identified in the IRP. We would suggest, for example, an energy stack graph which suggests over the next 20 years how we should target new resources like nuclear, renewables, net metering and the like so that we can be making smart decisions now that will influence the optimal resource allocations in the future.

Response:
In the IRP, a stack graph showing the costs of different resources is shown on page 53. Again, the intent in the IRP is to define a process to analyze, assess, and acquire the optimal energy resource(s) at the time when they are needed for load. UMPA will conduct a timely study and report to the Board, Technical Committee and member cities prior to the acquisition for any future energy resource(s). We believe that the IRP offers the prudent steps in making those critical future energy decisions while allowing flexibility to react to future opportunities.

We appreciate the opportunity to weigh in on these issues and look forward to a robust discussion on the IRP in St. George and thereafter.

--
This mail is sent via contact form on UMPA - Utah Municipal Power Agency
http://www.umpa.cc

These comments were “hand-delivered” to UMPA

2655 North 140 East   Suite 105
Provo UT 84604

1 April 2013

Mr. Leon Paxton
UMPA
P.O. Box 818
Spanish Fork UT 84660

RE: Comments – Integrated Resource Plan

Dear Leon:

Attached for your consideration are my comments regarding the Integrated Resource Plan, and are contained within following documents:

- “Redlined” hard copy of the dated 27 February 2013
- My comments pertaining to the IRP

Understanding the 30-day comment period closes 3 April 2013, this is submitted just under the wire.

Sincerely,

Robert R. Rhoads

Attachments

Cc: Tad Smallcomb

COMMENTS
FY2013 INTEGRATED RESOURCE PLAN
UTAH MUNICIPAL POWER AGENCY
1 APRIL 2013

COMMENTS SUBMITTED BY: Robert Rhoads, Provo, UT

NOTE: These comments are submitted for consideration in the final document, but in no way are these to be perceived as being critical of the document writer(s), or the mission of UMPA.

1. Check for grammar, punctuation, spelling:

Pages	6	7	8	9	10	11	12	13	14	15	18	22	23	25	26	27	28	29	30	31	55

2. Comments:

PAGE	ISSUE	COMMENT
14	Chart Heading (...Non-Coincidental Load Growth...)	Would not Coincidental Load Growth be more realistic from historical & projection perspective?
15	20-year Growth	Clarification just to be sure: Demand 2.04%; 2.02% Energy? But, chart is energy trend; What about a Demand growth chart?
20	2nd Paragraph "...highly robust economic..."	a. Attempt to legitimize the vague wording. b. Somehow one would expect particular load growth among the UMPA municipalities as the South Utah, Juab and San Pete counties as residential and commercial development expands south. Would not a comment addressing this be appropriate somewhere within the IRP projections? c. Has a Utah State government agency made any projections?
22	Base Load explanation	Is <u>Plant Factor</u> another parameter in describing production?
23	3rd Para. - "...138 kv bus-bar deliveries."	What is the rational stipulating the 138 kv parameter? Is this real, or hypothetical?
26	2nd Para. – Engine serviceability	How frequently are the engines overhauled?
30	3rd Para. - At one time UMPA would mention the ownership of a portion of a transmission line into Mona substation.	Is that still the case, and if so, what is the purpose; what entity maintains it?
31	Page 55 – DSM Programs	Is it possible to quantify the impact of increased electrical rates upon rate-payers? This is, in a way, tied to the "Education" factor on Page 58.
32	Appendix A – MW Demand Charts	Capacity Billing Chart for each municipality is confusing because the MW value on the "Y" axis is disconnected from Customer Profile preceding the chart. Is the annual MW chart a 12-month accumulative of each calendar year?

Response to grammar, punctuation, spelling:
Thank you for the details. We have addressed the suggested changes.

Response Page 14
For planning purposes, we examine the historical data and project the power and energy loads for each member. We acknowledge that there are likely coincidental benefits within the loads to be captured in our daily and monthly scheduling efforts. However, in the past, the coincidence factor is typically small and difficult to predict with all the seasonal and weather factors.

Response Page 15
The projected load for power and energy charts are shown on the pages 16 and 17 following the statement.

Response Page 20
We agree and the forecasts attempt to address the expected growth in the counties as noted. At this time, no projections developed by the state of Utah were considered. This may be considered in future forecast studies.

Response Page 22
We agree and have revised to reflect plant availability or plant factor in the IRP where appropriate.

Response Page 23
Yes, all generations are compared and evaluated using the same 138 kV interconnection voltage.

Response Page 26
The diesel engines are routinely maintained and inspected. A major overhaul is performed as needed when indicated by maintenance trouble or about every 4 to 7 years.

Response Page 30
Yes, UMPA still has transmission rights on the Bonanza Plant to Mona Substation. Deseret G&T maintains the transmission line.

Response Page 55
We are not aware of any method to quantify the DSM values from the impacts of raising retail rates. Although rate increases impact demand in simple economic terms, we are not sure that it would qualify as a DSM program.

Response Appendix A
We agree and have modified the charts and data to reflect the corrected "Y" axis using the term of MW-Months.