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Energy Independent Community

an evaluation
for

Bloomfield
EST. 1855

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economic development

Energy Independent Community

An evaluation for the

City of Bloomfield, Iowa

Conducted by
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Executive Summary

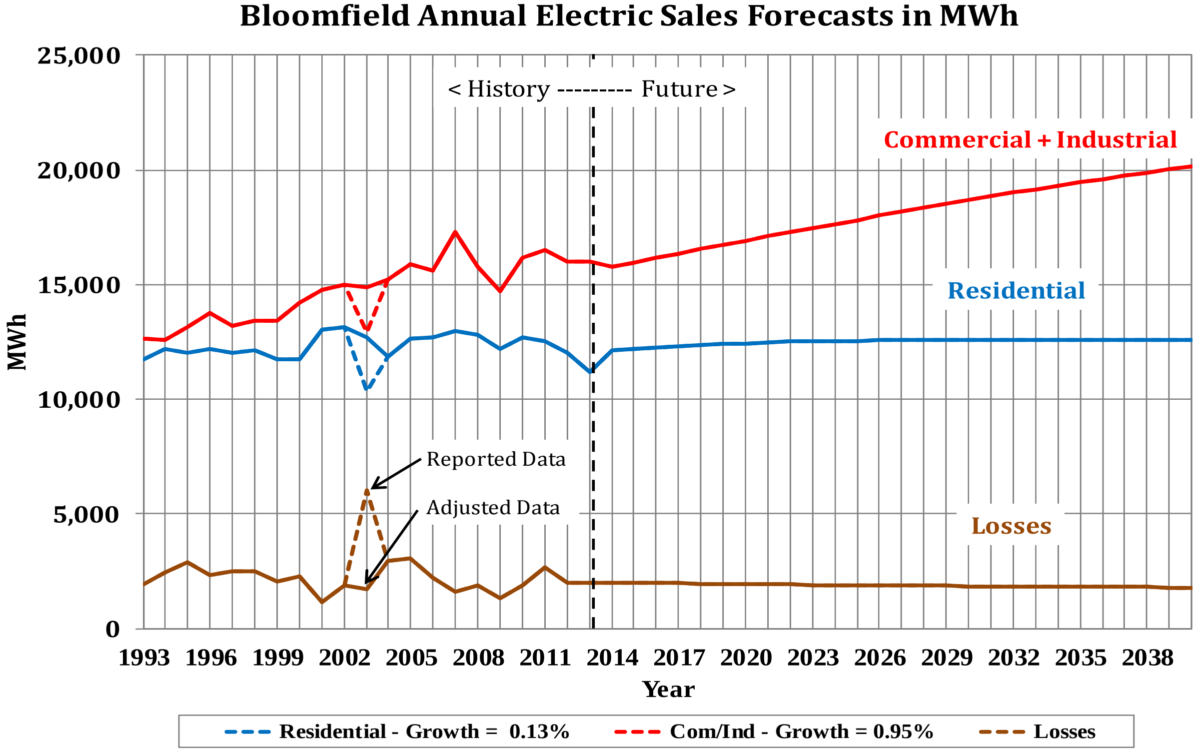
This study looked at the technical and financial feasibility of the city of Bloomfield (City) becoming energy independent. Could the City obtain most of its energy from local resources given the declining cost of solar and wind power?

Since there are no local natural gas wells, and there are very limited potential sources of methane from biodigesters, it is nearly impossible to eliminate the City's dependence on outside natural gas. The energy efficiency programs analyzed could potentially reduce natural gas usage by 14%. Although a significant amount of natural gas space heating could be converted to geothermal or air source heat pumps, it is not usually economical to spend the money to convert a heating system if electricity prices are above about 7-8 cents per kWh, which is less than the City's current residential electric rate and comparable to its commercial and industrial rates. Therefore, the City would need to develop an incentive rate to motivate its customers to switch from natural gas heating to electric heating. Even if it were practical and desirable to convert all residential natural gas space and water heating needs to electricity, doing so would only reduce gas consumption by about 50%. In summary, it would be very difficult to become energy independent from outside natural gas, and the decisions necessary to make this happen would be outside of the City's control.

Unlike natural gas, it is technically feasible for the city and its customers to become independent in terms of electric use. Therefore this study focused on the technical and economic factors for reducing the City's dependency on outside sources of electricity. The City's connection to the regional electric grid brings significant benefits in terms of economy and reliability, and there would be no practical reason for being disconnected from this regional grid. However, if the City could produce more electricity such that it would still be receiving electricity at times and then delivering electricity at other times to offset its receipts, then over the course of a year it would be a "net zero electricity" community. For purposes of this study, achieving this "net zero electricity" was deemed to be a practical way of being "energy independent" from an electricity usage perspective.

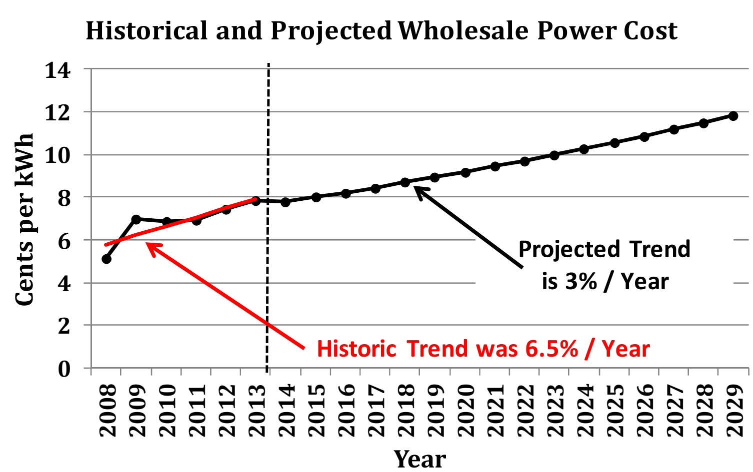
Since this is a forward-looking study, it was necessary to project the City's electricity needs into the future, based on a Business As Usual (BAU) scenario. The consultants correlated the Bloomfield Municipal Utility's historic electricity sales to its customers with local economic, demographic, and weather data to develop statistically based models for future electricity needs. Figure Executive Summary-1 (ES-1) on the following page shows the resulting projection of electricity usage for the residential customers and the combined group of commercial and industrial customers. The forecast predicts average annual growth of about 1.0% in the commercial / industrial customer usage and only about 0.1% growth in residential usage.

FIGURE ES-1



For many years the City has purchased nearly all of its electricity needs from wholesale suppliers that bring in electricity generated from large power plants in the region. Although this has historically been a very economic source of electricity, many smaller coal-fired power plants will be retired due to tighter pollution standards, which will tighten the regional demand-supply balance. Together with increasing natural gas prices, wholesale power prices are widely expected to increase in the future. The future prices for wholesale purchased power are a significant factor in evaluating the economics of becoming energy independent. Figure ES-2 illustrates the average price of wholesale power that the City has purchased since 2008, along with projections for the next 15 years. The short red trend line indicates that recent prices have increased an average of 6.5% annually. Since past yearly variations in the cost per kWh are due in part to the summer weather, there will likely be similar variations in the future. However, in this study, the wholesale power rates are assumed to increase 3% annually over the 15-year study period.

FIGURE ES-2



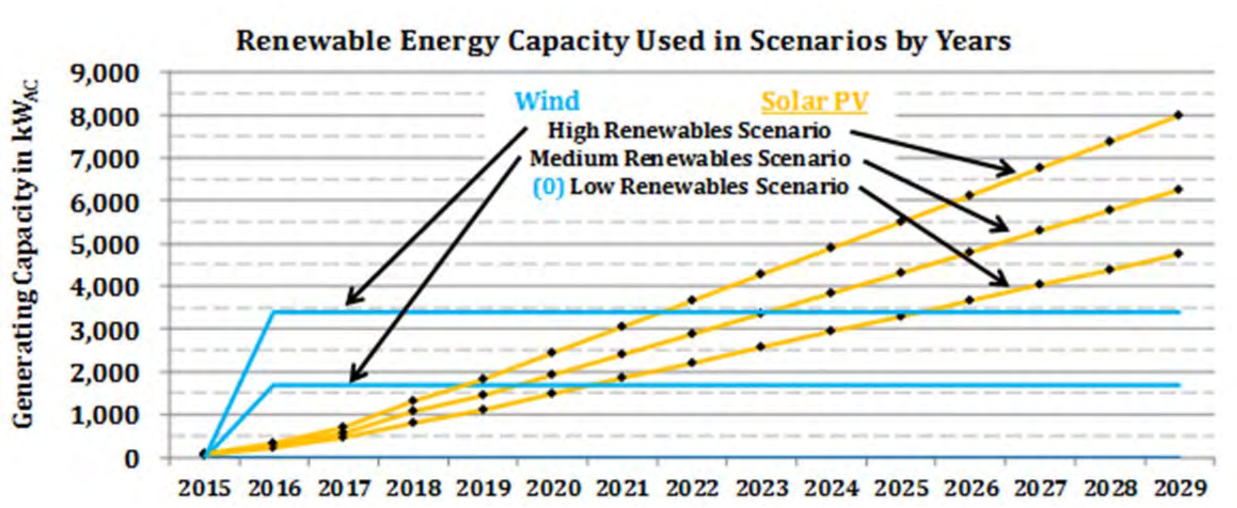
Six different strategies or scenarios were developed, evaluated and compared to the Business As Usual (BAU) scenario as part of a process of becoming more energy independent over time. A description of these strategies and goals is shown in Table ES-1.

TABLE ES-1 – Summary of Strategies Developed and Evaluated to Become More Energy Independent

#	Name	Description	Goal	Local Generation Added
1	BAU	Business as usual	Status Quo	None
2	EE	Implement a comprehensive set of Energy Efficiency (EE) programs to reduce electricity usage as much as economically practical	Reduce electricity usage gradually over a ten-year implementation period by 23%	None
3	DLC	Install Direct Load Control (DLC) equipment that intermittently interrupts central air conditioning compressors and electric water heaters during peak load periods	Reduce summer peak loads and wholesale power demand charges	None
4	PS	Use the City's dual-fueled diesel generators during high load periods to reduce the monthly or annual peak usage	Reduce peak loads and demand charges by Peak Shaving (PS) with the existing diesel generators	None
5	Low RE	Contract with companies to install, operate, maintain, and sell power to the City from solar photovoltaic (PV) arrays in and adjacent to the City so as to use Renewable Energy (RE)	Reduce electricity usage and increase locally generated electricity to reduce net electricity purchases by 50% compared to BAU	Use power from 6,800 kW_{DC} of solar power installed over a 15-year period in large arrays and on rooftops
6	Medium RE	Like Scenario 5, but with more solar PV, plus buying power from a local wind turbine	Reduce electricity usage and increase locally generated electricity to reduce net electricity purchases by 75% compared to BAU	Use power from 8,900 kW_{DC} of solar power installed over 15 years, one large wind turbine, and 130 kW of micro-turbines
7	High RE	Like Scenarios 5 and 6, but with even more solar PV and wind power	Reduce electricity usage and increase locally generated electricity to reduce net electricity purchases by 100% compared to BAU	Use power from 11,400 kW_{DC} of solar power installed over 15 years, two large wind turbines, and 130 kW of micro-turbines

As Table ES-1 indicates, the purpose of the strategies is to make the City's consumers of electricity as energy efficient as possible, by implementing a comprehensive set of energy efficiency programs over a 10-year period. These programs reduce customers' power bills as well as the City's wholesale power purchases. As energy efficiency programs are implemented, other strategies will also be implemented to trim and shave the utility's peak demands, which would further reduce the City's wholesale power costs. As these strategies are adopted, then using locally produced renewable energy (RE) becomes the next most economical thing to do to become more energy independent. Scenarios 5, 6 and 7 evaluate the economics of reducing outside energy purchases by 50%, 75%, and 100% respectively over a 15-year period. At the 100% level the City will generate or purchase enough locally produced energy to offset the energy that is used during times with no or little solar or wind power, thereby making the City "net zero energy", or energy independent. Figure ES-3 depicts the amount of renewable energy in the Low, Medium, and High Renewables scenarios.

FIGURE ES-3



The use of biodigesters, geothermal energy, and energy storage batteries were also evaluated. Although these technologies will likely be cost effective for certain applications, more in-depth evaluations would be required to determine the amount and cost of these resources. Because of their smaller anticipated financial impact on the study results, they were not included in these strategies. If more in-depth evaluations show their cost effectiveness, then including them would hopefully reduce the cost of becoming energy independent.

The technical analysis included hourly load and generation simulations for the 15-year period that determined what renewable energy resources might be reasonably expected to be available to serve the City's load at any specific hour, based on historical wind patterns and solar insolation levels. From this simulation, the amount of outside wholesale power that was needed to serve the remaining load was calculated. A financial model for the City's electric utility was built, so that the financial impact of implementing these strategies, as well as selling fewer kilowatt-hours (kWhs) to customers, could be evaluated. This evaluation determined the amount of revenue and needed electric rate increases to maintain a reasonable operating margin. The costs to both the City's utility and its electric customers was determined for each of the six strategies and compared to the BAU scenario.

The graph in Figure ES-4 illustrates how the energy savings and new local energy resources collectively achieve the 50%, 75%, and 100% self-sufficiency goals.

FIGURE ES-4

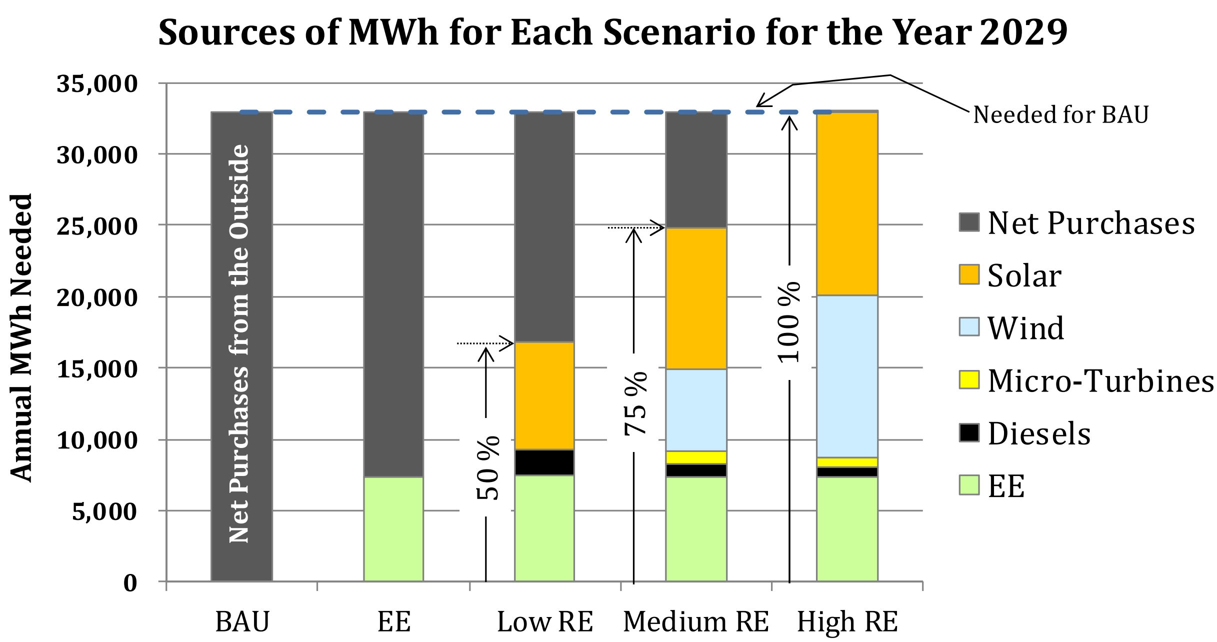
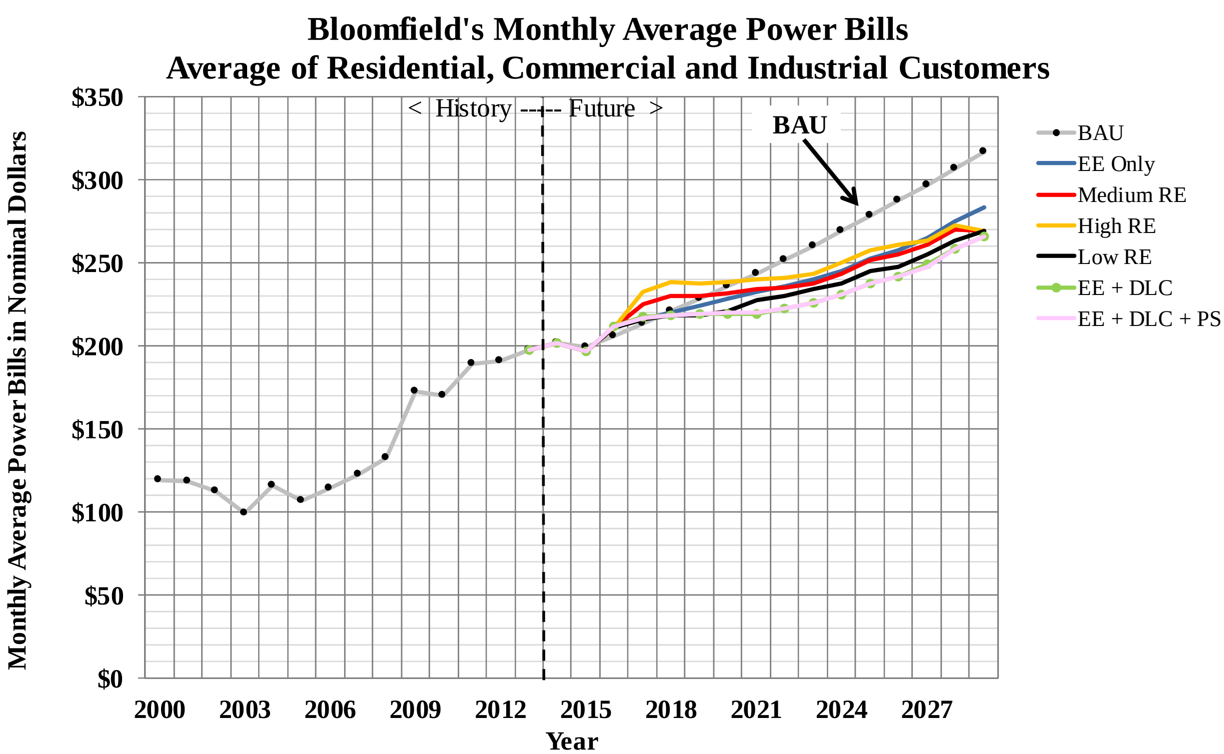


Figure ES-5 depicts the average historical and projected amount of all retail customers' electric bills for the BAU and six alternative strategy scenarios over the next 15 years.

FIGURE ES-5



As the graph suggests, the electric customers would expect to generally pay lower power bills in the long-term future for all of the six alternative strategies compared to the BAU scenario. In some scenarios, power bills are a little higher during the first five years but lower in the longer-term.

Table ES-2 on page 5 provides a summary and comparison of the results of the financial analysis of all seven scenarios. It provides the results from both the utility's perspective (green shading) and the customer's perspective (yellow shading). From the utility's perspective, its operating costs are lower than the BAU scenario for all six of the alternative scenarios. This operating cost includes all of the utility's operating costs, less credits for any excess generation sales back to the grid. The utility's operating margins are essentially the same for all seven scenarios. From the customer's perspective, they save money for all of the six alternative scenarios over the 15-year period compared to the BAU scenario.

TABLE ES-2

Summary of Results from Financial Analysis of All Seven Scenarios												
		Results from the Utility's Perspective							Results from the Customer's Perspective		
		Utility Operating Costs (Includes Revenue Credits for Sale of Excess Solar and Wind Generation)		Average Cost of Resource Over the 15-Year Study Period in ¢ / kWh					Customer Power Bills Over the 15-Year Period		
Scenario Number	Description	15-Year Total	Savings	EE / DLC	Whole-sale Power	Solar PV	Wind Power	Excess Power Sales	Total	Savings Compared to BAU	Average Monthly Bill Savings
		$1,000's	$1,000's	¢ / kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh	$1,000's	$1,000's	$
	Column Number 2	3	4	5	6	7	8	9	10	11	12
1	Business As Usual	$ 58,420	$ -	-	9.8	-	-	-	$ 63,190	$ -	$ -
2	Energy Efficiency Programs	$ 55,060	$ 3,360	3.5 (EE Only)	10.1	-	-	-	$ 59,380	$ 3,810	$ 15
3	EE + Direct Load Controls	$ 52,260	$ 6,160	-0.3 (EE+DLC)	9.3	-	-	-	$ 56,890	$ 6,300	$ 25
4	EE + DLC + Peak Shaving	$ 52,260	$ 6,160	-0.3 (EE+DLC)	8.4	-	-	-	$ 56,900	$ 6,290	$ 25
5	All of the Above + Low Renewables	$ 53,240	$ 5,180	-0.3 (EE+DLC)	8.6	7.5	-	7.7	$ 57,840	$ 5,350	$ 21
6	All of the Above + Medium Renewables	$ 54,780	$ 3,640	-0.3 (EE+DLC)	9.9	7.5	5.8	7.8	$ 59,340	$ 3,850	$ 15
7	All of the Above + High Renewables	$ 55,950	$ 2,470	-0.3 (EE+DLC)	12.0	7.5	5.8	7.4	$ 60,500	$ 2,690	$ 11

The results of this study clearly indicate that starting an aggressive energy efficiency program and installing direct load control equipment will save utility customers money. Furthermore, it appears that adopting the Low Renewables strategy would likely save all customers money in the long run. The Medium and High Renewables strategies are also shown to save customers money. However, the savings are less, and given the uncertainties in forward-looking studies, the savings are much less certain. There is no doubt that any of these alternative strategies can be accomplished. Of course, some further evaluation and planning would be required to implement these strategies.

To achieve any of these savings, any new power supply contract needs to incorporate more flexibility and incentive for the City to manage its peak demand and add renewable energy.

The implementation of these strategies would result in more local jobs and business due to the energy efficiency programs. Furthermore, the installation of the wind and solar power generation for the 100% self-sufficiency would result in about $35 million of solar and wind power investment in the community, which brings additional construction, operation, and maintenance jobs.

Although nearly all utilities in Iowa have energy efficiency programs and some renewable energy in their power supply, no Iowa or Midwest utility has yet attempted to get a majority of its needs from a combination of aggressive energy efficiency programs coupled with solar and wind power. Comprehensive planning would be required, and the key to accomplishing this goal will be having a core group of community leaders that can motivate the community to achieve these goals.

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August 16, 2014

Section 1 - Projected Future Electricity Needs

An econometric-based electric load forecast was made to project the future electricity requirements for the City of Bloomfield (City). This load forecast methodology used a multiple regression statistical analysis to determine what demographic, economic, and weather factors have influenced the City's electricity needs over the past 21 years. Historical and projected demographic and economic data for Davis County were purchased from Woods and Poole Economics, Inc. Weather data was obtained from the US National Oceanic and Atmospheric Administration (NOAA). Based on those past relationships between the demographic data, economic data, weather data, and customer electricity sales, statistical models were developed for projecting these factors into the future. The impact of Bloomfield's current energy efficiency programs was also taken into consideration in the statistical analysis. Four models were developed for the City.

1) **Residential Electric Sales**
   The statistical analysis found that residential sales in the past were correlated to the number of households in the county, manufacturing employee earnings, heating degree days, and cooling degree days. The model could account for about 82% of the growth and variability in the historical residential sales.

2) **Commercial and Industrial Sales**
   The analysis found that the combination of commercial and industrial sales was well correlated to the mean household income in the county, heating degree days, and cooling degree days.

3) **Summer Peak Demand**
   The summer peak load was largely determined by the total annual energy sales and the maximum temperature on the summer peak day.

4) **Winter Peak Demand**
   The winter peak was determined by the annual energy sales, plus the average daily temperatures just prior to the winter peak day.

The distribution system losses and unaccounted for energy were also projected into the future. However, a simple trend model was used.

Figure 1 depicts both the historical and projected electric sales in megawatt-hours (MWh) by customer class out through the year 2040. This graph is based on normal weather, and the graph indicates that the commercial and industrial sales will likely have more growth, as indicated by the 0.95% average annual growth rate shown in the legend. The residential sector has very little growth expected. The distribution system losses and unaccounted for energy should be steady in the future.

The one-year sharp drop in the 2003 customer sales with a comparable increase in losses the same year (dashed lines) is likely just an error in the reported data. Adjustments were made in the historical data and analysis to account for this suspected data error.

The Commercial and Industrial sales forecast took into consideration the recent closure of the Bloomfield foundry.

FIGURE 1

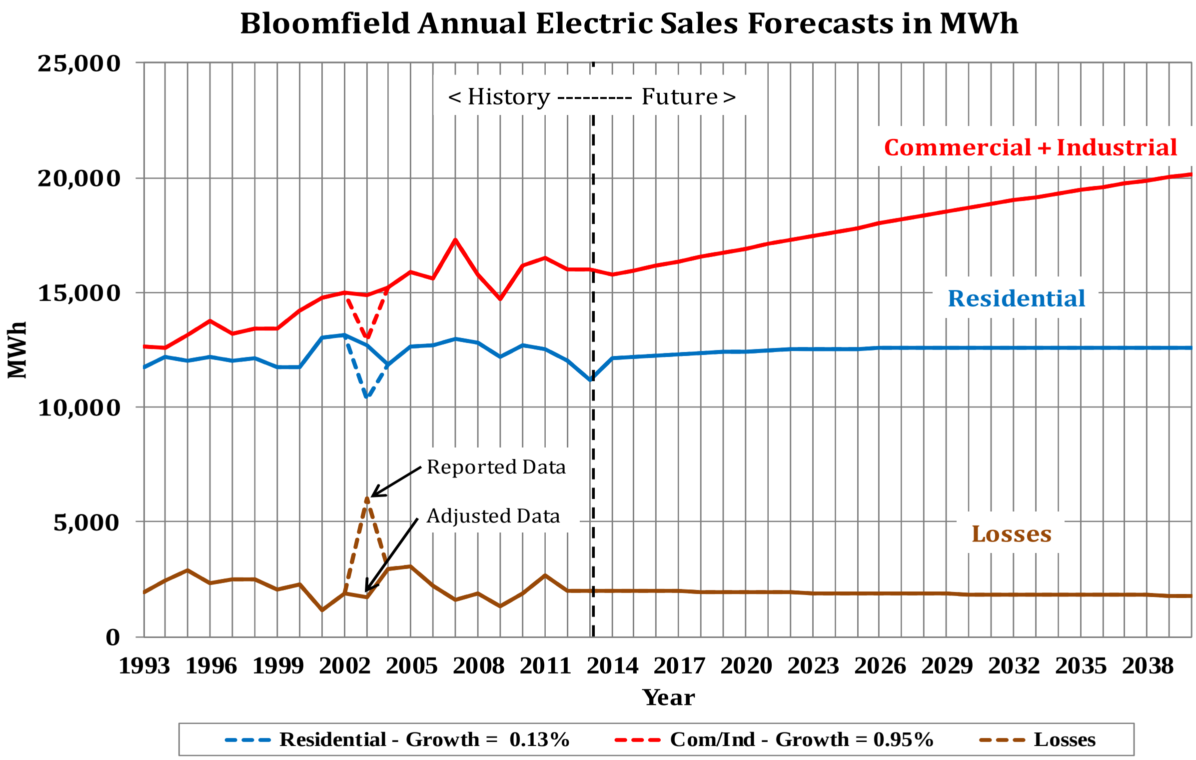


Figure 2 shows the total system energy in MWh, which includes all of the sales to the customers and the losses. The median or base forecast is shown by the blue circles, which has an annual average growth rate of 0.55% per year over the forecast period. Figure 2 also shows, using the dashed red lines, how the weather can affect the annual sales. For example, cool summer weather and mild winter weather could collectively reduce the annual system energy, as shown by the lower red dashed line. Likewise, a hot summer and cold winter could increase the annual sales by a comparable amount, as shown by the upper red dashed line.

This forecast is based on a Business As Usual (BAU) scenario, where the City does not make any significant initiatives to adopt more energy efficiency or peak load control programs.

Since there is always some uncertainty in any projection of the future, alternative high and low projections were made for the demographic and economic projections made by Woods and Poole. The upper and lower lines (depicted by the green triangles) provide some measure of the uncertainties in the forecast. Furthermore, a hot summer and cold winter, along with more optimistic demographic and economic projections, could provide sales even higher than shown by the top line of green triangles. The median or base forecast (shown by the blue dots) is used as a starting point for the analysis in this report. The median projected system energy in 2014 is 29,900 MWh, which is comprised of 12,100 MWh for residential sales, 15,800 MWh for commercial and industrial sales, and 2,000 MWh for losses and unaccounted for energy.

FIGURE 2

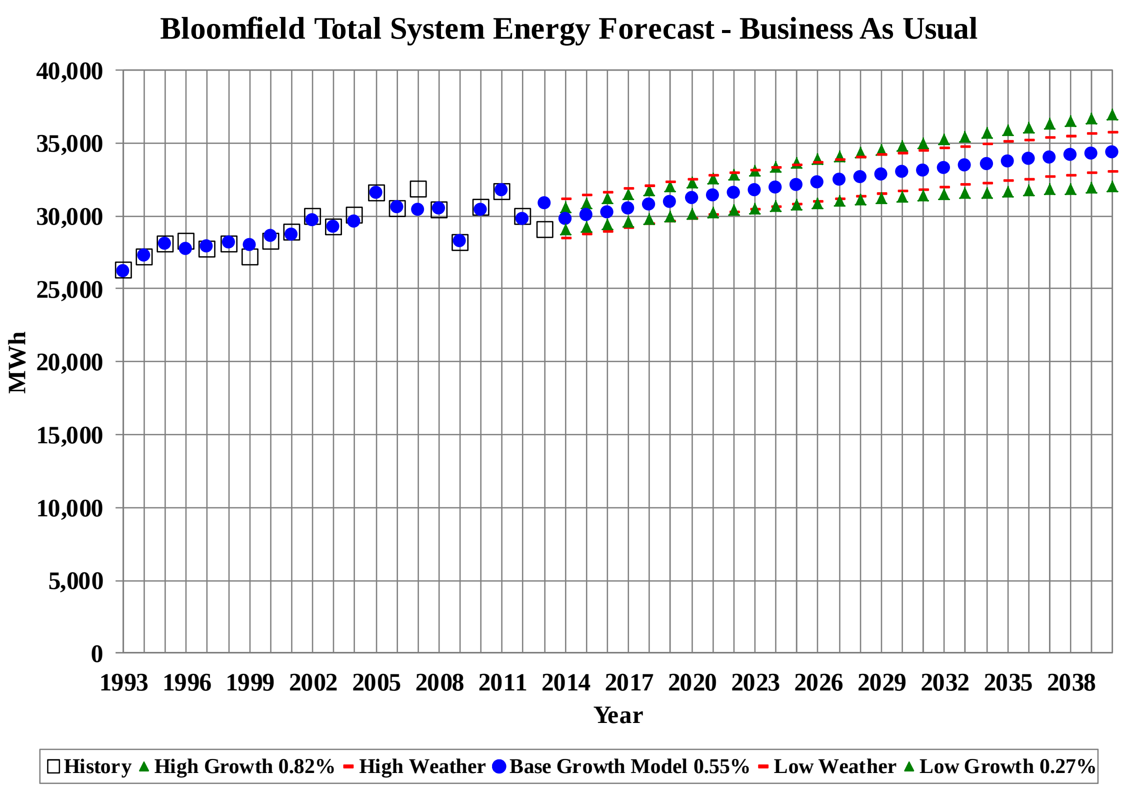
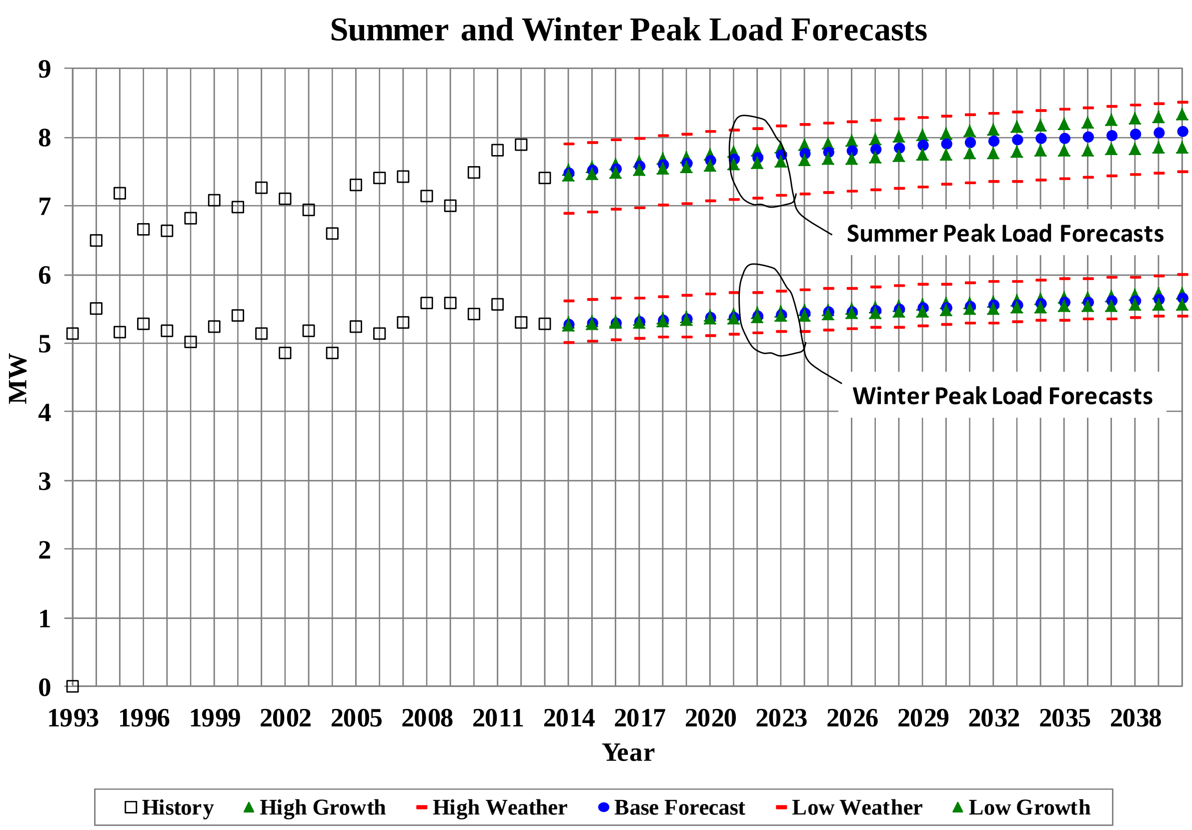


Figure 3 illustrates both the summer and winter peak load forecasts. Both of these forecasts indicate a modest upward trend averaging 0.3% per year. The 2014 summer peak forecast for normal weather is projected to be 7.5 MW. Very hot and humid conditions could increase the peak to 8.0 MW, as shown by the upper red line. Conversely, a mild summer could have a peak as low as 7.0 MW. The median winter peak is projected to be 5.3 MW.

FIGURE 3



Electric sales for a small community like Bloomfield can vary a lot due to the expansion or closure of a large industrial facility. Since these events can't be predicted, there is always some uncertainty in projections of future energy sales and peak loads.

With the 2013 annual system energy of 30,265 MWh and a summer peak of 7,406 kW, the annual capacity factor was 46%. The capacity factor is projected to stay at this level in the future for the normal weather scenario.

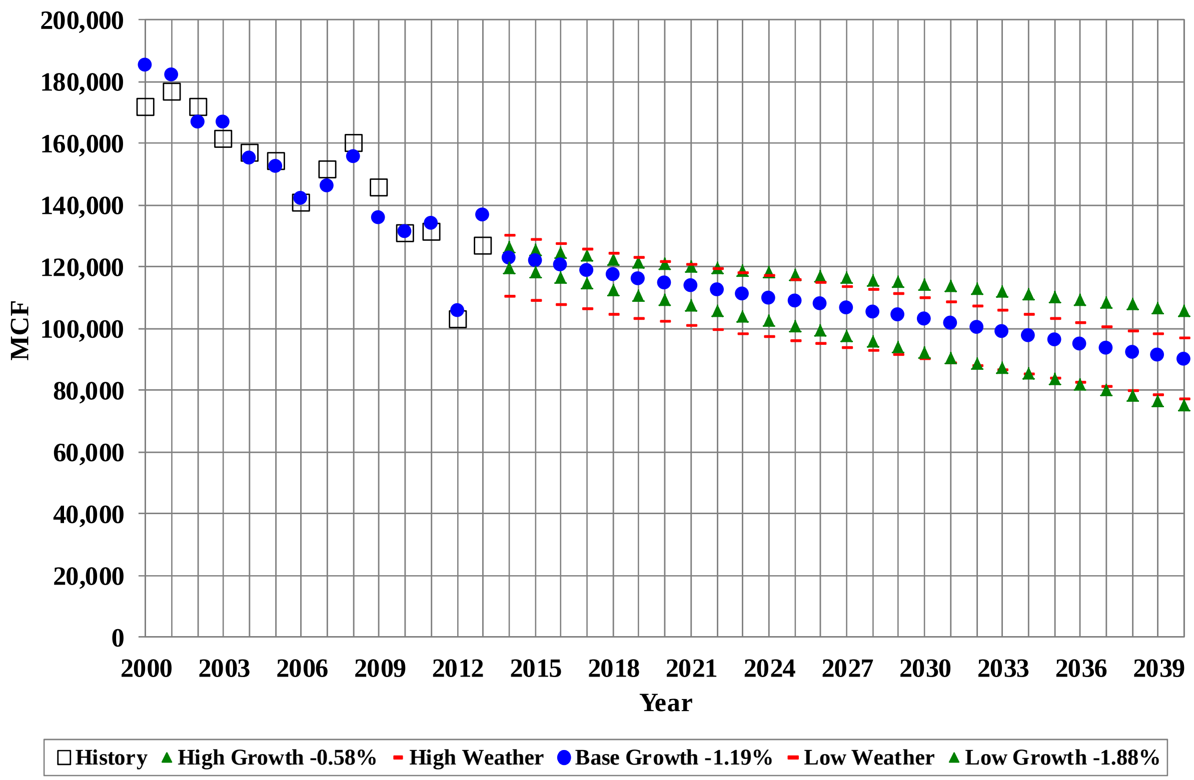
Appendix 1 contains additional details about the econometric models that were developed.

Figure 4 presents a projection of the natural gas sales volume. This projection excludes natural gas that was used for generating electricity. It was difficult to find any local demographic and economic data that was correlated to the historical natural gas sales. However, correlations to both the national trend in manufacturing employment and the national trend in residential natural gas consumption were found, along with the local heating degree days. Based on these correlations, the forecast shown below was made. It shows a continuing decline of about 1.2% per year.

An evaluation was made to determine how much natural gas could be saved through implementation of a selected group of energy efficiency programs. By the end of the 15- year period of the analysis or when the programs were fully-implemented, retail gas sales would be reduced by nearly 14%. This is a significant reduction (80% of the estimated economic potential), due in part to the impact of other programs designed to reduce consumption of electricity. Although about 50% of the remaining sales could technically be converted to geothermal or air source heat pumps, it is not usually economical to spend the money to convert a heating system if electricity prices are above about 7-8 cents per kWh, which is less than the City's current residential electric rate and comparable to its commercial and industrial rates. Therefore, it would be very difficult to become energy independent from outside natural gas, and the decisions necessary to make this happen would be outside of the City's control. Therefore, this study primarily focused on electric sales.

FIGURE 4

Bloomfield Natural Gas Sales Forecast



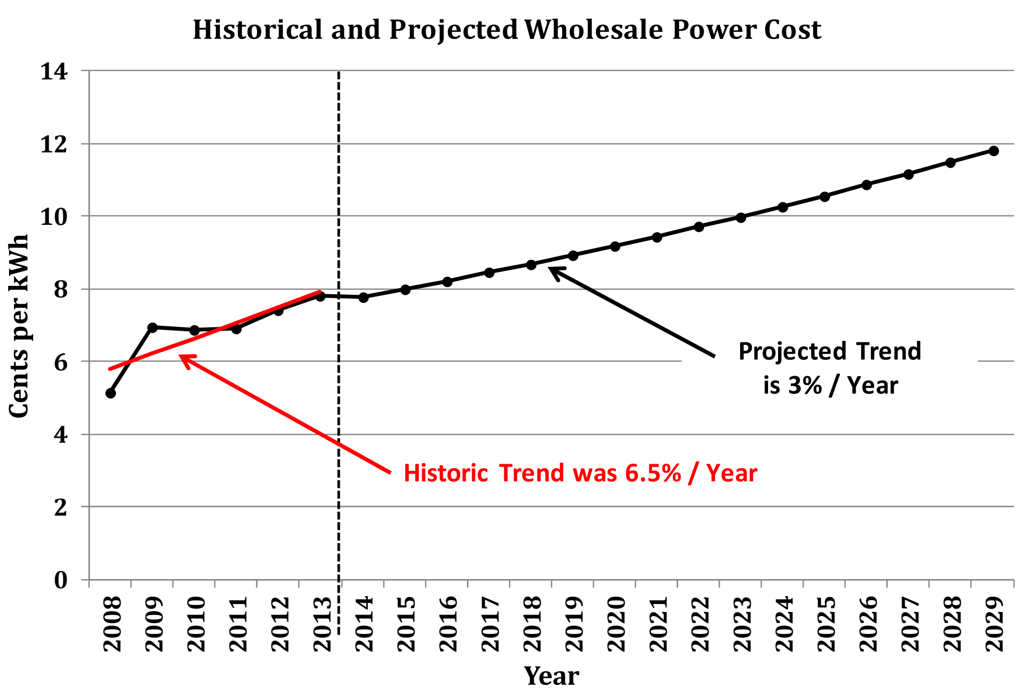
Section 2 - Wholesale Electricity Purchase Cost Projections

The City buys nearly all of its electricity needs from Southern Iowa Electric Cooperative, which in turn gets power from Northeast Power and Associated Electric Cooperative, both based in Missouri. The power supply contract has a rate for energy purchases ($0.0359 per kWh) and a rate for peak demand at $13.90 per kW per month. The peak demand is based on the City's highest peak over the previous 11 months (11 month ratchet), which is essentially the City's summer peak load. Last year the total energy charges were $1,099,000 and the total demand charges were $1,270,000, giving a total of $2,369,000. This made an average rate of 7.8¢ per kWh. This includes all transmission charges.

The current contract does not allow the City to run its diesel generators to trim or shave its summer peak load as a way to save money.

In this study wholesale costs were assumed to stay the same for 2014, but increase at an annual rate of 3% per year starting in 2015. This 3% annual increase would be applied to both the energy charge and the demand charge. Rates are expected to go up, due to the cost of replacing old coal-fired generators with newer generators, and for the cost of new transmission system improvements in the region. This 3% compounded rate increase in wholesale costs would result in wholesale purchases costing 11.8¢ per kWh in 15 years. Figure 5 shows the average annual wholesale power cost rate since 2008, with projections to 2029. The average rate fluctuates year to year, due to how high the summer peak is for a particular year. For example, a high summer peak increases the demand charge for the next 11 months, which raises the average rate during that period. Likewise a relatively low summer peak would lower the average rates for the ensuing 11 months.

FIGURE 5



The wholesale power contract with Southern Iowa Electric Cooperative expires within a year, and it is uncertain from whom the City will purchase power after that. Furthermore, the rates and relative sizes of the energy and demand charges could change, as well as the method of calculating the billing demand. Because none of this information is known at this time, it was simply assumed that the City would buy power under the same rate structure as now, but with the rates going up 3% per year. However, it has been assumed that the City would negotiate for the right to shave its peak load by running its diesel generators in the future. This is discussed in more detail in Section 8.

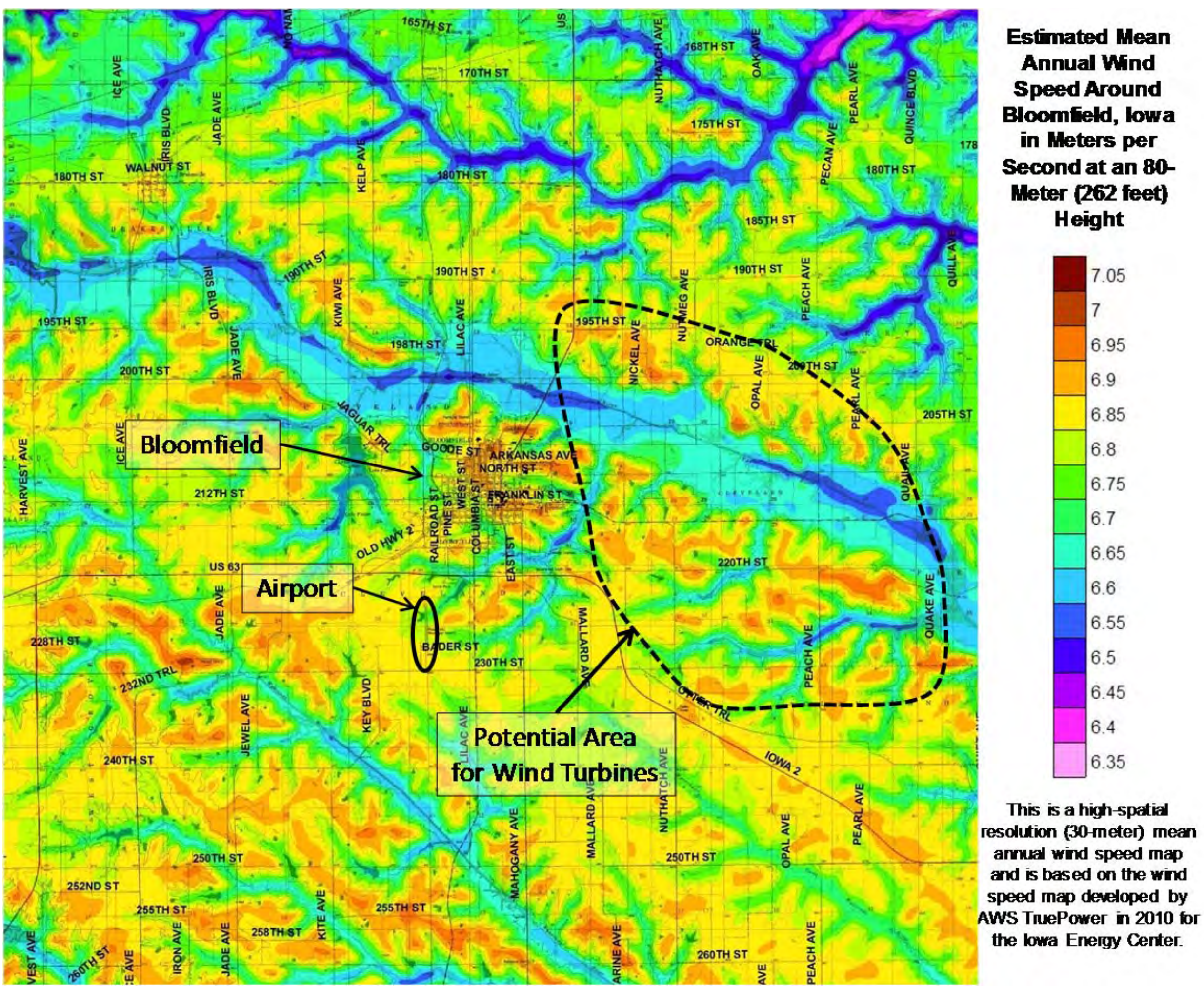
Typically the rates in new power supply contracts tend to reflect the projected regional market price of power in the future. Although regional market prices have been depressed since 2009 due to the recession and much lower natural gas prices, market prices are widely expected to increase. The increase would reflect some modest load growth, the retirement of older coal-fired capacity, and the gradual increase in natural gas prices.

Section 3 – Wind Generation Options

The initial evaluations of both wind generation and solar photovoltaic (PV) generation options indicate that they both can be economically viable for the City, based on the projected wholesale power costs. However, their economic viability depends in large part upon the projects qualifying for the federal and state income tax benefits. This means that they cannot be owned by the City, at least initially, since the City's ownership would preclude the projects from receiving the income tax benefits. Therefore, this study assumes that all renewable energy projects would be privately owned, either by local area residents or by outside parties.

Figure 6 is a wind speed map showing the average annual wind speed at 80 meters above ground, which is the typical height of a wind turbine nacelle. The orange areas in the region encircled by the dashed black line indicate potential places where one or two large wind turbines could be installed. A more detailed evaluation would be needed to determine the availability of land and the minimum acceptable distance from the airport.

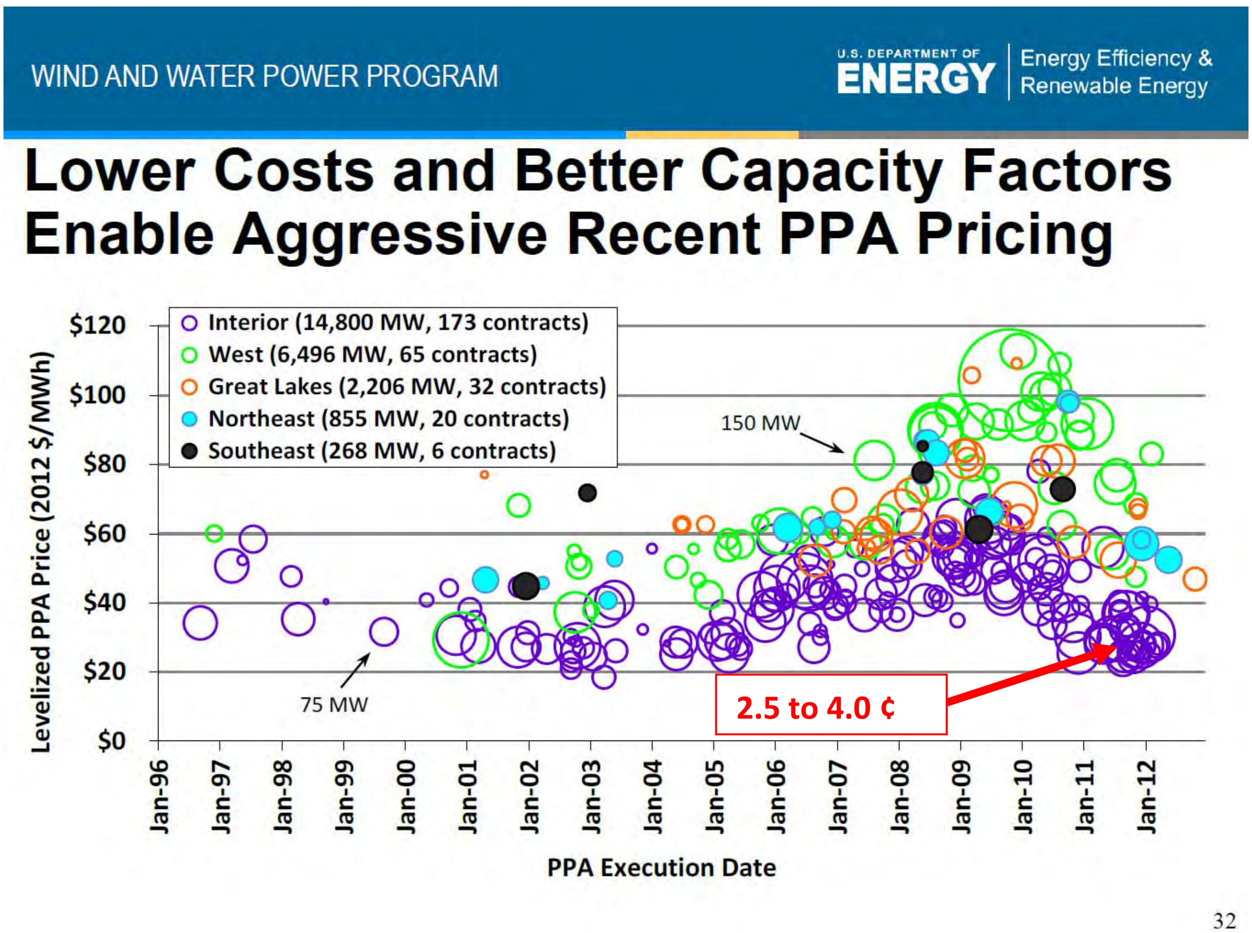
FIGURE 6



Based on the wind speeds shown in Figure 6, it has been estimated that one or two privately-owned wind turbines could potentially offer wind power to the City for a Power Purchase Agreement (PPA) rate of 5.5¢ per kWh with a 1% annual escalation in the rate. This estimated rate is based on the receipt of the typical federal income tax benefits and Iowa's Section 476C state production tax credit that is available for community-owned wind farms like this.

The cost of wind power from large utility-scale wind turbines has generally been declining over time, due to better wind turbine technology and larger wind turbines. Figure 7 illustrates the general trend in the contract cost of power from large wind farms in the US since 1996. The purple circles show the PPA rates for large wind farms selling their power. Larger circles represent larger wind farms. As of 2012, the typical PPA rates for wind farms in the upper Midwest ranged from $25 to $40 per MWh, or 2.5 to 4.0¢ per kWh. Although the annual report for 2013 has not yet been published, this new report will show the average PPA rate in the upper Midwest in 2013 fell to about 2.2¢ per kWh. This represents a significant drop in wind power prices since 2009, primarily due to longer blades being used on the same size of wind turbines.

FIGURE 7

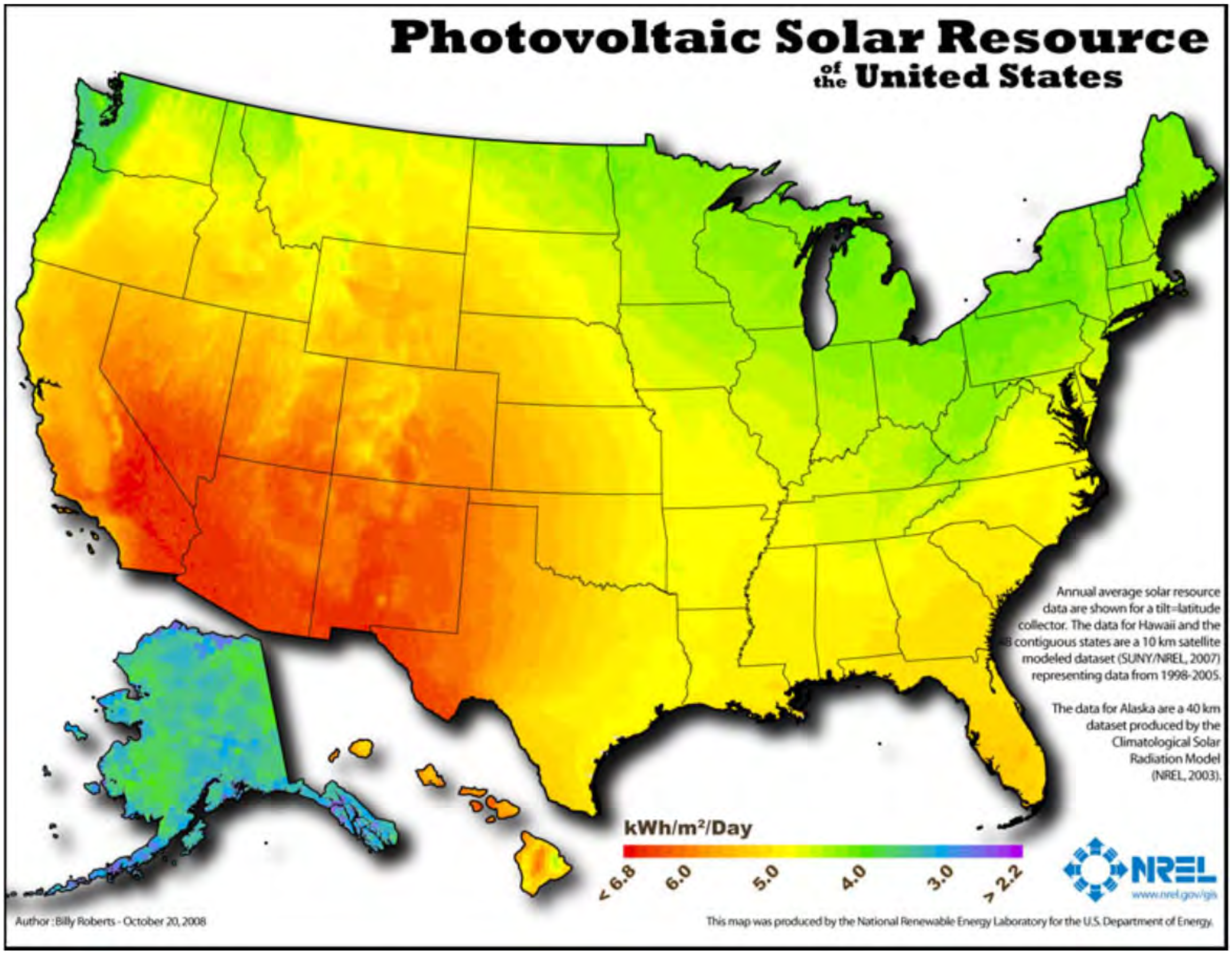


The average wind power cost in Iowa from large wind farms is likely around 3¢ per kWh in areas where transmission capacity is available. This is based on the continuation of the federal Production Tax Credit (PTC) of 2.3¢ per kWh. The 5.5¢ estimated cost for one or two turbines at Bloomfield is higher, due to lower wind speeds at Bloomfield, and only having one or two turbines compared to 50 or more turbines at a large wind farm. The Iowa 476C 1.5¢ state tax credit enables such a small project in a less windy area like Bloomfield to have a PPA price of 5.5¢ per kWh. Three years ago this PPA price would likely have been 7¢ per kWh. In this study it has been assumed that the initial PPA price for wind power would be 5.5¢ in 2015 and would decline by 2% per year thereafter. In other words, the City would pay less for energy from turbines installed after 2015, assuming the federal and state tax credits are still in effect. Once a PPA contract has been executed, the PPA rate in subsequent years of the contract was assumed to escalate 1% per year to provide a small hedge against operating cost inflation for the wind turbine owners. Again, the 5.5¢ rate is predicated on the continuation of the federal PTC incentive. If the PTC is not available, the PPA rate would likely be between 7.0 and 7.5¢ per kWh.

Section 4 – Solar PV Generation Options

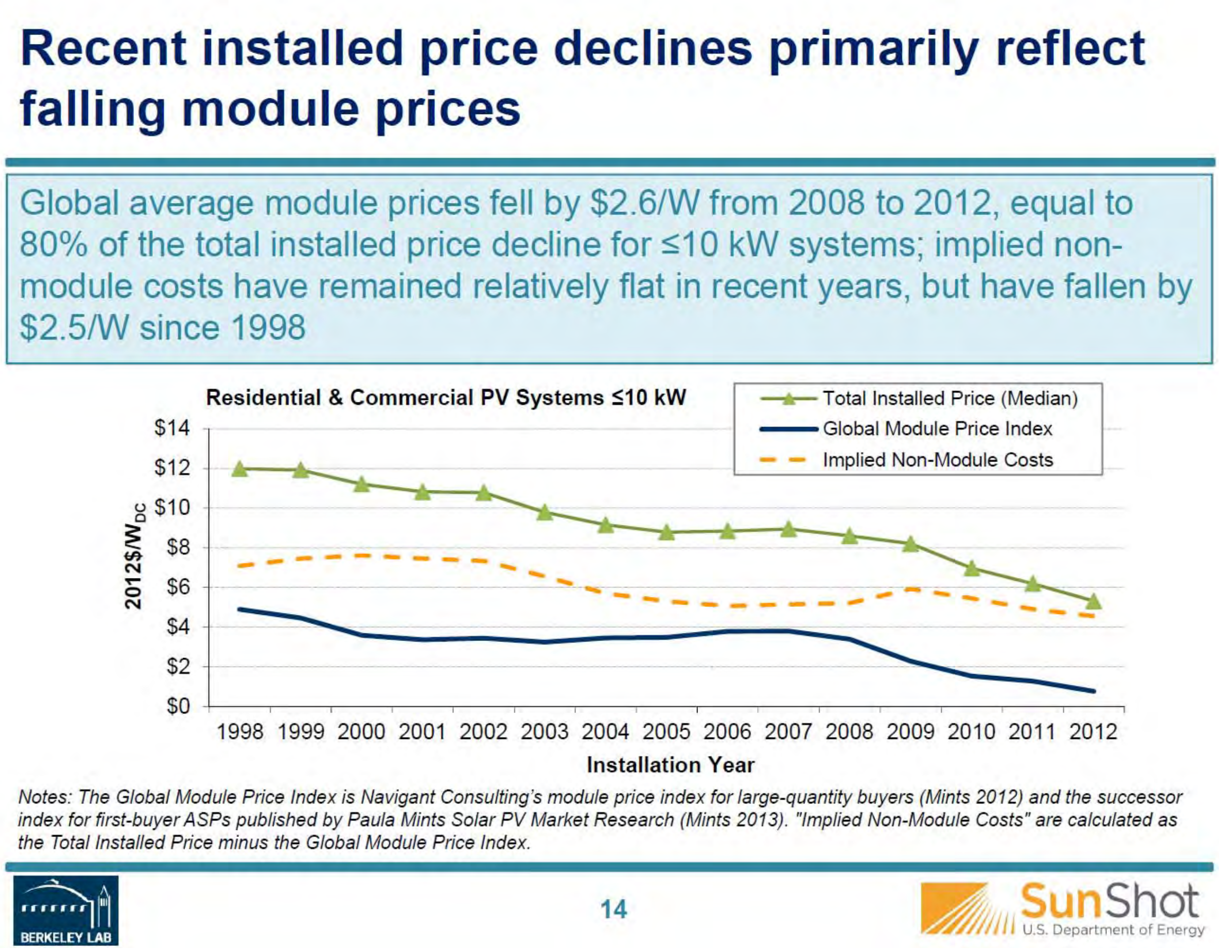
The solar energy resources at Bloomfield are above the average for the state as a whole; and Iowa ranks below average when compared to other states, as illustrated in Figure 8. Nevertheless, using solar energy in Iowa is now becoming economically viable.

FIGURE 8



There has been a long downward march in the cost of solar photovoltaic (PV) generation costs since the PV effect was discovered at Bell labs in 1954. Figure 9 from a DOE study depicts the price trends from 1998 through 2012 for smaller PV systems less than 10 kW. The top green line shows that the cost in 2012 was $5.25 per direct current (DC) watt of panel rated capacity. Now, the majority of the costs of PV systems are not in the hardware costs, but in the soft costs. Soft costs include installation labor, permitting, inspection, interconnection, customer acquisition, financing costs, and installer/integrator margins. PV costs in Germany were half of those in the US, because they have much lower soft costs. This suggests that the cost of PV systems will continue to fall as soft costs come down.

FIGURE 9

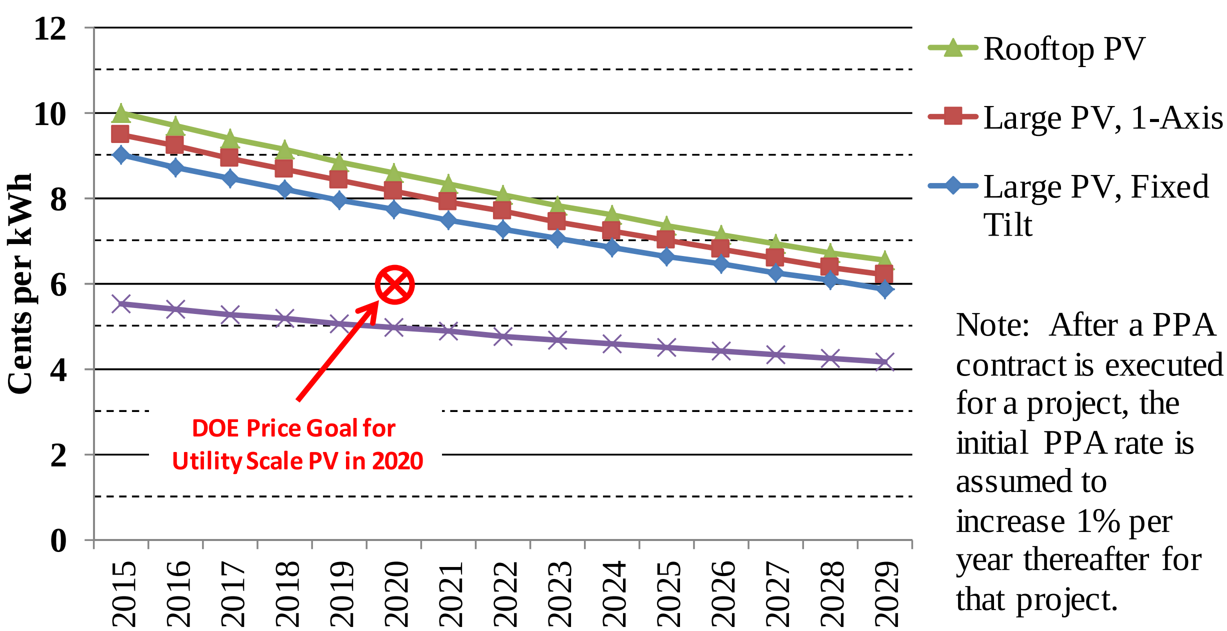


PV prices are even lower today. Furthermore, larger utility-scale PV systems have even lower costs compared to commercial systems. Today in Iowa, utility-scale PV systems of 500 kW in size cost less than $2.50 per watt$_{DC.}$ This is still 100% more than the Department of Energy's (DOE) goal of $1.25 per watt$_{DC}$ for larger commercial-scale systems, and $1.00 per watt$_{DC}$ for utility-scale projects in the year 2020. Therefore, PV system prices will likely continue to decline for some time.

Figure 10 portrays the projected PPA prices for 3 types of solar PV installations in Bloomfield used in this study. For example, a large utility-scale ground-mounted 30° fixed-tilt PV array is projected to need a PPA rate of 9.0¢ per kWh for installation in 2015 (as depicted by the blue line in Figure 10). This rate is based on receiving the federal income tax incentive which now equals 30% of the project's capital cost. If the same project is implemented in 2020, the initial PPA rate is projected to be 7.8¢ per kWh with continuation of the federal tax incentive because it has been assumed that the PV initial PPA prices will fall about 3% per year. In both cases, once the project is built, the PPA rate for that project is assumed to increase 1% per year thereafter. Therefore, a project built in 2020 would start out with a 7.7¢ PPA rate, which would escalate to 8.5¢ in 10 years. The amount of kWh generated by a PV system was assumed to decline by 0.8% per year due to panel degradation. This long slow degradation also increases the cost of PV power per kWh, since fewer kWh are generated over time. Therefore the average cost of PV power over the 10-year period in the above example would be 8.1¢ per kWh. Again, all of these PPA price projections are based on the continuation of the 30% federal investment tax incentives.

FIGURE 10

Initial PPA Rate for Solar PV and Wind Power Projects by Vintage



Two other types of PV systems were assumed to be installed in this study. The second type is a large PV system with a single-axis tracker that tilts the panels around one axis to follow the sun during the day. This PV system with a 30° southward tilt generates about 26% more kWh over the course of the day, since it is better oriented toward the sun, especially in the early morning and late afternoon. This additional power in the morning and afternoon allows the PV system to better match the utility's daily load curves, which in turn reduces the net summer peak demands. In this study it was assumed the single-axis tracker systems cost 0.5¢ per kWh more than the fixed-tilt systems. However, they are more cost effective for the utility, because they reduce the summer peak demands. A dual- axis tracking system would deliver 32% more kWh than the fixed-tilt system. This type of system was not considered in this study, because of the additional complexity and costs of those systems.

The third type of PV system used in this study is a roof-mounted system that utility customers would install on their roofs. Because of the smaller size and loss of economies of scale, this system was assumed to cost 1.0¢ per kWh more than the larger fixed-tilt systems. This system would have an initial PPA price of 10.0¢ per kWh if installed in 2015. In this study it was assumed that the utility would have a contract with its customers to pay this 10.0¢ per kWh rate for all kWh produced by the rooftop PV system. This would be in lieu of having a net metering tariff. Therefore, the customer with the rooftop PV system would continue to buy all of its power from the utility at the normal rate, and then it would receive a credit on its bill for 10¢ per kWh for all kWh generated by the PV system. Of course, the utility could implement a net metering tariff if so desired. In either case, it would need to allow customers to connect any rooftop PV system behind their meter if they so choose. For the purposes of this study it does not make much difference which way the rooftop systems are handled by the utility. Again, it was assumed that the federal 30% investment tax credit would continue into the future.

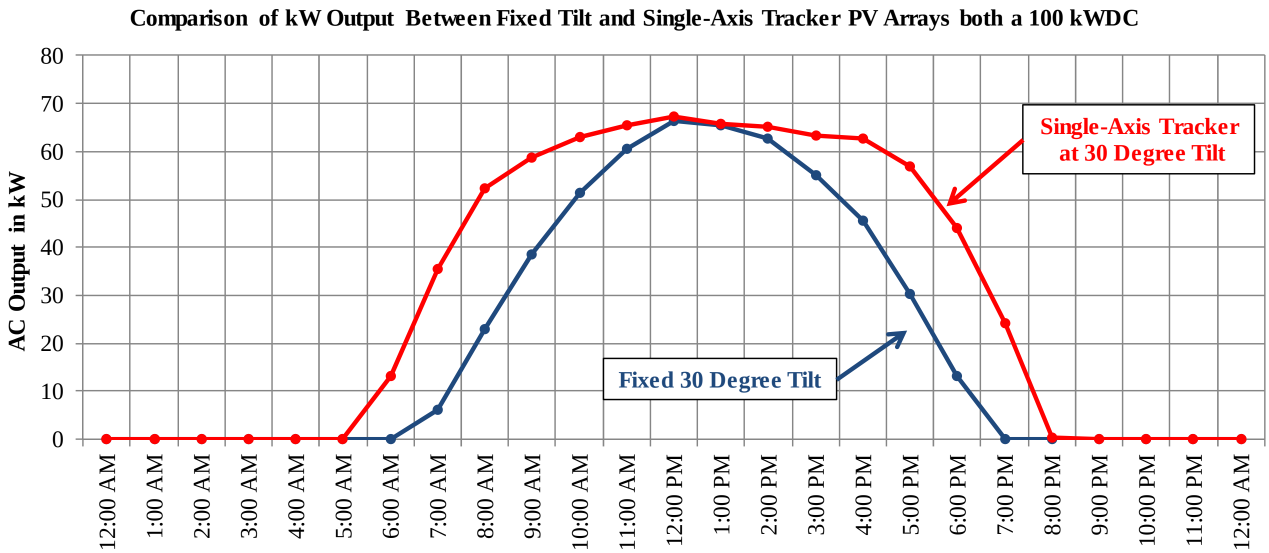
TABLE 1

Average Annual kWh Output from 1 kW_{DC} PV Systems			
	Initial	In 20 Years	Average Years 1-20
30 ° Fixed Tilt & Rooftop	1,074	922	998
30 ° Single-Axis Tracker	1,353	1,162	1,258

Table 1 summarizes the initial, long-term, and average annual generation per 1 kW_{DC} of panel rating at Bloomfield that were assumed for this study. For example a 1 kW 30° fixed-tilt PV system would generate 1,074 kW per year the first year and 922 kWh after 20 years. The average over 20 years would be about 1,000 kWh per 1 kW of rating. The peak output of the system will depend upon a number of factors, such as the tilt angle, the month, the relative size of the inverters compared to the DC panel ratings, and the actual design of the PV system. In this analysis, a 1 kW_{DC} PV 30° fixed-tilt system would typically generate a maximum of about 0.70 $kW_{AC,}$ with only about 100 hours per year that it would generate above that amount. The absolute maximum output would be 0.87 kW_{AC}. When the PV system is generating, it averages 0.26 kW_{AC} and the system will generate at least some small amount of power for 47% of the hours during the year.

Because a 30° single-axis tracker follows the sun throughout the day, it generates about 26% more energy during the year for the same identical panels. It would also have more hours with high output. Figure 11 compares the output of a 100 kW_{DC} 30° fixed-tilt system and a 100 kW_{DC} single-axis tracker tilted at 30° on a sunny day in early July in Bloomfield. The single-axis tracker generates considerably more power in the early morning and late afternoon. For example, at an hour ending 8:00 AM (standard time), the single-axis tracker had generated 53 kWh versus 23 kWh, which is 2.3 times as much. Likewise at an hour ending 5:00 PM, the single-axis tracker had generated 57 kWh versus 30 kWh, or 1.9 times as much for the same hour.

FIGURE 11



Although PV systems with single-axis trackers cost more, they generate more energy and generate more during the mornings and evenings, which better matches the utility's needs.

Section 5 – Other Generation Options

Micro-Turbines

Micro-turbines use natural gas or diesel fuel to generate electricity. They are often supplied with waste heat boilers to provide hot water for facility heating, and can be outfitted with absorption chillers to provide air conditioning. Operating in this Combined Heat and Power (CHP) mode increases the overall thermal efficiency up to 80%. Figure 12 shows a picture of a Capstone 65 kW micro-turbine with a waste heat boiler. There are at least 3 locations in Bloomfield where a micro-turbine may be economically attractive: 1) at the utility power plant where the waste heat could provide diesel engine jacket water heating, 2) at the hospital where the waste heat would supplement the existing gas-fired boilers, and 3) at the downtown geothermal heating and cooling system where waste heat could supplement the geothermal system during the heating season. The electrical generation from the micro-turbine would reduce the utility's monthly and annual peak demands.

FIGURE 12

C65 ICHP MicroTurbine

Since the city is also the natural gas supplier, using a micro-turbine to generate electricity will make the community more self-sufficient.

In this study, a micro-turbine designed for CHP was assumed to cost $3,500 per kW of electrical capacity and have an average annual heat rate of 13,500 BTU per kWh. A credit of 3¢ per kWh generated was given for the value of the heat provided by the waste heat boiler. The analysis in this study suggests that micro-turbines are economical where the excess heat can be used most of the year.

Battery Energy Storage

Commercial-scale Battery Energy Storage (BES) is now available, but it is expensive. BES systems can be economical where demand charges and daytime energy are very high and nighttime energy costs are low. Although the City has relatively high demand charges, the price of energy is the same day or night under the current wholesale power supply contract. Therefore, under the current supply contract, BES systems at current prices would not be competitive with other systems for reducing peak demands.

The cost of a BES system was assumed to be $3,000 per kW of capacity with a 4-hour discharge capacity at full rating. The round-trip efficiency was estimated to be 80%.

The capital cost of BES systems is projected to continue to decline as battery technology advances, while the performance of batteries will continue to improve. If the City eventually depends heavily on renewable energy, then BES systems may be economically feasible in the next 10 years, depending upon the structure and terms of the City's power supply contract at the time.

Biodigester Generation

Where there are sufficient quantities of biomass in the form of crop residue, animal waste, food processing waste or other biomass waste streams, advances in anaerobic digesters make it possible to convert these wastes to methane. Methane may be burned to produce heat or used as a fuel for engine powered electric generators. Among advantages of this technology is the possibility of the short-term storage of the gas, so that electricity can be produced to balance intermittent output of wind and solar generators or for shaving the peak. Another advantage is that the combustion of methane reduces greenhouse gas, since the natural decay of the biomass would produce methane. In the future there may be a dollar value for reducing methane emissions.

An evaluation of Bloomfield's waste treatment plant facility could be done to determine the cost effectiveness of adding an engine generator or micro-turbine generator at that location.

Geothermal Energy

Geothermal energy systems in the Midwest do not generate any electricity, but they use electricity to convert low-grade heat from the earth to a higher temperature, which is more useful for heating. Converting gas-fired heating systems for homes and businesses to geothermal energy heating systems greatly reduces the amount of natural gas used for heating. If the electricity used by the geothermal heating systems is produced by local renewable energy systems, then this helps the community become more energy independent. This cost effectiveness of this strategy for home and business owners depends upon the availability of a low-cost electric rate for geothermal energy systems. Since the City does not have a low-cost rate option for this, it would need to develop this rate. This might be a good strategy for increasing electric revenue to offset the decline in revenue due to energy efficiency programs. Although this study did not consider any significant conversion from gas heat to electrically powered geothermal heat, it is likely that this type of conversion program would not cause electric rates to increase, and could possibly lower electric rates. This type of program would fit well with an overall goal of making the City more energy independent.

Section 6 – Energy Efficiency Programs

Energy efficiency (EE) programs have been the most cost-effective way to lower customer power bills and keep more dollars in the pockets of Bloomfield residents and businesses by creating jobs and economic activity. Energy efficiency programs run by Iowa's municipal utilities have been avoiding the need to buy or generate power for as little as a few cents per kWh. This is usually less expensive than generating or buying wholesale power.

Using the results of other utilities, an analysis was performed, based on a study conducted for IAMU by the Energy Center of Wisconsin. The study looked at a broad range of energy efficiency programs that were designed for residential, commercial, and industrial customers. The results of that study were evaluated for the Bloomfield study to determine which programs would be cost effective for Bloomfield's electric customers, based on the City's wholesale power costs and other demographic data. A total of 55 energy efficiency programs designed for residential customers and 115 programs for commercial and industrial customers were considered. Of these programs, the analysis indicated that about 17 residential programs and 34 commercial and industrial customer programs could be cost effective and worthwhile over the long run for the City. Collectively the 51 different programs could save the utility about 7,000,000 kWh per year when they are all fully implemented, which is about 23% of Bloomfield's annual projected electricity needs. The analysis indicated that residential customers could achieve a 28% reduction in electricity usage, while the commercial and industrial customers could achieve a 20% reduction.

Based on this initial evaluation it was determined that the energy efficiency programs would be very beneficial to the electric customers, and would save the utility enough wholesale power purchases to more than pay for implementing the energy efficiency programs. Therefore in this study it was assumed that the City will gradually implement all of the cost-effective energy efficiency programs over a 10-year period. This would require hiring one full-time employee to administer the programs. These programs will result in a significant amount of work for businesses to provide the products and services called for in the energy efficiency programs. After the 10-year period, it was assumed that the utility employee would continue to implement energy efficiency programs using new products and technologies that will undoubtedly develop over the 10-year phase-in period. This continuation of the energy efficiency programs ensures the continued savings in energy over the longer term.

Since Bloomfield has a relatively small utility, the administrative cost for implementing the energy efficiency programs was conservatively assumed to be double that for the same programs in larger communities on a per customer basis. This upward adjustment in administration costs also accounts for having to administer and aggressively market a broader range of energy efficiency programs than typically done in a small community.

Table 2 presents the results of the analysis of implementing the full complement of energy efficiency programs that are gradually phased in over a 10-year period starting in 2015. The information in the table shows all of the energy efficiency program costs and all of the resulting energy savings over the 15-year study period. The green shaded row indicates that from the customer's perspective, the energy efficiency programs will save them about $8.5 million over the 15-year period. This net savings considers the extra out-of-pocket costs they will incur for purchasing more efficient appliances and improving their homes.

The yellow shaded row shows that from the perspective of the utility, the energy efficiency programs will provide a net savings of $3.4 million for the utility.

The blue shaded row points out that the cost to save 1 kWh is $0.035 on average over the 15-year period. The light brown shaded row indicates that it only costs about one-third as much to save 1 kWh as it does to buy 1 kWh of wholesale power. As discussed previously, the cost of saving energy is much less than the cost of buying or generating energy. Therefore, it is very cost effective for both the customers and the utility to implement a comprehensive set of energy efficiency programs.

TABLE 2

Comprehensive Energy Efficiency Program Energy Savings and Program Costs
All Numbers are Cumulative Totals Over 15 Years Specifically for Bloomfield

	Residential	Commercial / Industrial	Total for All Customers
Energy Saved, including Losses, in kWh	36,800,000	36,900,000	73,700,000
Average Percentage Saved Over 15 Years	20%	14%	17%
Percentage Saved After Programs Fully Implemented	28%	20%	23%
Customer Power Bill Savings Compared to BAU	$ 5,700,000	$ 3,960,000	$ 9,660,000
Extra Out-of-Pocket Costs for Customers	$ (391,000)	$ (813,000)	$ (1,204,000)
Net Savings to Customers Who Use Programs	$ 5,309,000	$ 3,147,000	**$ 8,456,000**
Utility Savings in Wholesale Power Costs			$ 5,951,000
Utility Cost for Running All Energy Efficiency Programs			$ (2,588,000)
Net Savings to Utility for Implementing the Energy Efficiency Programs			**$ 3,363,000**
Total Projected Cost to Utility for All EE Programs for Next 15 Years			$ 2,588,000
Total Projected Energy Saved by All EE Programs over the Next 15 Years, in kWh			73,700,000
Projected Total Average Cost to Utility to Save 1 kWh with EE Programs			**$0.035**
BAU Projected Average Cost of Buying Wholesale Power for Next 15 Years in $/kWh			$0.098
Cost to Save 1 kWh Compared to the Cost to Buy 1 kWh			**36%**

Note: If the EE costs to the customer are included, then the cost to save 1 kWh is $0.051 / kWh

The only downside to implementing energy efficiency programs is that the cost per kWh will be a little higher because the utility would be selling fewer kWhs. Although the utility's operating expenses will go down because it is buying less wholesale power, many of its other operating expenses will continue to rise with inflation, which is assumed to be 2% annually. Therefore the utility's total operating expenses do not go down as much as its retail sales revenue goes down. Therefore the average rate per kWh must go up more than it would for the Business As Usual (BAU) scenario. Based on this analysis, electric rates would average about $0.015 per kWh higher than the BAU scenario. Although rates are a little higher, customer's power bills will be on average about 6% less with the energy efficiency programs. Therefore, both the customers and the utility will save money with the energy efficiency programs.

In this cost analysis, it was conservatively assumed that the utility would pay a 50% rebate for the out-of-pocket cost the customer would have to pay for the more efficient appliances, insulation, or other items. The cost of this 50% rebate would increase the program costs for the utility, which tends to raise rates. However, one alternative to providing a rebate is to have the utility pay for the upfront cost the customer would otherwise have to pay for energy efficiency improvements. The utility would then add an extra amount to the customer's bill every month to recoup all or most of the upfront cost. This method of having the utility finance the energy efficiency improvements through the customer's electric bill makes it extremely easy for the customer, since the customer has no upfront cost to pay. Furthermore, the amount added to the customer's bill would be calculated so that the bill would still be less than it would have been without the energy efficiency improvements. If the customer doesn't have to pay any upfront costs and is essentially guaranteed it will reduce its monthly electric bill, then the participation rate will be higher. The cost for doing this on bill financing is likely less than providing a 50% rebate, even if some smaller rebate is built into the arrangement. If this on-bill financing is used by the City, then the overall cost savings from the energy efficiency program will be a little higher than estimated in this study.

If some customers don't take advantage of any of the energy efficiency programs, their power bills will be higher than they would be under a BAU scenario. Therefore, it is important to get as many people to participate as possible. There may also be instances where low-income residents simply do not participate for other reasons. If this becomes a concern, then special provisions could be allowed for them to ensure that they receive the benefits of the energy efficiency programs.

Appendix 2 shows the energy efficiency programs that were projected to be cost effective to implement. It should be noted that the list represents an aggressive approach to energy efficiency. It is unlikely that any other utility in Iowa has made this type of commitment to saving energy.

Section 7 – Direct Load Controls

One method to reduce dependency on the electric grid is to reduce the peak demand of the utility. If a utility has peak demand charges above about $8-10 per kW-month, then a Direct Load Control (DLC) system is likely a very cost-effective option for reducing the utility's wholesale power demand charges. In this study a radio-based DLC program that controlled both residential and commercial central air conditioners and electric water heaters was evaluated. When triggered to control the peak demand, the DLC system would interrupt the central air conditioner compressor 24 volt control signal to turn off the compressor for 20 minutes every hour. The DLC system would interrupt the 240 volt power circuit to the water heater continuously during the control period. Table 3 summarizes the number of air conditioners and electric water heaters that were assumed to be controlled by which type of customer.

TABLE 3

Direct Load Control Program Cost and Performance Assumptions

	Central Air Conditioner Controls		Electric Water Heater Controls	
	Residential	Commercial	Residential	Commercial
Number of Customers	1141	241	1141	241
Target % of Customers for DLC	75%	50%	15%	10%
Target Number of Customers for DLC	856	121	171	24
Peak Demand Savings per DLC Control, kW	1.00	1.00	1.00	1.00
Peak Demand Savings by Group, kW	856	121	171	24
Peak Demand Savings by Type, kW	976		195	
Summer Peak Demand Savings for All Controls, kW	**1,172**			
Capital Cost per Control Point	$234			
Total Capital Cost of DLC System	**$274,387**			
Total Annual Operational Costs	**$14,058**			

The table indicates that the DLC system will reduce the utility's summer peak demand by about 1,200 kW. Although not used in this study, the winter peak demand could be trimmed by the using the electric water heater controls, which would total about 140 kW.

Based on this relatively simple analysis and the City's current wholesale power costs, the simple payback for this DLC system appears to be about four years. It was assumed the equipment would be installed over a 4-year period starting in 2016. Other DLC systems using radio-controlled "smart" thermostats could be used in place of the radio-controlled air conditioner switches.

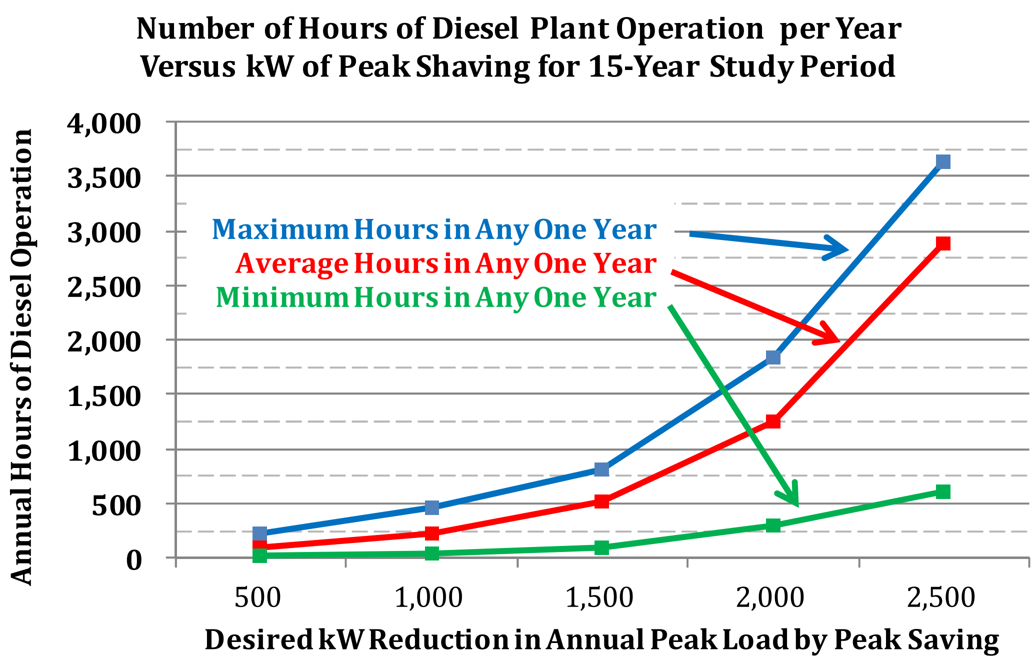
Section 8 – Use of Existing Diesel Power Plant

The existing diesel electric power plant is a valuable asset for the city for two reasons. If the transmission system that brings power into the city is damaged by a storm or ice, the city's power plant can be started to restore power. In a worst-case ice storm lasting several days, having a local power plant can save city residents millions of dollars in lost business, added expenses, and inconvenience; plus it can maintain essential services that ensure public safety. Having a local power plant is like having a top of the line insurance policy (with no deductibles) against natural disasters. Secondly, having a local power plant can provide a hedge or credit against higher wholesale power costs. Although this value varies over time due to wholesale market conditions and is difficult to quantify, it is probably worth $200,000 per year on average over the long term.

The current wholesale power supply contract requires the City to run its diesel power plant when requested by Associated Electric Power Cooperative or the local distribution cooperative. This arrangement minimizes the number of times and the amount of hours the diesels run, because they are only run when the regional power market has high prices. Because of adequate supplies of power in the region over the last 5 years, the diesels were rarely called to run. As the regional economy continues to grow and thousands of megawatts of smaller old coal-fired power plants are retired due to their higher air emissions, the balance between regional supply and demand will tighten. Although there have been many large wind farms constructed every year in the region, the need for power during summer peak periods and some winter peak periods will only grow, since wind farm output is typically not high during many of those periods. This need for power during peak periods will only increase the value of the city's local power plant.

As discussed in Section 2 previously, a new power supply contract will be negotiated and acquired within the next 12 months, and it has been assumed that the City would negotiate for the right to shave its peak load by running its diesel generators in the future. Likewise, in this study it has been assumed that the diesels would be run to reduce annual peak demand. The amount of peak demand reduction desired will determine how many hours per year the diesels must run to keep the total demand under the target. Figure 13 illustrates an estimate of the number of hours per year the diesels would be operated to trim the utility's peak load by 500 kW, 1,000 kW, 1,500 kW, 2,000 kW and 2,500 kW. These estimates were based on simulated hourly loads going 15 years into the future. Since some years were hotter than normal and some cooler, the number of hours varied from year to year. The red line shows the average number of hours per year for the 15-year period. For example, to trim the annual peak by 1,500 kW, the diesels would run an average of 500 hours per year. The most number of hours was 800, and least number of hours was 100 hours per year. It was assumed the minimum run time would be 3 hours if they were started. Based on these estimates, a reasonable target reduction in the annual peak was selected to be 1,500 kW.

FIGURE 13



The City's current air emission permits do not allow the diesel generators to operate other than during emergency conditions. To be able to operate more hours per year and meet the national Reciprocating Internal Combustion Engines (RICE) air emission regulations, catalytic converters must be installed, which are estimated to cost a total of $475,000. It was assumed that bonds would be sold to pay for this capital expenditure. Using the diesels for peak shaving will not reduce future transmission system delivery charges, which are estimated to currently be equivalent to about $2.00 per kW-month. These charges are now embedded in the single $13.90 per kW-month demand charge paid to Southern Iowa Electric Coop.

If the utility did operate its diesel generators to shave the peak, then it was assumed that natural gas costs, diesel fuel, lube oil, and maintenance costs would substantially increase from today's level. For example, it was assumed that maintenance costs would be 4¢ per kWh generated and that 2.5 Full Time Equivalent (FTE) employees would be added to the utility's payroll to run and maintain the diesel plant. All of these extra costs would be recouped by the savings in the demand charges. The overall impact on customer utility bills is projected to be a savings of about $45,000 per year to shave the peak, and would be about the same regardless of how much renewable energy the utility uses.

Of course the specific contract terms of any future power supply contract will determine the cost effectiveness of peak shaving. For example, if a ratchet clause is used for calculating the billing demand charge, then there is more incentive to shave the peak during the summer period, since it may reduce the demand charges year around.

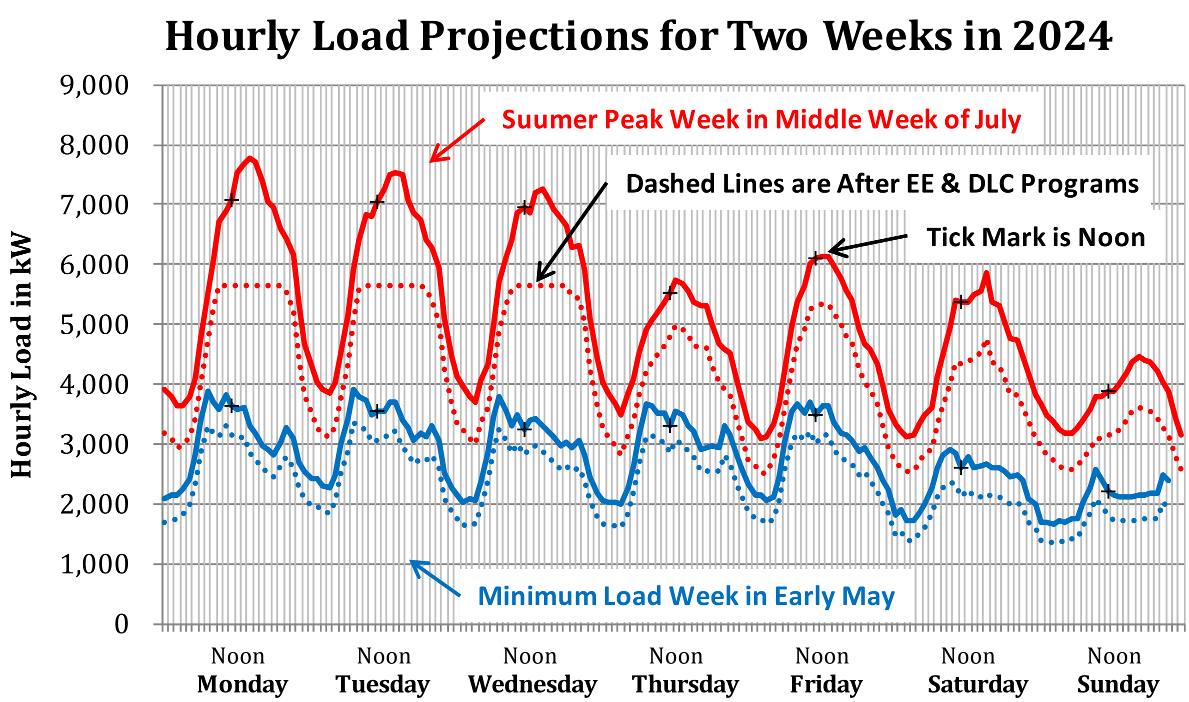
For the purposes of this study on how the City can become more energy independent, it was assumed the utility would generate more of its own power locally, and using the diesels is part of the overall strategy. As a result, there would be more employment in the city to operate the diesel generators, and they would likely be kept in a better ready status for emergencies because of their more frequent operation.

Section 9 – Projection of Future Hourly Loads

A detailed analysis was done on an hour-by-hour basis to determine how the various options for becoming more energy independent would affect the utility's wholesale power purchases over time. The analysis started with an estimate of Bloomfield's hourly loads. Since hourly load data was not readily available from the utility, hourly loads were taken from another Iowa municipal utility and adjusted to better represent Bloomfield's expected loads. Fifteen years of hourly load data was available from Algona Municipal Utilities. Algona has about four times the electric load of Bloomfield, and its annual load factor is higher. A simple multiplier of around 25% was used on the hourly loads of Algona, so that the resulting total annual kWh matched the electric load forecast projections for Bloomfield that were discussed in Section 1 of this report. This simple multiplication resulted in an annual peak load that was lower than the peak load forecast for Bloomfield. A second adjustment was then made to the days with high loads to boost the loads up, so that the highest hourly load for the year matched the projected summer peak for Bloomfield. Making these two adjustments resulted in hourly load projections that gave the same total annual kWh and summer peak as the load forecast projected. Since this study looks out 15 years into the future, and since 15 different years of hourly load data was available from Algona, the hourly load projections for each future year used a different historical year of data from Algona as a starting point. Therefore, the projected load patterns changed a little from year to year just like actual loads do. This procedure for estimating the hourly loads is not perfect, but the procedure does provide some variability in the load profile from one year to the next, which is a natural feature.

Figure 14 depicts two different weeks of projected hourly loads in the year 2024. The load patterns were taken from Algona's actual hourly loads for the year 2011. The peak in that year occurred on a Monday afternoon at 3:00 PM in the middle week of July. The Algona loads were adjusted downward to the level expected in Bloomfield. The peak in Figure 14 is also shown on a Monday at 3:00 PM at a value of 7,768 kW, which is the value in the peak load forecast. The solid red line depicts the hourly loads for the peak week in the year 2024. The peaks on Monday through Wednesday may be a little sharper and more pointed than Bloomfield's actual peaks are, because of the inaccuracies of the extrapolation process used on Algona's hourly loads. The dotted red line right below the solid red line depicts the projected loads if all of the energy efficiency programs are implemented, and if the Direct Load Control (DLC) equipment is added to trim the central air conditioner and water heater loads. The dotted red line shows how the DLC equipment is able to hold the peak at about 5600 kW during the three hot days in July. The DLC equipment was not used during any of the other days. The load reductions from the energy efficiency programs were estimated from the data from the University of Wisconsin analysis, which projected the amount of load reduction and the hours that each of the various energy efficiency programs would trim the load. For example, using higher efficiency air conditioners primarily reduces load during the summer on-peak period, whereas higher efficiency refrigeration equipment would save energy year round.

FIGURE 14



The minimum load for 2024 is projected to be 1651 kW at 3:00 AM in the first week of May. The solid blue line shows the projected loads for that week, whereas the dotted blue line shows the loads if all of the energy efficiency programs were implemented.

Hourly loads were projected in a similar manner for every hour for the 15-year study period.

Section 10 – Financial Impacts of Energy Efficiency, Direct Load Controls and Peak Shaving on the Utility and Customers

A detailed hourly simulation was done for all of the various options that are available for the City to become more energy independent. This simulation provided information on how much power the City had to purchase from its power supplier, whoever that might be in the future. A financial model of the utility was developed to project how much revenue the utility would need each year out through the year 2029. This revenue requirement was based on setting an annual target operating margin of $350,000 to $400,000 starting in 2014, with an annual 4% increase in the target. The resulting calculated revenue requirement would then determine how much electric rates would need to be increased to try to obtain the target margin. Electric rates were adjusted each year in the study to meet the target margin, so that the financial impact of the addition of energy efficiency programs, direct load controls, micro-turbines, and renewable energy could be more accurately determined and compared to not doing anything, or the Business As Usual (BAU) scenario. The BAU scenario simply assumes that none of the programs discussed in the previous sections are implemented, nor is any locally generated renewable energy purchased and used. Figure 15 graphically shows the annual energy needs in MWh, along with the wholesale purchases and local generation since the year 2010 out through the entire 15-year study period to 2029 for the BAU scenario. Energy needs are expected to grow slightly over time for the BAU scenario and would be supplied by wholesale purchases.

FIGURE 15

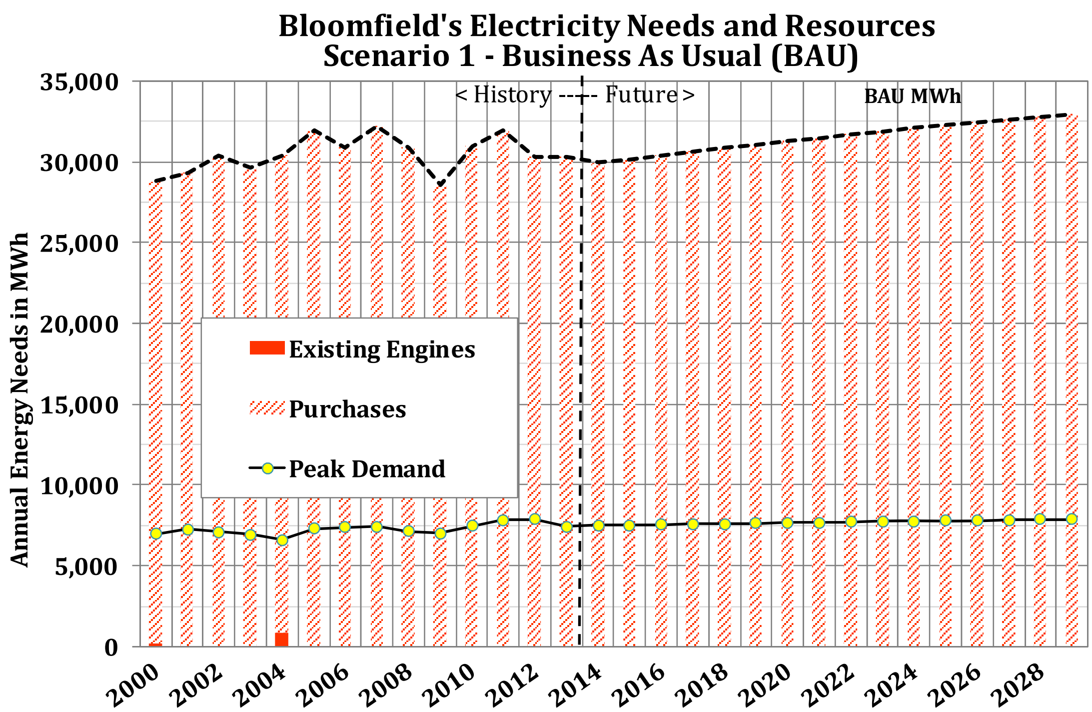
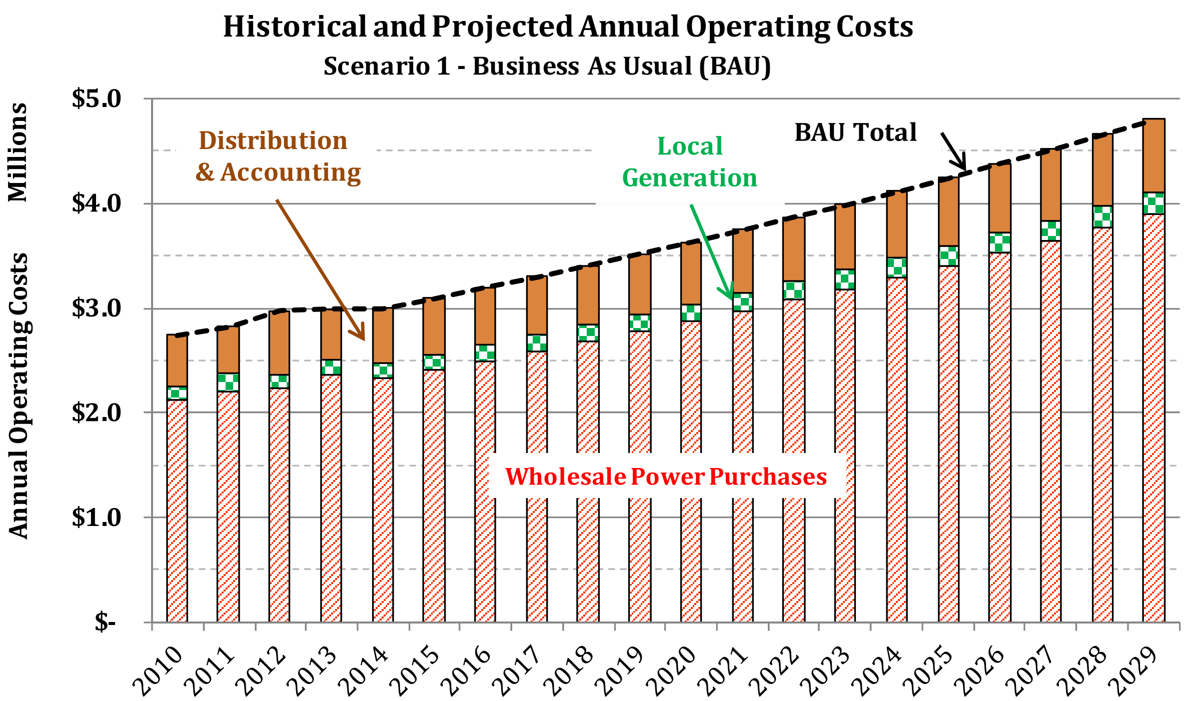


Figure 16 shows information from the financial model starting in the year 2010. As the graph clearly shows, a majority of the utility's operating costs are for wholesale power.

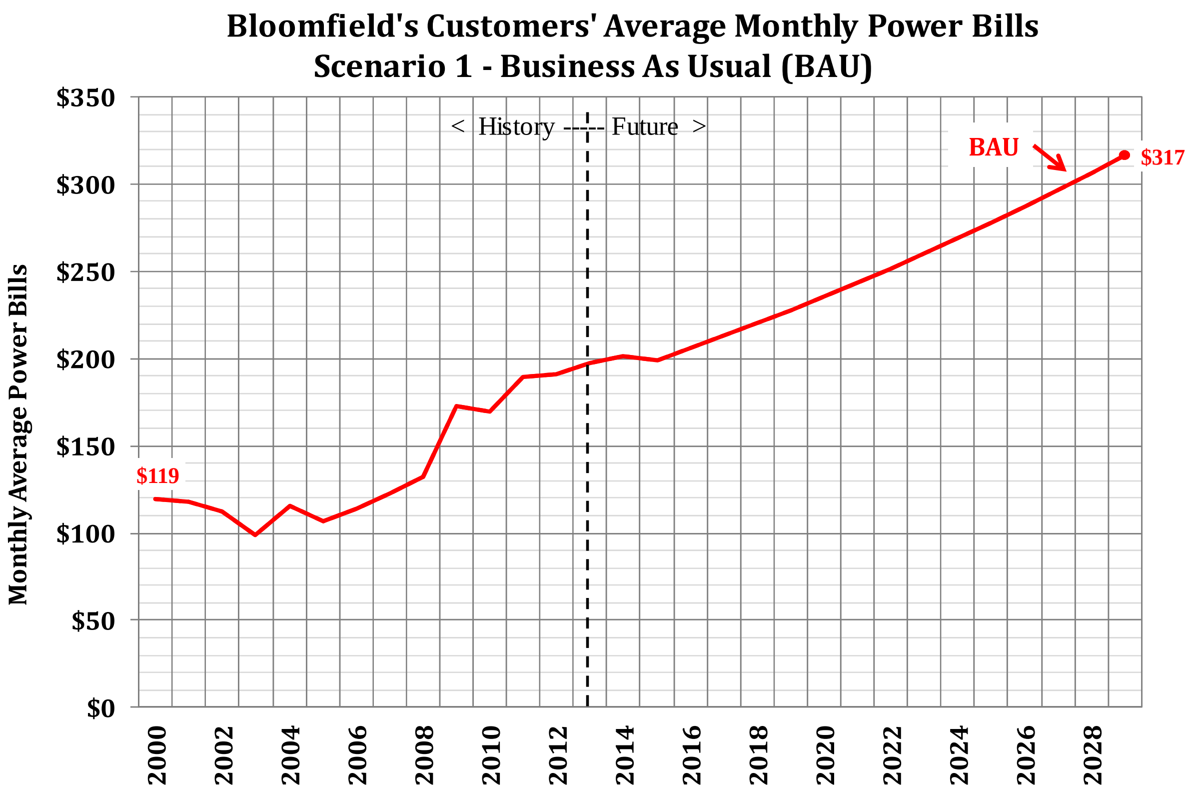
FIGURE 16



The primary reason for the increase in operating costs is the escalation of wholesale power purchase costs. They go up for two reasons: an increase in kWh purchases and an increase in the power supply contract rates. The power supply contract rates are assumed to increase at a 3% annual rate starting in 2015.

Figure 17 illustrates the average monthly power bills for all residential, commercial and industrial customers as a group. It shows how the actual power bills have varied since 2000, and what they are projected to be out through the study period. It was assumed that the number of customers would stay the same, even though there was some growth in kWh sales, especially for the commercial and industrial customer class. As the graph clearly shows, the power bills are lower in the early years of the study and higher in the later years due to inflation, and also to a lesser extent due to an increase in projected usage for the commercial / industrial customers. The average monthly customer bill for all customers was $119 in 2000 and $197 in 2013. Under Business As Usual, their power bill is projected to be $317 in 2029, which represents a 3.0% average annual increase from the 2013 amount. Part of the increase is due to slightly higher consumption per customer over the study period. However, most of the increase is due to higher projected wholesale power costs, which were projected to increase at the same 3.0% annual increase.

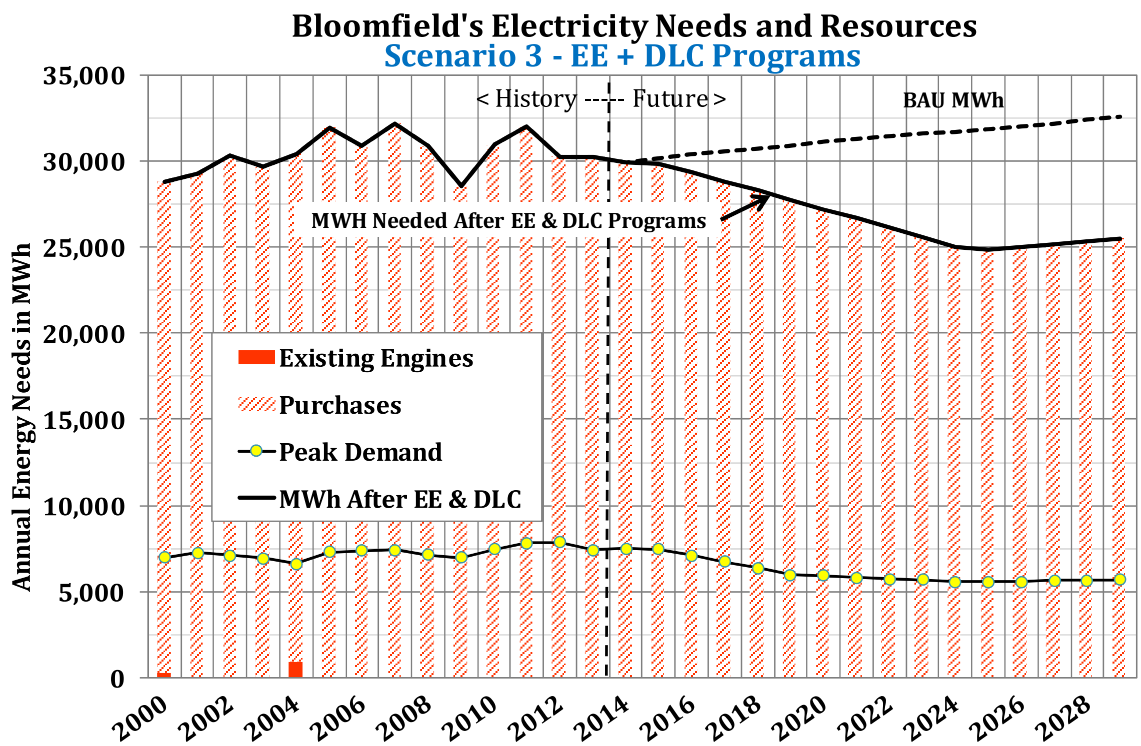
FIGURE 17



All of the financial information is based on the summary information and is shown in Appendix 3. This information was taken from a more detailed financial model developed in an Excel spreadsheet.

If all of the energy efficiency programs are implemented and the Direct Load Control equipment is installed, then the customer kWh usage will go down. This is portrayed in Figure 18.

FIGURE 18

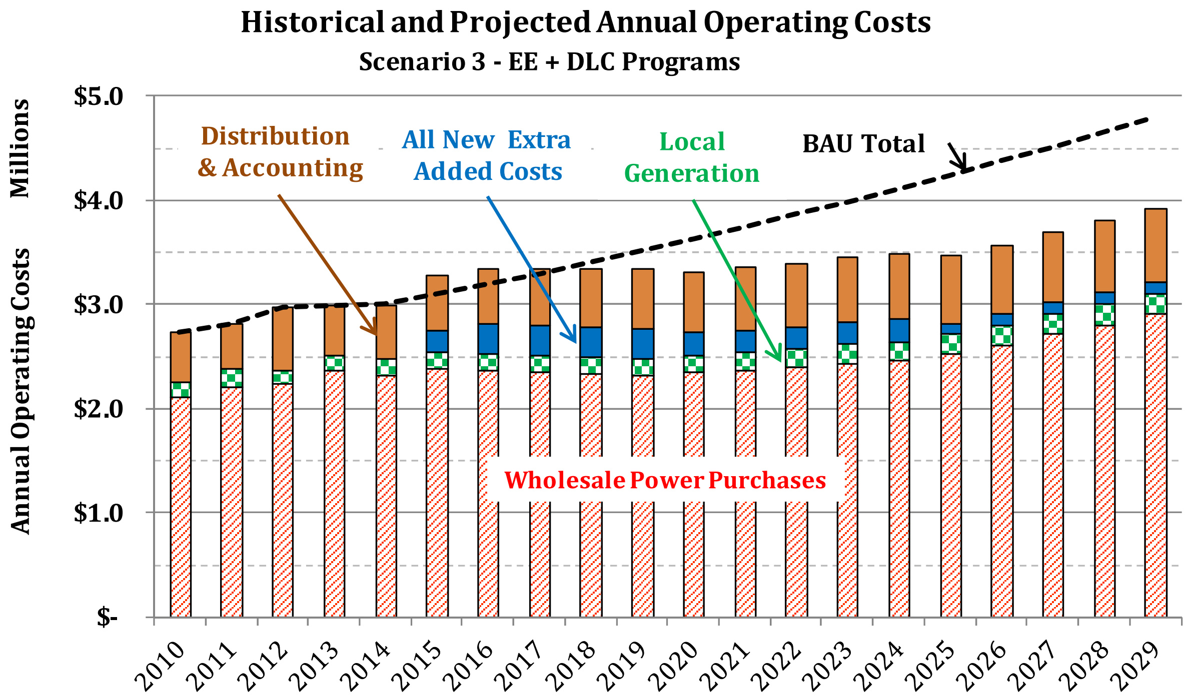


The energy efficiency programs would reduce the energy needs of the utility by 23% by the time they would all be fully implemented. This reduction in energy needs is shown by the black line in Figure 18. Since the energy efficiency programs reduce the kWh usage, they also reduce the annual peak demand. This reduction would be about 1,000 kW after full implementation of the programs.

The direct load control (DLC) equipment has a negligible impact on the energy sales, but the controls very effectively reduce the annual peak demand by about 1200 kW. This reduction in annual peak demand from both the energy efficiency programs and the DLC equipment is shown by the thin black line with yellow markers near the bottom of the graph in Figure 18.

Figure 19 shows that the operating costs go down because of a leveling off of the wholesale power purchases. The blue bars show the utility's added costs for implementing the energy efficiency programs and installing the DLC equipment. They both add to the annual operating cost of the utility. The total annual operating cost is at the top of the brown bars. Under this scenario the total operating costs are initially a little higher for three years during the startup of the programs, but substantially less over the longer term than they were for the BAU scenario. The only reason for the drop in operating cost is simply because customers are using less power.

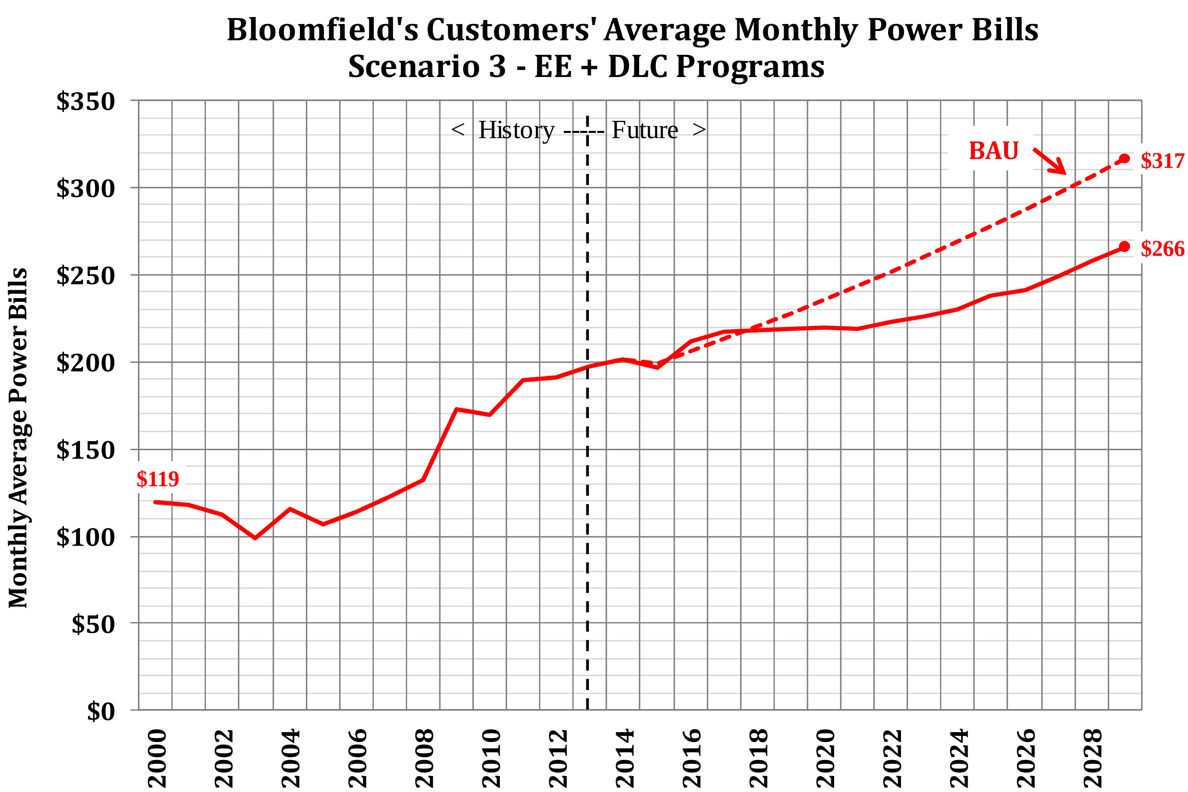
FIGURE 19



The previous graphs describe this scenario as Scenario 3. Scenario 2 shows the addition of the energy efficiency programs without the addition of the DLC equipment. The details of that scenario are not shown in the main body of this report; however they are shown in Appendix 3. The customer power bills are lower if either of the two programs is implemented individually. They are even lower when both programs are implemented together.

The average monthly bills are displayed in the graph in Figure 20 below for both the BAU scenario and this new scenario with the energy efficiency and Direct Load Control equipment. It shows that the average monthly bills would initially be a little higher for two years, and then be less after that (where the solid red line crosses under the dashed line representing the BAU scenario). At the end of the period, the average power bill is projected to be $266 per month, which is about 16% less. All of this reduction is due to the fact that average usage for these customers has declined by 19% due to the energy savings of the energy efficiency programs. The average electric rate in 2029 is about 1.4¢ per kWh higher or 8% higher than the BAU scenario. All customers would benefit from these programs, assuming they all participated in the programs in some way.

FIGURE 20



A summary table of the financial model for this scenario is included in Appendix 3. This table shows that the customer bills are projected to average $229 per month over the study period, compared to $254 for the BAU scenario. Therefore, customers on average would save $25 per month, or about 10% on their monthly bills during the study period. Over the 15-year study period, the City's customers would save $6.3 million on their power bills by implementing the energy efficiency and DLC programs compared to BAU.

The next option analyzed was the operation of the dual-fueled diesel engines to trim or shave the annual peak loads by 1,500 kW starting in year 2016, assuming the new wholesale power supply contract provides savings for this. Figure 21 shows the diesel plant generation with the solid red bars, and the resulting drop in the peak demand trend line. Figure 22 displays the annual financial impact of this scenario. Even with the additional plant operators (included in the blue bars) the operation of the diesels has little effect on the overall cost of power, and the customer bills are almost identical to Scenario 3.

FIGURE 21

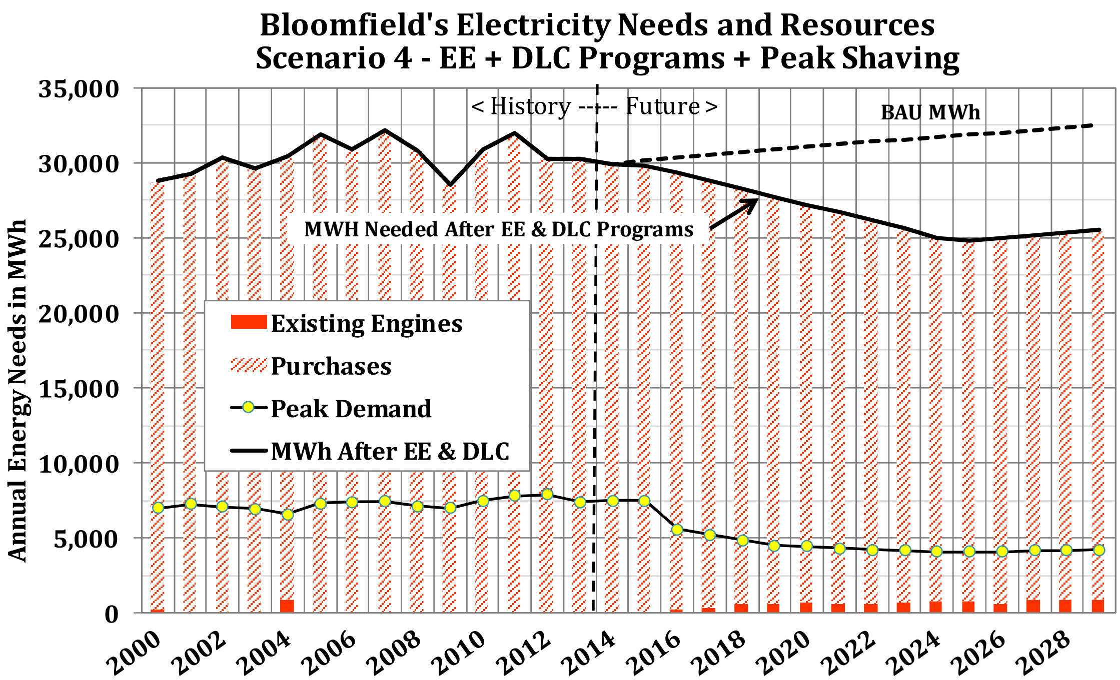
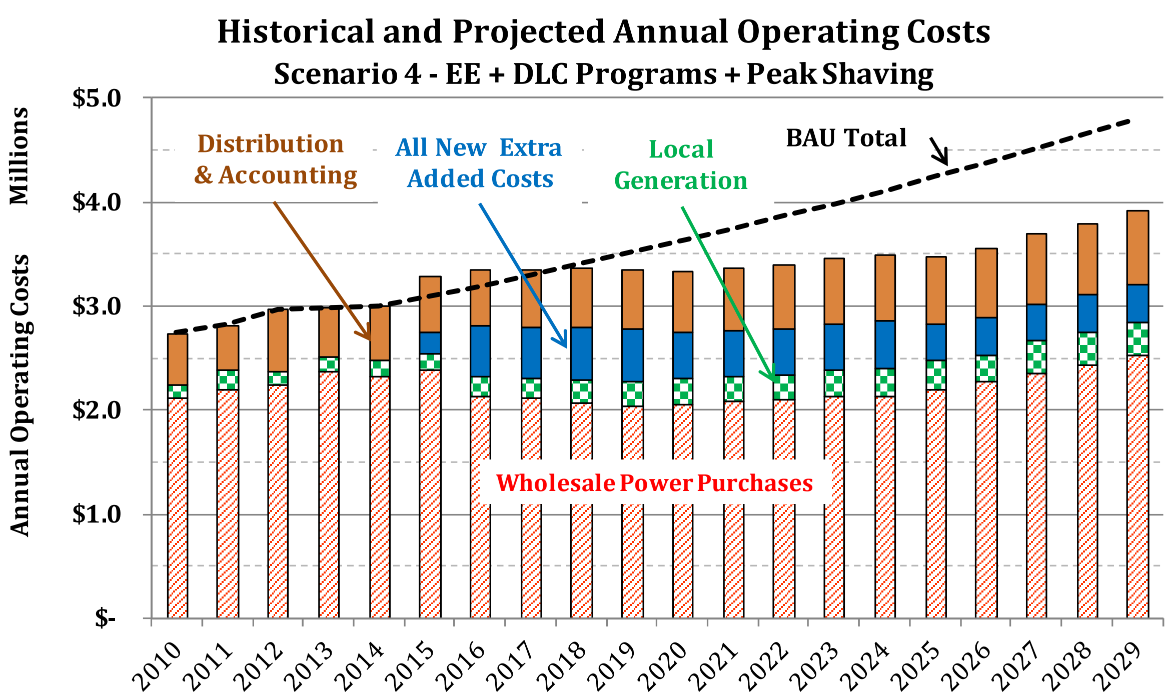


FIGURE 22



Section 11 – Financial Impacts of the Low Renewables Scenario

The financial impacts on the utility and the customers were analyzed for three penetration levels of local renewable energy. The three scenarios were designed to result in an ever increasing ratio of energy that was supplied locally, compared to the BAU scenario where essentially all of the energy was purchased and generated remotely by a power supplier. The first scenario, called the "Low Renewables" relied exclusively on solar PV arrays to obtain additional local generation. It used a combination of large arrays, both with a fixed- tilt mounting and with single-axis trackers, and rooftop solar panels on homes and businesses, totaling 6,800 kW_{DC}. The amount of solar PV capacity was sized so that the energy savings from the energy efficiency programs, plus the solar PV generation, plus the local diesel generation supplied 50% of the BAU energy needs by the 15th year of the study period, or 2029. The remaining needs were provided by wholesale power purchases.

The second scenario, called "Medium Renewables", relied on one 1,700 kW wind turbine, 8,900 kW of solar PV generation, and 130 kW of micro-turbine capacity. Collectively with the energy efficiency savings, this scenario supplied 75% of the BAU energy by 2029. With this much renewable energy capacity, 2,900 MWh of excess generation above the City's needs was assumed to be sold back to the grid. Essentially all of this was during the middle part of sunny days. The selling price was assumed to be equal to 70% of the Midcontinent Independent System Operator (MISO) market prices that were projected for the Bloomfield area from a recent MISO planning study. These selling prices ranged from about 4¢ per kWh in the early years to 8.5¢ in 2029. This 2,900 MWh of excess power sales was netted with about 11,000 MWh of purchases to get a net purchase of 8,100 MWh, which accounts for 25% of the BAU energy needs.

The third scenario was the "High Renewables" scenario which had two 1,700 kW turbines, 11,400 kW of solar PV, and 130 kW of micro-turbine capacity. Collectively with the energy efficiency savings, this scenario supplied 100% of the BAU energy by 2029. With this much renewable energy capacity, there was 7,600 MWh of excess generation, which matched the 7,600 kW of purchases thereby netting the purchases to about zero. There were 3,700 hours with excess generation that reached a maximum of 9,800 kW sold to the grid in 2029.

This third scenario with the large amount of renewable generation makes the City "energy independent" in a sense and largely reliant on renewable energy. Of course, with the existing local dual-fueled diesel generation capacity, Bloomfield could in theory be energy independent today from an electrical perspective. However, generating power with the diesels would be more costly than purchasing power.

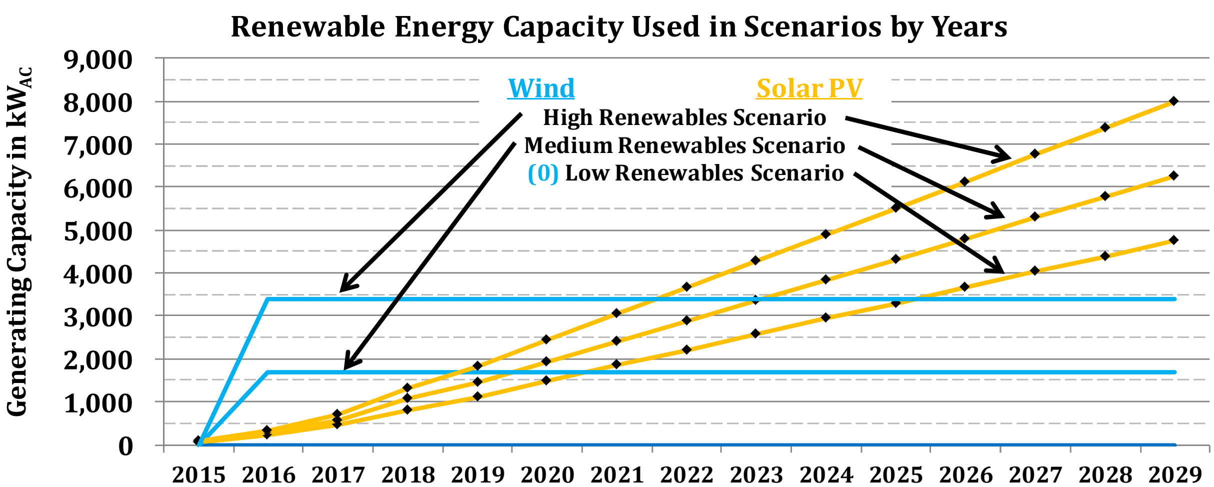
Table 4 shows the amount of new local generating capacity in kW for each of the three renewable energy scenarios. The Solar PV capacity is in direct current kW, or kWDC. The typical maximum AC output is about 70% of those values, with the absolute highest peak at about 83%.

TABLE 4

New Local Generating Capacity in kW Used for Three Renewable Energy Scenarios															
Year >	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Low Renewables Scenario															
Large Solar PV - Fixed Tilt	0	90	90	460	460	830	830	1,200	1,200	1,570	1,570	1,940	1,940	2,310	2,310
Large Solar PV - Tracker	0	0	180	180	460	460	830	830	1,200	1,200	1,570	1,570	1,940	1,940	2,310
Rooftop Solar PV	75	225	375	525	675	825	975	1,125	1,275	1,425	1,575	1,725	1,875	2,025	2,175
Wind Turbines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro-Turbines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Totals	**75**	**315**	**645**	**1,165**	**1,595**	**2,115**	**2,635**	**3,155**	**3,675**	**4,195**	**4,715**	**5,235**	**5,755**	**6,275**	**6,795**
Medium Renewables Scenario															
Large Solar PV - Fixed Tilt	0	130	130	640	640	1,150	1,150	1,660	1,660	2,170	2,170	2,680	2,680	3,190	3,190
Large Solar PV - Tracker	0	0	260	260	640	640	1,150	1,150	1,660	1,660	2,170	2,170	2,680	2,680	3,190
Rooftop Solar PV	88	263	438	613	788	963	1,138	1,313	1,488	1,663	1,838	2,013	2,188	2,363	2,538
Wind Turbines	0	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
Micro-Turbines	0	130	130	130	130	130	130	130	130	130	130	130	130	130	130
Totals	**88**	**2,223**	**2,658**	**3,343**	**3,898**	**4,583**	**5,268**	**5,953**	**6,638**	**7,323**	**8,008**	**8,693**	**9,378**	**10,063**	**10,748**
High Renewables Scenario															
Large Solar PV - Fixed Tilt	0	170	170	850	850	1,530	1,530	2,210	2,210	2,890	2,890	3,570	3,570	4,250	4,250
Large Solar PV - Tracker	0	0	340	340	850	850	1,530	1,530	2,210	2,210	2,890	2,890	3,570	3,570	4,250
Rooftop Solar PV	100	300	500	700	900	1,100	1,300	1,500	1,700	1,900	2,100	2,300	2,500	2,700	2,900
Wind Turbines	0	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400
Micro-Turbines	0	130	130	130	130	130	130	130	130	130	130	130	130	130	130
Totals	**100**	**4,000**	**4,540**	**5,420**	**6,130**	**7,010**	**7,890**	**8,770**	**9,650**	**10,530**	**11,410**	**12,290**	**13,170**	**14,050**	**14,930**

Figure 23 illustrates the amount of renewable generation capacity installed by year.

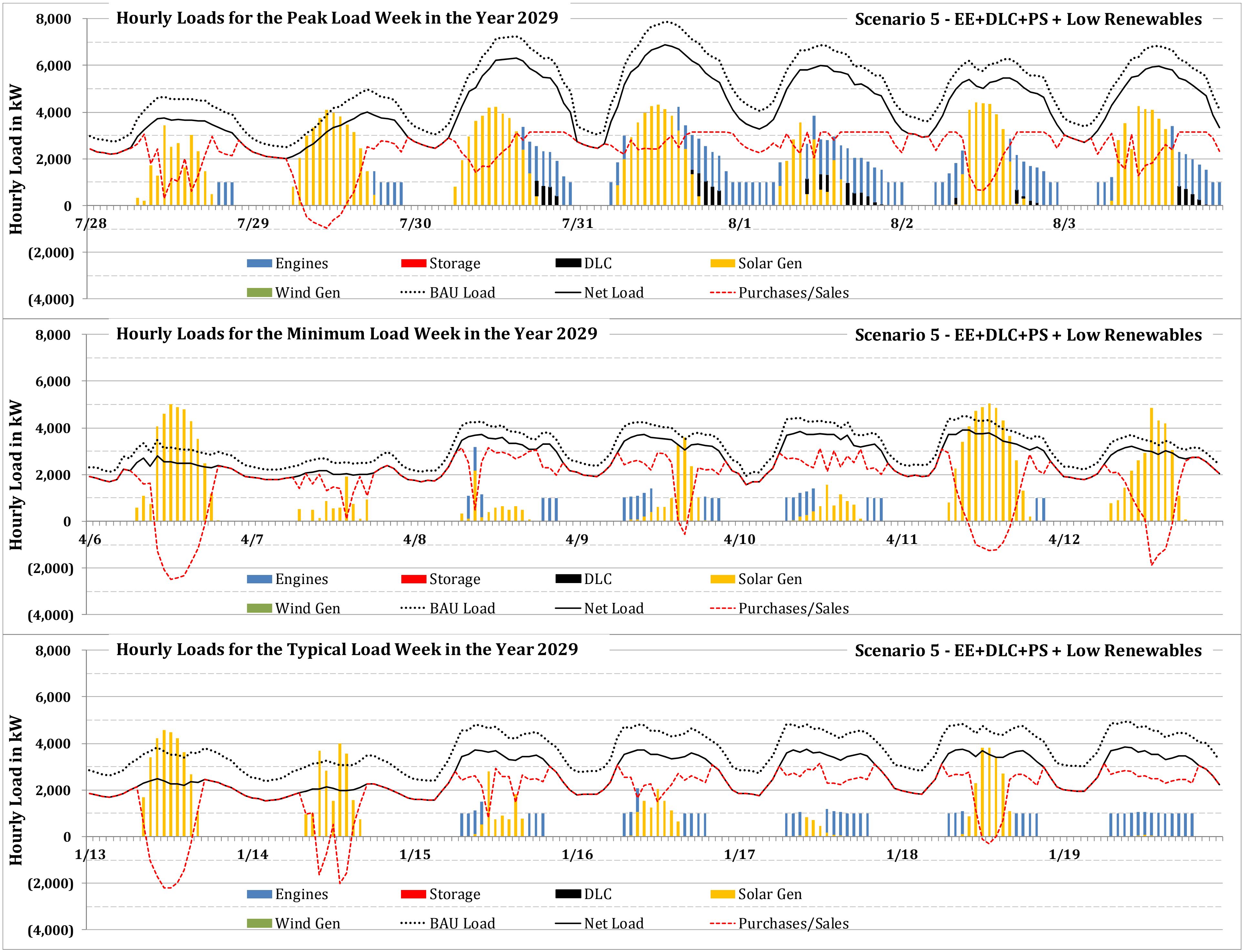
FIGURE 23



The Low Renewables Scenario has a total of about 6,800 kWDC of solar PV generation added nearly linearly over the 15-year study period. In this study it was assumed that the utility would have contracts to buy all of this solar power from private owners. Under this scenario, the net purchases of wholesale power are reduced to half of what they would be under the BAU scenario by implementing the energy efficiency programs and adding the solar PV generation.

Figure 24 on the following page shows the projected hourly loads during three periods of time in the last year of the study, when all of the solar PV is projected to be installed. The top strip chart shows the peak week in 2029, which runs from July 28 through August 3. The peak was on Tuesday, July 31st, and it would be 7,880 kW for the BAU scenario (top black dotted line). Assuming all of the energy efficiency programs have been fully implemented by that year, the peak load would be reduced to 6,870 kW (solid black line). The solar PV generation for the last day in July for a Typical Meteorological Year (TMY) for the Bloomfield area, shows a peak of about 4,000 kW of generation centered on the hour 1:00 PM daylight savings time. This solar PV generation is based on about 2/3 fixed-tilt collectors and 1/3 single-axis tracking. As the solar PV output starts declining later in the afternoon, the diesel generators are brought on line to make up for the declining solar PV, so as to trim 1,500 kW from the load that day to stay under the target annual peak of 3,160 kW. The dashed red line is the net power purchased from the grid and it is capped out at 3,160 kW each day. The DLC equipment on the central air conditioners is also called on to assist with controlling the peak load. It is interesting to note that the diesels or DLC equipment were not needed at the peak hour, because there was enough solar PV power to keep the peak below the target level.

FIGURE 24 – Hourly Loads for the Peak Load Week, Minimum Load Week, and Typical Load Week in the Year 2029

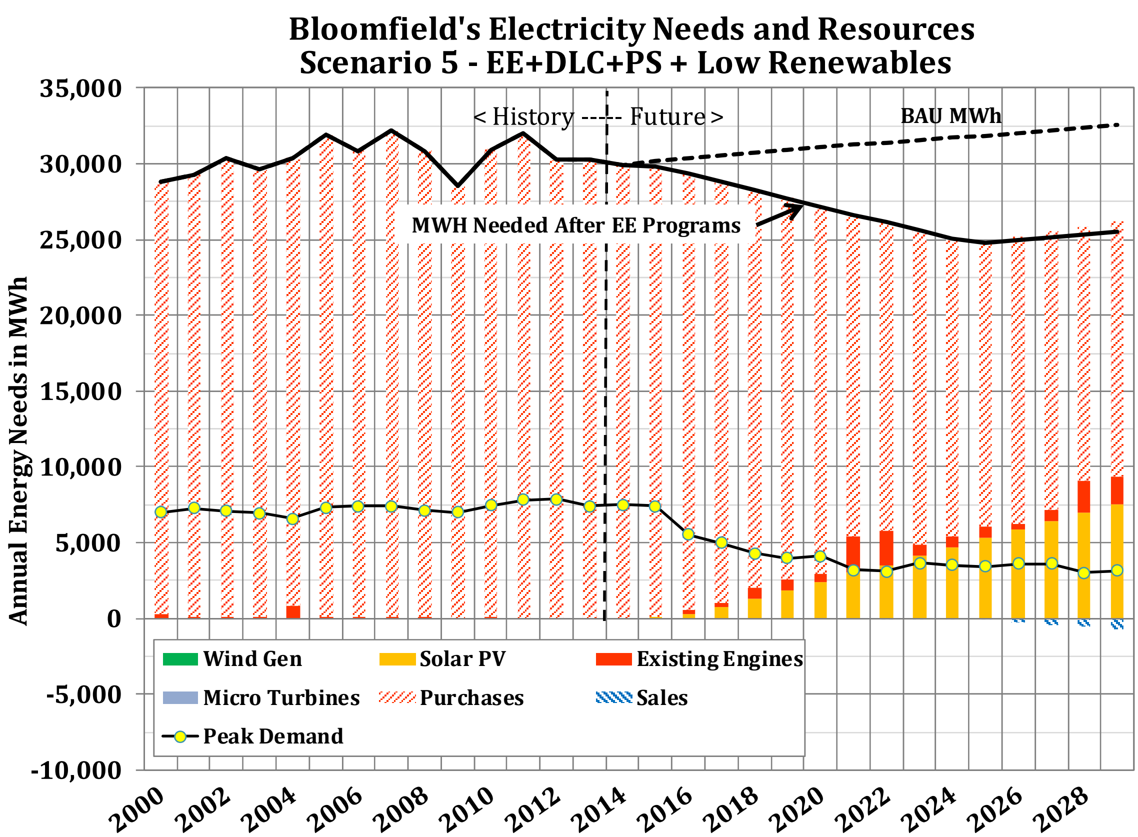


The second strip chart graph shows the minimum load day in 2029, which was the second week in April. The minimum load was projected to be 1,550 kW very early on a Tuesday morning. The loads were fairly low all week and a sunny day produced excess power that was sold to the grid. This is shown by the red dashed lines looping down below zero on four days that week.

The last strip chart shows a more normal load week in January that has a combination of sunny and cloudy days. Note that the diesels are run during cloudy weekdays at a minimum generation setting assumed to be 1,000 kW, so as to keep the load below the target peak load level of 3,160 kW.

Figure 25 illustrates how the various energy sources contribute to the annual energy needs during each year of the study period for the Low Renewables scenario. The diesel engine generation varies from year to year, depending primarily upon how long the hot weather is during the summer, or how cloudy it is during high load periods during cold weather. During the last year of the study the solar PV arrays provided about 30% of the annual energy needs, while the diesels provided 7%.

FIGURE 25



During the last four years of the study, as the amount of solar PV generation increased, there were times when the solar PV produced more power than was needed by Bloomfield. The excess generation would be sold to the grid and the total amount sold is shown by the small blue striped bars dropping below the zero line in the figure above. In the last year, the projections showed a total of 700 MWh of excess solar generation. The installed capacity in 2029 was assumed to be 6,795 kW_{DC}, which has a typical maximum AC output of 4,800 kW_{AC} on a sunny late spring day, when the sun is most perpendicular to the tilt of the panels.

The graph in Figure 26 displays a simple summary of how the utility's operating costs are affected by the Low Renewables scenario, and how the total compares to that for the BAU scenario. The addition of the solar PV generation comprises most of the green checkered bars and the blue bars, because it was assumed the city would add a technician because of all of the new solar generation. The cost of operating the solar PV projects by the private owners is already covered in the contract PPA price. These extra costs are being offset by the reduced wholesale power purchases. The net result is that there is very little change in the overall operating cost for the utility, compared to the previous scenario with the energy efficiency programs and DLC equipment.

FIGURE 26

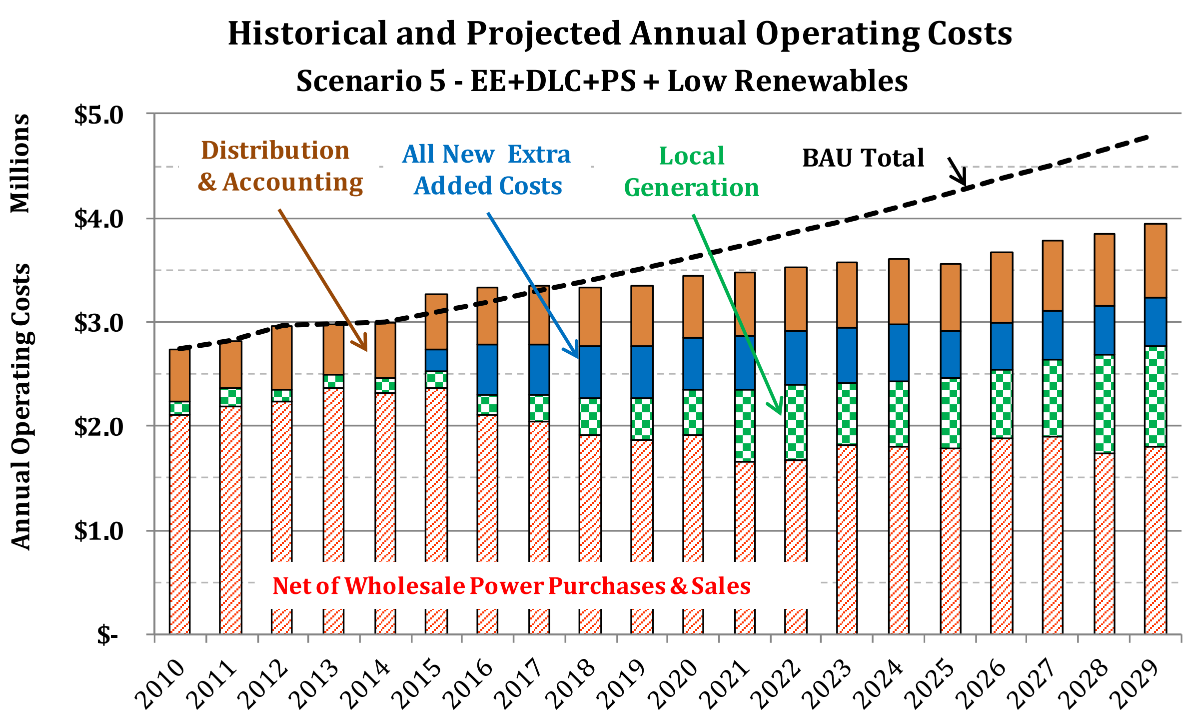
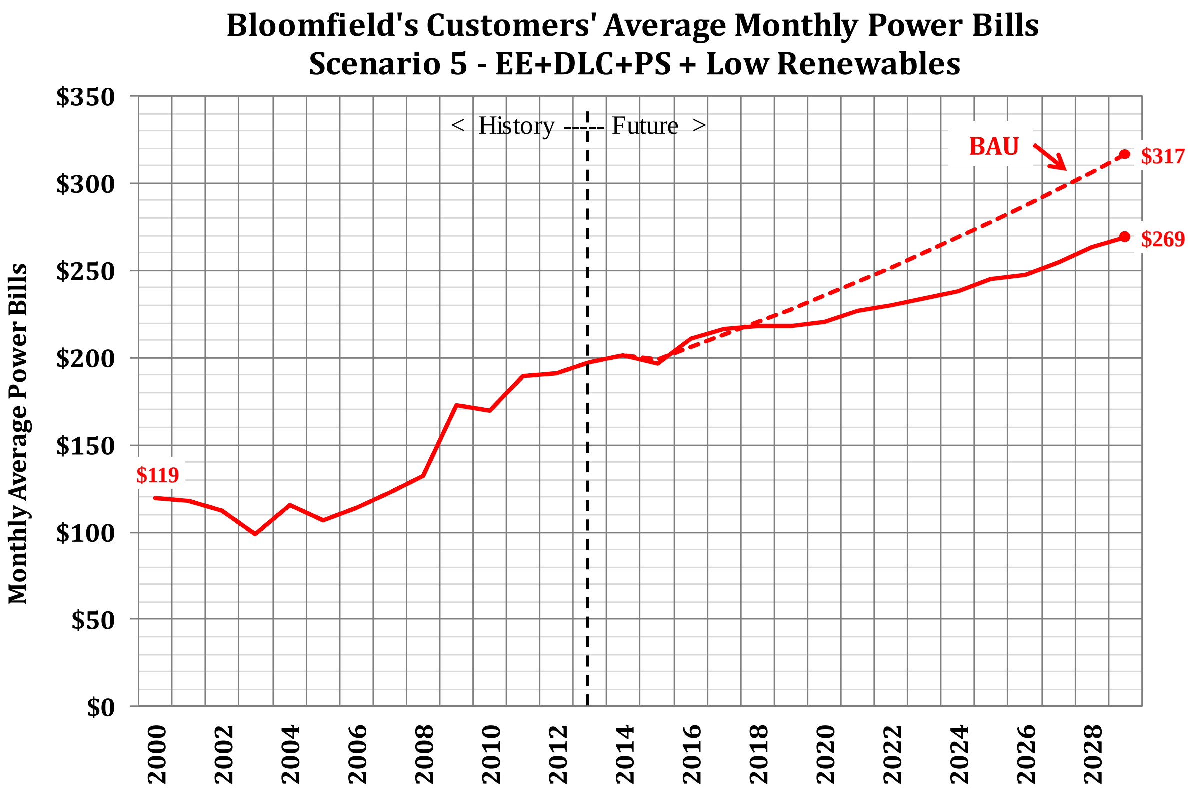


Figure 27 illustrates the impact of the Low Renewables scenario on the monthly customer bills. At the end of the study period, the average customer bill would be $269 per month, which is still less than the BAU amount of $317. This represents a 15% savings. These savings are almost the same as if the energy efficiency programs and DLC equipment were installed. Compared to the BAU scenario, these customer bill savings total about $5.3 million over the 15-year study period. As the trend lines indicate, power bills will escalate less in the future with renewable resources than without. A stable rate is one of the primary benefits of renewable resources.

FIGURE 27



In summary it appears that adding about 7,000 kWDC of solar generation along with incorporating energy efficiency programs and DLC equipment can save customers a substantial amount of money ($5.3 million) but not quite as much as implementing energy efficiency and DLC programs alone ($6.3 million).

Section 12 – Financial Impacts of the Medium Renewables Scenario

The Medium Renewables Scenario has a total of 8,900 kW_{DC} of solar PV generation, added nearly linearly over the 15-year study period. It also has a 1,700 kW wind turbine installed in 2016, as well as 130 kW of micro-turbines. Again, it was assumed that the utility would have contracts to buy all of this solar and wind power from private owners, but would own the micro-turbines. Under this scenario, the net purchases of wholesale power are reduced by 75% of what they would be under the BAU scenario by implementing the energy efficiency programs, and adding the solar PV, wind, and micro-turbine generation. Figure 28 on the following page shows the projected hourly loads during the peak load week, the minimum load week and a typical load week in 2029. Again, the top strip chart shows the same peak week as before in 2029. The solar PV generation for the summer peak day shows a peak of about 5,700 kW of generation. The wind generation on that day would average 400 kW in the morning, but would pick up to an average of 1,100 kW until after dark. The diesels would be brought on line from 4 to 11 PM to keep the peak load below the 3,000 kW target. The DLC equipment on the central air conditioners would not be needed on the peak day, because there would be adequate wind and solar power.

The second strip chart graph shows the same minimum load day in 2029, which would be the second week in April. The wind turbine would average 750 kW during the week for a 44% capacity factor. Because the loads would be fairly low all week, there would be excess power almost every day, as shown by the red dashed lines looping down below zero. On Thursday of that week, the excess generation peaks out at 4,500 kW delivered to the grid, due to the sunny and windy day. Any time excess power is going to the grid, it was assumed that the micro-turbines would be turned off. The micro-turbine generation is included in with the diesel generation and shown as the blue bars.

The last strip chart illustrates the same week in January that has a combination of sunny and cloudy days, and windy and still days. The combination of solar and wind generation does a fairly good job of keeping the peak load down, so that the diesels are not needed very much to keep the peak below the target level.

FIGURE 28 – Hourly Loads for the Peak Load Week, Minimum Load Week, and Typical Load Week in the Year 2029

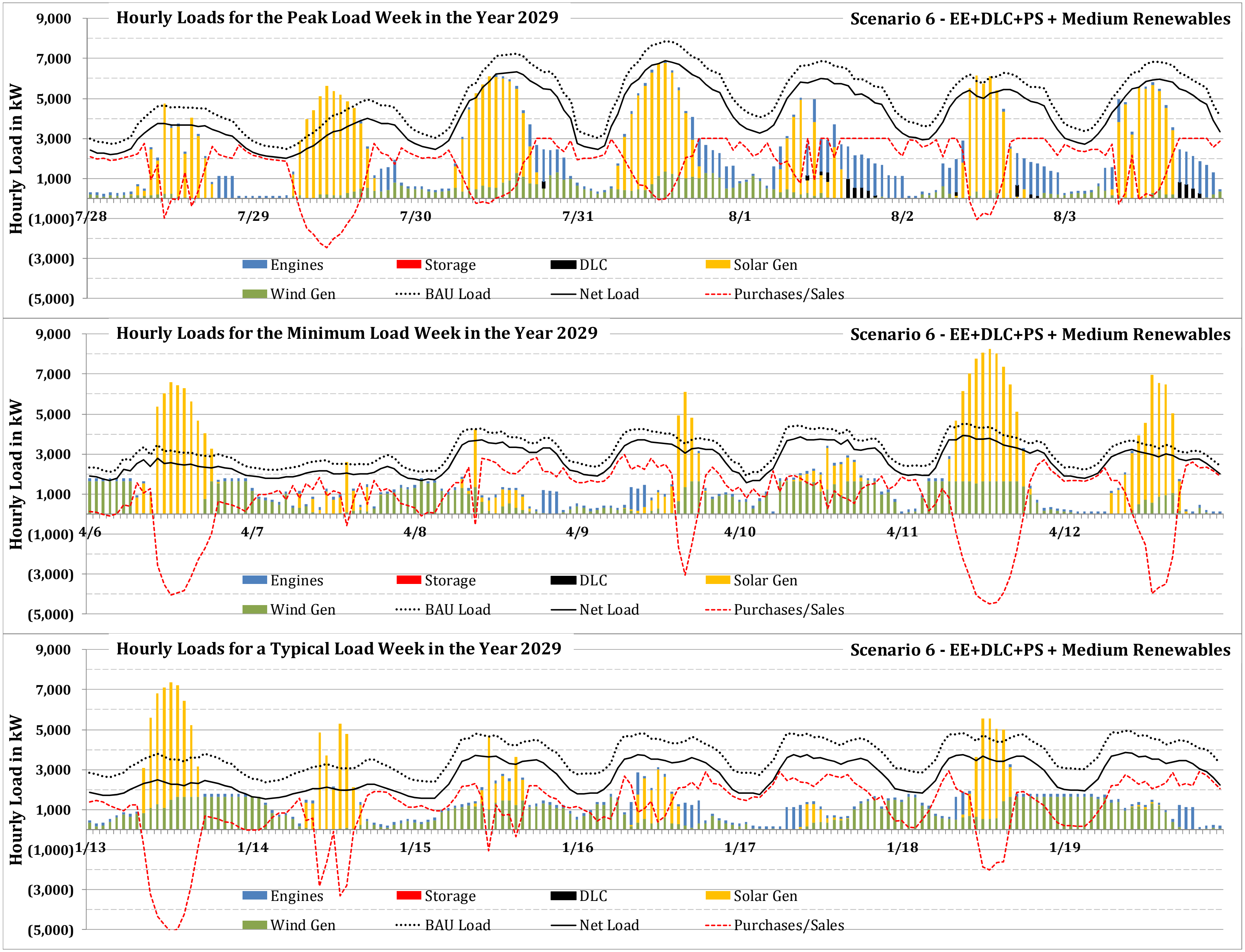
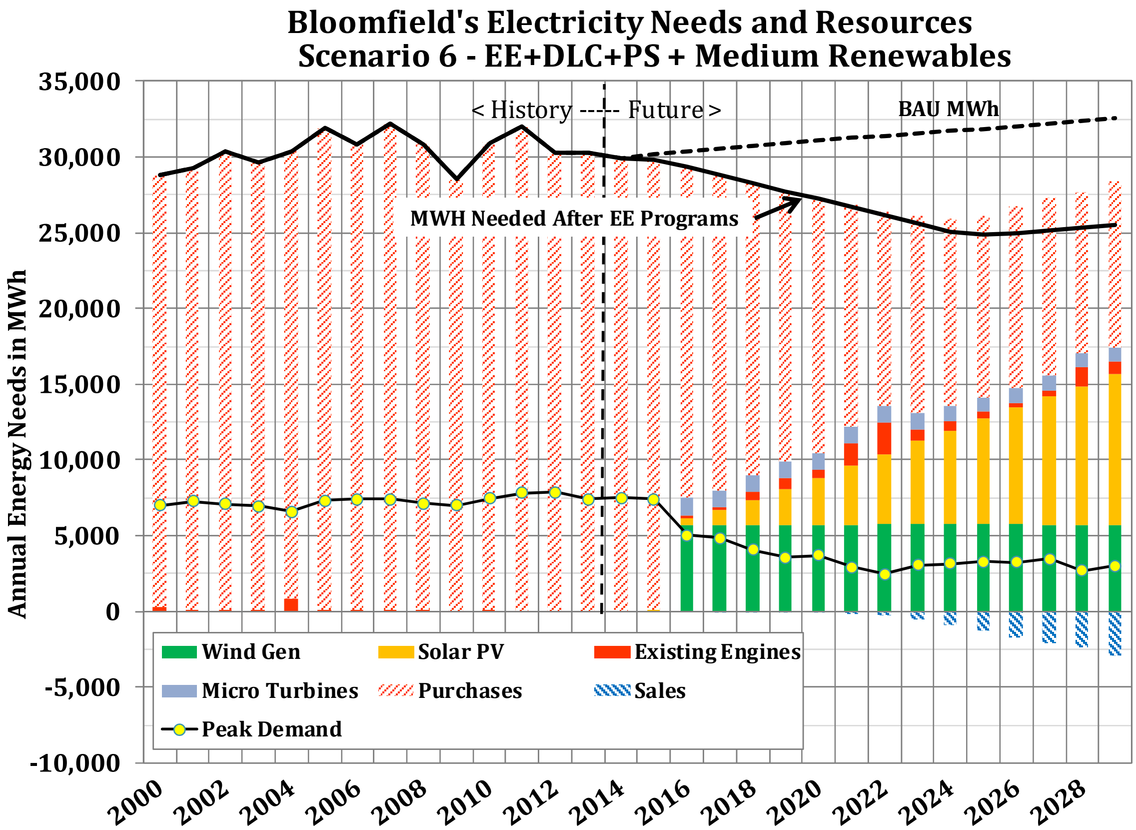


Figure 29 illustrates how the various energy sources contribute to the annual energy needs during each year of the study period for the Medium Renewables scenario. The wind generation was modeled on an hourly basis and the hourly patterns changed in each year of the study. However, the total amount was adjusted, so as to make the annual total wind generation match the median wind power projection. During the last year of the study, the wind turbines would provide 22% of Bloomfield's net energy needs, the solar PV arrays 39%, the micro-turbines 3.5%, and the diesels 3%.

FIGURE 29



In the last year of the study there would be excess generation about 21% of the time, which totals 2,900 MWh, as shown by the small blue striped bar. The maximum hourly outflow to the grid was projected to be 6,300 kW. The renewable energy generating capacity is 6,300 kW_{AC} for the solar and 1,700 kW for the wind turbine, which totals 8,000 kW. The minimum load for the utility in 2029 was projected to be 1,330 kW after the energy efficiency programs were fully implemented.

The graph in Figure 30 displays the utility's operating costs for the Medium Renewables scenario. Although the operating costs are higher for five years, they again become substantially lower than that for the BAU scenario. The solar PV and wind generation comprise most of the green checkered bars. The blue bars include costs for the following:

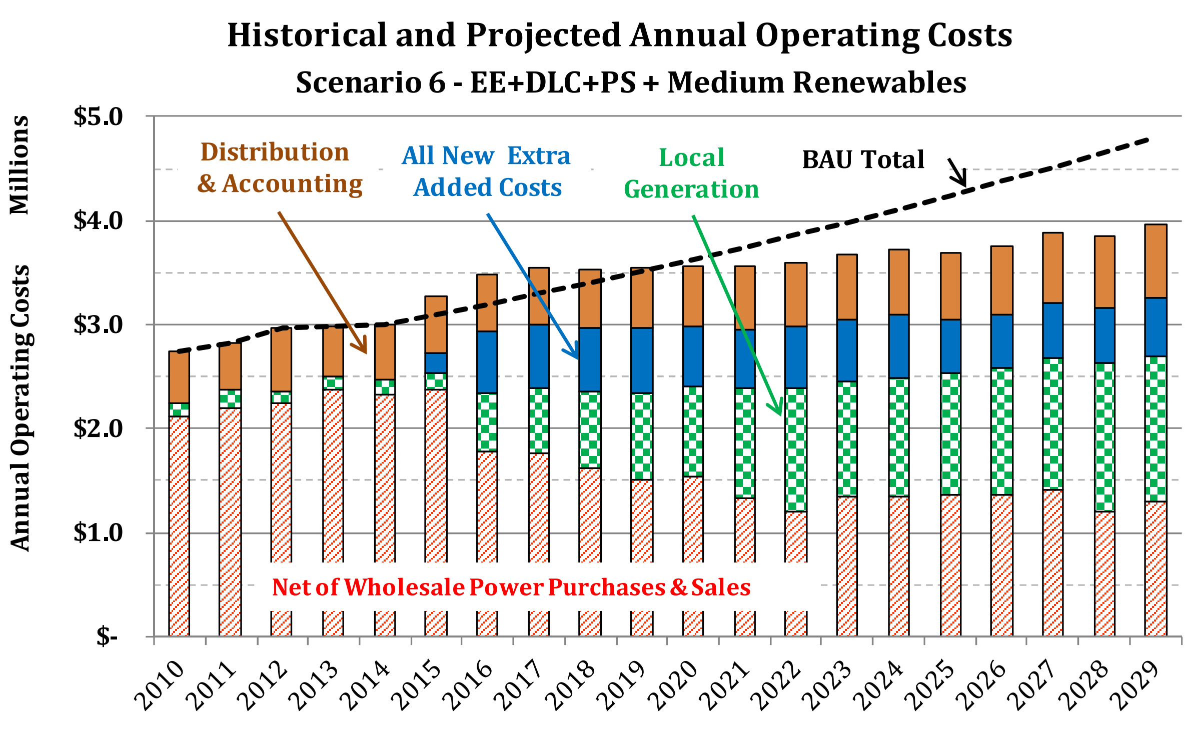
1) All energy efficiency and DLC program and equipment costs
2) 2.5 FTE power plant operators
3) 1.0 FTE technician for generation operations
4) Fixed charges on capital investments for Reciprocating Internal Combustion Engine (RICE) compliance equipment and micro-turbines
5) Fixed charges on improvements that are assumed to be needed for interconnecting all of the solar PV and wind generation to the distribution system

The total capital costs giving rise to the fixed charges in items 4 and 5 above is estimated to be $1.5 million.

The cost of operating the solar PV and wind generation projects by the private owners is already covered in the contract PPA price, and might amount to 1 or 2 FTE technicians.

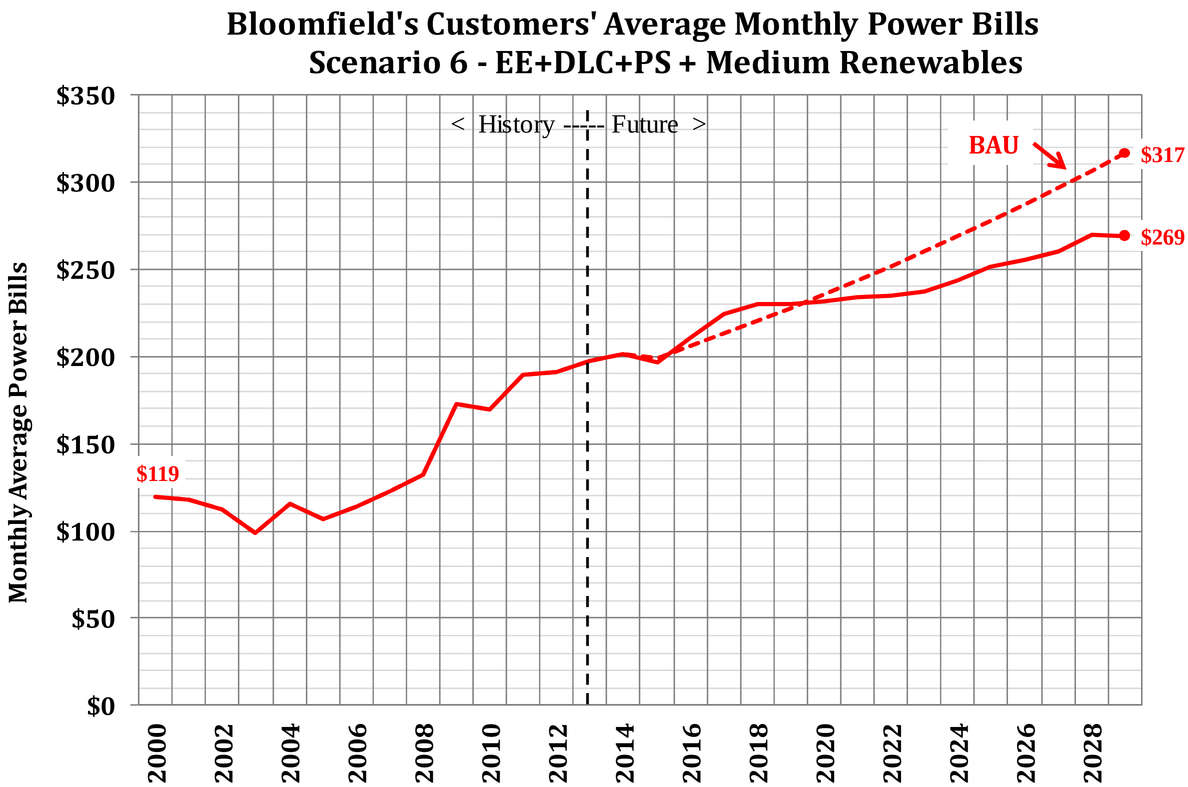
As before, all of these extra costs are being offset by the reduced wholesale power purchases. The net result is that the operating costs are still lower than the BAU scenario, but higher than for the Low Renewables scenario.

FIGURE 30



The customer bill impact of implementing the Medium Renewables scenario is illustrated in Figure 31. At the end of the study period, the average bill would be $269 per month, which is still less than the BAU amount of $317, and about the same as for the Low Renewables scenario. Again, this represents a 15% savings. The residential customers again have a larger savings, which are about the same as for the Low Renewables Scenario. Compared to the BAU scenario, these customer bill savings total about $3.8 million over the 15-year study period, which are less than the $5.3 million for the Low Renewables scenario. This reduction in savings is due to costs that are a little higher in the earlier years of the study.

FIGURE 31



In summary, it appears that adding about 8,900 kW_{DC} of solar generation, 1,700 of wind generation, 130 kW of micro-turbines, along with incorporating energy efficiency programs and DLC equipment can save customers $3.8 million over the study period.

Section 13 – Financial Impacts of the High Renewables Scenario

The High Renewables Scenario has a total of 11,400 kW_{DC} of solar PV generation two 1,700 kW wind turbines installed in 2016, as well as 130 kW of micro-turbines. Again, all of the solar and wind power would be contracted from private owners. Under this scenario, the net purchases of wholesale power are reduced by 100% of what they would be under the BAU scenario. Figure 32 on the following page shows the projected hourly loads during the peak load week, the minimum load week and a typical load week in 2029. Again, the top strip chart shows the same peak week in 2029. The solar PV generation for the summer peak day would have a peak of about 6,900 kW of generation. The wind generation peaks out at 2,700 kW during the peak hour and declines somewhat after that. The diesels would be brought on line in the late afternoon, and run until the early evening to keep the peak load below the 3,000 kW target. The DLC equipment on the central air conditioners would not be needed on the peak day, because there would be adequate wind and solar power.

The second strip chart graph shows the same minimum load day as before in 2029. The two wind turbines collectively would average 1500 kW during the week for a 44% capacity factor. Because the loads would be fairly low all week, there would be quite a bit of excess power during the week. On Thursday of that week, the excess generation peaks out at 8,000 kW delivered to the grid, due to the sunny and windy day.

The last strip chart illustrates the same week in January that has a combination of sunny and cloudy days, and windy and still days. The combination of solar and wind generation does a fairly good job of keeping the peak load down. The diesel engines would be brought on for a total of 6 hours during that week and the micro-turbines would run 100 hours, or any time there was no excess generation going to the grid.

FIGURE 32 – Hourly Loads for the Peak Load Week, Minimum Load Week, and Typical Load Week in the Year 2029

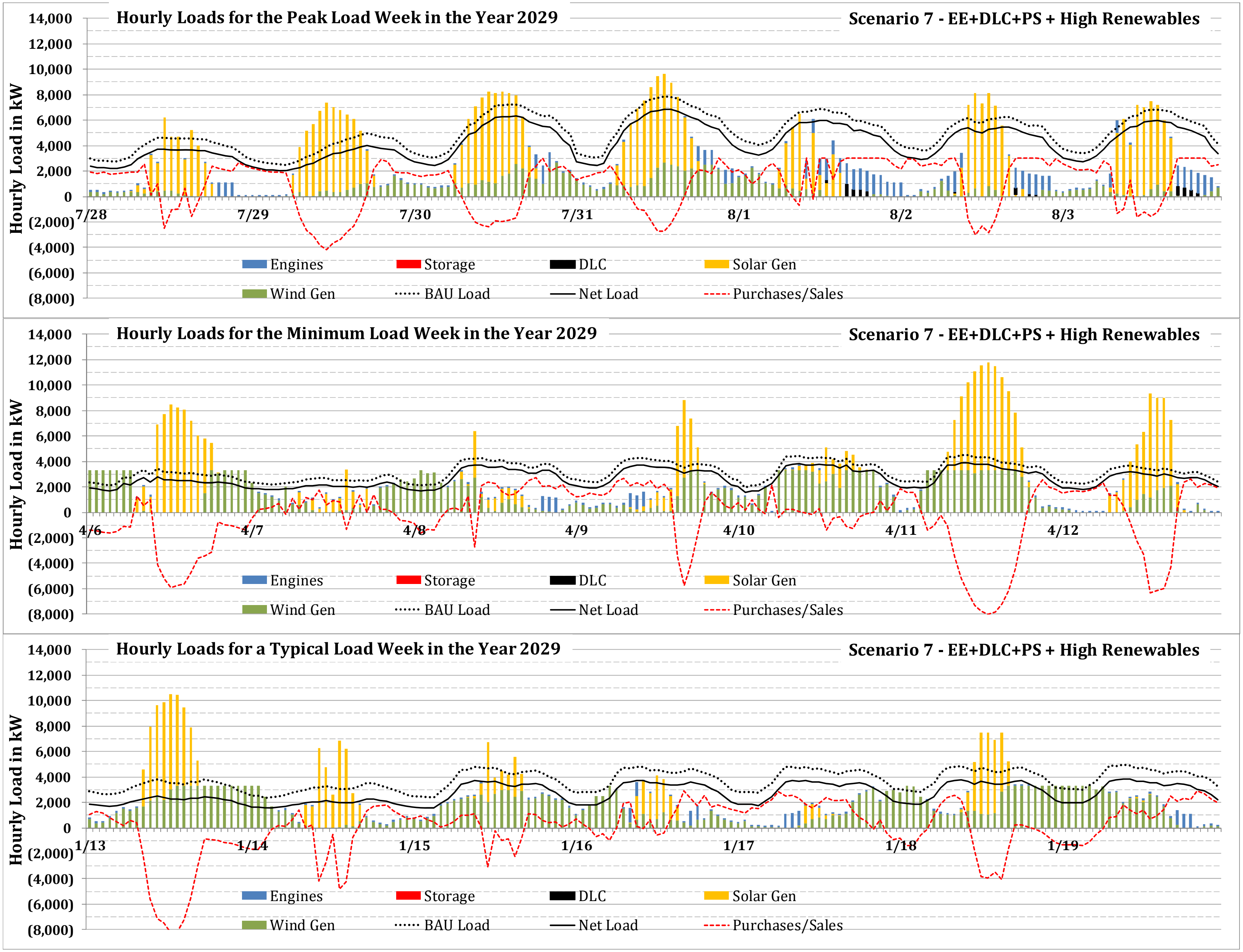
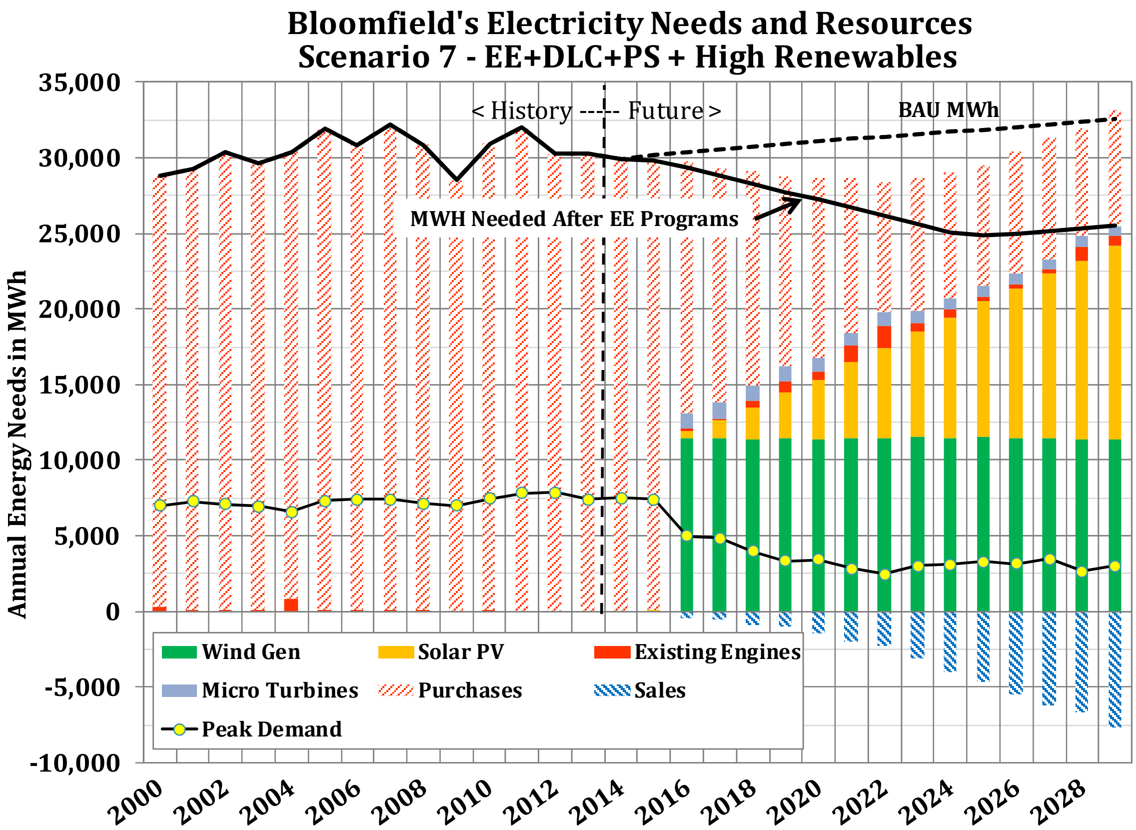


Figure 33 shows the various energy sources meeting the total annual energy needs during the last year of the study period for the High Renewables scenario. During the last year of the study, the two wind turbines provide 45% of the City's net energy needs, the solar PV arrays provide 50%, and the diesels and micro-turbines contribute about 2.5% each.

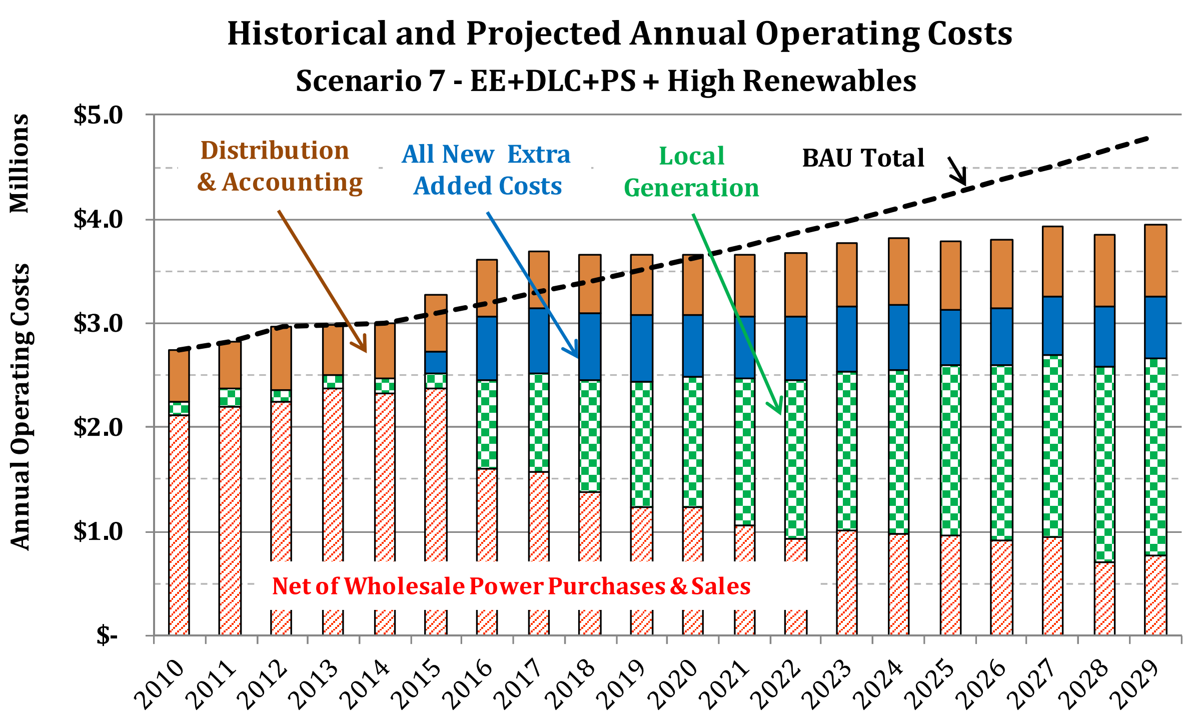
FIGURE 33



In the last year of the study there was excess generation about 42% of the time, which totaled 7,600 MWh, as shown by the downward blue striped bar. The maximum hourly outflow to the grid was projected to be 9,800 kW. The renewable energy generating capacity was 8,000 kW_{AC} for the solar and 3,400 kW for the wind turbines, which totals 11,400 kW.

The graph in Figure 34 displays the utility's operating costs for the High Renewables scenario. Although the operating costs are higher for six years, they again become lower than that for the BAU scenario. Although there is no net purchase of power from the grid since the sales offset the purchases, there is a net cost because the purchases include peak demand charges, transmission costs, and extra charges for renewable energy integration costs. Because of the wide swings in power purchases due to the solar and wind generation, it was assumed that there would be some type of extra charge or penalty from the power supplier to accommodate these swings. Although these types of charges are not used by wholesale suppliers today, it is assumed that they would be charged in the future. The level of these charges would depend upon a number of factors, including who the supplier is, and they simply cannot be predicted very well since there is little precedent for them. Hopefully these future charges would reflect the market cost of accommodating the variability of Renewable Energy. Several studies have been done the last five years on wind integration costs for large utilities and regional power markets. It is not known if the integration costs will go up or down when solar power is also included in these integration studies. The consultants made a very rough estimate of what these integration costs might be for each year of the study, based on the percentage of total power coming from the solar PV and wind turbines. In the year 2029, this estimate totals $100,000 per year for the High Renewables scenario. Integration costs were also included in the other two renewable energy scenarios, although they were considerably less.

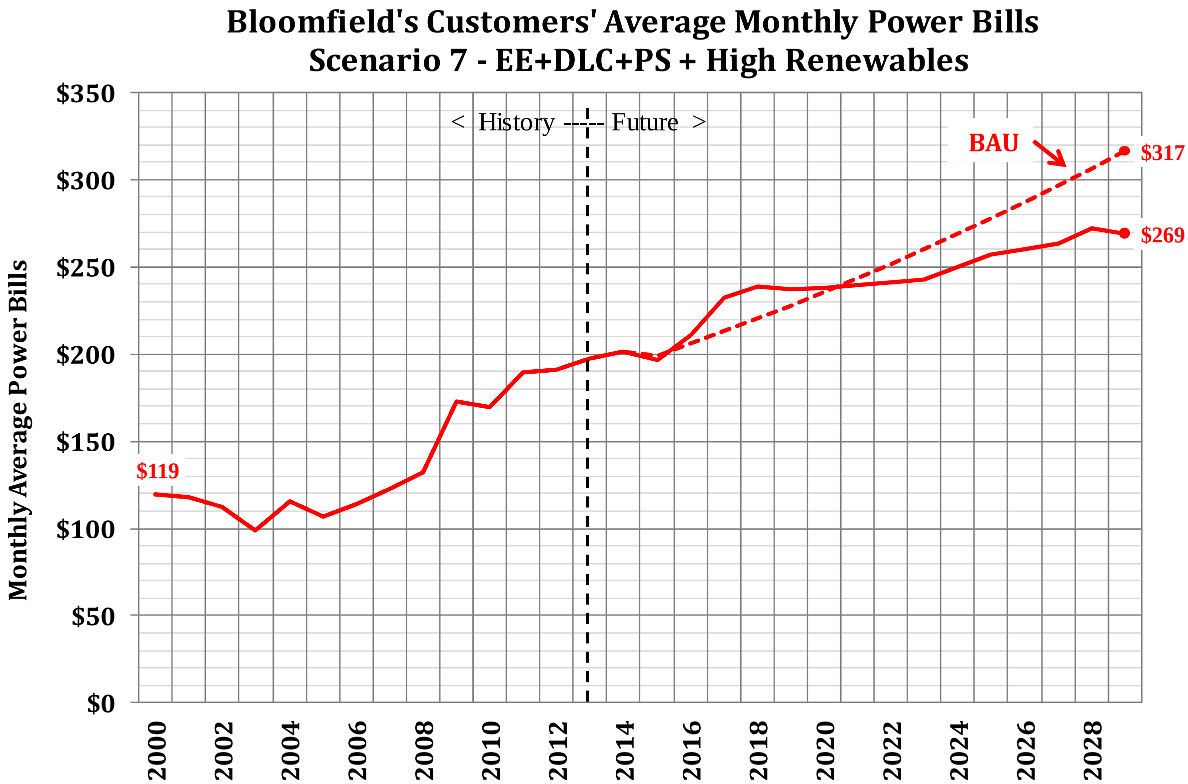
FIGURE 34



The utility staffing levels were assumed to be essentially the same for all three renewable energy scenarios. The cost of operating the solar PV and wind generation projects by the private owners is already covered in the contract PPA price, and might amount to 2 or 3 FTE technicians. As before, all of these extra costs are being offset by the reduced wholesale power purchases. The net result is that the operating costs are still lower than the BAU scenario, but higher than for both the Low and Medium Renewables scenarios.

The customer bill impact of implementing the High Renewables scenario is illustrated in Figure 35. At the end of the study period, the average bill would be $269 per month, which is less than the BAU amount of $317, and about the same as for the Low and Medium Renewables scenario. Again, this represents a 15% savings over BAU. Compared to the BAU scenario, these customer bill savings total about $2.7 million over the 15-year study period. These savings are less than the $5.3 million for the Low Renewables scenario and the $3.8 million for the Medium Renewables scenario. This reduction in savings with the higher levels of renewable energy is due to higher costs than the BAU in the earlier years of the study. The slight downward trend for the last year was due to the year-to-year variability in the utility load patterns and is anticipated to be a one-year event.

FIGURE 35



In summary, incorporating 11,400 kW_{DC} of solar generation, 3,400 kW of wind generation, 130 kW of micro-turbines, along with incorporating energy efficiency programs and DLC equipment can potentially save customers $2.7 million over the study period.

Section 14 – Summary and Comparison of Results

Table 5 provides a summary and comparison of the results of the financial analysis of all seven scenarios. It provides the results from both the utility's perspective (green shading) and the customer's perspective (yellow shading). From the Utility's perspective, its operating costs are lower than the BAU scenario for all of the other alternative six scenarios. This operating cost includes everything, less credits for any excess generation sales back to the grid. The operating margins are essentially the same for all seven scenarios. From the customer's perspective, they save money for all of the other six alternative scenarios over the 15-year period compared to the BAU scenario.

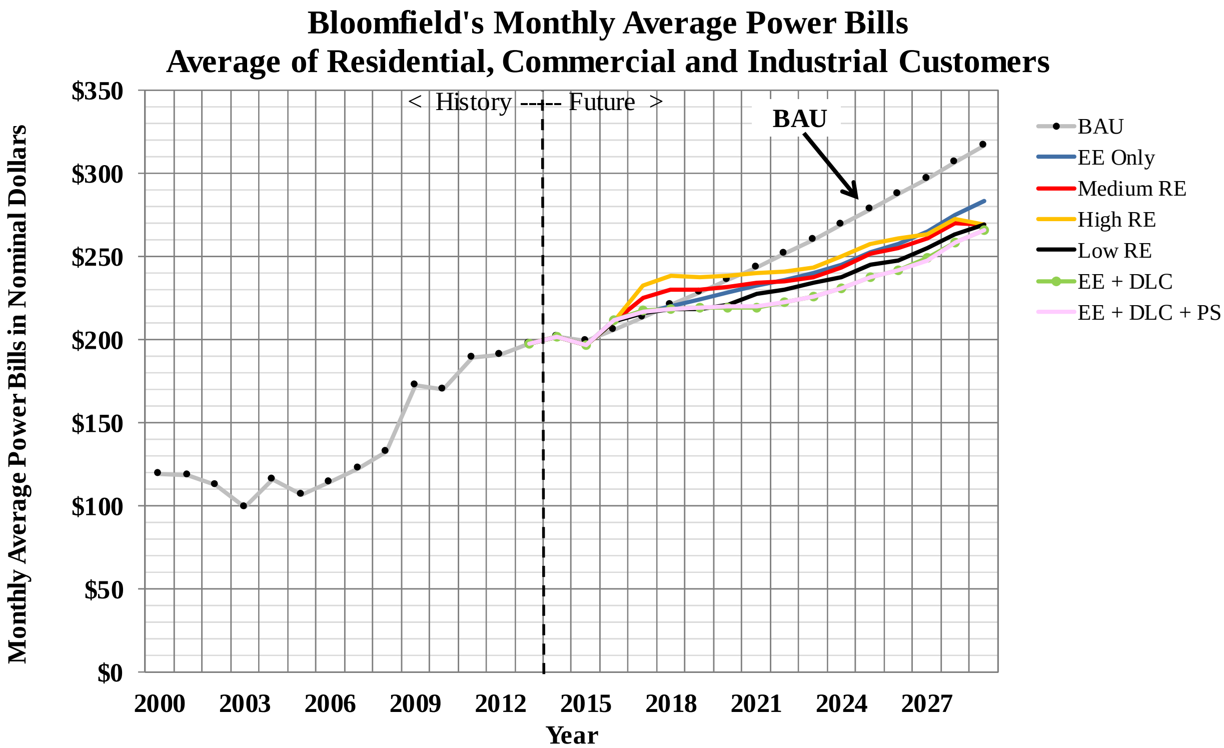
TABLE 5

Summary of Results from Financial Analysis of All Seven Scenarios

		Results from the Utility's Perspective							**Results from the Customer's Perspective**		
		Utility Operating Costs (Includes Revenue Credits for Sale of Excess Solar and Wind Generation)		Average Cost of Resource Over the 15-Year Study Period in ¢ / kWh					Customer Power Bills Over the 15-Year Period		
Scenario Number	Description	15-Year Total	Savings	EE / DLC	Whole-sale Power	Solar PV	Wind Power	Excess Power Sales	Total	Savings Compared to BAU	Average Monthly Bill Savings
		$1,000's	**$1,000's**	**¢ / kWh**	**¢/kWh**	**¢/kWh**	**¢/kWh**	**¢/kWh**	**$1,000's**	**$1,000's**	**$**
	Column Number 2	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1	Business As Usual	$ 58,420	$ -	-	9.8	-	-	-	$ 63,190	$ -	$ -
2	Energy Efficiency Programs	$ 55,060	$ 3,360	3.5 (EE Only)	10.1	-	-	-	$ 59,380	$ 3,810	$ 15
3	EE + Direct Load Controls	$ 52,260	$ 6,160	-0.3 (EE+DLC)	9.3	-	-	-	$ 56,890	$ 6,300	$ 25
4	EE + DLC + Peak Shaving	$ 52,260	$ 6,160	-0.3 (EE+DLC)	8.4	-	-	-	$ 56,900	$ 6,290	$ 25
5	All of the Above + Low Renewables	$ 53,240	$ 5,180	-0.3 (EE+DLC)	8.6	7.5	-	7.7	$ 57,840	$ 5,350	$ 21
6	All of the Above + Medium Renewables	$ 54,780	$ 3,640	-0.3 (EE+DLC)	9.9	7.5	5.8	7.8	$ 59,340	$ 3,850	$ 15
7	All of the Above + High Renewables	$ 55,950	$ 2,470	-0.3 (EE+DLC)	12.0	7.5	5.8	7.4	$ 60,500	$ 2,690	$ 11

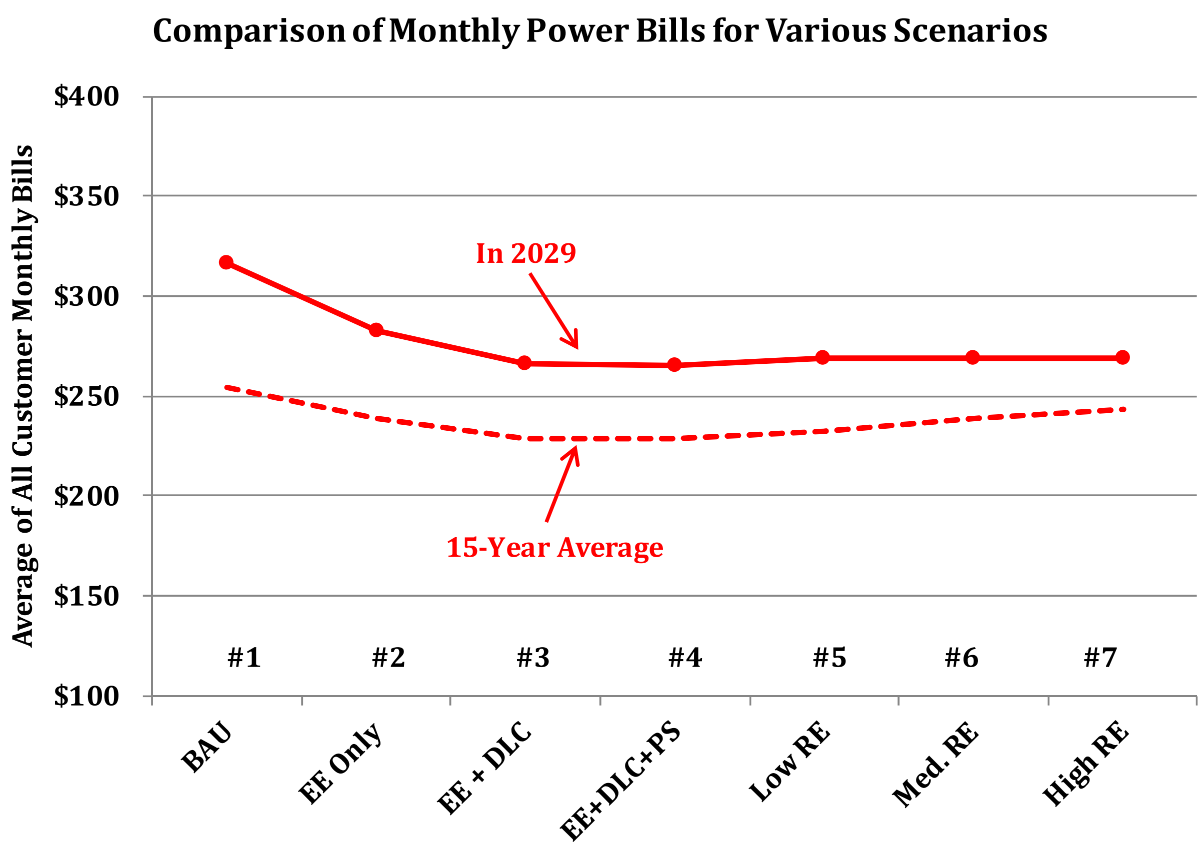
Figure 36 shows how the power bills vary over time for each of the 7 scenarios.

FIGURE 36



A different perspective of comparing future power bills for the 7 scenarios is presented in Figure 37, which compares the average monthly power bills over the 15 years and the bills specifically in 2029. The top red line indicates that power bills in 2029 are the highest for the BAU scenario (on the left side) and noticeably lower for all of the other scenarios. The dashed red line indicates that when the 15-year averages are compared, there is much less difference between the scenarios. However, scenarios #3 and #4 have slightly lower bills.

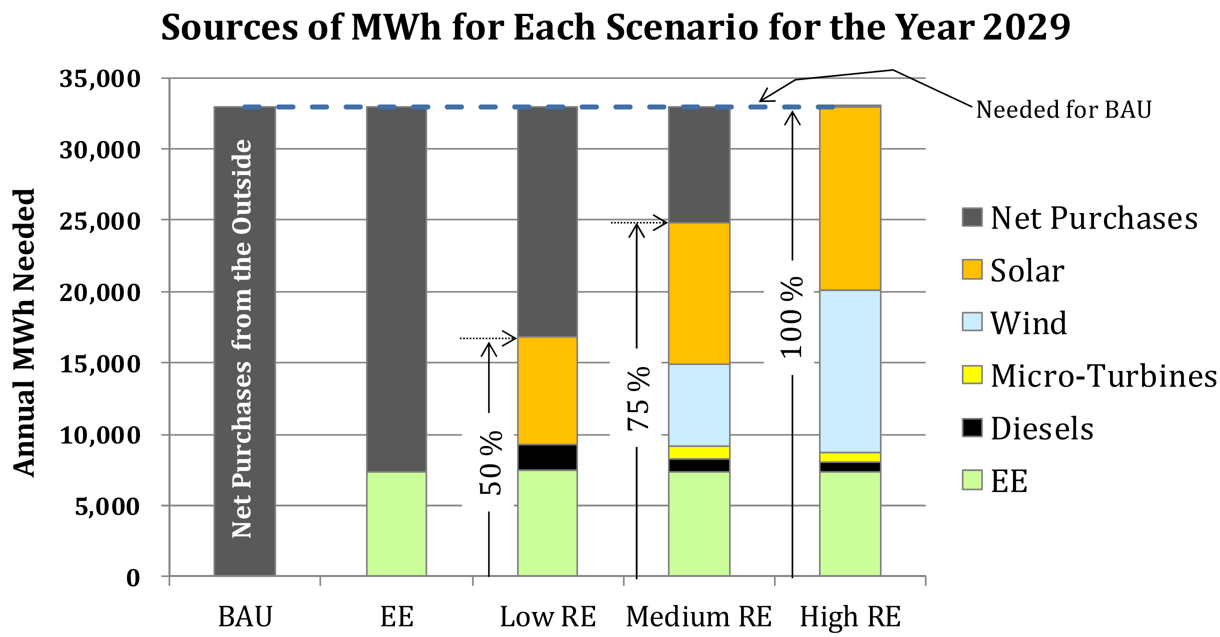
FIGURE 37



The most cost-effective programs are the energy efficiency and DLC programs, closely followed by the Low Renewables scenario.

Figure 38 graphically illustrates how the different technologies are used to achieve the 50%, 75%, and 100% levels of energy independence, where local resources are used to supply Bloomfield's electricity needs. The net purchases of power from outside the community are decreased as energy efficiency programs are implemented and as renewable energy generation is increased.

FIGURE 38



These are the primary benefits from pursuing any of these alternative scenarios compared to the BAU scenario:

1) Electric customers save money.
2) Electric power bills will escalate less in the longer-term future, because the cost of renewable energy is more stable than that from fossil fuels.
3) More money stays and circulates in the community because of the home and business improvements fostered by the energy efficiency programs.
4) Several stable and good paying jobs are created.
5) Air pollution and greenhouse gas emissions are reduced, since less energy is used and most of it is from renewable energy generation.

The other community-wide economic impact benefits of these alternative scenarios would require some additional analysis. However, the table below summarizes some of the key factors that affect the overall economic impact on the community. The yellow shaded area shows how the alternative scenarios compare to the BAU scenario. For example, the right- hand column on the top line in yellow shading shows that $25,475,000 less will be spent on wholesale power costs for the High Renewables scenario compared to BAU. This $25 million savings would be used to pay for local renewable energy, energy efficiency investments, additional local employees, and to reduce customers' power bills.

TABLE 6

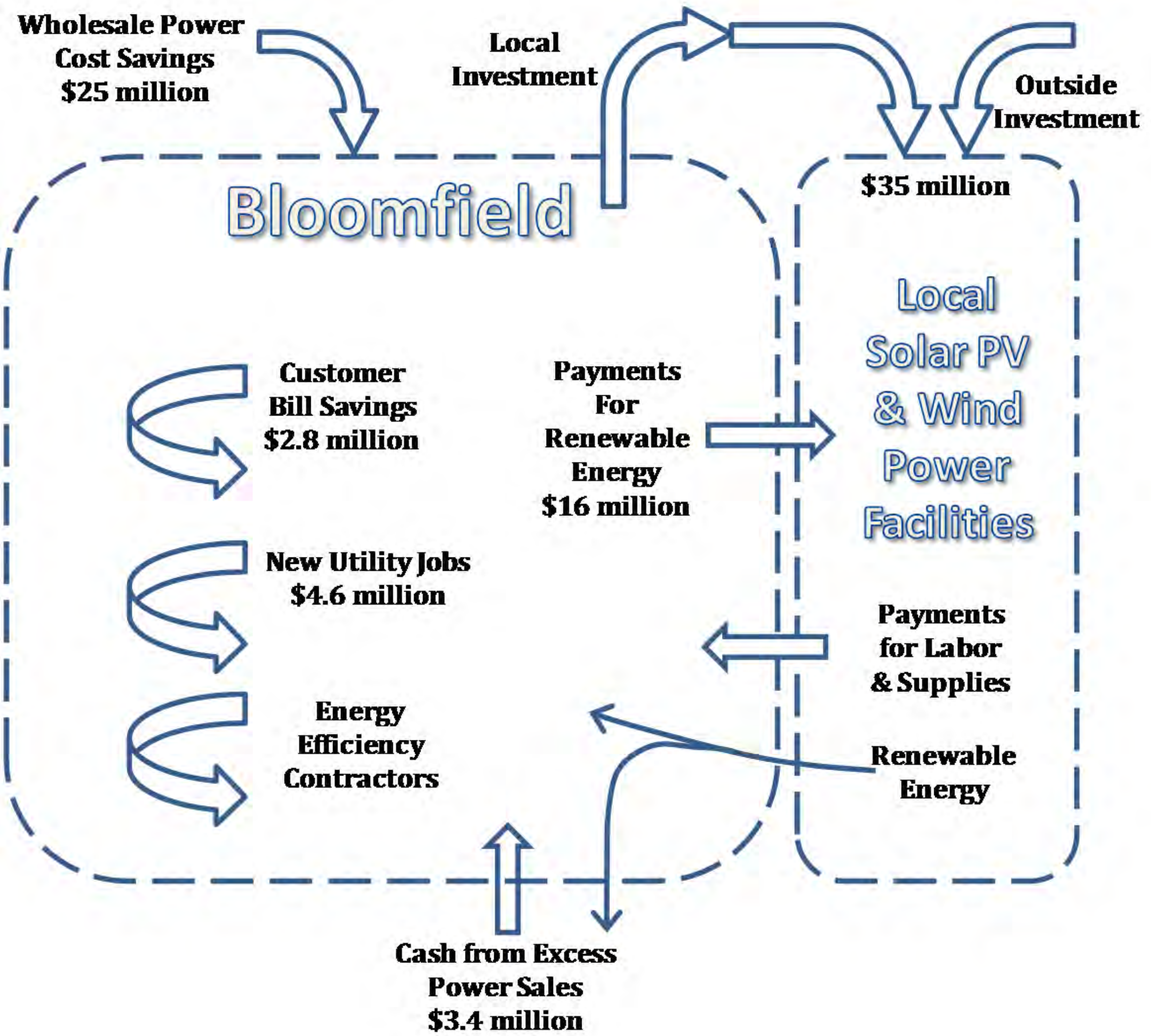
Measures of Economic Activity - Cumulative Sums Over 15 Years in $1,000's							
	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**	**Scenario 5**	**Scenario 6**	**Scenario 7**
	BAU	**EE Only**	**EE + DLC**	**EE+DLC+PS**	**Low RE**	**Med. RE**	**High RE**
Cost of Wholesale Power Purchases	$ 46,565	$ 40,613	$ 37,369	$ 33,058	$ 28,570	$ 23,448	$ 21,089
Sales for Resale (Revenue)	$ -	$ -	$ -	$ -	$ 152	$ 950	$ 3,408
Additional Employee Wages & Benefits	$ -	$ 982	$ 982	$ 3,578	$ 4,364	$ 4,637	$ 4,637
Energy Efficiency Investments by Customers	$ -	$ 301	$ 301	$ 301	$ 301	$ 301	$ 301
Local Renewable Energy Purchased	$ -	$ -	$ -	$ -	$ 4,059	$ 9,946	$ 16,035
Customer's Power Bills	$ 63,191	$ 59,376	$ 56,893	$ 56,904	$ 57,844	$ 59,345	$ 60,501
Changes in Values Compared to BAU, in $1,000's							
Cost of Wholesale Power Purchases	Reference	$ (5,951)	$ (9,196)	$ (13,507)	$ (17,995)	$ (23,117)	**$ (25,475)**
Sales for Resale (Revenue)	Reference	$ -	$ -	$ -	$ 152	$ 950	$ 3,408
Additional Employee Wages & Benefits	Reference	$ 982	$ 982	$ 3,578	$ 4,364	$ 4,637	$ 4,637
Energy Efficiency Investments by Customers	Reference	$ 301	$ 301	$ 301	$ 301	$ 301	$ 301
Local Renewable Energy Purchased	Reference	$ -	$ -	$ -	$ 4,059	$ 9,946	$ 16,035
Customer's Power Bills	Reference	$ (3,816)	$ (6,298)	$ (6,288)	$ (5,348)	$ (3,847)	$ (2,690)

This $25 million savings and its reinvestment in the local community also have multiplier effects that increase other business activity. For example, the private sector capital investment in the local renewable energy generation equipment is projected to be $35 million to the High Renewables scenario. The construction of these facilities alone will involve perhaps 20 man-years of local construction work. This economic benefit is not shown in the above table.

Some of the investment for the renewable energy facilities could come from local area investors if the City specified that desire in the planning and procurement process.

Figure 39 provides a pictorial diagram illustrating the cumulative additional flows of cash over the 15-year period for the High Renewables scenario discussed above.

FIGURE 39



Evaluating the overall economic impact of these changes in cash flows is beyond the scope of this study, but would not be difficult to do.

Section 15 – Uncertainties and Limitations

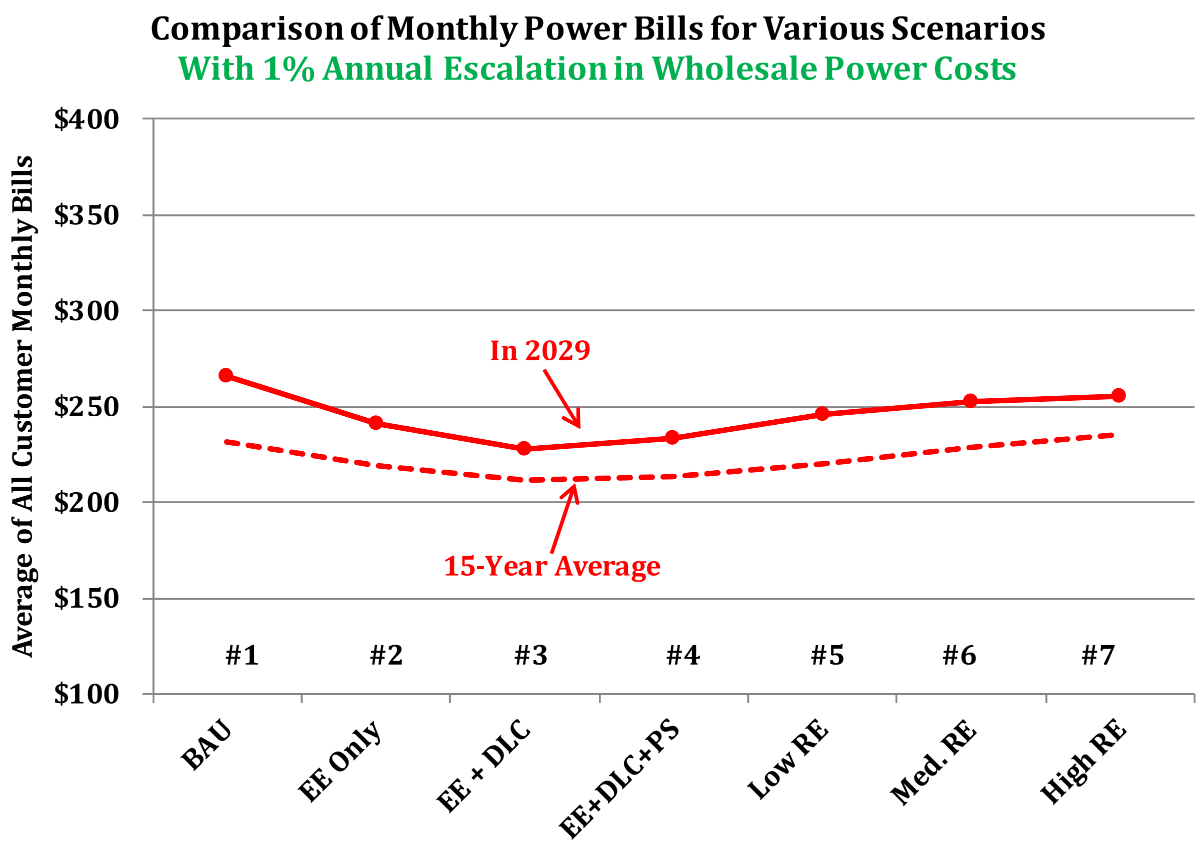
Any engineering and financial analysis that projects out into the future depends upon many assumptions about the future. The most important economic factor for this study is the future cost of wholesale power purchases. The average cost for the City was 7.8¢ per kWh in 2013, which included transmission delivery charges. A hot summer with a high peak demand increases the average cost for the following 11 months, because of the ratchet on the higher demand charge. Under a new power supply contract, two factors may change. The first factor is whether the rates are higher or lower than before. Higher wholesale power costs will improve the economics of all of the alternative scenarios. The second factor is the relative ratio of the demand charges and energy charges, and how the monthly demand charge is calculated. In general the following impacts can be expected:

1) Higher demand charges improve the economics of:
    a. Direct load control equipment
    b. Peak shaving with local engine or micro-turbine generation
    c. Solar PV generation to a lesser extent
    d. Battery storage
2) Higher energy charges in general improve the economics of:
    a. Wind generation
3) Time-of-day energy charges improve the economics of:
    a. Solar PV generation
    b. Battery storage

Since the economics of the energy efficiency programs are strong, it is doubtful that the new power supply contract will have much impact on their cost-effectiveness, regardless of its structure.

To illustrate the impact of wholesale power costs on the alternative scenarios, two sensitivity cases were evaluated. The first used an annual escalation of only 1%, instead of 3%, again starting in 2015. The second case used a higher 5% annual escalation. In both cases, the annual escalation for the cost of transmission delivery was maintained at 3%. Figure 40 displays how the customers' power bills compare for the various alternative scenarios, if the wholesale power costs only escalate at 1% per year.

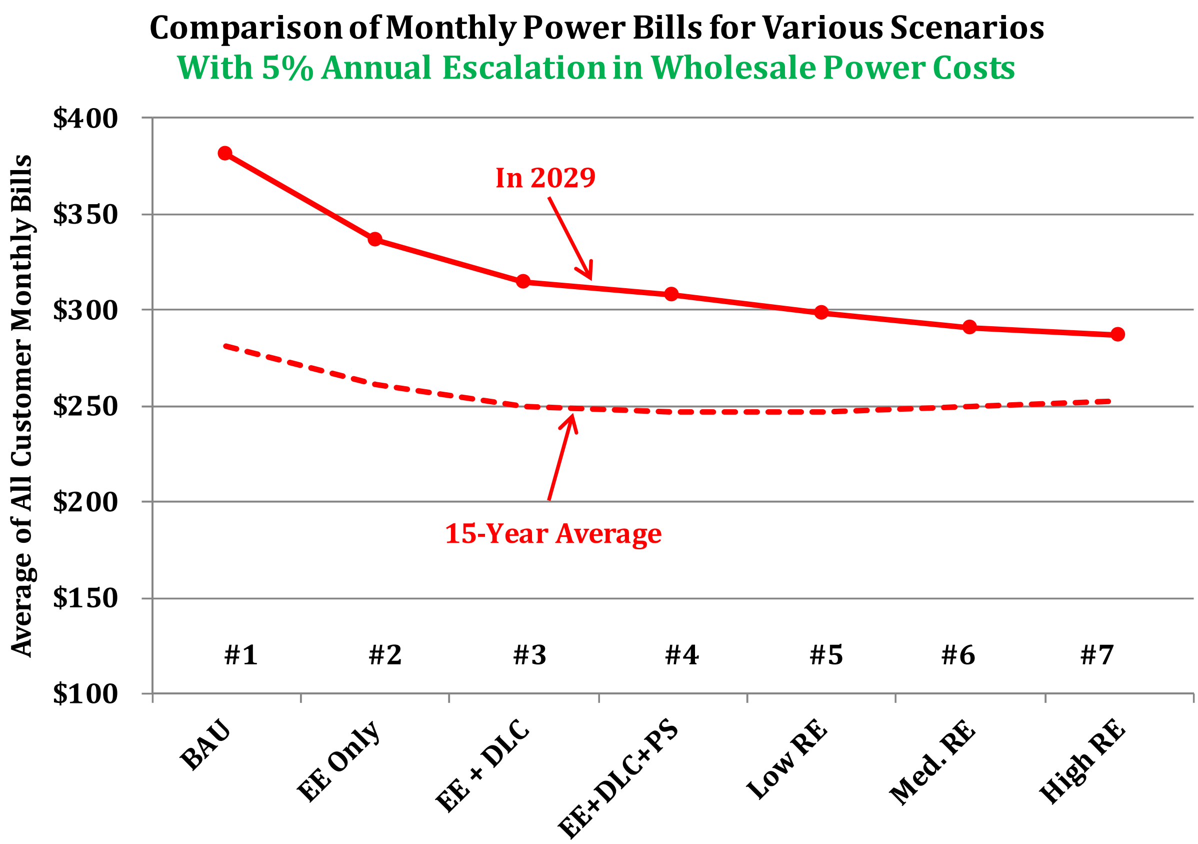
FIGURE 40



This lower wholesale power cost escalation rate almost eliminates the savings from adding renewable energy. However, the Low Renewables scenario is still better than the BAU scenario.

The second sensitivity case uses a 5% annual escalation rate in the wholesale power supply costs. Figure 41 shows markedly different results than for the lower escalation rate. In all cases the alternative scenarios will save customers money, especially in the longer term.

FIGURE 41



In summary, if wholesale power costs escalate very little, then customers' bills will still be lower with the energy efficiency and DLC programs along with the Low Renewables scenario, but not with higher amounts of renewable energy. It should be noted that the Low Renewables scenario has a considerable amount of solar PV capacity; 6,800 kW_{DC} which provides 30% of Bloomfield's annual electricity needs in 2029. This is still likely to be much more on a relative scale than any other utility has today.

Another uncertainty is whether the federal and state governments will continue to provide some level of subsidy to renewable energy. The federal government provides a 30% investment tax credit for solar through the end of 2016. The 10-year 2.3¢ per kWh federal production tax credit has lapsed for new wind projects, and must be renewed again for wind power to be economically feasible for Bloomfield. There is a reasonable chance that Congress will renew this tax credit for one more 2-3 year period of time. Renewal after that is questionable. The state's 10-year 1.5¢ per kWh state tax credit is available for a couple more years, too. This tax credit is also economically necessary for the City to use locally generated wind power. Because there is always some uncertainty about the future availability of these subsidies, it may be beneficial to commit to renewable energy projects while the tax credits are known to be available, rather than risking paying a higher price later on when there are less or no tax credits.

Because of the limited time and resources allowed for this study, an evaluation of Bloomfield's 4.16 kV distribution system was not made. With the capacity of the solar and wind generation in the Low Renewables and Medium Renewables scenarios, some higher capacity distribution lines will be needed to interconnect the solar and wind power into the system. For example, it was assumed that a 12.47 kV or higher voltage dedicated collection circuit going to the substation would be needed for one or more wind turbines, and probably for some of the larger solar PV arrays. Some allowances for these costs were included in this study, but it is not known if the allowances are enough.

There is some uncertainty with the coincidence of the solar PV output with the utility's load. The solar PV output data used in this study was based on the Typical Meteorological Year (TMY) data compiled by government-supported researchers. They analyzed the solar incidence data on a monthly basis to determine a typical representative month. This TMY monthly data used in this analysis is not synchronized with the utility loads. Therefore it is not known if the solar PV output is too high or too low on those hot and humid summer days when air conditioners cause high utility loads. Although personal observations suggest the sun is shining on those days, some additional analysis is needed to refine the modeling technique.

It should be noted that the hourly wind production data from Algona is synchronized with the hourly load data from Algona. Since all of this data was used as a starting basis for this study for the City, the wind power output on an hourly load basis should be realistically modeled.

Another assumption surrounded by uncertainty concerns the rough estimates made for the renewable energy integration costs. As mentioned previously, the High Renewables scenario assumed extra wholesale power supply contract charges of $100,000 per year in 2029. This was to account for the wide swings in purchases due to the large variability in renewable energy generation. This is what is **not known** at this time:

1) Will the power supply contract that is in effect 5 to 15 years from now require the City to project its net hourly purchases?
    a. If so, how much will a service contract cost to provide hourly renewable energy generation for the next 48 hours?
    b. Will many other utilities also be doing this so that the costs are nominal?
2) Will the power supply contract contain extra charges because of the local renewable energy generation?
3) Will Bloomfield's load be pooled with many other small utilities so that the City's purchase variability is averaged out with other utility loads and renewable energy generation, so that it causes little problems or little extra costs for the City?
4) Will the wholesale market make special provisions for accommodating renewable energy generation variability without significant added costs?
5) Will all renewable energy generation be modeled on a regional grid basis, so as to smooth out its variability and impact on the regional market, which may lead to a socialization of these costs across all users?

This is what **is known**: Variability in net load increases the generation dispatch cost of a regional grid. The amount of cost increase is uncertain, it changes over time, it varies with renewable energy penetration, it is a moving target, it depends on many factors, and it is very hard to quantify. It is not zero. But the cost may ultimately be socialized anyway. With so much uncertainty involved, the consultants simply used cost estimates they believed to be conservative, in order to not overestimate the benefits of renewable energy.

This study showed much more power bill savings in the future for the residential customers than for the commercial and industrial customers. This is caused primarily by the higher percentage of energy efficiency savings that the residential customers were able to achieve. A secondary factor is that there was more kWh consumption growth projected for the commercial and industrial customers than for the residential customers. Both of these factors suggest that if the commercial and industrial customers could save more energy through energy efficiency programs, then they could also achieve lower future power bills. It is recommended that the energy efficiency potential study be refined to see if there are more potential savings to be achieved for the larger customers.

Section 16 – Observations

The results of this study clearly indicate that starting an aggressive energy efficiency program and installing DLC equipment will save utility customers money.

Furthermore, there is little doubt that incorporating some level of solar PV is also likely to save customers money in the long run.

The solar and wind power cost estimates used in this study for the next three years or so are likely to be conservative, but longer-term price trends are uncertain. Therefore, evaluating the benefits of adding some renewable energy in the next few years will not be too difficult, once the new power supply contract terms are known. Making the decision to add renewable energy should be relatively easy, because there will less uncertainty about the future benefits.

The utility should also consider incorporating wind power in the next couple of years because of possible expiration of future government subsidies. If they expire, the near-term economic feasibility will disappear.

Fortunately the utility does not need to make a decision on which of the three renewable energy scenarios to implement. The results show that the Low Renewables scenario of adding 6,800 kW_{DC} of solar PV is likely a cost-saving plan. To start the plan, the utility simply makes the decision to add one large array at a time. After that the utility can decide whether to proceed or to stop.

Any new power supply contract needs to incorporate more flexibility and incentive for the City to manage its peak demand. Furthermore, there should be no extra penalties or hurdles for incorporating renewable energy.

Battery energy storage was not deemed to be economic in this study, because of the particular terms of the existing power supply contract, and how the cost of future wholesale power purchases was modeled. If the City's future power supply contracts better reflect market prices, then energy storage may become economical before the end of the 15-year study period, since battery prices are projected to decline.

If the City is concerned about local economic growth, then it should evaluate the economic benefits that adopting one of the aggressive renewable energy scenarios would bring. It should then take these benefits into consideration when making any decisions about whether to pursue any of these alternative scenario strategies.

Although nearly all utilities in Iowa have some renewable energy in their power supply, no Iowa or Midwest utility has yet attempted to get a majority of its needs from solar and wind power. As a result, this effort will require some further analysis and planning. Since the City would be forging a new path, there will likely be some unanticipated issues that will have to be addressed as they arise over time. There is no doubt that any of these alternative scenarios can be accomplished. All of the challenges that will be encountered along the way are just not known yet.

Section 17 – Other Considerations

Under all of the alternative scenarios customers would pay lower bills but rates per kWh would be higher primarily because fewer kWhs would be sold. What this really means is that customers who take advantage of energy efficiency programs would pay less. Renters and those who lack the means to capture efficiencies in their use of energy may end up paying a little more. There are several things the City can do to mitigate that risk.

a) Successful energy efficiency programs require professional staff committed to that success. This study assumes funding for a full-time energy efficiency professional and additional contract personnel. Efficiency goals for rental properties and low-income housing should be made a priority for these personnel.
b) The City should consider adopting minimum standards of energy efficiency for rental housing. IAMU has a model ordinance that requires broken windows to be replaced and cracked ones replaced or taped. It requires basic weatherization measures, repair of cracks, gaps, or other holes in the building envelope that allow significant air infiltration. It also requires minimum standards of efficiency based on the age of the refrigerator.
c) Grant funding could be sought to hire a summer intern who would merge basic information about the size and type of buildings from the county recorder's web site with energy usage from utility records to create an index of building efficiency. Such indices rank buildings on the basis of energy use in British Thermal Units (Btu) per square foot. The index helps the energy efficiency professional to find and direct program dollars to the least efficient buildings and systems to capture the greatest efficiencies for the lowest investment.
d) The city could provide opportunities for renters and for homeowners who do not have good solar access to invest in community solar projects. As described elsewhere in this report, community projects offer economies of scale and allow customers to match their investment in renewables to their own budgets.

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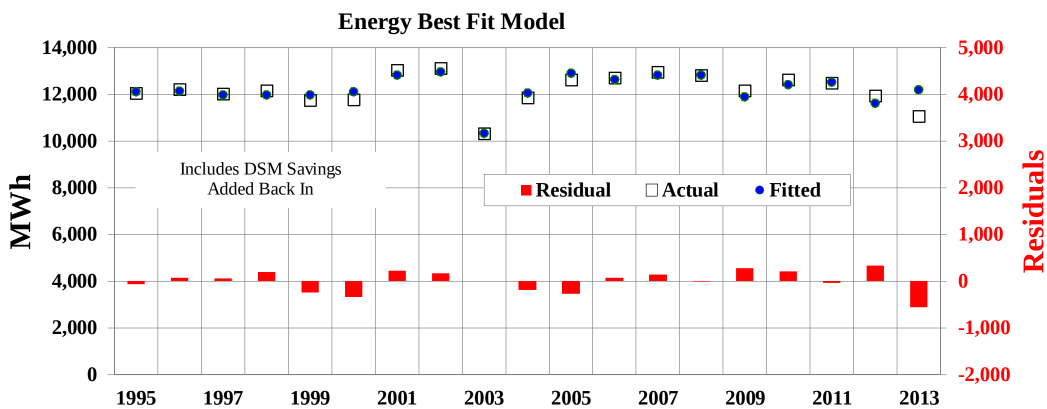
Joel Logan, Iowa Association of Municipal Utilities
Bob Haug, Iowa Association of Municipal Utilities

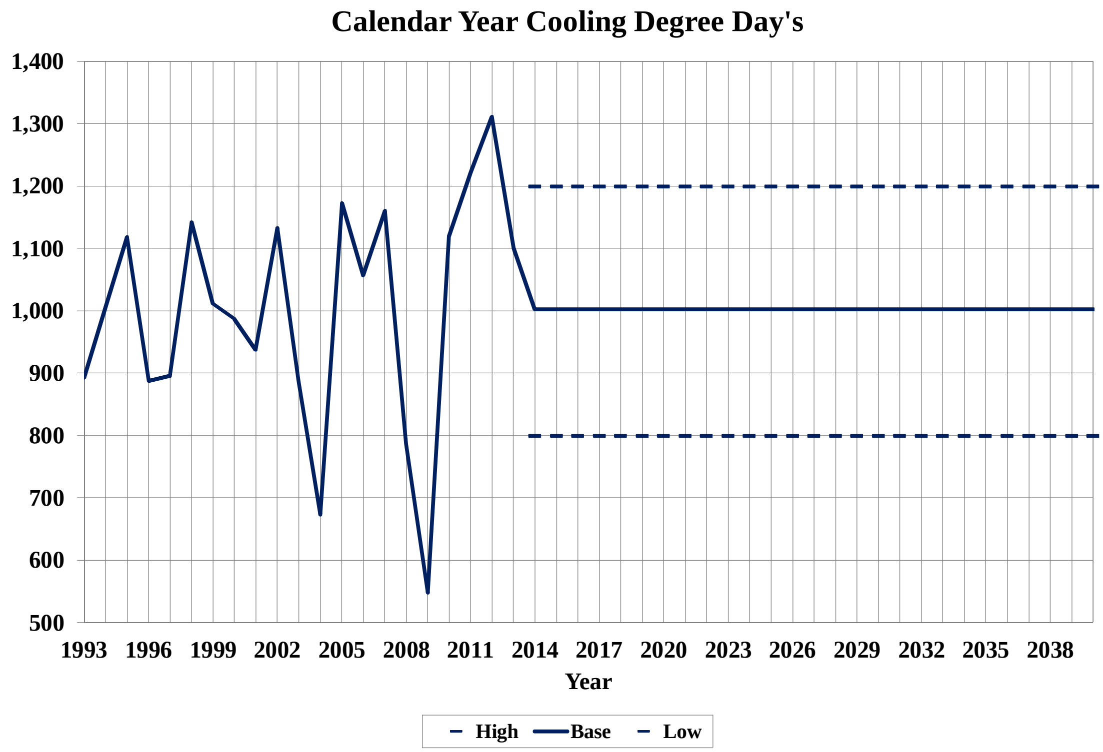
August 16, 2014

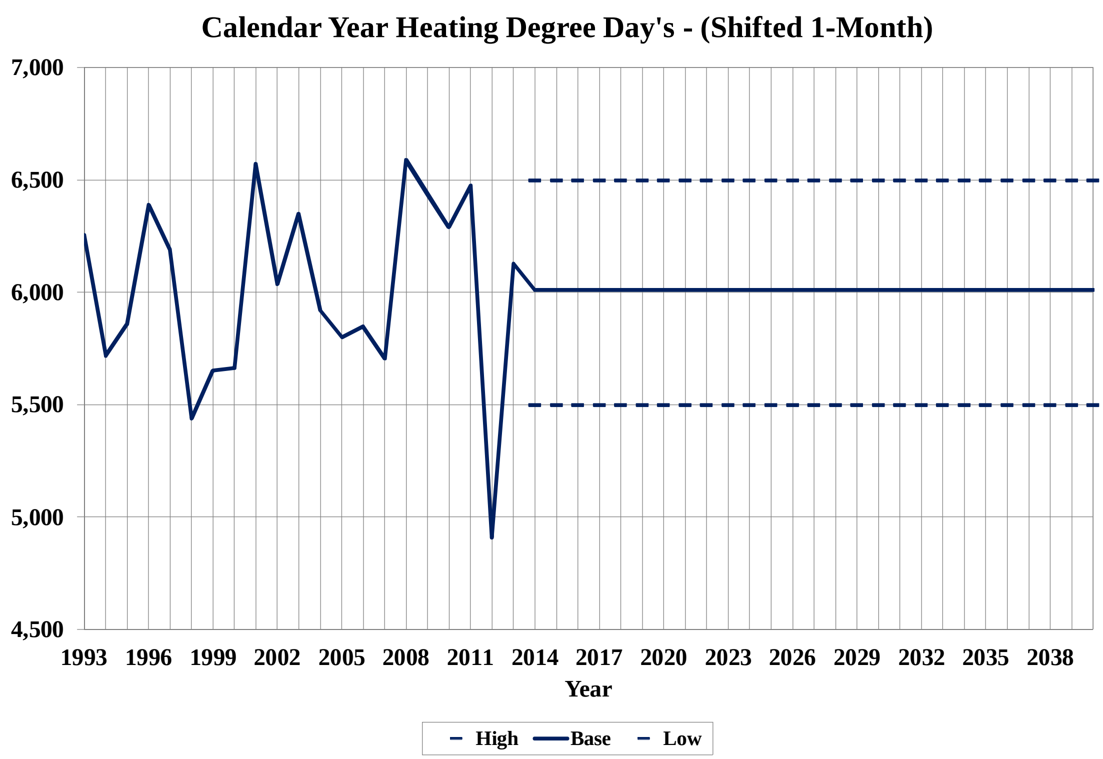
Residential Econometric Forecast Model Formula & Independent Variables

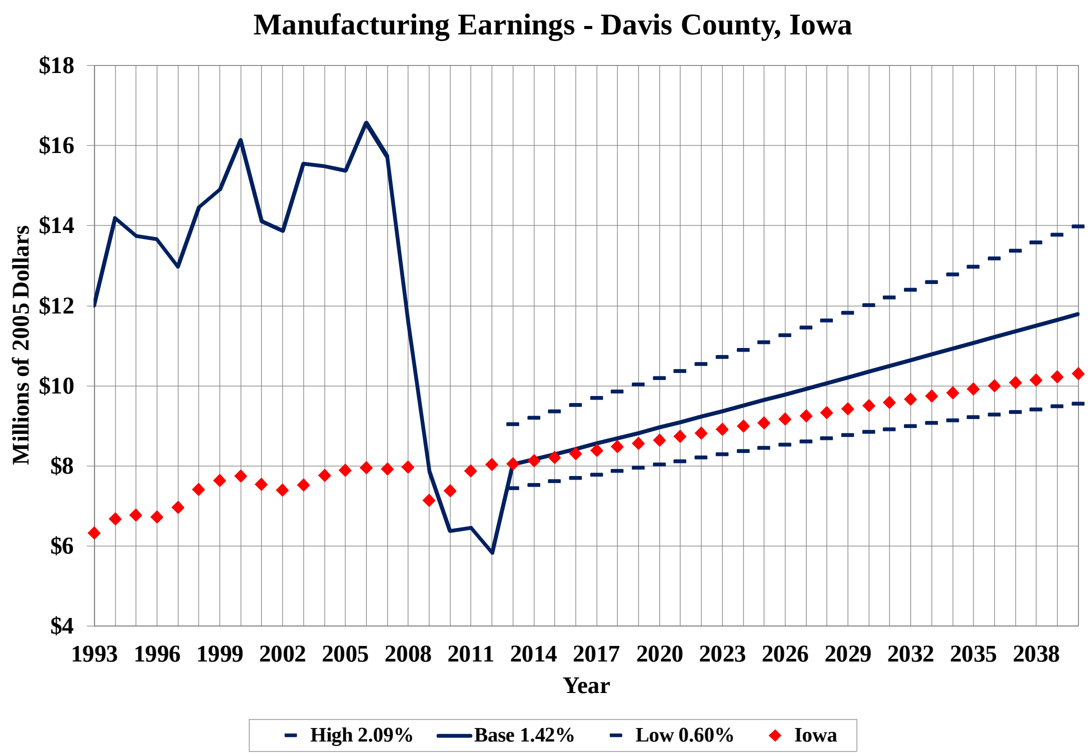
		Output Summary				
					Coefficient	t Stat
		Adjusted R Square	0.825	Cooling Degree Days	1.816	4.227
		Standard Error	273.297	Heating Degree Days	0.734	4.107
1995	Start	F-Statistic	17.943	Dummy Variable	-2,352.859	-8.007
2013	Stop	Durbin-Watson	1.899	Manufacturing Earnings - Davis County, Iowa	72.980	3.650
		Constant	-9,257.067	Households - Davis County, Iowa	4,468.631	3.313

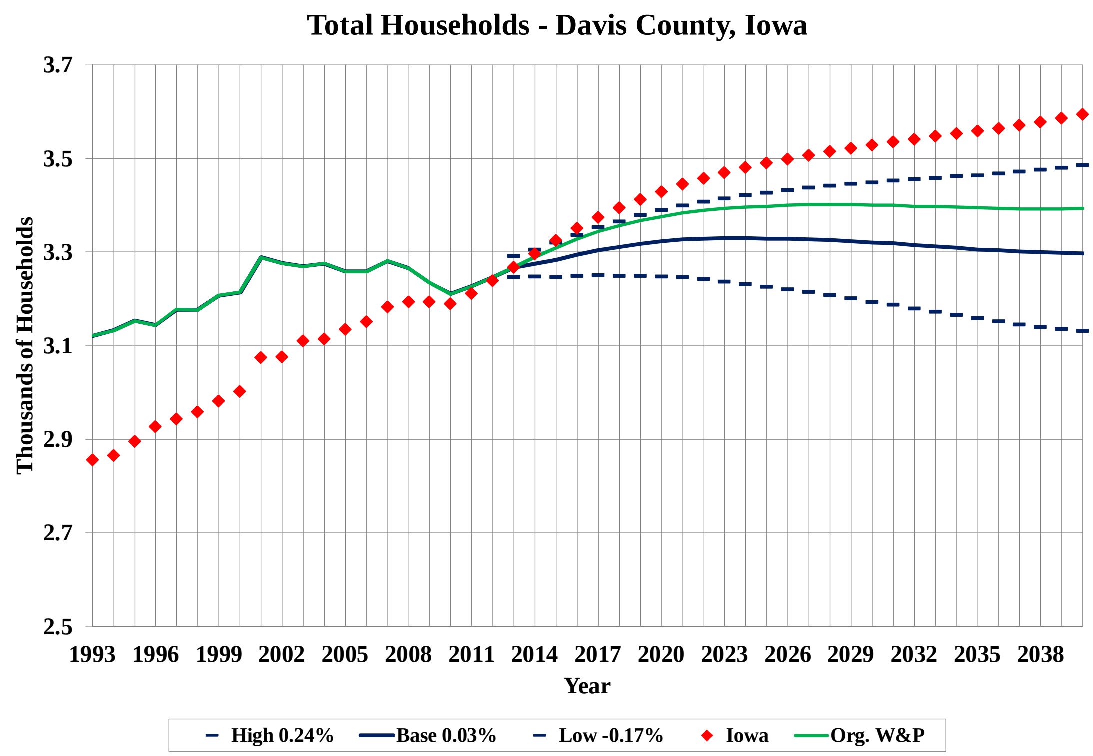
Date	Dependent Variable	Variable 1	Variable 2	Variable 3	Variable 4	Variable 5
1995	12,042	1119	5,856	0	14.19	3.13
1996	12,203	887	6,390	0	13.74	3.15
1997	12,009	896	6,190	0	13.66	3.14
1998	12,145	1142	5,439	0	12.97	3.18
1999	11,737	1011	5,650	0	14.47	3.18
2000	11,767	987	5,663	0	14.92	3.21
2001	13,025	937	6,570	0	16.13	3.21
2002	13,123	1132	6,037	0	14.11	3.29
2003	10,315	888	6,350	1	13.88	3.28
2004	11,867	673	5,918	0	15.55	3.27
2005	12,618	1173	5,799	0	15.48	3.28
2006	12,702	1057	5,849	0	15.38	3.26
2007	12,951	1160	5,705	0	16.57	3.26
2008	12,803	787	6,589	0	15.72	3.28
2009	12,166	548	6,435	0	11.57	3.27
2010	12,620	1119	6,290	0	7.87	3.23
2011	12,484	1222	6,474	0	6.38	3.21
2012	11,951	1311	4,909	0	6.46	3.23
2013	11,076	1101	6,128	0	5.84	3.25




Calendar Year Cooling Degree Day's
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
1993
1996
1999
2002
2005
2008
2011
2014
2017
2020
2023
2026
2029
2032
2035
2038
Year
High
Base
Low


Calendar Year Heating Degree Day's - (Shifted 1-Month)
7,000
6,500
6,000
5,500
5,000
4,500
1993
1996
1999
2002
2005
2008
2011
2014
2017
2020
2023
2026
2029
2032
2035
2038
Year
High
Base
Low


Manufacturing Earnings - Davis County, Iowa
$18
$16
$14
$12
$10
$8
$6
$4
Millions of 2005 Dollars
1993 1996 1999 2002 2005 2008 2011 2014 2017 2020 2023 2026 2029 2032 2035 2038
Year
High 2.09%
Base 1.42%
Low 0.60%
Iowa


Total Households - Davis County, Iowa
3.7
3.5
3.3
3.1
2.9
2.7
2.5
Thousands of Households
1993 1996 1999 2002 2005 2008 2011 2014 2017 2020 2023 2026 2029 2032 2035 2038
Year
High 0.24%
Base 0.03%
Low -0.17%
Iowa
Org. W&P

Commercial Econometric Forecast Model Formula & Independent Variables

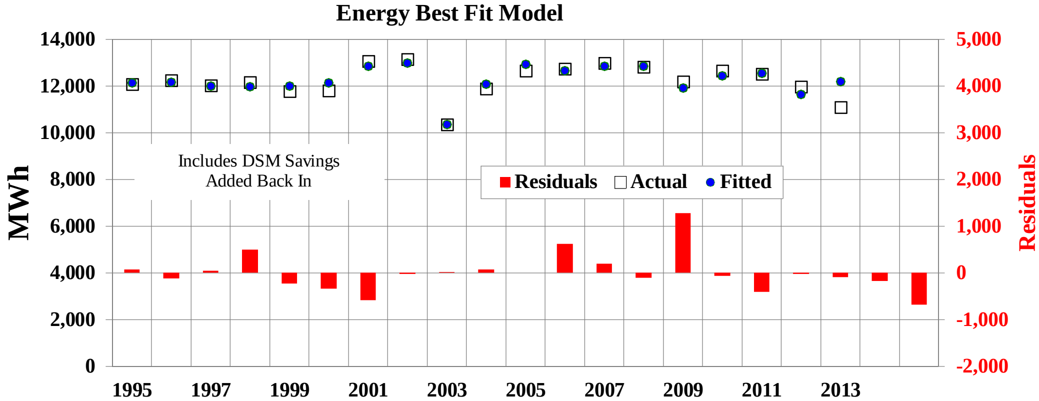
Output Summary

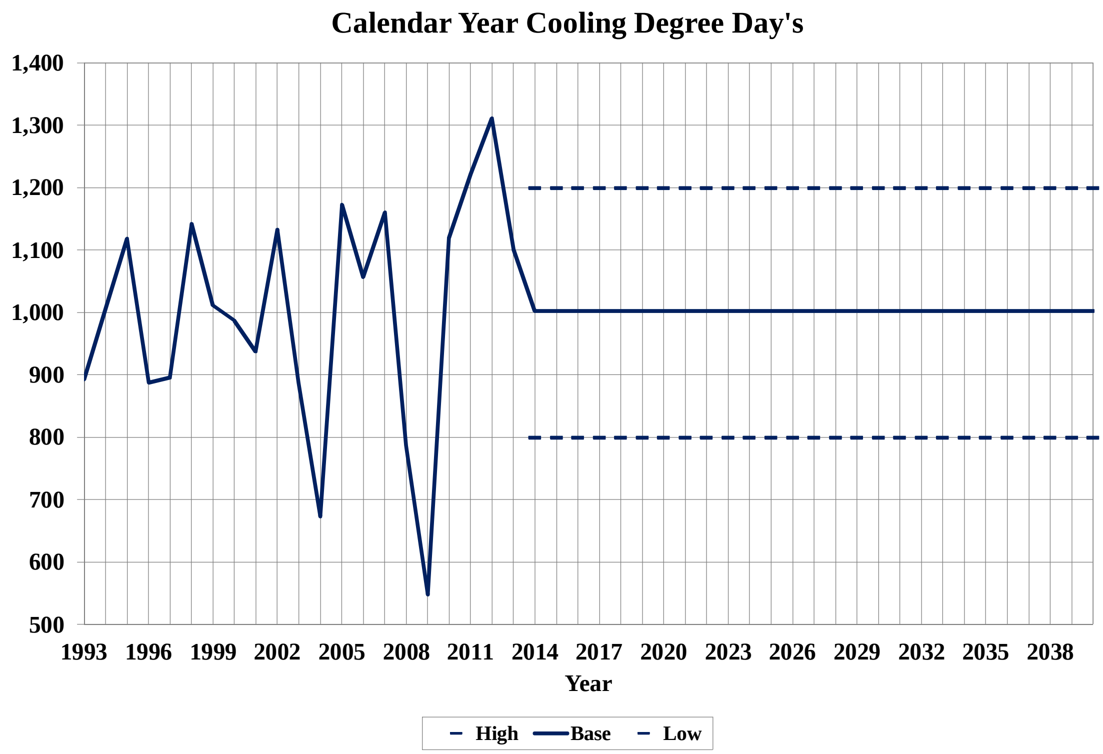
Adjusted R Square	0.891		**Coefficient**	**t Stat**
Standard Error	469.563	Cooling Degree Days	1.660	2.428
F-Statistic	41.663	Heating Degree Days	0.545	1.830
Durbin-Watson	1.730	U.S. Gross Domestic Product	88.664	11.300
Constant	1,800.371	Dummy Variable	-1,970.826	-4.018

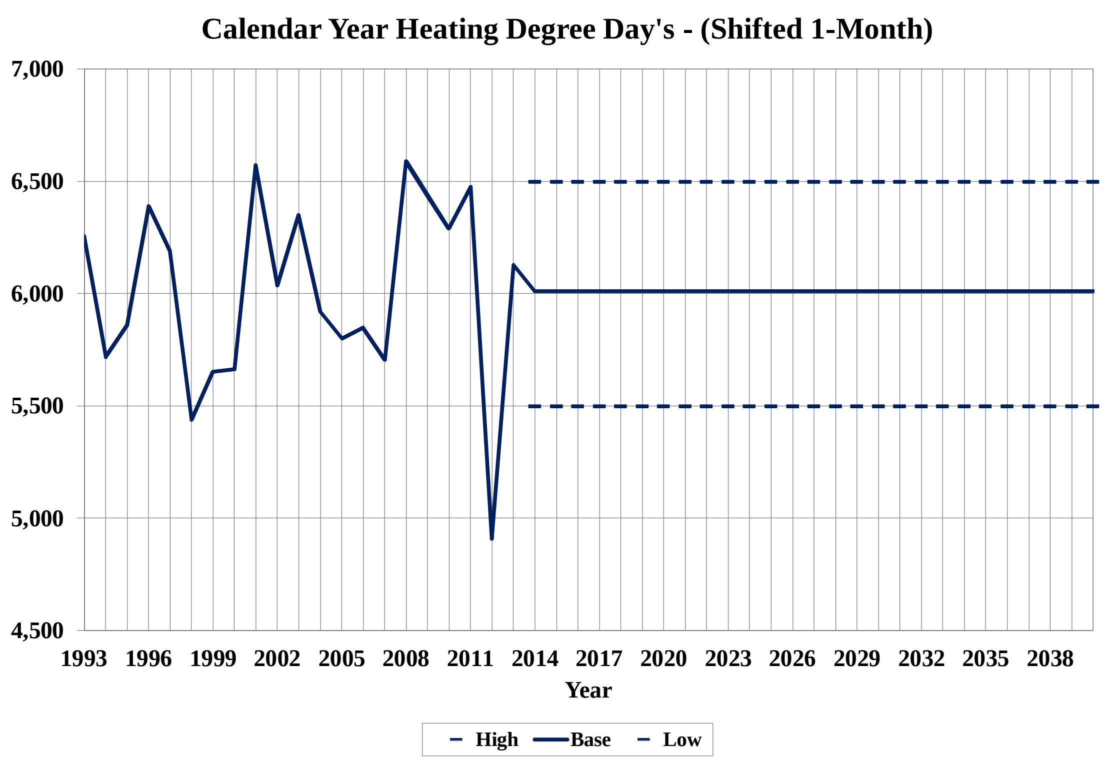
1995	Start
2013	Stop

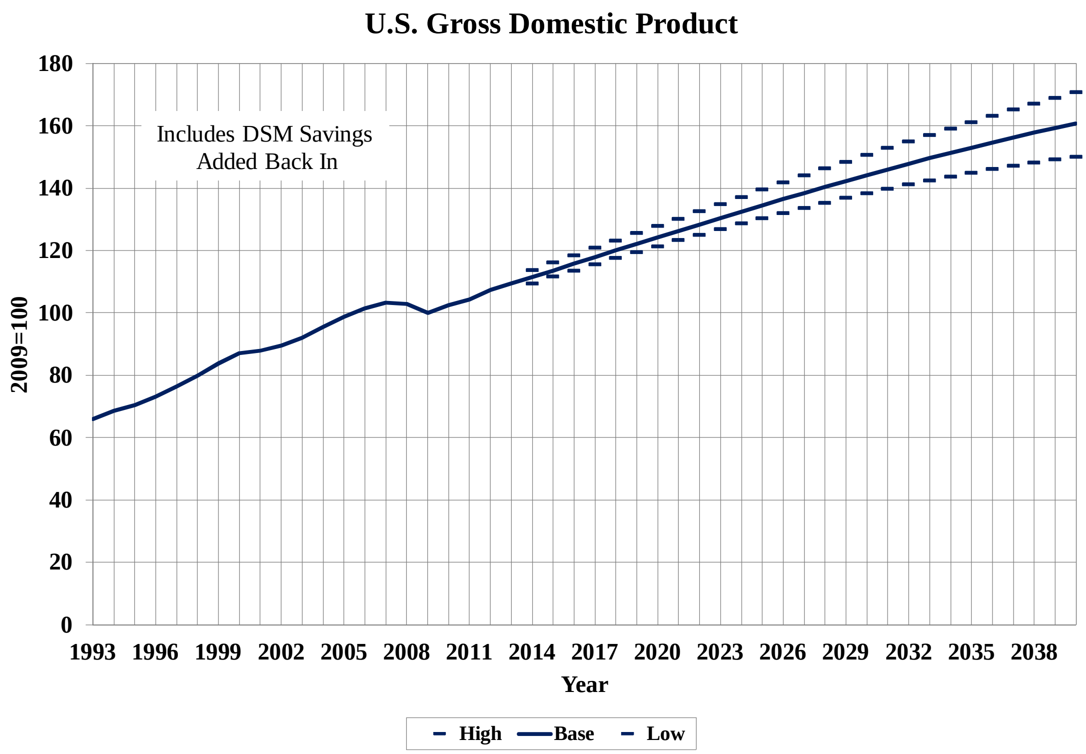
Date	Dependent Variable	Variable 1	Variable 2	Variable 3	Variable 4	Variable 5
1993	12,616	892	6,256	66	0.00	
1994	12,553	1008	5,718	69	0.00	
1995	13,153	1119	5,856	70	0.00	
1996	13,747	887	6,390	73	0.00	
1997	13,218	896	6,190	76	0.00	
1998	13,406	1142	5,439	80	0.00	
1999	13,396	1011	5,650	84	0.00	
2000	14,226	987	5,663	87	0.00	
2001	14,747	937	6,570	88	0.00	
2002	14,987	1132	6,037	90	0.00	
2003	12,926	888	6,350	92	1.00	
2004	15,238	673	5,918	96	0.00	
2005	15,866	1173	5,799	99	0.00	
2006	15,624	1057	5,849	101	0.00	
2007	17,264	1160	5,705	103	0.00	
2008	15,763	787	6,589	103	0.00	
2009	14,684	548	6,435	100	0.00	
2010	16,159	1119	6,290	103	0.00	
2011	16,527	1222	6,474	104	0.00	
2012	15996.815	1310.7	4908.9	107.302	0	
2013	15986.39	1101.1	6128.2	109.358	0	

Energy Best Fit Model




Calendar Year Cooling Degree Day's
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
1993 1996 1999 2002 2005 2008 2011 2014 2017 2020 2023 2026 2029 2032 2035 2038
Year
High
Base
Low


Calendar Year Heating Degree Day's - (Shifted 1-Month)
7,000
6,500
6,000
5,500
5,000
4,500
1993 1996 1999 2002 2005 2008 2011 2014 2017 2020 2023 2026 2029 2032 2035 2038
Year
High
Base
Low


U.S. Gross Domestic Product
Includes DSM Savings Added Back In
2009=100
0
20
40
60
80
100
120
140
160
180
1993
1996
1999
2002
2005
2008
2011
2014
2017
2020
2023
2026
2029
2032
2035
2038
Year
High
Base
Low

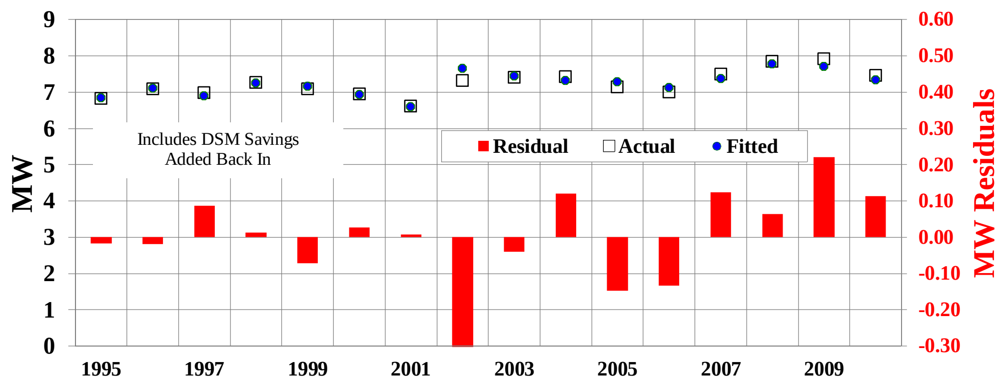
Summer Peak Econometric Forecast Model Formula & Independent Variables

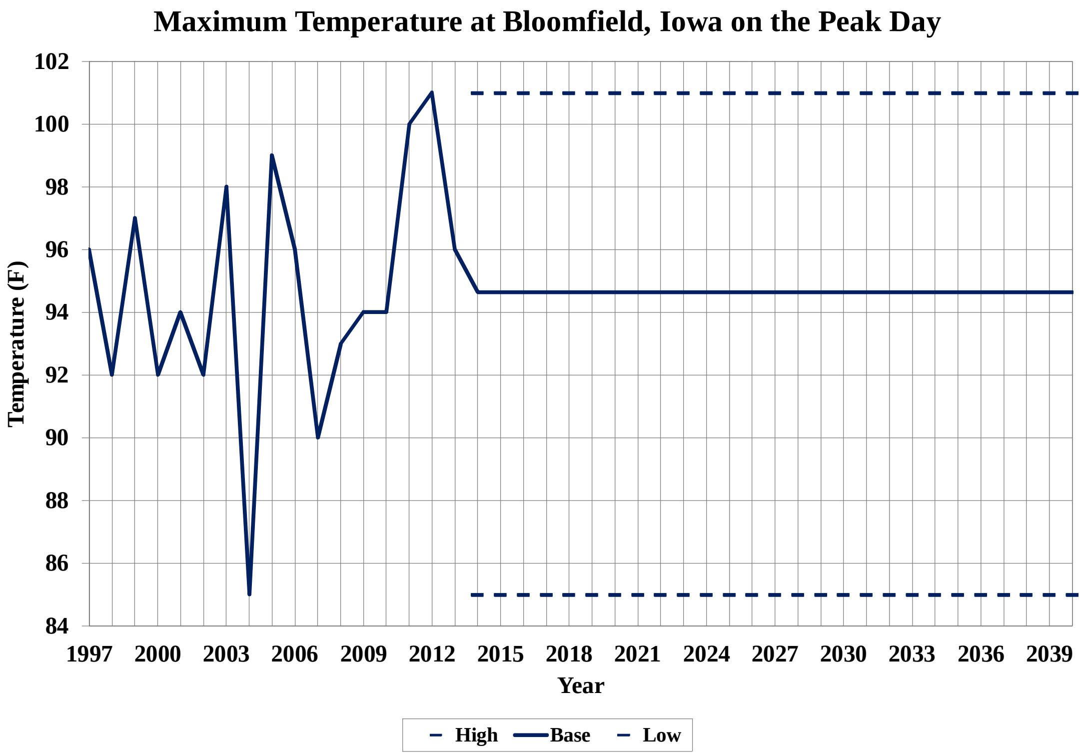
Output Summary

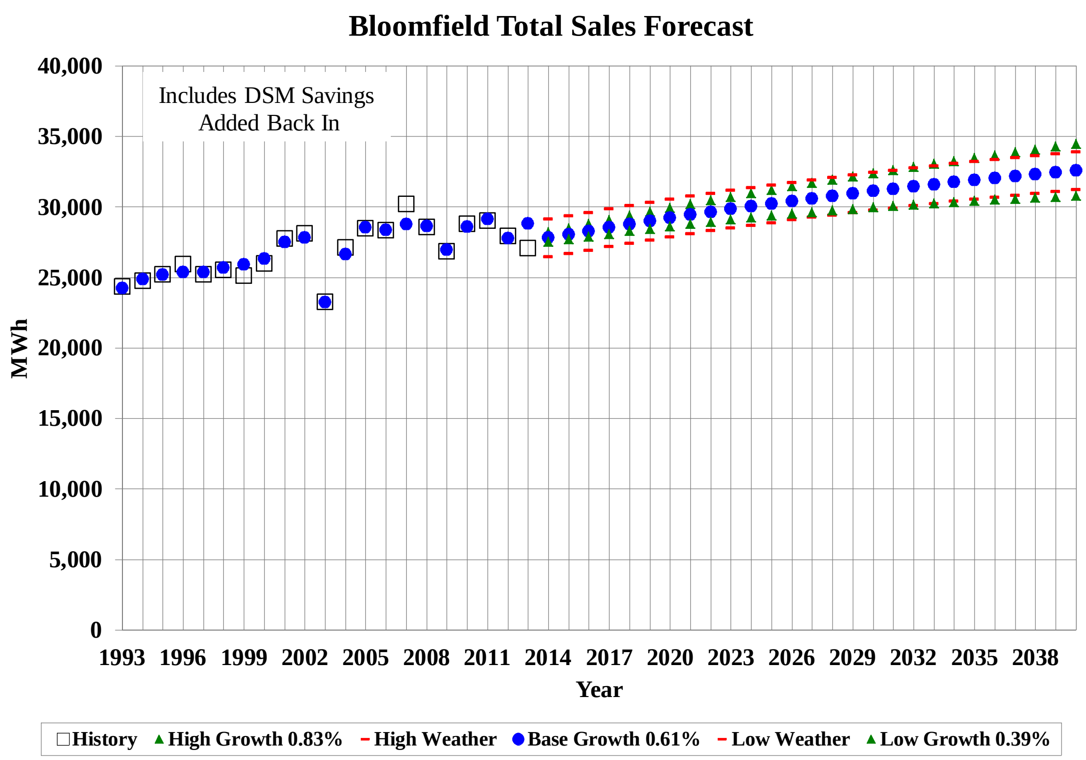
				Coefficient	t Stat
	Adjusted R Square	0.832	Maximum Temperature	0.063	6.859
	Standard Error	0.144	Actual Annual Sales, in MWh	0.000	5.892
1998 Start	F-Statistic	38.017			
2013 Stop	Durbin-Watson	1.685			
	Constant	-2.228			

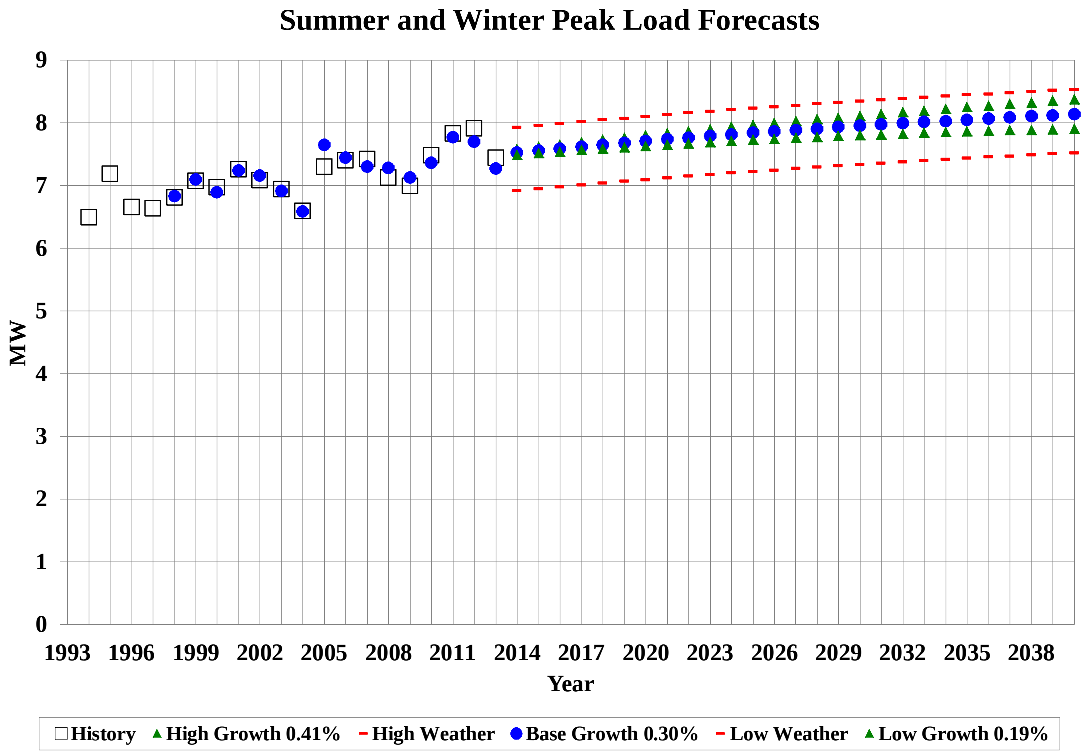
Date	Dependent Variable	Variable 1	Variable 2	Variable 3	Variable 4	Variable 5
1998	6.82	92.00	25,551			
1999	7.08	97.00	25,133			
2000	6.98	92.00	25,993			
2001	7.26	94.00	27,772			
2002	7.09	92.00	28,110			
2003	6.95	98.00	23,241			
2004	6.60	85.00	27,105			
2005	7.31	99.00	28,484			
2006	7.40	96.00	28,326			
2007	7.43	90.00	30,215			
2008	7.14	93.00	28,566			
2009	7.00	94.00	26,850			
2010	7.49	94.00	28,725			
2011	7.84	100.00	28,949			
2012	7.92	101.00	27,872			
2013	7.45	96.00	26,972			

Summer Peak Best Fit Model




Maximum Temperature at Bloomfield, Iowa on the Peak Day
102
100
98
96
94
92
90
88
86
84
Temperature (F)
1997 2000 2003 2006 2009 2012 2015 2018 2021 2024 2027 2030 2033 2036 2039
Year
High
Base
Low


Bloomfield Total Sales Forecast
Includes DSM Savings Added Back In
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MWh
1993 1996 1999 2002 2005 2008 2011 2014 2017 2020 2023 2026 2029 2032 2035 2038
Year
History
High Growth 0.83%
High Weather
Base Growth 0.61%
Low Weather
Low Growth 0.39%


Summer and Winter Peak Load Forecasts
MW
9
8
7
6
5
4
3
2
1
0
1993 1996 1999 2002 2005 2008 2011 2014 2017 2020 2023 2026 2029 2032 2035 2038
Year
History
High Growth 0.41%
High Weather
Base Growth 0.30%
Low Weather
Low Growth 0.19%

2014 Residential Energy Efficiency Potential	Economic Potential (kWH)	Cost of Deployed Units, $2012	Net of Program Costs, $2012	Gas Economic Potential (therms)	% of Potential 100.0% / Cutoff Level 20,000
			$ 269,332		
Totals for Programs that Are Selected >	**3,493,557**	**$ 1,051,719**	**$ 782,387**	**$ (26,386)**	**3,493,557**
Energy Efficiency Measure					**Selected**
LED Bulbs, purchased replacement (2012)	958,280	$172,765	$27,570	(2,126)	958,280
CFL Bulbs, purchased replacement (2012)	669,292	$58,071	$33,182	(15,680)	669,292
Second Refrigerator Turn In	340,985	$47,338	$37,304	(3,128)	340,985
Whole-house Electricity-Use Feedback Display Retrofit	328,814	$134,989	$123,365	(3,806)	328,814
Direct load control of water heaters	307,866	$72,363	$55,978	0	307,866
Radiant Barrier (Ceiling) -- Central AC	207,547	$62,036	$46,283	0	207,547
Direct load control of air conditioners	180,241	$173,291	$161,255	0	180,241
Exterior Lighting Controls	169,393	$82,710	$70,753	0	169,393
Low Flow Showerhead	72,381	$9,217	$5,882	0	72,381
ECM Furnace	40,882	$9,737	$6,509	0	40,882
Water Heater Blanket	39,865	$4,441	$1,856	0	39,865
CAC Tune-Up	38,151	$143,911	$139,520	0	38,151
Shower Controls (Shower Start Technology)	36,905	$10,205	$9,071	0	36,905
Second Freezer Turn In	35,674	$5,979	$4,929	(323)	35,674
2-Stage Central AC	24,660	$47,812	$44,597	0	24,660
Water Heater fuel switch	21,394	$7,207	$5,998	(1,323)	21,394
Heat Pump Water Heater	21,227	$9,648	$8,336	0	21,227
Common Area Lighting Improvements in Multifamily	19,566	$1,273	$0	(616)	-
Room A/C Turn In	19,381	$2,765	$1,893	0	-
Air Source Heat_Pump 18 SEER, 9.0 HSPF	17,518	$5,236	$3,907	0	-
Heat Pump Clothes Dryer	16,464	$16,670	$15,435	0	-
Home Electronics Efficiency Upgrade (Energy Star)	15,120	$1,521	$810	(268)	-
Faucet aerator (3 per home)	14,483	$4,490	$3,733	0	-
Air Source Heat_Pump 16 SEER, 8.8 HSPF	12,175	$3,639	$2,715	0	-
Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	11,018	$3,460	$2,815	0	-
High Efficiency Central AC (Tier 2)	7,803	$23,179	$22,038	0	-
Smart Power Strip	6,442	$604	$389	(141)	-
Desuperheater for central air conditioner (ASHP) system	6,054	$0	$0	88	-
Radiant Barrier (Ceiling) -- Central Heat	5,927	$4,159	$3,243	0	-
LED Exterior Lighting	5,843	$3,636	$3,209	0	-
Air Source Heat_Pump 14 SEER, 8.5 HSPF	4,670	$0	$0	0	-
Radiant Barrier (Ceiling) -- Heat pump	4,669	$0	$0	0	-
High Efficiency Central AC (Tier 1)	4,256	$12,605	$11,998	0	-
Radiant Barrier (Ceiling) -- Room AC	3,846	$0	$0	0	-
Energy Star Compliant Top-Mount Refrigerator	3,802	($2,097)	($1,610)	(111)	-
Air Conditioner - Central - Proper sizing	3,538	$370	$58	0	-
Faucet aerator (2 per home)	3,492	$947	$777	0	-
Exit Lighting Improvements in Multifamily	2,038	$153	$0	(7)	-
Water Heater Setback	1,843	$615	$0	0	-
Ceiling Fan Efficiency Upgrade	1,836	($0)	($0)	0	-
Energy Star Dishwasher (Electric Water Heating)	1,674	$387	$270	0	-
Energy Star Room A/C	1,603	$0	$0	0	-
Hot Water Demand Recirculation	1,442	$398	$325	0	-
Energy Star Compliant Side-by-Side Refrigerator	968	($478)	($332)	(31)	-
Energy Star Dehumidifer	655	$1,690	$1,254	0	-
Energy Star Clothes Washer (w/ Elec. WH & NG Dryer)	243	$129	$114	7	-
Energy Star Compliant Upright Freezer (Manual Def.)	59	($11)	($10)	(1)	-
Energy Star Compliant Chest Freezer	35	($4)	($4)	(1)	-
Conditioned Space Design (Central heat)	0	$48	$29	0	-
Conditioned Space Design (Central AC)	0	($0)	($0)	0	-
New Construction, Improved Plumbing Design	0	$457	$348	0	-
Conditioned Space Design (heat pump)	0	$0	$0	0	-
Heat_Pump - Ground or Water-Source - Open Loop (Desuperhea	0	$0	$0	0	-
Heat_Pump - Ground or Water-Source - Open Loop (Desuperhea	0	$0	$0	0	-
New Construction, Sub-Slab Ventilation	0	$31,243	$30,701	0	-
	3,692,023	1,168,804	886,490	(27,468)	3,493,557

2014 Non-Residential Energy Efficiency Potential	Economic Potential (kWH)	Cost of Deployed Units, $2012	Net of Program Costs, $2012	Gas Economic Potential (therms)	% of Potential 100.0%
					Cutoff Level
			$0.281		20,000
Totals for Programs that Are Selected >	**3,480,668**	**1,789,245**	**1,625,208**	**33,284**	**3,501,384**
Energy Efficiency Measure					**Selected**
HVAC System Retrocommissioning	485,876	$216,294	$200,520	33,376	485,876
Occupancy Sensor	384,284	$63,761	$42,145	(6,068)	384,284
Scheduled interior lighting	293,983	$54,579	$37,148	(4,813)	293,983
HPT8 Fixture to replace T12	250,976	$76,985	$70,548	(3,610)	250,976
DHW Fuel Switching (elec to gas)	210,551	$65,177	$45,809	(6,096)	210,551
Shell: Insulating and Air Sealing	170,282	$621,352	$611,491	11,841	170,282
HVAC System maintenance (service buy-down)	143,288	$38,355	$37,004	10,924	143,288
Heat Pump Water Heating	136,937	$2,053	$1,817	0	136,937
CFL Screw in	131,485	$18,992	$13,787	(2,389)	131,485
Fuel Switching (elec to gas)	111,534	$14,788	$1,418	(4,296)	111,534
Grey Water Heat Exchanger	95,563	$14,419	$12,874	0	95,563
Energy Management System	89,297	$244,699	$239,078	4,903	89,297
HE Rooftop AC systems	86,875	$17,332	$11,887	0	86,875
Energy Efficient Data Centers (virtualiz., cooling, and power sup|	83,277	$17,666	$14,517	0	83,277
Economizer for Coolers	77,664	$16,996	$11,510	0	77,664
HPT8 Fixture to replace T8	76,795	$4,301	$4,002	(1,045)	76,795
HE Packaged AC (non rooftop)	61,547	$1,715	$1,327	0	61,547
Floating Head Pressure Control	57,989	$16,762	$14,569	0	57,989
HE Halogen	55,352	$4,369	$1,601	(886)	55,352
Reduced Temperature Setpoints	54,648	$7,264	$2,144	0	54,648
Bi-level stairwell lighting	45,981	$16,101	$14,366	(645)	45,981
Refrigeration System Maintenance	45,552	$7,633	$6,160	0	45,552
Power Management Software	37,954	$8,425	$6,919	(527)	37,954
PTAC and PTHP	37,726	$3,006	$2,833	0	37,726
Programmable Thermostat	35,955	$140,471	$137,196	3,209	35,955
Refrigerated Case Doors - Door Misers	33,861	$2,795	$2,245	0	33,861
ECM Motors on fans	31,332	$1,075	$785	0	31,332
Evaporative Cooling	30,787	$8,164	$6,594	0	30,787
HE Chillers (air and water cooled)	29,242	$36,614	$30,751	0	29,242
Chilled Water Free Cooling Controls and Equipments	28,542	$36,803	$33,409	0	28,542
HE (ES) Icemakers	22,142	$772	$682	(285)	22,142
HE (ES) Computers	21,989	$2,324	$1,970	(312)	21,989
HE Motors (VSDs, ECMs, on fans)	21,401	$6,875	$5,837	0	21,401
HE Water Heaters	20,716	$328	$266	0	20,716
Improve Duct Sealing	19,780	$12,132	$10,590	1,330	-
HE Compressors	19,345	$8,278	$6,833	0	-
HO T5 lamps	19,257	$6,779	$5,620	(289)	-
Chilled Water Reset, Optimizer for Chiller(s)	18,357	$6,930	$6,341	0	-
New case doors	16,942	$4,539	$3,925	0	-
Parallel Rack Systems	16,652	$7,375	$5,951	0	-
Cycle fan off with thermostat; duty cycle occasionally when off	15,900	$2,797	$1,751	0	-
Strip Curtains	15,392	$1,530	$1,235	0	-
Refrigerated Case Doors - Low/No Anti-Sweat Heat	13,143	$902	$378	0	-
Pool Cover	12,929	$4,566	$4,342	0	-
Anti-sweat heater controls	12,850	$2,572	$2,091	0	-
Plug Load Sensors	12,599	$6,094	$4,840	(191)	-
Defrost Control System	11,376	$5,403	$4,680	0	-
Electronic ballast	11,354	$25,648	$22,671	(157)	-
HE (ES) Other Office Equipment	11,253	$587	$490	(154)	-
Low Flow Pre-Rinse Nozzles	10,864	$1,003	$420	0	-
Timers	10,801	$4,304	$3,267	0	-
Water Heater Cycling	10,750	$4,251	$3,229	0	-
Guest room contls	9,566	$13,650	$13,252	3,770	-
Cooler/Freezer Door Auto Closers	8,234	$1,541	$1,243	0	-
Faucet Aerators	7,955	$410	$300	0	-
LED Exit Lights	7,880	$4,582	$4,096	(107)	-
Heat Trap	7,010	$2,478	$2,204	0	-
HE (ES) Hot Food Holding Cabinets	5,726	$155	$125	0	-
Advanced Metal Halide	5,519	$1,651	$1,467	(104)	-
Time Clock	5,494	$130,233	$127,136	430	-
Induction	5,291	$2,279	$2,132	0	-
Chemical Sanitizing (Low Temp) Dishwashing Machine (ES)	5,136	$60	$51	0	-
Refrigeration E-Cube	4,285	$1,341	$1,208	0	-

2014 Non-Residential Energy Efficiency Potential	Economic Potential (kWH)	Cost of Deployed Units, $2012	Net of Program Costs, $2012 $0.281	Gas Economic Potential (therms)	% of Potential 100.0% Cutoff Level 20,000
Totals for Programs that Are Selected >	**3,480,668**	**1,789,245**	**1,625,208**	**33,284**	**3,501,384**
Energy Efficiency Measure					**Selected**
HE Commercial Clothes Washers	4,044	$78	$58	(58)	-
Case Lights-off timer (12am and 6am)	3,715	$283	$227	0	-
Exterior light timers	3,711	$2,925	$2,000	0	-
HE Battery Charging Station	3,511	$664	$563	(48)	-
Vendor Miser	3,376	$1,463	$1,316	0	-
HE Ventilation Hoods	3,351	$2,775	$2,617	0	-
VSD on Refrigeration Fan	3,315	$1,175	$1,051	0	-
Geothermal Heat Pumps	3,314	$8,032	$7,856	23,410	-
Cooler/Freezer Door Gaskets	2,923	$643	$519	0	-
TOD Pool Pump Timer	2,646	$277	$235	0	-
Insulating Blankets	2,498	$708	$631	0	-
Liquid Pressure Amplifiers	2,494	$7,801	$6,257	0	-
Evaporator Fan Controller	2,251	$246	$166	0	-
Mechanical Subcooling - additional subcooled compressor, valve	2,243	$8,417	$7,103	0	-
LED Refrigerated Case Door Lighting	2,145	$106	$87	0	-
Ultraviolet A/C Coil Cleaning System	1,776	$2,695	$2,542	0	-
HE (ES) Steam Cookers / Steamers	1,641	$71	$59	0	-
Connectionless (Boilerless) Steamers	1,641	$70	$59	0	-
HE Griddles	1,417	$71	$63	0	-
HE Commercial Clothes Dryers	1,164	$37	$32	(14)	-
Upgrade Ellipsoidal Reflector Lamps	1,153	$1,122	$930	(16)	-
HE Air Source Heat Pumps - heating	996	$0	$0	0	-
Night Covers for Display Cases	977	$147	$129	0	-
HE Broilers	849	$67	$63	0	-
Air Curtain Technologies	717	$234	$210	0	-
HE Induction Cooking	703	$51	$47	0	-
Insulate Pipes/Lines	655	$694	$674	0	-
Low Flow Showerhead	577	$222	$188	0	-
Pipe Insulation	319	$25	$22	0	-
HE (ES) Fryers	247	$30	$28	0	-
Ultrasonic Faucet Control	175	$11	$9	0	-
Direct load control AC	6	$3,981	$3,981	0	-
HE Ovens	3	$0	$0	0	-
Ambient Sub-Cooling - oversized condenser	0	$0	$0	0	-
CFL Fixture	0	$442	$242	0	-
Desiccant Dehumidification	0	$1,216	$1,153	0	-
Economizer	0	$856	$620	0	-
Efficient lighting design/layout	0	$1,903	$1,410	0	-
HE (ES) Refrig. Bev. Vending Machines	0	$0	$0	0	-
HE Clothes Washers	0	$0	$0	0	-
HE Dishwashers	0	$0	$0	0	-
HE Water Heating System Design	0	$60	$46	0	-
Heat Recovery for Hot Water Use	0	$31,157	$31,083	0	-
High performance integrated design	0	$19,890	$19,006	0	-
HVAC System Commissioning	0	$2,786	$2,639	0	-
LED Exterior Lighting	0	$115	$106	0	-
Low Pressure Drop Pool Filter	0	$0	$0	0	-
Shell: Improved Insulation and Air Sealing	0	$4,919	$4,640	0	-
Shell: Reduced Solar Gain	0	$2,358	$2,095	0	-
Solar Pool Heater	0	$144	$128	0	-
Thermal Energy Storage	0	$178	$178	0	-
VSD on Refrigeration Circulating Pump	0	$0	$0	0	-
	3,893,579	2,164,460	1,970,146	61,087	3,501,384

SCENARIO 1

	Scenario 1	Business As Usual (BAU)										
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Residential Sales	$ 1,544,172	$ 1,596,499	$ 1,586,215	$ 1,668,768	$ 1,759,222	$ 1,730,465	$ 1,783,306	$ 1,839,395	$ 1,895,868	$ 1,952,375	$ 2,011,068
2	Commercial/Industrial/Other	$ 1,269,409	$ 1,538,398	$ 1,581,381	$ 1,605,018	$ 1,583,931	$ 1,570,862	$ 1,631,583	$ 1,694,340	$ 1,758,794	$ 1,825,740	$ 1,895,599
3	Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Other Revenue / adjustments	$ 310,741	$ 147,540	$ 114,801	$ 144,922	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737
5	**Total Operating Revenue**	**$ 3,124,322**	**$ 3,282,437**	**$ 3,282,398**	**$ 3,418,708**	**$ 3,464,891**	**$ 3,423,064**	**$ 3,536,626**	**$ 3,655,472**	**$ 3,776,399**	**$ 3,899,852**	**$ 4,028,404**
6	Wind Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Solar PV Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Diesel Power Plant	$ 130,484	$ 180,364	$ 121,040	$ 142,350	$ 150,000	$ 153,000	$ 156,060	$ 159,181	$ 162,365	$ 165,612	$ 168,924
9	Micro-Turbines	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**Total Cost of Local Generation**	**$ 130,484**	**$ 180,364**	**$ 121,040**	**$ 142,350**	**$ 150,000**	**$ 153,000**	**$ 156,060**	**$ 159,181**	**$ 162,365**	**$ 165,612**	**$ 168,924**
11	Wholesale Power Energy Costs	$ 1,224,683	$ 1,155,407	$ 1,087,762	$ 1,099,225	$ 1,077,051	$ 1,117,671	$ 1,159,848	$ 1,203,984	$ 1,249,471	$ 1,296,033	$ 1,344,169
12	Wholesale Power Demand Costs	$ 894,743	$ 1,047,032	$ 1,154,097	$ 1,270,057	$ 1,069,146	$ 1,105,549	$ 1,143,216	$ 1,182,364	$ 1,222,701	$ 1,264,102	$ 1,306,835
13	Wholesale Power Transmission Costs	$ -	$ -	$ -	$ -	$ 179,688	$ 185,807	$ 192,137	$ 198,717	$ 205,496	$ 212,454	$ 219,636
14	RE Integration Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	**Total Cost of Wholesale Power**	**$ 2,119,426**	**$ 2,202,438**	**$ 2,241,859**	**$ 2,369,282**	**$ 2,325,886**	**$ 2,409,026**	**$ 2,495,201**	**$ 2,585,065**	**$ 2,677,668**	**$ 2,772,589**	**$ 2,870,640**
16	Energy Efficiency, Direct Load Controls	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	New Operators & Technicians	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Electric Distribution	$ 328,658	$ 282,404	$ 440,497	$ 308,261	$ 350,000	$ 357,000	$ 364,140	$ 371,423	$ 378,851	$ 386,428	$ 394,157
19	Electric Accounting	$ 160,154	$ 153,142	$ 167,713	$ 168,681	$ 172,000	$ 175,440	$ 178,949	$ 182,528	$ 186,178	$ 189,902	$ 193,700
20	Bond Payments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	**Total Operating Costs**	**$ 2,738,722**	**$ 2,818,349**	**$ 2,971,110**	**$ 2,988,574**	**$ 2,997,886**	**$ 3,094,466**	**$ 3,194,350**	**$ 3,298,197**	**$ 3,405,063**	**$ 3,514,531**	**$ 3,627,421**
22	**Net Operating Margin**	**$ 385,600**	**$ 464,088**	**$ 311,288**	**$ 430,134**	**$ 467,005**	**$ 328,598**	**$ 342,277**	**$ 357,275**	**$ 371,337**	**$ 385,321**	**$ 400,984**
23	Average Retail Electric Rate	$0.099	$0.108	$0.114	$0.119	$0.120	$0.117	$0.120	$0.123	$0.127	$0.130	$0.133
24	Average Monthly Bill	$170	$189	$191	$197	$202	$199	$206	$213	$220	$228	$236

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2015-2029	Average
1	Residential Sales	$ 2,070,614	$ 2,131,887	$ 2,193,186	$ 2,256,391	$ 2,321,084	$ 2,387,256	$ 2,455,795	$ 2,525,628	$ 2,597,032	$ 32,151,349	$ 2,143,423
2	Commercial/Industrial/Other	$ 1,967,929	$ 2,043,045	$ 2,120,852	$ 2,201,892	$ 2,285,840	$ 2,372,788	$ 2,462,837	$ 2,555,820	$ 2,652,083	$ 31,040,003	$ 2,069,334
3	Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Other Revenue / adjustments	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 1,826,059	$ 121,737
5	**Total Operating Revenue**	**$ 4,160,280**	**$ 4,296,669**	**$ 4,435,775**	**$ 4,580,020**	**$ 4,728,661**	**$ 4,881,781**	**$ 5,040,370**	**$ 5,203,185**	**$ 5,370,852**	**$ 65,017,411**	**$ 4,334,494**
6	Wind Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Solar PV Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Diesel Power Plant	$ 172,303	$ 175,749	$ 179,264	$ 182,849	$ 186,506	$ 190,236	$ 194,041	$ 197,922	$ 201,880	$ 2,645,893	$ 176,393
9	Micro-Turbines	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**Total Cost of Local Generation**	**$ 172,303**	**$ 175,749**	**$ 179,264**	**$ 182,849**	**$ 186,506**	**$ 190,236**	**$ 194,041**	**$ 197,922**	**$ 201,880**	**$ 2,645,893**	**$ 176,393**
11	Wholesale Power Energy Costs	$ 1,393,699	$ 1,444,816	$ 1,497,142	$ 1,551,077	$ 1,606,652	$ 1,663,888	$ 1,723,050	$ 1,783,942	$ 1,846,595	$ 21,882,038	$ 1,458,803
12	Wholesale Power Demand Costs	$ 1,350,825	$ 1,396,188	$ 1,442,747	$ 1,490,724	$ 1,540,153	$ 1,591,063	$ 1,643,607	$ 1,697,707	$ 1,753,398	$ 21,131,179	$ 1,408,745
13	Wholesale Power Transmission Costs	$ 227,029	$ 234,653	$ 242,478	$ 250,542	$ 258,849	$ 267,406	$ 276,237	$ 285,329	$ 294,689	$ 3,551,459	$ 236,764
14	RE Integration Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	**Total Cost of Wholesale Power**	**$ 2,971,554**	**$ 3,075,657**	**$ 3,182,367**	**$ 3,292,343**	**$ 3,405,654**	**$ 3,522,357**	**$ 3,642,894**	**$ 3,766,978**	**$ 3,894,682**	**$ 46,564,676**	**$ 3,104,312**
16	Energy Eff., Direct Load Controls	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	New Operators & Technicians	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Electric Distribution	$ 402,040	$ 410,081	$ 418,282	$ 426,648	$ 435,181	$ 443,885	$ 452,762	$ 461,818	$ 471,054	$ 6,173,750	$ 411,583
19	Electric Accounting	$ 197,574	$ 201,525	$ 205,556	$ 209,667	$ 213,860	$ 218,138	$ 222,500	$ 226,950	$ 231,489	$ 3,033,957	$ 202,264
20	Bond Payments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	**Total Operating Costs**	**$ 3,743,471**	**$ 3,863,013**	**$ 3,985,469**	**$ 4,111,508**	**$ 4,241,201**	**$ 4,374,615**	**$ 4,512,198**	**$ 4,653,667**	**$ 4,799,106**	**$ 58,418,275**	**$ 3,894,552**
22	**Net Operating Margin**	**$ 416,809**	**$ 433,656**	**$ 450,306**	**$ 468,513**	**$ 487,460**	**$ 507,166**	**$ 528,172**	**$ 549,517**	**$ 571,746**	**$ 6,599,136**	**$ 439,942**
23	Average Retail Electric Rate	$0.137	$0.140	$0.144	$0.148	$0.152	$0.156	$0.160	$0.164	$0.169		$0.141
24	Average Monthly Residential Bill	$244	$252	$260	$269	$278	$287	$297	$306	**$317**	$3,810	$254

SCENARIO 2

	Scenario 2	Energy Efficiency Programs Only										
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Residential Sales	$ 1,544,172	$ 1,596,499	$ 1,586,215	$ 1,668,768	$ 1,759,222	$ 1,705,681	$ 1,823,542	$ 1,846,707	$ 1,866,670	$ 1,885,240	$ 1,901,698
2	Commercial/Industrial/Other	$ 1,269,409	$ 1,538,398	$ 1,581,381	$ 1,605,018	$ 1,583,931	$ 1,553,637	$ 1,686,323	$ 1,732,977	$ 1,779,395	$ 1,828,687	$ 1,878,521
3	Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Other Revenue / adjustments	$ 310,741	$ 147,540	$ 114,801	$ 144,922	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737
5	**Total Operating Revenue**	**$ 3,124,322**	**$ 3,282,437**	**$ 3,282,398**	**$ 3,418,708**	**$ 3,464,891**	**$ 3,381,056**	**$ 3,631,603**	**$ 3,701,421**	**$ 3,767,802**	**$ 3,835,664**	**$ 3,901,956**
6	Wind Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Solar PV Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Diesel Power Plant	$ 130,484	$ 180,364	$ 121,040	$ 142,350	$ 150,000	$ 153,000	$ 156,060	$ 159,181	$ 162,365	$ 165,612	$ 168,924
9	Micro-Turbines	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**Total Cost of Local Generation**	**$ 130,484**	**$ 180,364**	**$ 121,040**	**$ 142,350**	**$ 150,000**	**$ 153,000**	**$ 156,060**	**$ 159,181**	**$ 162,365**	**$ 165,612**	**$ 168,924**
11	Wholesale Power Energy Costs	$ 1,224,683	$ 1,155,407	$ 1,087,762	$ 1,099,225	$ 1,077,051	$ 1,104,706	$ 1,119,786	$ 1,132,540	$ 1,145,765	$ 1,158,237	$ 1,170,369
12	Wholesale Power Demand Costs	$ 894,743	$ 1,047,032	$ 1,154,097	$ 1,270,057	$ 1,069,146	$ 1,098,043	$ 1,119,524	$ 1,141,649	$ 1,165,117	$ 1,185,473	$ 1,209,766
13	Wholesale Power Transmission Costs	$ -	$ -	$ -	$ -	$ 179,688	$ 184,545	$ 188,155	$ 191,874	$ 195,818	$ 199,239	$ 203,322
14	RE Integration Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	**Total Cost of Wholesale Power**	**$ 2,119,426**	**$ 2,202,438**	**$ 2,241,859**	**$ 2,369,282**	**$ 2,325,886**	**$ 2,387,293**	**$ 2,427,465**	**$ 2,466,063**	**$ 2,506,700**	**$ 2,542,949**	**$ 2,583,457**
16	Energy Efficiency, Direct Load Controls	$ -	$ -	$ -	$ -	$ -	$ 207,054	$ 207,054	$ 207,054	$ 207,054	$ 207,054	$ 207,054
17	New Operators & Technicians	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Electric Distribution	$ 328,658	$ 282,404	$ 440,497	$ 308,261	$ 350,000	$ 357,000	$ 364,140	$ 371,423	$ 378,851	$ 386,428	$ 394,157
19	Electric Accounting	$ 160,154	$ 153,142	$ 167,713	$ 168,681	$ 172,000	$ 175,440	$ 178,949	$ 182,528	$ 186,178	$ 189,902	$ 193,700
20	Bond Payments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	**Total Operating Costs**	**$ 2,738,722**	**$ 2,818,349**	**$ 2,971,110**	**$ 2,988,574**	**$ 2,997,886**	**$ 3,279,787**	**$ 3,333,667**	**$ 3,386,248**	**$ 3,441,148**	**$ 3,491,945**	**$ 3,547,292**
22	**Net Operating Margin**	**$ 385,600**	**$ 464,088**	**$ 311,288**	**$ 430,134**	**$ 467,005**	**$ 101,269**	**$ 297,935**	**$ 315,173**	**$ 326,654**	**$ 343,719**	**$ 354,664**
23	Average Retail Electric Rate	$0.099	$0.108	$0.114	$0.119	$0.120	$0.117	$0.128	$0.133	$0.138	$0.143	$0.148
24	Average Monthly Bill	$170	$189	$191	$197	$202	$197	$212	$216	$220	$224	$228

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2015-2029	Average
1	Residential Sales	$ 1,918,328	$ 1,930,339	$ 1,939,023	$ 1,952,957	$ 1,997,232	$ 2,020,289	$ 2,070,248	$ 2,133,301	$ 2,186,367	$ 29,177,621	$ 1,945,175
2	Commercial/Industrial/Other	$ 1,932,260	$ 1,984,676	$ 2,039,070	$ 2,103,305	$ 2,190,279	$ 2,240,906	$ 2,321,693	$ 2,419,113	$ 2,507,243	$ 30,198,084	$ 2,013,206
3	Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Other Revenue / adjustments	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 1,826,059	$ 121,737
5	**Total Operating Revenue**	**$ 3,972,325**	**$ 4,036,753**	**$ 4,099,830**	**$ 4,178,000**	**$ 4,309,248**	**$ 4,382,933**	**$ 4,513,678**	**$ 4,674,151**	**$ 4,815,347**	**$ 61,201,765**	**$ 4,080,118**
6	Wind Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Solar PV Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Diesel Power Plant	$ 172,303	$ 175,749	$ 179,264	$ 182,849	$ 186,506	$ 190,236	$ 194,041	$ 197,922	$ 201,880	$ 2,645,893	$ 176,393
9	Micro-Turbines	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**Total Cost of Local Generation**	**$ 172,303**	**$ 175,749**	**$ 179,264**	**$ 182,849**	**$ 186,506**	**$ 190,236**	**$ 194,041**	**$ 197,922**	**$ 201,880**	**$ 2,645,893**	**$ 176,393**
11	Wholesale Power Energy Costs	$ 1,181,897	$ 1,192,925	$ 1,202,983	$ 1,212,373	$ 1,238,449	$ 1,283,761	$ 1,331,721	$ 1,381,090	$ 1,431,871	$ 18,288,476	$ 1,219,232
12	Wholesale Power Demand Costs	$ 1,228,077	$ 1,246,460	$ 1,276,760	$ 1,296,166	$ 1,336,009	$ 1,373,316	$ 1,433,455	$ 1,474,904	$ 1,528,047	$ 19,112,765	$ 1,274,184
13	Wholesale Power Transmission Costs	$ 206,400	$ 209,489	$ 214,582	$ 217,843	$ 224,539	$ 230,809	$ 240,917	$ 247,883	$ 256,815	$ 3,212,229	$ 214,149
14	RE Integration Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	**Total Cost of Wholesale Power**	**$ 2,616,374**	**$ 2,648,874**	**$ 2,694,325**	**$ 2,726,382**	**$ 2,798,997**	**$ 2,887,887**	**$ 3,006,093**	**$ 3,103,877**	**$ 3,216,733**	**$ 40,613,471**	**$ 2,707,565**
16	Energy Eff., Direct Load Controls	$ 207,054	$ 207,054	$ 207,054	$ 207,054	$ 103,527	$ 103,527	$ 103,527	$ 103,527	$ 103,527	$ 2,588,169	$ 172,545
17	New Operators & Technicians	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Electric Distribution	$ 402,040	$ 410,081	$ 418,282	$ 426,648	$ 435,181	$ 443,885	$ 452,762	$ 461,818	$ 471,054	$ 6,173,750	$ 411,583
19	Electric Accounting	$ 197,574	$ 201,525	$ 205,556	$ 209,667	$ 213,860	$ 218,138	$ 222,500	$ 226,950	$ 231,489	$ 3,033,957	$ 202,264
20	Bond Payments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	**Total Operating Costs**	**$ 3,595,345**	**$ 3,643,283**	**$ 3,704,481**	**$ 3,752,600**	**$ 3,738,072**	**$ 3,843,672**	**$ 3,978,924**	**$ 4,094,094**	**$ 4,224,683**	**$ 55,055,239**	**$ 3,670,349**
22	**Net Operating Margin**	**$ 376,980**	**$ 393,470**	**$ 395,350**	**$ 425,400**	**$ 571,176**	**$ 539,260**	**$ 534,755**	**$ 580,057**	**$ 590,663**	**$ 6,146,526**	**$ 409,768**
23	Average Retail Electric Rate	$0.154	$0.160	$0.166	$0.172	$0.179	$0.181	$0.185	$0.190	$0.195		$0.159
24	Average Monthly Residential Bill	$232	$236	$240	$245	$253	$257	$265	$275	$283	$3,580	$239

SCENARIO 3

	Scenario 3	Energy Efficiency & Direct Load Control Programs										
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Residential Sales	$ 1,544,172	$ 1,596,499	$ 1,586,215	$ 1,668,768	$ 1,759,222	$ 1,705,681	$ 1,823,542	$ 1,856,968	$ 1,850,925	$ 1,842,073	$ 1,830,132
2	Commercial/Industrial/Other	$ 1,269,409	$ 1,538,398	$ 1,581,381	$ 1,605,018	$ 1,583,931	$ 1,553,637	$ 1,686,323	$ 1,742,607	$ 1,764,387	$ 1,786,815	$ 1,807,827
3	Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Other Revenue / adjustments	$ 310,741	$ 147,540	$ 114,801	$ 144,922	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737
5	**Total Operating Revenue**	**$ 3,124,322**	**$ 3,282,437**	**$ 3,282,398**	**$ 3,418,708**	**$ 3,464,891**	**$ 3,381,056**	**$ 3,631,603**	**$ 3,721,312**	**$ 3,737,049**	**$ 3,750,625**	**$ 3,759,696**
6	Wind Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Solar PV Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Diesel Power Plant	$ 130,484	$ 180,364	$ 121,040	$ 142,350	$ 150,000	$ 153,000	$ 156,060	$ 159,181	$ 162,365	$ 165,612	$ 168,924
9	Micro-Turbines	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**Total Cost of Local Generation**	**$ 130,484**	**$ 180,364**	**$ 121,040**	**$ 142,350**	**$ 150,000**	**$ 153,000**	**$ 156,060**	**$ 159,181**	**$ 162,365**	**$ 165,612**	**$ 168,924**
11	Wholesale Power Energy Costs	$ 1,224,683	$ 1,155,407	$ 1,087,762	$ 1,099,225	$ 1,077,051	$ 1,104,706	$ 1,119,754	$ 1,132,348	$ 1,144,854	$ 1,156,972	$ 1,167,855
12	Wholesale Power Demand Costs	$ 894,743	$ 1,047,032	$ 1,154,097	$ 1,270,057	$ 1,069,146	$ 1,098,043	$ 1,075,154	$ 1,050,247	$ 1,023,901	$ 991,534	$ 1,010,007
13	Wholesale Power Transmission Costs	$ -	$ -	$ -	$ -	$ 179,688	$ 184,545	$ 180,698	$ 176,512	$ 172,084	$ 166,644	$ 169,749
14	RE Integration Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	**Total Cost of Wholesale Power**	**$ 2,119,426**	**$ 2,202,438**	**$ 2,241,859**	**$ 2,369,282**	**$ 2,325,886**	**$ 2,387,293**	**$ 2,375,606**	**$ 2,359,107**	**$ 2,340,839**	**$ 2,315,150**	**$ 2,347,611**
16	Energy Efficiency, Direct Load Controls	$ -	$ -	$ -	$ -	$ -	$ 207,054	$ 279,165	$ 282,679	$ 286,194	$ 289,708	$ 221,112
17	New Operators & Technicians	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Electric Distribution	$ 328,658	$ 282,404	$ 440,497	$ 308,261	$ 350,000	$ 357,000	$ 364,140	$ 371,423	$ 378,851	$ 386,428	$ 394,157
19	Electric Accounting	$ 160,154	$ 153,142	$ 167,713	$ 168,681	$ 172,000	$ 175,440	$ 178,949	$ 182,528	$ 186,178	$ 189,902	$ 193,700
20	Bond Payments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	**Total Operating Costs**	**$ 2,738,722**	**$ 2,818,349**	**$ 2,971,110**	**$ 2,988,574**	**$ 2,997,886**	**$ 3,279,787**	**$ 3,353,919**	**$ 3,354,918**	**$ 3,354,428**	**$ 3,346,800**	**$ 3,325,504**
22	**Net Operating Margin**	**$ 385,600**	**$ 464,088**	**$ 311,288**	**$ 430,134**	**$ 467,005**	**$ 101,269**	**$ 277,684**	**$ 366,394**	**$ 382,621**	**$ 403,824**	**$ 434,192**
23	Average Retail Electric Rate	$0.099	$0.108	$0.114	$0.119	$0.120	$0.117	$0.128	$0.134	$0.137	$0.140	$0.143
24	Average Monthly Bill	$170	$189	$191	$197	$202	$197	$212	$217	$218	$219	$219

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2015-2029	Average
1	Residential Sales	$ 1,810,114	$ 1,820,602	$ 1,827,544	$ 1,838,961	$ 1,878,889	$ 1,896,594	$ 1,943,799	$ 2,003,404	$ 2,053,913	$ 27,983,143	$ 1,865,543
2	Commercial/Industrial/Other	$ 1,823,260	$ 1,871,851	$ 1,921,839	$ 1,980,533	$ 2,060,497	$ 2,103,703	$ 2,179,886	$ 2,271,813	$ 2,355,350	$ 28,910,328	$ 1,927,355
3	Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Other Revenue / adjustments	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 1,826,059	$ 121,737
5	**Total Operating Revenue**	**$ 3,755,111**	**$ 3,814,190**	**$ 3,871,121**	**$ 3,941,231**	**$ 4,061,123**	**$ 4,122,035**	**$ 4,245,423**	**$ 4,396,954**	**$ 4,531,001**	**$ 58,719,530**	**$ 3,914,635**
6	Wind Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Solar PV Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Diesel Power Plant	$ 172,303	$ 175,749	$ 179,264	$ 182,849	$ 186,506	$ 190,236	$ 194,041	$ 197,922	$ 201,880	$ 2,645,893	$ 176,393
9	Micro-Turbines	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**Total Cost of Local Generation**	**$ 172,303**	**$ 175,749**	**$ 179,264**	**$ 182,849**	**$ 186,506**	**$ 190,236**	**$ 194,041**	**$ 197,922**	**$ 201,880**	**$ 2,645,893**	**$ 176,393**
11	Wholesale Power Energy Costs	$ 1,180,788	$ 1,192,476	$ 1,201,529	$ 1,210,712	$ 1,235,776	$ 1,281,882	$ 1,329,219	$ 1,380,006	$ 1,429,693	$ 18,268,569	$ 1,217,905
12	Wholesale Power Demand Costs	$ 1,022,317	$ 1,034,535	$ 1,058,481	$ 1,071,331	$ 1,104,428	$ 1,134,779	$ 1,187,772	$ 1,221,846	$ 1,267,408	$ 16,351,784	$ 1,090,119
13	Wholesale Power Transmission Costs	$ 171,818	$ 173,871	$ 177,896	$ 180,056	$ 185,618	$ 190,719	$ 199,626	$ 205,352	$ 213,010	$ 2,748,199	$ 183,213
14	RE Integration Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	**Total Cost of Wholesale Power**	**$ 2,374,924**	**$ 2,400,882**	**$ 2,437,906**	**$ 2,462,099**	**$ 2,525,822**	**$ 2,607,381**	**$ 2,716,616**	**$ 2,807,205**	**$ 2,910,111**	**$ 37,368,551**	**$ 2,491,237**
16	Energy Eff., Direct Load Controls	$ 221,112	$ 221,112	$ 221,112	$ 221,112	$ 117,585	$ 117,585	$ 117,585	$ 117,585	$ 117,585	$ 3,038,281	$ 202,552
17	New Operators & Technicians	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Electric Distribution	$ 402,040	$ 410,081	$ 418,282	$ 426,648	$ 435,181	$ 443,885	$ 452,762	$ 461,818	$ 471,054	$ 6,173,750	$ 411,583
19	Electric Accounting	$ 197,574	$ 201,525	$ 205,556	$ 209,667	$ 213,860	$ 218,138	$ 222,500	$ 226,950	$ 231,489	$ 3,033,957	$ 202,264
20	Bond Payments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	**Total Operating Costs**	**$ 3,367,952**	**$ 3,409,349**	**$ 3,462,120**	**$ 3,502,375**	**$ 3,478,954**	**$ 3,577,224**	**$ 3,703,505**	**$ 3,811,479**	**$ 3,932,119**	**$ 52,260,432**	**$ 3,484,029**
22	**Net Operating Margin**	**$ 387,160**	**$ 404,841**	**$ 409,001**	**$ 438,857**	**$ 582,169**	**$ 544,810**	**$ 541,918**	**$ 585,475**	**$ 598,882**	**$ 6,459,097**	**$ 430,606**
23	Average Retail Electric Rate	$0.145	$0.151	$0.156	$0.162	$0.169	$0.170	$0.174	$0.179	$0.183		$0.152
24	Average Monthly Residential Bill	$219	$223	$226	$230	$238	$241	$249	$258	**$266**	$3,431	$229

SCENARIO 4

	Scenario 4	Energy Efficiency, Direct Load Control Programs & Peak Shaving										
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Residential Sales	$ 1,544,172	$ 1,596,499	$ 1,586,215	$ 1,668,768	$ 1,759,222	$ 1,705,681	$ 1,823,542	$ 1,855,007	$ 1,849,476	$ 1,847,001	$ 1,835,857
2	Commercial/Industrial/Other	$ 1,269,409	$ 1,538,398	$ 1,581,381	$ 1,605,018	$ 1,583,931	$ 1,553,637	$ 1,686,323	$ 1,740,766	$ 1,763,006	$ 1,791,595	$ 1,813,483
3	Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Other Revenue / adjustments	$ 310,741	$ 147,540	$ 114,801	$ 144,922	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737
5	**Total Operating Revenue**	**$ 3,124,322**	**$ 3,282,437**	**$ 3,282,398**	**$ 3,418,708**	**$ 3,464,891**	**$ 3,381,056**	**$ 3,631,603**	**$ 3,717,511**	**$ 3,734,220**	**$ 3,760,333**	**$ 3,771,078**
6	Wind Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Solar PV Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Diesel Power Plant	$ 130,484	$ 180,364	$ 121,040	$ 142,350	$ 150,000	$ 153,000	$ 177,931	$ 188,626	$ 219,109	$ 231,816	$ 244,933
9	Micro-Turbines	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**Total Cost of Local Generation**	**$ 130,484**	**$ 180,364**	**$ 121,040**	**$ 142,350**	**$ 150,000**	**$ 153,000**	**$ 177,931**	**$ 188,626**	**$ 219,109**	**$ 231,816**	**$ 244,933**
11	Wholesale Power Energy Costs	$ 1,224,683	$ 1,155,407	$ 1,087,762	$ 1,099,225	$ 1,077,051	$ 1,104,706	$ 1,111,285	$ 1,120,861	$ 1,122,558	$ 1,130,779	$ 1,137,585
12	Wholesale Power Demand Costs	$ 894,743	$ 1,047,032	$ 1,154,097	$ 1,270,057	$ 1,069,146	$ 1,098,043	$ 847,909	$ 816,185	$ 782,817	$ 743,217	$ 754,241
13	Wholesale Power Transmission Costs	$ -	$ -	$ -	$ -	$ 179,688	$ 184,545	$ 180,698	$ 176,512	$ 172,084	$ 166,644	$ 169,749
14	RE Integration Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	**Total Cost of Wholesale Power**	**$ 2,119,426**	**$ 2,202,438**	**$ 2,241,859**	**$ 2,369,282**	**$ 2,325,886**	**$ 2,387,293**	**$ 2,139,892**	**$ 2,113,558**	**$ 2,077,459**	**$ 2,040,640**	**$ 2,061,575**
16	Energy Efficiency, Direct Load Controls	$ -	$ -	$ -	$ -	$ -	$ 207,054	$ 279,165	$ 282,679	$ 286,194	$ 289,708	$ 221,112
17	New Operators & Technicians	$ -	$ -	$ -	$ -	$ -	$ -	$ 162,500	$ 165,750	$ 169,065	$ 172,446	$ 175,895
18	Electric Distribution	$ 328,658	$ 282,404	$ 440,497	$ 308,261	$ 350,000	$ 357,000	$ 364,140	$ 371,423	$ 378,851	$ 386,428	$ 394,157
19	Electric Accounting	$ 160,154	$ 153,142	$ 167,713	$ 168,681	$ 172,000	$ 175,440	$ 178,949	$ 182,528	$ 186,178	$ 189,902	$ 193,700
20	Bond Payments	$ -	$ -	$ -	$ -	$ -	$ -	$ 47,472	$ 47,472	$ 47,472	$ 47,472	$ 47,472
21	**Total Operating Costs**	**$ 2,738,722**	**$ 2,818,349**	**$ 2,971,110**	**$ 2,988,574**	**$ 2,997,886**	**$ 3,279,787**	**$ 3,350,049**	**$ 3,352,036**	**$ 3,364,328**	**$ 3,358,413**	**$ 3,338,844**
22	**Net Operating Margin**	**$ 385,600**	**$ 464,088**	**$ 311,288**	**$ 430,134**	**$ 467,005**	**$ 101,269**	**$ 281,554**	**$ 365,475**	**$ 369,892**	**$ 401,920**	**$ 432,234**
23	Average Retail Electric Rate	$0.099	$0.108	$0.114	$0.119	$0.120	$0.117	$0.128	$0.134	$0.137	$0.140	$0.143
24	Average Monthly Bill	$170	$189	$191	$197	$202	$197	$212	$217	$218	$219	$220

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2015-2029	Average
1	Residential Sales	$ 1,816,623	$ 1,820,444	$ 1,825,980	$ 1,840,629	$ 1,879,572	$ 1,897,648	$ 1,935,195	$ 2,004,488	$ 2,051,521	$ 27,988,665	$ 1,865,911
2	Commercial/Industrial/Other	$ 1,829,816	$ 1,871,688	$ 1,920,194	$ 1,982,329	$ 2,061,246	$ 2,104,872	$ 2,170,236	$ 2,273,042	$ 2,352,606	$ 28,914,841	$ 1,927,656
3	Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Other Revenue / adjustments	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 1,826,059	$ 121,737
5	**Total Operating Revenue**	**$ 3,768,177**	**$ 3,813,868**	**$ 3,867,912**	**$ 3,944,696**	**$ 4,062,555**	**$ 4,124,257**	**$ 4,227,168**	**$ 4,399,267**	**$ 4,525,864**	**$ 58,729,565**	**$ 3,915,304**
6	Wind Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Solar PV Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Diesel Power Plant	$ 232,752	$ 238,720	$ 261,493	$ 269,680	$ 283,108	$ 261,109	$ 308,821	$ 309,604	$ 318,086	$ 3,698,788	$ 246,586
9	Micro-Turbines	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**Total Cost of Local Generation**	**$ 232,752**	**$ 238,720**	**$ 261,493**	**$ 269,680**	**$ 283,108**	**$ 261,109**	**$ 308,821**	**$ 309,604**	**$ 318,086**	**$ 3,698,788**	**$ 246,586**
11	Wholesale Power Energy Costs	$ 1,156,564	$ 1,167,092	$ 1,168,195	$ 1,175,325	$ 1,196,210	$ 1,252,718	$ 1,281,777	$ 1,333,655	$ 1,381,279	$ 17,840,586	$ 1,189,372
12	Wholesale Power Demand Costs	$ 758,878	$ 763,193	$ 778,999	$ 783,464	$ 807,925	$ 829,381	$ 873,212	$ 897,849	$ 933,691	$ 12,469,006	$ 831,267
13	Wholesale Power Transmission Costs	$ 171,818	$ 173,871	$ 177,896	$ 180,056	$ 185,618	$ 190,719	$ 199,626	$ 205,352	$ 213,010	$ 2,748,199	$ 183,213
14	RE Integration Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	**Total Cost of Wholesale Power**	**$ 2,087,260**	**$ 2,104,156**	**$ 2,125,090**	**$ 2,138,845**	**$ 2,189,753**	**$ 2,272,818**	**$ 2,354,614**	**$ 2,436,856**	**$ 2,527,980**	**$ 33,057,790**	**$ 2,203,853**
16	Energy Eff., Direct Load Controls	$ 221,112	$ 221,112	$ 221,112	$ 221,112	$ 117,585	$ 117,585	$ 117,585	$ 117,585	$ 117,585	$ 3,038,281	$ 202,552
17	New Operators & Technicians	$ 179,413	$ 183,001	$ 186,661	$ 190,395	$ 194,203	$ 198,087	$ 202,048	$ 206,089	$ 210,211	$ 2,595,765	$ 173,051
18	Electric Distribution	$ 402,040	$ 410,081	$ 418,282	$ 426,648	$ 435,181	$ 443,885	$ 452,762	$ 461,818	$ 471,054	$ 6,173,750	$ 411,583
19	Electric Accounting	$ 197,574	$ 201,525	$ 205,556	$ 209,667	$ 213,860	$ 218,138	$ 222,500	$ 226,950	$ 231,489	$ 3,033,957	$ 202,264
20	Bond Payments	$ 47,472	$ 47,472	$ 47,472	$ 47,472	$ 47,472	$ 47,472	$ 47,472	$ 47,472	$ 47,472	$ 664,608	$ 44,307
21	**Total Operating Costs**	**$ 3,367,623**	**$ 3,406,066**	**$ 3,465,666**	**$ 3,503,819**	**$ 3,481,162**	**$ 3,559,093**	**$ 3,705,803**	**$ 3,806,374**	**$ 3,923,877**	**$ 52,262,939**	**$ 3,484,196**
22	**Net Operating Margin**	**$ 400,553**	**$ 407,802**	**$ 402,246**	**$ 440,877**	**$ 581,393**	**$ 565,165**	**$ 521,365**	**$ 592,893**	**$ 601,987**	**$ 6,466,626**	**$ 431,108**
23	Average Retail Electric Rate	$0.146	$0.151	$0.156	$0.163	$0.169	$0.170	$0.173	$0.179	$0.183		$0.152
24	Average Monthly Residential Bill	$220	$223	$226	$231	$238	$241	$248	$258	**$266**	$3,431	$229

SCENARIO 5

	Scenario 5	Energy Efficiency, Direct Load Control Programs, Peak Shaving & Low Renewable Energy Scenario										
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Residential Sales	$ 1,544,172	$ 1,596,499	$ 1,586,215	$ 1,668,768	$ 1,759,222	$ 1,705,681	$ 1,818,589	$ 1,848,513	$ 1,850,739	$ 1,838,220	$ 1,838,768
2	Commercial/Industrial/Other	$ 1,269,409	$ 1,538,398	$ 1,581,381	$ 1,605,018	$ 1,583,931	$ 1,553,637	$ 1,681,743	$ 1,734,672	$ 1,764,209	$ 1,783,078	$ 1,816,359
3	Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Other Revenue / adjustments	$ 310,741	$ 147,540	$ 114,801	$ 144,922	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737
5	**Total Operating Revenue**	**$ 3,124,322**	**$ 3,282,437**	**$ 3,282,398**	**$ 3,418,708**	**$ 3,464,891**	**$ 3,381,056**	**$ 3,622,069**	**$ 3,704,923**	**$ 3,736,685**	**$ 3,743,035**	**$ 3,776,864**
6	Wind Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Solar PV Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,442	$ 67,901	$ 115,516	$ 160,754	$ 202,878
8	Diesel Power Plant	$ 130,484	$ 180,364	$ 121,040	$ 142,350	$ 150,000	$ 153,000	$ 176,852	$ 190,256	$ 236,881	$ 244,121	$ 233,602
9	Micro-Turbines	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**Total Cost of Local Generation**	**$ 130,484**	**$ 180,364**	**$ 121,040**	**$ 142,350**	**$ 150,000**	**$ 153,000**	**$ 185,294**	**$ 258,157**	**$ 352,397**	**$ 404,876**	**$ 436,481**
11	Wholesale Power Energy Costs	$ 1,224,683	$ 1,155,407	$ 1,087,762	$ 1,099,225	$ 1,077,051	$ 1,101,718	$ 1,098,809	$ 1,091,137	$ 1,062,888	$ 1,049,608	$ 1,041,634
12	Wholesale Power Demand Costs	$ 894,743	$ 1,047,032	$ 1,154,097	$ 1,270,057	$ 1,069,146	$ 1,091,320	$ 840,177	$ 778,747	$ 691,115	$ 656,334	$ 705,337
13	Wholesale Power Transmission Costs	$ -	$ -	$ -	$ -	$ 179,688	$ 184,545	$ 180,698	$ 176,512	$ 172,084	$ 166,644	$ 169,749
14	RE Integration Costs	$ -	$ -	$ -	$ -	$ -	$ 2	$ 29	$ 143	$ 444	$ 898	$ 1,544
15	**Total Cost of Wholesale Power**	**$ 2,119,426**	**$ 2,202,438**	**$ 2,241,859**	**$ 2,369,282**	**$ 2,325,886**	**$ 2,377,586**	**$ 2,119,713**	**$ 2,046,538**	**$ 1,926,531**	**$ 1,873,484**	**$ 1,918,264**
16	Energy Efficiency, Direct Load Controls	$ -	$ -	$ -	$ -	$ -	$ 207,054	$ 279,165	$ 282,679	$ 286,194	$ 289,708	$ 221,112
17	New Operators & Technicians	$ -	$ -	$ -	$ -	$ -	$ -	$ 162,500	$ 165,750	$ 169,065	$ 172,446	$ 247,660
18	Electric Distribution	$ 328,658	$ 282,404	$ 440,497	$ 308,261	$ 350,000	$ 357,000	$ 364,140	$ 371,423	$ 378,851	$ 386,428	$ 394,157
19	Electric Accounting	$ 160,154	$ 153,142	$ 167,713	$ 168,681	$ 172,000	$ 175,440	$ 178,949	$ 182,528	$ 186,178	$ 189,902	$ 193,700
20	Bond Payments	$ -	$ -	$ -	$ -	$ -	$ -	$ 47,472	$ 47,472	$ 47,472	$ 47,472	$ 47,472
21	**Total Operating Costs**	**$ 2,738,722**	**$ 2,818,349**	**$ 2,971,110**	**$ 2,988,574**	**$ 2,997,886**	**$ 3,270,079**	**$ 3,337,233**	**$ 3,354,548**	**$ 3,346,688**	**$ 3,364,317**	**$ 3,458,845**
22	**Net Operating Margin**	**$ 385,600**	**$ 464,088**	**$ 311,288**	**$ 430,134**	**$ 467,005**	**$ 110,977**	**$ 284,837**	**$ 350,375**	**$ 389,997**	**$ 378,719**	**$ 318,019**
23	Average Retail Electric Rate	$0.099	$0.108	$0.114	$0.119	$0.120	$0.117	$0.128	$0.133	$0.137	$0.139	$0.143
24	Average Monthly Bill	$170	$189	$191	$197	$202	$197	$211	$216	$218	$218	$220

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2015-2029	Average
1	Residential Sales	$ 1,875,173	$ 1,877,781	$ 1,890,930	$ 1,898,403	$ 1,936,849	$ 1,942,663	$ 1,992,199	$ 2,046,732	$ 2,078,563	$ 28,439,803	$ 1,895,987
2	Commercial/Industrial/Other	$ 1,888,792	$ 1,930,639	$ 1,988,495	$ 2,044,551	$ 2,124,059	$ 2,154,803	$ 2,234,164	$ 2,320,946	$ 2,383,617	$ 29,403,763	$ 1,960,251
3	Sales for Resale	$ -	$ 108	$ 1,439	$ 3,370	$ 7,793	$ 15,865	$ 29,391	$ 38,161	$ 56,294	$ 152,420	$ 10,161
4	Other Revenue / adjustments	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 1,826,059	$ 121,737
5	**Total Operating Revenue**	**$ 3,885,702**	**$ 3,930,265**	**$ 4,002,602**	**$ 4,068,060**	**$ 4,190,437**	**$ 4,235,067**	**$ 4,377,491**	**$ 4,527,577**	**$ 4,640,211**	**$ 59,822,045**	**$ 3,988,136**
6	Wind Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Solar PV Generation	$ 252,779	$ 289,156	$ 332,263	$ 363,251	$ 399,935	$ 426,043	$ 456,889	$ 478,630	$ 504,251	$ 4,058,689	$ 270,579
8	Diesel Power Plant	$ 441,766	$ 433,570	$ 261,725	$ 273,681	$ 276,814	$ 244,395	$ 290,263	$ 476,254	$ 448,194	$ 4,381,375	$ 292,092
9	Micro-Turbines	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**Total Cost of Local Generation**	**$ 694,545**	**$ 722,726**	**$ 593,988**	**$ 636,932**	**$ 676,749**	**$ 670,438**	**$ 747,152**	**$ 954,884**	**$ 952,445**	**$ 8,440,064**	**$ 562,671**
11	Wholesale Power Energy Costs	$ 938,528	$ 926,745	$ 973,752	$ 949,472	$ 940,081	$ 972,366	$ 970,821	$ 911,100	$ 941,275	$ 14,969,932	$ 997,995
12	Wholesale Power Demand Costs	$ 558,184	$ 563,756	$ 680,350	$ 675,318	$ 674,451	$ 731,758	$ 753,052	$ 652,330	$ 702,404	$ 10,754,632	$ 716,975
13	Wholesale Power Transmission Costs	$ 171,819	$ 187,517	$ 177,896	$ 180,057	$ 185,619	$ 190,720	$ 199,627	$ 205,354	$ 213,008	$ 2,761,849	$ 184,123
14	RE Integration Costs	$ 2,548	$ 3,601	$ 5,109	$ 6,617	$ 8,563	$ 10,226	$ 12,401	$ 14,331	$ 16,823	$ 83,278	$ 5,552
15	**Total Cost of Wholesale Power**	**$ 1,671,079**	**$ 1,681,618**	**$ 1,837,107**	**$ 1,811,463**	**$ 1,808,714**	**$ 1,905,070**	**$ 1,935,900**	**$ 1,783,115**	**$ 1,873,510**	**$ 28,569,691**	**$ 1,904,646**
16	Energy Eff., Direct Load Controls	$ 221,112	$ 221,112	$ 221,112	$ 221,112	$ 117,585	$ 117,585	$ 117,585	$ 117,585	$ 117,585	$ 3,038,281	$ 202,552
17	New Operators & Technicians	$ 252,614	$ 257,666	$ 262,819	$ 268,076	$ 273,437	$ 278,906	$ 284,484	$ 290,174	$ 295,977	$ 3,381,574	$ 225,438
18	Electric Distribution	$ 402,040	$ 410,081	$ 418,282	$ 426,648	$ 435,181	$ 443,885	$ 452,762	$ 461,818	$ 471,054	$ 6,173,750	$ 411,583
19	Electric Accounting	$ 197,574	$ 201,525	$ 205,556	$ 209,667	$ 213,860	$ 218,138	$ 222,500	$ 226,950	$ 231,489	$ 3,033,957	$ 202,264
20	Bond Payments	$ 47,472	$ 47,742	$ 51,070	$ 54,397	$ 57,725	$ 61,053	$ 64,381	$ 67,709	$ 71,037	$ 759,946	$ 50,663
21	**Total Operating Costs**	**$ 3,486,435**	**$ 3,542,469**	**$ 3,589,934**	**$ 3,628,294**	**$ 3,583,252**	**$ 3,695,074**	**$ 3,824,765**	**$ 3,902,234**	**$ 4,013,097**	**$ 53,397,264**	**$ 3,559,818**
22	**Net Operating Margin**	**$ 399,267**	**$ 387,796**	**$ 412,668**	**$ 439,766**	**$ 607,185**	**$ 539,993**	**$ 552,726**	**$ 625,343**	**$ 627,114**	**$ 6,424,781**	**$ 428,319**
23	Average Retail Electric Rate	$0.150	$0.155	$0.161	$0.168	$0.174	$0.174	$0.178	$0.183	$0.185		$0.155
24	Average Monthly Residential Bill	$227	$230	$234	$238	$245	$247	$255	$263	**$269**	$3,488	$233

SCENARIO 6

	Scenario 6	Energy Efficiency, Direct Load Control Programs, Peak Shaving & Medium Renewable Energy Scenario										
		2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	Residential Sales	$ 1,544,172	$ 1,596,499	$ 1,586,215	$ 1,668,768	$ 1,759,222	$ 1,705,681	$ 1,817,764	$ 1,922,103	$ 1,953,231	$ 1,934,918	$ 1,930,573
2	Commercial/Industrial/Other	$ 1,269,409	$ 1,538,398	$ 1,581,381	$ 1,605,018	$ 1,583,931	$ 1,553,637	$ 1,680,979	$ 1,803,731	$ 1,861,909	$ 1,876,875	$ 1,907,044
3	Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4	$ 170	$ 833	$ 3,208
4	Other Revenue / adjustments	$ 310,741	$ 147,540	$ 114,801	$ 144,922	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737
5	**Total Operating Revenue**	**$ 3,124,322**	**$ 3,282,437**	**$ 3,282,398**	**$ 3,418,708**	**$ 3,464,891**	**$ 3,381,056**	**$ 3,620,481**	**$ 3,847,575**	**$ 3,937,047**	**$ 3,934,364**	**$ 3,962,562**
6	Wind Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ 307,803	$ 312,123	$ 313,063	$ 318,831	$ 319,275
7	Solar PV Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,194	$ 87,616	$ 150,247	$ 209,082	$ 264,570
8	Diesel Power Plant	$ 130,484	$ 180,364	$ 121,040	$ 142,350	$ 150,000	$ 153,000	$ 177,473	$ 178,996	$ 216,018	$ 237,756	$ 226,994
9	Micro-Turbines	$ -	$ -	$ -	$ -	$ -	$ -	$ 51,686	$ 54,478	$ 57,271	$ 60,050	$ 62,557
10	**Total Cost of Local Generation**	**$ 130,484**	**$ 180,364**	**$ 121,040**	**$ 142,350**	**$ 150,000**	**$ 153,000**	**$ 549,157**	**$ 633,214**	**$ 736,598**	**$ 825,718**	**$ 873,396**
11	Wholesale Power Energy Costs	$ 1,224,683	$ 1,155,407	$ 1,087,762	$ 1,099,225	$ 1,077,051	$ 1,101,221	$ 833,843	$ 816,751	$ 779,261	$ 743,652	$ 723,247
12	Wholesale Power Demand Costs	$ 894,743	$ 1,047,032	$ 1,154,097	$ 1,270,057	$ 1,069,146	$ 1,090,200	$ 763,150	$ 756,152	$ 652,892	$ 590,862	$ 634,841
13	Wholesale Power Transmission Costs	$ -	$ -	$ -	$ -	$ 179,688	$ 184,545	$ 180,698	$ 176,512	$ 172,084	$ 166,645	$ 169,749
14	RE Integration Costs	$ -	$ -	$ -	$ -	$ -	$ 2	$ 11,166	$ 11,655	$ 12,221	$ 13,407	$ 14,538
15	**Total Cost of Wholesale Power**	**$ 2,119,426**	**$ 2,202,438**	**$ 2,241,859**	**$ 2,369,282**	**$ 2,325,886**	**$ 2,375,968**	**$ 1,788,857**	**$ 1,761,070**	**$ 1,616,459**	**$ 1,514,565**	**$ 1,542,375**
16	Energy Efficiency, Direct Load Controls	$ -	$ -	$ -	$ -	$ -	$ 207,054	$ 279,165	$ 282,679	$ 286,194	$ 289,708	$ 221,112
17	New Operators & Technicians	$ -	$ -	$ -	$ -	$ -	$ -	$ 228,800	$ 233,376	$ 238,044	$ 242,804	$ 247,660
18	Electric Distribution	$ 328,658	$ 282,404	$ 440,497	$ 308,261	$ 350,000	$ 357,000	$ 364,140	$ 371,423	$ 378,851	$ 386,428	$ 394,157
19	Electric Accounting	$ 160,154	$ 153,142	$ 167,713	$ 168,681	$ 172,000	$ 175,440	$ 178,949	$ 182,528	$ 186,178	$ 189,902	$ 193,700
20	Bond Payments	$ -	$ -	$ -	$ -	$ -	$ -	$ 93,400	$ 94,209	$ 98,796	$ 102,214	$ 106,801
21	**Total Operating Costs**	**$ 2,738,722**	**$ 2,818,349**	**$ 2,971,110**	**$ 2,988,574**	**$ 2,997,886**	**$ 3,268,461**	**$ 3,482,467**	**$ 3,558,499**	**$ 3,541,120**	**$ 3,551,340**	**$ 3,579,201**
22	**Net Operating Margin**	**$ 385,600**	**$ 464,088**	**$ 311,288**	**$ 430,134**	**$ 467,005**	**$ 112,594**	**$ 138,014**	**$ 289,077**	**$ 395,927**	**$ 383,024**	**$ 383,361**
23	Average Retail Electric Rate	$0.099	$0.108	$0.114	$0.119	$0.120	$0.117	$0.128	$0.139	$0.144	$0.147	$0.151
24	Average Monthly Bill	$170	$189	$191	$197	$202	$197	$211	$225	$230	$230	$231

		2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2015-2029**	**Average**
1	Residential Sales	$ 1,932,332	$ 1,917,392	$ 1,918,985	$ 1,942,826	$ 1,989,842	$ 2,005,544	$ 2,035,610	$ 2,094,880	$ 2,080,171	$ 29,181,853	$ 1,945,457
2	Commercial/Industrial/Other	$ 1,946,365	$ 1,971,365	$ 2,017,998	$ 2,092,394	$ 2,182,175	$ 2,224,551	$ 2,282,847	$ 2,375,544	$ 2,385,462	$ 30,162,877	$ 2,010,858
3	Sales for Resale	$ 9,833	$ 16,975	$ 34,831	$ 60,968	$ 89,717	$ 129,185	$ 162,393	$ 194,728	$ 247,145	$ 949,989	$ 63,333
4	Other Revenue / adjustments	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 1,826,059	$ 121,737
5	**Total Operating Revenue**	**$ 4,010,268**	**$ 4,027,469**	**$ 4,093,551**	**$ 4,217,926**	**$ 4,383,471**	**$ 4,481,017**	**$ 4,602,587**	**$ 4,786,889**	**$ 4,834,514**	**$ 62,120,778**	**$ 4,141,385**
6	Wind Generation	$ 324,696	$ 329,136	$ 333,263	$ 335,927	$ 339,443	$ 342,485	$ 343,856	$ 346,158	$ 349,727	$ 4,615,786	$ 307,719
7	Solar PV Generation	$ 330,970	$ 378,923	$ 436,318	$ 477,180	$ 526,037	$ 560,469	$ 601,560	$ 630,237	$ 664,375	$ 5,329,778	$ 355,319
8	Diesel Power Plant	$ 324,821	$ 411,145	$ 269,756	$ 260,383	$ 234,917	$ 232,141	$ 245,304	$ 364,156	$ 311,148	$ 3,844,009	$ 256,267
9	Micro-Turbines	$ 64,464	$ 66,690	$ 68,156	$ 69,097	$ 70,438	$ 71,866	$ 73,926	$ 77,111	$ 78,909	$ 926,698	$ 61,780
10	**Total Cost of Local Generation**	**$ 1,044,951**	**$ 1,185,894**	**$ 1,107,493**	**$ 1,142,587**	**$ 1,170,835**	**$ 1,206,961**	**$ 1,264,646**	**$ 1,417,662**	**$ 1,404,158**	**$ 14,716,271**	**$ 981,085**
11	Wholesale Power Energy Costs	$ 649,687	$ 585,338	$ 612,165	$ 595,267	$ 593,731	$ 614,770	$ 619,053	$ 579,461	$ 618,995	$ 10,466,440	$ 697,763
12	Wholesale Power Demand Costs	$ 510,472	$ 447,623	$ 570,072	$ 604,722	$ 648,749	$ 663,633	$ 725,792	$ 582,055	$ 673,494	$ 9,914,709	$ 660,981
13	Wholesale Power Transmission Costs	$ 171,820	$ 174,133	$ 177,895	$ 180,057	$ 185,619	$ 190,722	$ 199,627	$ 205,354	$ 213,009	$ 2,748,468	$ 183,231
14	RE Integration Costs	$ 16,693	$ 18,862	$ 21,816	$ 24,658	$ 28,167	$ 30,947	$ 34,494	$ 37,677	$ 41,943	$ 318,245	$ 21,216
15	**Total Cost of Wholesale Power**	**$ 1,348,671**	**$ 1,225,956**	**$ 1,381,949**	**$ 1,404,704**	**$ 1,456,265**	**$ 1,500,072**	**$ 1,578,965**	**$ 1,404,547**	**$ 1,547,440**	**$ 23,447,862**	**$ 1,563,191**
16	Energy Eff., Direct Load Controls	$ 221,112	$ 221,112	$ 221,112	$ 221,112	$ 117,585	$ 117,585	$ 117,585	$ 117,585	$ 117,585	$ 3,038,281	$ 202,552
17	New Operators & Technicians	$ 252,614	$ 257,666	$ 262,819	$ 268,076	$ 273,437	$ 278,906	$ 284,484	$ 290,174	$ 295,977	$ 3,654,837	$ 243,656
18	Electric Distribution	$ 402,040	$ 410,081	$ 418,282	$ 426,648	$ 435,181	$ 443,885	$ 452,762	$ 461,818	$ 471,054	$ 6,173,750	$ 411,583
19	Electric Accounting	$ 197,574	$ 201,525	$ 205,556	$ 209,667	$ 213,860	$ 218,138	$ 222,500	$ 226,950	$ 231,489	$ 3,033,957	$ 202,264
20	Bond Payments	$ 111,388	$ 115,975	$ 120,562	$ 125,149	$ 129,736	$ 134,323	$ 138,910	$ 143,497	$ 148,084	$ 1,663,047	$ 110,870
21	**Total Operating Costs**	**$ 3,578,350**	**$ 3,618,209**	**$ 3,717,773**	**$ 3,797,943**	**$ 3,796,900**	**$ 3,899,869**	**$ 4,059,852**	**$ 4,062,233**	**$ 4,215,788**	**$ 55,728,005**	**$ 3,715,200**
22	**Net Operating Margin**	**$ 431,918**	**$ 409,261**	**$ 375,779**	**$ 419,983**	**$ 586,571**	**$ 581,148**	**$ 542,735**	**$ 724,656**	**$ 618,726**	**$ 6,392,773**	**$ 426,185**
23	Average Retail Electric Rate	$0.155	$0.159	$0.164	$0.172	$0.179	$0.180	$0.182	$0.187	$0.185		$0.159
24	Average Monthly Residential Bill	$234	$234	$237	$243	$252	$255	$260	$270	**$269**	$3,578	$239

SCENARIO 7

	Scenario 7	Energy Efficiency, Direct Load Control Programs, Peak Shaving & High Renewable Energy Scenario										
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Residential Sales	$ 1,544,172	$ 1,596,499	$ 1,586,215	$ 1,668,768	$ 1,759,222	$ 1,705,681	$ 1,816,939	$ 1,987,673	$ 2,024,408	$ 1,995,511	$ 1,985,536
2	Commercial/Industrial/Other	$ 1,269,409	$ 1,538,398	$ 1,581,381	$ 1,605,018	$ 1,583,931	$ 1,553,637	$ 1,680,216	$ 1,865,262	$ 1,929,759	$ 1,935,651	$ 1,961,338
3	Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,608	$ 22,470	$ 45,548	$ 56,179	$ 86,995
4	Other Revenue / adjustments	$ 310,741	$ 147,540	$ 114,801	$ 144,922	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737
5	**Total Operating Revenue**	**$ 3,124,322**	**$ 3,282,437**	**$ 3,282,398**	**$ 3,418,708**	**$ 3,464,891**	**$ 3,381,056**	**$ 3,631,500**	**$ 3,997,142**	**$ 4,121,451**	**$ 4,109,079**	**$ 4,155,606**
6	Wind Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ 615,606	$ 624,246	$ 626,125	$ 637,662	$ 638,551
7	Solar PV Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,946	$ 107,331	$ 187,723	$ 263,699	$ 335,030
8	Diesel Power Plant	$ 130,484	$ 180,364	$ 121,040	$ 142,350	$ 150,000	$ 153,000	$ 173,331	$ 174,429	$ 206,772	$ 245,457	$ 231,725
9	Micro-Turbines	$ -	$ -	$ -	$ -	$ -	$ -	$ 46,700	$ 48,576	$ 49,056	$ 50,427	$ 50,153
10	**Total Cost of Local Generation**	**$ 130,484**	**$ 180,364**	**$ 121,040**	**$ 142,350**	**$ 150,000**	**$ 153,000**	**$ 851,583**	**$ 954,582**	**$ 1,069,676**	**$ 1,197,245**	**$ 1,255,459**
11	Wholesale Power Energy Costs	$ 1,224,683	$ 1,155,407	$ 1,087,762	$ 1,099,225	$ 1,077,051	$ 1,100,723	$ 634,817	$ 611,054	$ 576,300	$ 523,606	$ 512,187
12	Wholesale Power Demand Costs	$ 894,743	$ 1,047,032	$ 1,154,097	$ 1,270,057	$ 1,069,146	$ 1,089,080	$ 754,262	$ 753,843	$ 637,157	$ 550,575	$ 585,826
13	Wholesale Power Transmission Costs	$ -	$ -	$ -	$ -	$ 179,688	$ 184,545	$ 180,698	$ 176,512	$ 172,084	$ 166,645	$ 169,749
14	RE Integration Costs	$ -	$ -	$ -	$ -	$ -	$ 3	$ 44,545	$ 46,024	$ 47,047	$ 49,964	$ 51,854
15	**Total Cost of Wholesale Power**	**$ 2,119,426**	**$ 2,202,438**	**$ 2,241,859**	**$ 2,369,282**	**$ 2,325,886**	**$ 2,374,350**	**$ 1,614,322**	**$ 1,587,433**	**$ 1,432,588**	**$ 1,290,789**	**$ 1,319,616**
16	Energy Efficiency, Direct Load Controls	$ -	$ -	$ -	$ -	$ -	$ 207,054	$ 279,165	$ 282,679	$ 286,194	$ 289,708	$ 221,112
17	New Operators & Technicians	$ -	$ -	$ -	$ -	$ -	$ -	$ 228,800	$ 233,376	$ 238,044	$ 242,804	$ 247,660
18	Electric Distribution	$ 328,658	$ 282,404	$ 440,497	$ 308,261	$ 350,000	$ 357,000	$ 364,140	$ 371,423	$ 378,851	$ 386,428	$ 394,157
19	Electric Accounting	$ 160,154	$ 153,142	$ 167,713	$ 168,681	$ 172,000	$ 175,440	$ 178,949	$ 182,528	$ 186,178	$ 189,902	$ 193,700
20	Bond Payments	$ -	$ -	$ -	$ -	$ -	$ -	$ 107,521	$ 110,579	$ 116,695	$ 121,282	$ 127,398
21	**Total Operating Costs**	**$ 2,738,722**	**$ 2,818,349**	**$ 2,971,110**	**$ 2,988,574**	**$ 2,997,886**	**$ 3,266,844**	**$ 3,624,479**	**$ 3,722,599**	**$ 3,708,226**	**$ 3,718,158**	**$ 3,759,101**
22	**Net Operating Margin**	**$ 385,600**	**$ 464,088**	**$ 311,288**	**$ 430,134**	**$ 467,005**	**$ 114,212**	**$ 7,021**	**$ 274,542**	**$ 413,225**	**$ 390,920**	**$ 396,505**
23	Average Retail Electric Rate	$0.099	$0.108	$0.114	$0.119	$0.120	$0.117	$0.128	$0.143	$0.150	$0.151	$0.155
24	Average Monthly Bill	$170	$189	$191	$197	$202	$197	$211	$232	$238	$237	$238

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2015-2029	Average
1	Residential Sales	$ 1,979,226	$ 1,968,981	$ 1,962,432	$ 1,992,778	$ 2,032,998	$ 2,046,593	$ 2,059,307	$ 2,117,124	$ 2,078,548	$ 29,753,735	$ 1,983,582
2	Commercial/Industrial/Other	$ 1,993,601	$ 2,024,406	$ 2,063,686	$ 2,146,191	$ 2,229,502	$ 2,270,083	$ 2,309,423	$ 2,400,769	$ 2,383,600	$ 30,747,122	$ 2,049,808
3	Sales for Resale	$ 120,186	$ 143,927	$ 205,755	$ 281,809	$ 340,447	$ 413,265	$ 484,413	$ 547,561	$ 647,146	$ 3,408,311	$ 227,221
4	Other Revenue / adjustments	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 121,737	$ 1,826,059	$ 121,737
5	**Total Operating Revenue**	**$ 4,214,751**	**$ 4,259,051**	**$ 4,353,610**	**$ 4,542,515**	**$ 4,724,685**	**$ 4,851,678**	**$ 4,974,880**	**$ 5,187,192**	**$ 5,231,031**	**$ 65,735,227**	**$ 4,382,348**
6	Wind Generation	$ 649,391	$ 658,272	$ 666,527	$ 671,854	$ 678,886	$ 684,970	$ 687,713	$ 692,317	$ 699,453	$ 9,231,571	$ 615,438
7	Solar PV Generation	$ 421,127	$ 482,820	$ 557,291	$ 609,884	$ 673,302	$ 717,632	$ 770,986	$ 807,917	$ 852,261	$ 6,802,948	$ 453,530
8	Diesel Power Plant	$ 294,283	$ 342,150	$ 244,380	$ 245,003	$ 221,266	$ 227,368	$ 228,506	$ 323,323	$ 285,200	$ 3,596,193	$ 239,746
9	Micro-Turbines	$ 50,956	$ 52,798	$ 50,877	$ 50,794	$ 51,874	$ 53,602	$ 55,482	$ 57,703	$ 58,784	$ 727,782	$ 48,519
10	**Total Cost of Local Generation**	**$ 1,415,757**	**$ 1,536,040**	**$ 1,519,074**	**$ 1,577,535**	**$ 1,625,328**	**$ 1,683,571**	**$ 1,742,686**	**$ 1,881,260**	**$ 1,895,698**	**$ 20,358,494**	**$ 1,357,233**
11	Wholesale Power Energy Costs	$ 450,672	$ 392,560	$ 413,318	$ 404,828	$ 398,211	$ 415,308	$ 426,106	$ 391,794	$ 429,870	$ 7,681,354	$ 512,090
12	Wholesale Power Demand Costs	$ 494,151	$ 442,268	$ 564,726	$ 598,668	$ 648,744	$ 639,677	$ 725,792	$ 568,196	$ 673,496	$ 9,726,461	$ 648,431
13	Wholesale Power Transmission Costs	$ 171,820	$ 174,739	$ 177,895	$ 180,057	$ 185,620	$ 190,722	$ 199,627	$ 205,355	$ 213,009	$ 2,749,076	$ 183,272
14	RE Integration Costs	$ 56,350	$ 60,712	$ 66,366	$ 71,582	$ 77,677	$ 81,998	$ 87,286	$ 92,146	$ 99,032	$ 932,586	$ 62,172
15	**Total Cost of Wholesale Power**	**$ 1,172,993**	**$ 1,070,278**	**$ 1,222,306**	**$ 1,255,135**	**$ 1,310,252**	**$ 1,327,705**	**$ 1,438,811**	**$ 1,257,491**	**$ 1,415,408**	**$ 21,089,477**	**$ 1,405,965**
16	Energy Eff., Direct Load Controls	$ 221,112	$ 221,112	$ 221,112	$ 221,112	$ 117,585	$ 117,585	$ 117,585	$ 117,585	$ 117,585	$ 3,038,281	$ 202,552
17	New Operators & Technicians	$ 252,614	$ 257,666	$ 262,819	$ 268,076	$ 273,437	$ 278,906	$ 284,484	$ 290,174	$ 295,977	$ 3,654,837	$ 243,656
18	Electric Distribution	$ 402,040	$ 410,081	$ 418,282	$ 426,648	$ 435,181	$ 443,885	$ 452,762	$ 461,818	$ 471,054	$ 6,173,750	$ 411,583
19	Electric Accounting	$ 197,574	$ 201,525	$ 205,556	$ 209,667	$ 213,860	$ 218,138	$ 222,500	$ 226,950	$ 231,489	$ 3,033,957	$ 202,264
20	Bond Payments	$ 133,514	$ 139,630	$ 145,746	$ 151,862	$ 157,978	$ 164,094	$ 170,210	$ 176,326	$ 182,442	$ 2,005,272	$ 133,685
21	**Total Operating Costs**	**$ 3,795,603**	**$ 3,836,331**	**$ 3,994,895**	**$ 4,110,033**	**$ 4,133,621**	**$ 4,233,882**	**$ 4,429,038**	**$ 4,411,603**	**$ 4,609,653**	**$ 59,354,068**	**$ 3,956,938**
22	**Net Operating Margin**	**$ 419,148**	**$ 422,719**	**$ 358,715**	**$ 432,482**	**$ 591,063**	**$ 617,795**	**$ 545,842**	**$ 775,589**	**$ 621,378**	**$ 6,381,158**	**$ 425,411**
23	Average Retail Electric Rate	$0.159	$0.163	$0.168	$0.176	$0.182	$0.183	$0.184	$0.189	$0.185		$0.162
24	Average Monthly Residential Bill	$240	$241	$243	$250	$257	$260	$263	$272	**$269**	$3,648	$243

Summaries of Totals for Each of the Seven Scenarios

Cumulative MWh, Revenues and Costs for the 15-Year Period from 2015 to 2029

Scenario Number >	1	2	3	4	5	6	7
Abbreviated Title >	BAU	EE Only	EE + DLC	EE+DLC+PS	Low RE	Med. RE	High RE
Scenario Title	Business As Usual	Energy Efficiency Programs Only	EE + Direct Load Control Programs Only	EE + DLC + Peak Shaving by Diesels	EE + DLC + PS + Low Renewables	EE + DLC + PS + Medium Renewables	EE + DLC + PS + High Renewables
MWh Needed							
Total MWh Sales to Ultimate Customers	445,657	375,708	375,708	375,708	375,708	375,708	375,708
System Losses	28,781	25,031	25,009	25,009	25,012	25,018	25,021
Total MWh Sales for Resale	0	0	0	0	1,987	12,242	46,220
Total MWh Needed ………………………………	474,438	400,739	400,717	400,717	402,707	412,969	446,948
Sources of MWh							
Wholesale Purchases, MWh	474,438	400,739	400,325	391,408	333,488	236,360	175,529
Diesel Plant Generation, MWh	0	0	0	8,917	14,664	10,267	8,186
Microturbine Generation, MWh	0	0	0	0	0	14,695	11,686
Wind Generation, MWh	0	0	0	0	0	80,207	160,415
Solar PV Generation, MWh	0	0	0	0	54,200	71,207	90,948
Other (DLC, Storage), MWh	0	0	392	392	355	231	185
Total Sources of Energy ……………………………	474,438	400,739	400,717	400,717	402,707	412,969	446,948
Measures of Energy Independence							
% Reduction in Retail Sales in 2029	0	22.5%	22.5%	22.5%	22.5%	22.5%	22.5%
% Reduction in Net Wholesale Purch., in 2029	0	22.5%	22.6%	25.2%	51.1%	75.4%	99.9%
% of Energy Locally Produced	0	0.0%	0.0%	3.4%	36.9%	68.2%	99.9%
Cumulative Operating Revenues - $1,000's							
Sales to Ultimate Customers	$ 63,191	$ 59,376	$ 56,893	$ 56,904	$ 57,844	$ 59,345	$ 60,501
Other Revenue	$ 1,826	$ 1,826	$ 1,826	$ 1,826	$ 1,826	$ 1,826	$ 1,826
Sales for Resale	$ -	$ -	$ -	$ -	$ 152	$ 950	$ 3,408
Total Utility Operating Revenue ………………	$ 65,017	$ 61,202	$ 58,720	$ 58,730	$ 59,822	$ 62,121	$ 65,735
Cumulative Operating Costs - $1,000's							
- Wholesale Power Costs	$ 46,565	$ 40,613	$ 37,369	$ 33,058	$ 28,570	$ 23,448	$ 21,089
- Energy Efficiency Programs	$ -	$ 2,588	$ 2,588	$ 2,588	$ 2,588	$ 2,588	$ 2,588
- Direct Load Control Programs	$ -	$ -	$ 450	$ 450	$ 450	$ 450	$ 450
- Microturbines, Energy Storage, Other	$ -	$ -	$ -	$ -	$ 95	$ 1,925	$ 2,068
- Renewable Energy Purchases	$ -	$ -	$ -	$ -	$ 4,059	$ 9,946	$ 16,035
- Additional Utility & Contract Labor	$ -	$ -	$ -	$ 2,596	$ 3,382	$ 3,655	$ 3,655
- Power Plant + RICE Compl. Costs	$ 2,646	$ 2,646	$ 2,646	$ 4,363	$ 5,046	$ 4,509	$ 4,261
- All Other Utility Costs	$ 9,208	$ 9,208	$ 9,208	$ 9,208	$ 9,208	$ 9,208	$ 9,208
Total Utility Operating Costs ……………………	$ 58,418	$ 55,055	$ 52,260	$ 52,263	$ 53,397	$ 55,728	$ 59,354
Cumulative Operating Margins ………………	$ 6,599	$ 6,147	$ 6,459	$ 6,467	$ 6,425	$ 6,393	$ 6,381
Measures of Economic Activity - $1,000's							
Cost of Wholesale Power Purchases	$ 46,565	$ 40,613	$ 37,369	$ 33,058	$ 28,570	$ 23,448	$ 21,089
Sales for Resale (Revenue)	$ -	$ -	$ -	$ -	$ 152	$ 950	$ 3,408
Additional Employee Wages & Benefits	$ -	$ 982	$ 982	$ 3,578	$ 4,364	$ 4,637	$ 4,637
Energy Efficiency Investments by Customers	$ -	$ 301	$ 301	$ 301	$ 301	$ 301	$ 301
Local Renewable Energy Purchased	$ -	$ -	$ -	$ -	$ 4,059	$ 9,946	$ 16,035
Customer's Power Bills	$ 63,191	$ 59,376	$ 56,893	$ 56,904	$ 57,844	$ 59,345	$ 60,501

Summaries of Totals for Each of the Seven Scenarios

Changes in Cumulative MWh, Revenues and Costs for the 15-Year Period from 2015 to 2029							
Future Scenario Title	Business As Usual	Energy Efficiency Programs Only	EE + Direct Load Control Programs Only	EE + DLC + Peak Shaving by Diesels	EE + DLC + PS + Low Renewables	EE + DLC + PS + Medium Renewables	EE + DLC + PS + High Renewables
Abbreviated Title >	BAU	EE Only	EE + DLC	EE+DLC+PS	Low RE	Med. RE	High RE
MWh Needed							
Total MWh Sales to Ultimate Customers	Reference	(69,949)	(69,949)	(69,949)	(69,949)	(69,949)	(69,949)
System Losses	Reference	(3,750)	(3,772)	(3,772)	(3,769)	(3,763)	(3,760)
Total MWh Sales for Resale	Reference	0	0	0	1,987	12,242	46,220
	Reference	(73,699)	(73,721)	(73,721)	(71,731)	(61,470)	(27,490)
Sources of MWh							
Wholesale Purchases, MWh	Reference	(73,699)	(74,113)	(83,030)	(140,950)	(238,078)	(298,909)
Diesel Plant Generation, MWh	Reference	0	0	8,917	14,664	10,267	8,186
Microturbine Generation, MWh	Reference	0	0	0	0	14,695	11,686
Wind Generation, MWh	Reference	0	0	0	0	80,207	160,415
Solar PV Generation, MWh	Reference	0	0	0	54,200	71,207	90,948
Other (DLC, Storage), MWh	Reference	0	392	392	355	231	185
	Reference	(73,699)	(73,721)	(73,721)	(71,731)	(61,470)	(27,490)
Cumulative Operating Revenues, in $1,000's							
Sales to Ultimate Customers	Reference	$ (3,816)	$ (6,298)	$ (6,288)	$ (5,348)	$ (3,847)	$ (2,690)
Other Revenue	Reference	$ -	$ -	$ -	$ -	$ -	$ -
Sales for Resale	Reference	$ -	$ -	$ -	$ 152	$ 950	$ 3,408
Total Utility Operating Revenue ……………………	Reference	$ (3,816)	$ (6,298)	$ (6,288)	$ (5,195)	$ (2,897)	$ 718
Cumulative Operating Costs, in $1,000's							
- Wholesale Power Costs	Reference	$ (5,951)	$ (9,196)	$ (13,507)	$ (17,995)	$ (23,117)	$ (25,475)
- Energy Efficiency Programs	Reference	$ 2,588	$ 2,588	$ 2,588	$ 2,588	$ 2,588	$ 2,588
- Direct Load Control Programs	Reference	$ -	$ 450	$ 450	$ 450	$ 450	$ 450
- Microturbines, Energy Storage, Other	Reference	$ -	$ -	$ -	$ 95	$ 1,925	$ 2,068
- Renewable Energy Purchases	Reference	$ -	$ -	$ -	$ 4,059	$ 9,946	$ 16,035
- Additional Utility & Contract Labor	Reference	$ -	$ -	$ 2,596	$ 3,382	$ 3,655	$ 3,655
- Power Plant + RICE Compl. Costs	Reference	$ -	$ -	$ 1,718	$ 2,400	$ 1,863	$ 1,615
- All Other Utility Costs	Reference	$ -	$ -	$ -	$ -	$ -	$ -
Total Utility Operating Costs …………………………	Reference	$ (3,363)	$ (6,158)	$ (6,155)	$ (5,021)	$ (2,690)	$ 936
Cumulative Operating Margins ……………………..	Reference	$ (453)	$ (140)	$ (133)	$ (174)	$ (206)	$ (218)
Measures of Economic Activity, in $1,000's							
Cost of Wholesale Power Purchases	Reference	$ (5,951)	$ (9,196)	$ (13,507)	$ (17,995)	$ (23,117)	$ (25,475)
Sales for Resale (Revenue)	Reference	$ -	$ -	$ -	$ 152	$ 950	$ 3,408
Additional Employee Wages & Benefits	Reference	$ 982	$ 982	$ 3,578	$ 4,364	$ 4,637	$ 4,637
Energy Efficiency Investments by Customers	Reference	$ 301	$ 301	$ 301	$ 301	$ 301	$ 301
Local Renewable Energy Purchased	Reference	$ -	$ -	$ -	$ 4,059	$ 9,946	$ 16,035
Customer's Power Bills	Reference	$ (3,816)	$ (6,298)	$ (6,288)	$ (5,348)	$ (3,847)	$ (2,690)