Boulder City Council
STUDY SESSION

Tuesday
February 26, 2013

Boulder's Energy Future Municipalization Exploration
6-9 PM

Council Chambers
Municipal Building
1777 Broadway

Submit Written Comments to City Council
ATTN: Alisa Lewis, City Clerk
1777 Broadway, 2nd Floor
P.O. Box 791
Boulder, CO 80306
or Fax to 303-441-4478
or E-mail: council@bouldercolorado.gov

TABLE OF CONTENTS

MEMORANDUM

TO: Members of City Council

FROM: Jane S. Brautigam, City Manager
Tom Carr, City Attorney
David Gehr, Deputy City Attorney
Kathy Haddock, Senior Assistant City Attorney
Debra Kalish, Senior Assistant City Attorney
Bob Eichem, Chief Financial Officer
Heather Bailey, Executive Director of Energy Strategy and Electric Utility Development
David Driskell, Executive Director of Community Planning and Sustainability
Maureen Rait, Executive Director of Public Works
Jonathan Koehn, Regional Sustainability Coordinator
Yael Gichon, Residential Sustainability Coordinator
Kelly Crandall, Sustainability Specialist II
Bob Harberg, Utilities Planning and Project Management Coordinator
Kara Mertz, Environmental Action Project Manager
Sarah Huntley, Media Relations/Communications Manager
Andrew Barth, Communication Specialist II
Ruth McHeyser, Senior Planner

DATE: Feb. 26, 2013

SUBJECT: Study Session: Boulder's Energy Future Municipalization Exploration

---

This memo was prepared to help City Council make a determination at its meeting on April 16 about whether to take the next important steps toward the potential formation of a municipal electric utility. If council decides to proceed on April 16, staff anticipates returning to council in July with a detailed work plan and schedule for Phase II, which is expected to include a request at council's Aug. 6 meeting to authorize the city's legal staff to begin negotiations with Xcel Energy (or Xcel) for the acquisition of the electric assets needed to serve Boulder.

I. PURPOSE

The purpose of this study session is to:

1. Provide preliminary results and receive council feedback on the municipalization exploration modeling and acquisition analysis to date with respect to the city's ability to meet Charter metrics developed last fall and engage in discussions with Xcel Energy. The analysis looks at six options that staff was able to model, including maintaining the status quo relationship with Xcel Energy;

2. Determine whether the analysis provides what council will need on April 16 when it will consider whether to continue to pursue municipalization as an option (i.e., begin meeting

with credit rating agencies, obtain vendor lists and indicative pricing, and prepare for necessary legal action); and

3. Receive feedback on the six Energy Future options modeled so far so that staff can begin to refine or narrow the scope of Phase II of the work plan.

II. QUESTIONS FOR COUNCIL

1. *Does council have any questions or comments about the process used to develop and analyze the five municipalization options and the "Xcel Baseline" option? For example:*
   - *The inputs and assumptions that were used in the analysis?*
   - *How the risks and uncertainties were determined and modeled?*
   - *The options that were modeled?*
2. *Does council have any questions or comments about the results of the analysis? For example:*
   - *The evaluation of the options in relation to the Charter metrics?*
   - *The modeling results?*
   - *The key findings?*
3. *Given the risks and opportunities identified to date, and following public input in March, will council have enough information at its meeting on April 16 to make a decision about whether to take the next steps listed on page 35 toward the potential creation of a local electric utility?*
4. *Does council have any questions or comments on the proposed next steps?*

III. EXECUTIVE SUMMARY

The City of Boulder has embarked on a significant undertaking that could change the future of electric service and energy management for its residents and businesses. As directed by council, city staff has been analyzing the viability of various options to help the community achieve its Energy Future goals. The process is grounded in commitments to be objective, to include as many alternate viewpoints as possible, and to project out not only the results on the first day of potential service from a municipal utility, but for 20 years into the future.

The analysis presented in this memo was designed to answer a critical first-level question:

- **Can the city municipalize?** In other words, is there at least one form of municipalization that meets the prerequisites that voters approved as part of the City Charter?

If council decides that the answer to that question is yes, staff will continue its work with the community over the next few months to answer equally important second-level questions:

- **How can the city best achieve its Energy Future goals?** Is a city-owned utility the best path to accomplish the broad set of goals the community set for its Energy Future? Would a city-owned electric utility provide value sufficient to offset potential risk and distinguish its services from those that Xcel Energy currently offers or could offer in the future through a new partnership? A question the city has posed in the past is, should we form a municipal utility? Staff believes the answer to this question will become more clear as the analysis continues and as part of a series of future decisions. The previous questions, however, are the ones the community and city officials should be starting to assess now.

Based on the current analyses, the answer to whether it is possible to municipalize is yes, and the findings to date are promising in terms of the potential value a local electric utility could bring when compared to other alternatives. The results detailed in this memo indicate that a local utility could operate effectively with cost savings and flexibility, creating significant advantages. Certain options for the local electric utility would meet the Charter metrics and with a very high likelihood be able to:

- Offer all three major customer classes (residential, commercial and industrial) lower rates than what they would pay Xcel, not just on day one, but on average over 20 years;
- Maintain or exceed current levels of system reliability and emergency response, and, if the community chose to, use future investments to enhance dependability;
- Reduce harmful greenhouse gas emissions by more than 50 percent from current levels and exceed the Kyoto Protocol target[1] in year one;
- Obtain 54 percent or more of its electricity from renewable resources; and
- Create a model public electric utility with leading-edge innovations in reliability, energy efficiency, renewable energy, related economic development and customer service.

The Electric Utility of the Future

At the core of these analyses is a vision of "the electric utility of the future" that is bold and exciting. No matter which energy path the city chooses to take, it strives to be a leader in reducing the impact its electric use has on climate change and in providing local energy services that meet the unique needs and community values of Boulder. For traditional electric utilities, "managing energy" is their core competence. Xcel has repeatedly said it is limited in its ability to shift from its current trajectory. The question Boulder faces is whether it wishes to be beholden to this antiquated business model for the next 20 years, while also recognizing community concerns that change represents risk.

Public utilities are not regulated at the state level in the same way as investor-owned utilities, but they are subject to local oversight that in many ways ensures the utility is held to a higher standard of service. Locally controlled public utilities, because they are not regulated by a state Public Utilities Commission, have the freedom to design programs and services that directly match the needs of the geographic and demographic area served. A regulated utility must provide more generalized services that are designed from a top down view of its entire service area. Typically, what the investor-owned utility offers to one set of customers it must offer to all, making customization difficult.

Boulder's vision for the future requires a utility willing to phase out the old business model and aggressively pursue a new way of operating. The community's Energy Future goals prioritize a

[1] Boulder's Kyoto Protocol target was to reduce community emissions seven percent below 1990 levels by the end of 2012.

cleaner energy supply; the ability to develop innovative energy efficiency and demand-side management programs that enhance customers' control; a structure that supports economic vitality through low costs and high reliability, as well as the creation of a high-tech test bed; and the opportunity to work with energy consumers to meet their diverse needs. Boulder's vision, either in partnership with Xcel Energy or through a municipal utility, is to transform from a utility model centered on selling more electrons to a new business model in which the mission is to collaborate with customers to provide options to use fewer electrons.

The opportunity exists for Boulder to transition to a new sustainable, low-carbon emission society, and it is coming much faster than anyone had anticipated just a few years ago. The growing differential between the rising costs of fossil fuels and the declining costs of renewable energy technologies is setting the stage for the emergence of a new economic paradigm for the next century. Boulder is poised to drive this process to tackle climate change, secure energy independence, and grow a sustainable 21st century economy all at the same time.

Public Outreach and Working Groups

Given the potential impact of a decision to create an electric utility on residents and businesses, more than 50 individuals, many of whom offered significant industry expertise, participated in developing the options, vetting assumptions and providing specific data inputs. Five working groups were formed, representing the major areas of finance, reliability, resources, decision analysis and public outreach (see **Attachment A**). The city staff extends a huge thank you to the community members who gave significant amounts of time to help ensure the integrity of this process. Draft recommendations included in this memo have been vetted with these work teams. Additionally, extensive community outreach will take place between the Feb. 26 study session and April 16 council meeting.

The Modeling Process

The analysis incorporated five major areas of focus: financial, reliability, resource mix, asset acquisition and legal issues. Models were designed to span 20 years, from 2017 to 2037. An extensive list of inputs, which were vetted by community working groups and consultants, drew upon current market pricing, analyses by federal laboratories, benchmarking from American Public Power Association and regional utilities, and a diversity of other sources to ensure that data was accurate, realistic, conservative, and locally relevant. A smaller number of high-impact variables were modeled with wide cost ranges to show the risks associated with future uncertainty. These variables included gas prices, wind prices, interest rates, operations and maintenance costs, stranded and acquisition costs, and the ability of the utility to generate sufficient debt service coverage. Although the models are robust, they have limitations—for example, they do not allow for the types of course changes that might happen in reality. The significance of this is that a city-owned utility could start on a path of least-cost power and move to more renewable energy based on changing market conditions, just as Xcel could.

The structure of the modeling for this phase was driven by the first-level question of whether municipalization is feasible under the conditions set by the City Charter. Staff modeled an Xcel Energy Baseline, based on publicly available documents and Xcel's own projections, for comparison to five municipalization-driven options that combine different resource packages and energy efficiency investments. The Xcel Baseline was modeled as conservatively as possible, giving Xcel a notable benefit of the doubt; significant cost increases, such as a planned $3.5 billion capital plan, may not have not been fully incorporated as not all of Xcel's forecasting information is available or accessible. The utility's latest rate increase was not included in this phase of modeling.

No alternative partnerships with Xcel Energy have been modeled at this time because the city does not have sufficient information from Xcel about the type of agreement—from among those proposed by the city in December 2012 or new ideas the company might have— Xcel would be interested in pursuing. It is possible that Xcel, working with the city, could become the utility of the future. In fact, it is possible that some of the municipalization options presented in this memo could be implemented in partnership with Xcel, if the company is willing and able to make some necessary changes. Staff is hopeful that Xcel will come to the table to develop these ideas more concretely in the upcoming months.

Reliability

Reliability was raised as a key concern by both the business community and by residents. Given its importance, a separate analysis and working group was formed to address this issue. Engineers were hired to evaluate the system and its current condition, provide recommendations about needed improvements, identify regulatory reliability requirements and recommend best practices to ensure the acquired system would be just as reliable, if not better, than it currently is. The city recognizes that it is fortunate to have major employers who are industrial customers, and these customers have processes that require high-quality power and a reliable supply. Power failures can have significant financial impacts to these customers. Therefore, it was critical to not only talk to these companies about their needs and concerns, but to have equipment, systems, and processes in place to meet those specific needs. All models assume that reliability is a requirement and are based on separation and service area recommendations that participating engineers have indicated will achieve this goal.

Conclusion

Results presented later in this memo show that three of the five options for forming a local electric utility could achieve all of the Charter metrics with medium to high likelihood. In all cases, except the Xcel Baseline, a significant reduction in greenhouse gas emissions and increased renewable resources could be achieved. Two options that were modeled to prioritize greenhouse gas emissions reductions did not meet the Charter requirement of rate parity at the time of acquisition, while a least-cost power option was able to bear even the highest cost stranded and acquisition rulings under certain conditions.

IV. MODELING/ ANALYSIS PROCESS

A. Purpose and Framework

Background information on the Energy Future project, including goals, work done to date, Charter requirements, and work done to date is provided in **Attachment C**.

Boulder's Energy Future Goals could be achieved to varying degrees through either of two broad paths:

1. Boulder residents and businesses could remain customers of Xcel Energy. Although Xcel is hampered at times by regulation, its economies of scale can produce dramatic impacts even in a status quo relationship. Even better (in terms of meeting the community's goals), Boulder and Xcel could form a new and creative long-term partnership that would provide a model for innovation and co-creation of clean energy opportunities; a possible outcome is potentially reflected in two of the options staff modeled (discussed in more detail on page 18); or,
2. Boulder could form a local electric utility – one that would offer residents and businesses a voice to articulate their values related to clean energy reasonable rates, and high reliability. This entity could focus on providing "energy as a service" rather than "energy as a commodity." This would involve managing different resource mixes, crafting more innovative and locally-centered services, and providing new infrastructure opportunities in response to community priorities. Under Colorado law, a municipal utility is governed locally and is independent from many of the state regulatory constraints that bind investor-owned utilities like Xcel. Municipal utilities are typically held to a higher standard by the community and local oversight board.

The information presented here shows the range of risks and opportunities associated with these two paths. Risks and opportunities are analyzed from two perspectives:

- Is municipalization feasible given the Charter requirements approved by Boulder voters in November 2011? According to the Charter and associated metrics, Xcel Energy's current performance related to rates, reliability, and renewable energy—projected over 20 years—provides the floor for determining whether a local electric utility can be formed.
- Which of the overarching paths—staying with Xcel, forming a local electric utility, or some variation on either—presents the greatest opportunities for the Boulder community to achieve the Energy Future goals, and what challenges might put those goals at risk of not being met?

The modeling performed to date explores both a status quo relationship with Xcel Energy and variations on forming a local electric utility. There is not sufficient information to model a new and creative partnership with Xcel, which could involve collaboration to create significant legislative or regulatory change. It is worth noting, however, that options that reflect a phasing out of power purchases with coal or a low cost supply that includes a lesser amount of coal could be a proxy for a potential partnership resource mix. These options, however, may not include future planned capital investments of $3.5 billion by Xcel, significant increases in coal prices, or other variables a utility would have to consider when creating long-term forecasts. City staff explored a potential partnership in a December 2012 paper[2] that described opportunities for innovation through a partnership with Xcel Energy. As is discussed in Section VI (page 35), the city and Xcel Energy have been in conversations about what a process for resumed dialogue around these ideas would involve and what parameters would lead to the greatest likelihood of success.

The modeling outputs, such as average rates and renewable energy purchases, cover 20 years (2017 to 2037). These outputs are based on the Charter requirements and are forecasted for the Boulder portion of Xcel's Colorado service territory. This means that a future where Boulder residents and businesses remain customers of Xcel Energy can be compared with a future where they become customers of a local electric utility. More information about the technical aspects of the modeling is provided in **Attachment B.**

This modeling builds on the 2011 feasibility[3] modeling in two key ways. First, the 2011 data has been refined with the assistance of the working groups and new experts, including the city's financial advisor, engineers, and resource modelers. Second, a limited number of high-impact inputs have been modeled probabilistically, i.e., with ranges of values and associated likelihoods. These inputs are called "uncertainties," things over which neither Boulder nor Xcel has total control. No one can predict the future, but uncertainties are important to model because they expose risks and opportunities. They can help identify whether an outcome is likely to occur and what other factors are connected to it that can make the impact better or worse.

Stakeholder and industry expert input helped ensure that the data being used was realistic, conservative, and locally relevant. This included feedback from the five working groups described in **Attachment A** and in **Attachment L**. Meeting notes of all working group meetings are also available at www.BoulderEnergyFuture.com.

[2] "Exploring Opportunities for Reaching Boulder's Energy Efficiency Goals" presented at the Dec. 6, 2012, Council Roundtable.

[3] Presented at the May 10 and June 14, 2011, City Council meetings and available at www.BoulderEnergyFuture.com

B. Options Modeled

The purpose of modeling options is to examine how various paths toward a "utility of the future" compare to the status quo. As shown in Figure 1, if council decides the preferred path is municipalization, a municipal electric utility could take different forms to achieve community goals: it could purchase power from Xcel Energy or from another provider, or both; it could have different resource mixes depending on community priorities that could also come from Xcel or another provider; it could have an intelligent grid infrastructure immediately, or develop it over time; etc. Therefore, the municipalization path was modeled under a variety of circumstances that would allow the city to test potential tradeoffs in values (e.g., between high renewable energy and low customer rates).

How Options Fit into Boulder's Energy Future Discussion

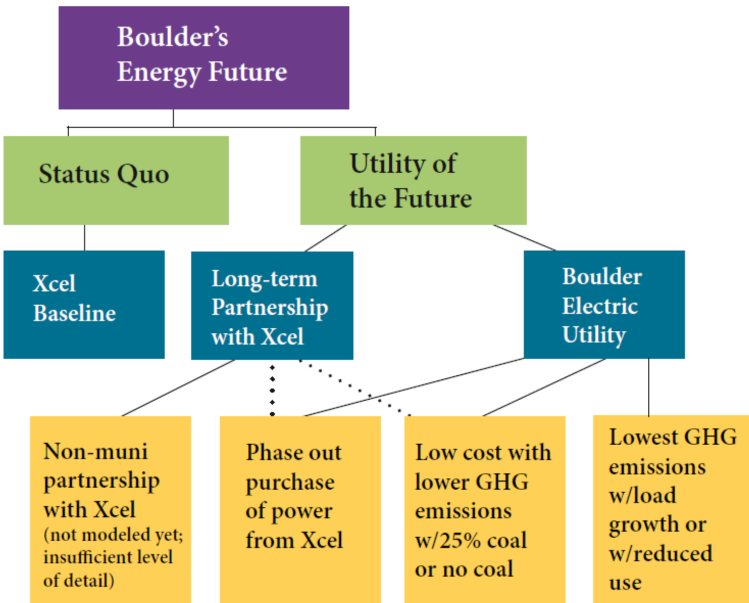


Figure 1

The working groups recommended six options, including an Xcel Baseline option, that were modeled with variations in preparation of the Feb. 26 study session. The options, as described below, are based on a presumed start date of 2017 (day one) and include projections out 20 years (2037). All of the options assume a continued investment in demand-side (DSM) initiatives such as energy conservation and efficiency, though the last option assumes a significant increase in the level of DSM investment.

Xcel Energy as Utility Provider Option

Xcel Baseline

The status quo was modeled to provide both a comparison point for municipalization options—which are required to meet or exceed Xcel Energy's performance to be feasible—and to start to explore to what degree the community's energy goals could be met under current and potential future conditions.

Municipal Electric Utility Options

The following options each represent some form of municipalization, with the ultimate goal of creating an "electric utility of the future" business model and achieving the community's energy goals.

Phase Out Power Sold by Xcel

This is a risk-mitigation option that would result in the creation of a city-run electric utility but would involve a five-year power purchase agreement (PPA) from Xcel Energy. This PPA would be based on Xcel's current wholesale energy mixture of coal, natural gas and a small amount of renewables. At the end of the five-year PPA, the city utility would be free to enter into PPAs with other energy providers, including those that offer different mixes, or cheaper sources of electricity.

Low Cost & Low Cost, No Coal

These options attempt to balance the community's desire to reduce emissions with concerns about costs. They set a goal of keeping generation costs as low as possible while also lowering emissions. The analysis of these options seeks to answer the question: Could the city exceed the Kyoto Protocol, the community's original energy future goal, and Xcel's state mandated emissions goals (30 percent renewable energy by 2020), but do so more cost effectively and with a different mix of fuel sources?

- **Low Cost**: Modeling for least-cost with a portfolio including 25 percent coal in 2017 as compared to Xcel's 50 percent coal, based on purchases from the wholesale energy market.
- **Low Cost, No Coal**: A variation on this that excluded coal was also modeled.

Lowest Greenhouse Gases (GHGs) & Lowest GHGs, Reduced Use

These options put the community goal of reducing Boulder's carbon footprint and reducing the release of harmful emissions first. They explore the effect that a maximum-impact renewable energy portfolio and greatly increased renewable energy investments could have on customer rates. These options represent the most dramatic and fastest shift from the status quo. Unlike the Low Cost options, these options were modeled without any requirement that the lowest generation costs be achieved. Like the Low Cost, No Coal option, these were modeled as no-coal options.

- **Lowest GHGs**: This was modeled with current energy efficiency and renewable energy investments and current electricity consumption trends.
- **Lowest GHGs, Reduced Use**: This was modeled as a variation that reflects the impact increased local energy efficiency investment would likely have in reducing energy consumption.

While six options are being presented, they are illustrative and **council is not being asked to choose a specific option at this time**. Rather, the analysis is intended to provide the level of information needed for council to make a decision on April 16 about whether to take the next steps toward forming a municipal utility, including preparing for litigation proceedings. The modeling also provides an opportunity to examine the movement and interdependency of the inputs that will be helpful later when an initial path is selected. For example:

- If the cost of wind power rises, how might it affect customer rates?
- Is there a point of diminishing returns for investment in renewable resources under current market and regulatory conditions?

C. Assumptions and Inputs

As described above, staff coordinated with consultants, industry experts and the working groups to define the modeling inputs and assumptions, utilizing a wide range of relevant sources. Data in the models were based on documented research, reference pricing, best practices, expert opinion and benchmarking of regional municipal utilities. Many of the modeling assumptions are unique to Xcel as an operating utility; some apply to both Xcel and a local electric utility; and others apply only to a local electric utility. A full list of assumptions and data sources is provided in **Attachment D**.

All Options
The assumptions and inputs used for all the options include:

- **Load Growth**: The modeling assumes Boulder-specific load growth rates over the 20-year planning horizon as provided by Xcel Energy[4] (except for the "reduced use" variation on the Lowest GHGs option, which reflects the impact increased energy efficiency would likely have on reducing electricity consumption).
- **Fuel Costs**: The modeled options use the same fuel cost projections that Xcel used in recent Colorado Public Utilities Commission (PUC) rate and resource proceedings. This ensures an equitable comparison among the options.

Xcel Baseline
The Xcel Baseline was designed with data from recent and publicly available information such as PUC documents, annual reports and Federal Energy Regulatory Commission (FERC) filings.

The assumptions that are unique to the Xcel Baseline option include:

- **Revenue Requirement & Rates:** The modeling uses Xcel's revenue requirement for 2013 from its most recent PUC rate cases. Xcel's rates were modeled based on its current rate structure by customer class (commercial, industrial and residential), including current tariff riders that were assumed to increase over time at an annual growth rate of 2.5 to 3 percent based on Xcel's projections.[5] However, this does not include Xcel's most recent Electric Commodity Adjustment (ECA).
- **Resource Mix:** The modeling uses Xcel's current and 20-year projected resource mix released in its 2011 Electric Resource Plan.[6]

Municipal Utility Options

[4] Boulder specific load growth was provided by Xcel Energy in Docket No. 11A-869E, 2011 Electric Resource Plan (ERP).
[5] Xcel Energy, Year End 2012 Earnings Release Presentation (Jan. 31, 2013), investors.xcelenergy.com/Cache/1500046219.PDF?D=&O=PDF&IID=4025308&Y=&T=&FID=1500046219.
[6] Xcel projected their resource mix in Docket No. 11A-869E, 2011 Electric Resource Plan (ERP).

An extensive list of inputs and assumptions was developed for the municipal utility options and vetted with the working groups. It is included as **Attachment D**. A few of the inputs are worth noting here:

- **Overall Design**:
  There are three "givens" in all of the municipal utility options: all are designed to meet the Charter metrics for revenue sufficiency (debt service coverage ratio of at least 1.25[7]), for reliability (as described more fully below), and for GHG reductions and increased renewables (short- and long-term plans to meet or exceed Xcel).

- **Service Territory**:
  The modeling assumes that the utility would serve an area that has been defined by the reliability and acquisition engineering consultants, Exponential Engineering, and the Reliability Working Group as the most technically optimal. The consultants considered the ability to separate the system at several locations without requiring duplicative facilities or a decrease in reliability. Because Boulder is separated from its neighboring communities, the electrical system has been built to serve a larger area than simply the city, and the optimal separation area became apparent. For more information on factors that were considered, see **Attachment D** and for the draft map, see **Attachment E**.

- **Electric Power Providers:**
  The modeling assumes that while existing local generation resources (e.g., hydroelectric, solar) continue to be utilized, the majority of the electricity requirements will be acquired through power purchase agreements (PPAs) for all the municipal options. While staff and the Resource Working Group agree that there will be advantages to owning and operating generation resources (e.g., hydroelectric, solar, etc.) in the long term, this will need to be evaluated in more detail, taking into consideration financial and other risks. In addition, all of the options assume a continued local investment in demand-side (DSM) initiatives such as energy conservation and efficiency. One Option (Lowest GHGs with Reduced Use) assumes a significant increase in the level of DSM (approximately three times the current levels of investment).

- **Reliability**:
  All utilities, whether municipally or investor owned, are subject to the same reliability requirements and penalties by the National Energy Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC). To ensure that all the municipal utility options will meet this standard over the 20-year modeling period, staff worked with the Reliability Working Group to address reliability in formulating the following plans and costs: separation; utility start-up; capital replacement schedule; energy resources; and, ongoing operation and maintenance (O&M). Ongoing O&M for the municipal utility options includes administration, operation, maintenance, monitoring, control, dispatch, project management, and customer service and response procedures to

[7] Debt Service Coverage Ratio (DSCR) is the ratio of net revenues available to pay debt service to the debt service requirements. The City Charter requires the utility to have a minimum 1.25 coverage ratio. The actual DSCR will vary depending on a target bond rating, although other factors will certainly impact the rating. The city's financial advisors believe the city could achieve a bond rating of "A-". For this level of bond rating, the DSCR will need to be higher than 1.25, more likely around 1.50-1.75. The model is being analyzed by exploring the sensitivity of higher target debt service coverage ratios using a range of 1.25-2.0.

assure reliable electrical service. See **Attachments D and F** for more detail on these assumptions and data sources. The analysis specifically evaluated reliability in terms of the system assets and configuration required to form a city-owned utility, ongoing capital investments, operations and maintenance costs and practices, regulatory standards, and resource reserve margins.

- **Stranded and Acquisition Costs:**
  Acquisition costs were modeled with $150 million as the highest cost scenario. That amount was the value provided by an Xcel consultant in a presentation to the city. In response to the city's request for Xcel's estimate of its stranded costs in June 2011, Xcel proposed a worst-case stranded cost figure of more than $330 million, for the first year, and $255 million if the city left Xcel's system in 2017. Therefore, stranded costs were modeled with a high of $255 million in 2017, a best case of zero obligation, and at 50 percent of the highest or worst case. Stranded and acquisition costs, also referred to as "legal" costs, were tested for sensitivity, but as described below, they were treated differently from other uncertain inputs.

D. What the Modeling Does and Doesn't Do

Attempting to forecast the future is always complex, especially looking out 20 years in an industry that is experiencing rapid change. The objective of the modeling was to, based on the metrics test, compare municipal utility options to the Xcel Energy Baseline (the status quo relationship with Xcel). Among the outputs compared were renewable resources as a percentage of total generation resources, GHG reductions over time, and rates. As in any modeling exercise, there are inherent limitations, which are discussed below. Some of these will be addressed in later phases.

The modeling outputs are based on the "can we" question.
The model outputs were tied to the quantitative metrics being used to measure performance against the Charter requirements. These metrics have to do with debt service coverage, rates, GHG emissions, and renewable energy. Analysis on reliability feeds into the financial model based on the funding needed for capital investment, self-insurance, operations and maintenance, etc. However, there are other values important to meeting Boulder's Energy Future goals—such as local job creation, and providing new options for commercial and residential customers to manage their own energy use. Analysis on these issues is being treated qualitatively at this stage in the process, but these could be modeled quantitatively as more information becomes available.

The ability to model options based on a new partnership with Xcel was limited by lack of information.
As described earlier, the modeling focuses on an Xcel Baseline option and five options related to forming a local electric utility. The Xcel Baseline was modeled using Xcel's own forecasts for the next few decades and is used in comparison with the municipal utility options. Dramatic shifts to Xcel's operations or business structure—such as the formation of a robust ancillary services market or the legislature dramatically increasing the Renewable Energy Standard—are not currently modeled, nor are most of the creative new partnerships that the city proposed in its December 2012 paper on alternatives. Xcel has not provided a response describing what

alternatives are viable and which are not, making it illogical to invest resources in modeling any of the partnership ideas that were presented.

This is not to say, however, that alternative partnerships have been excluded entirely. In December, staff proposed that Xcel could provide power purchase agreements to a Boulder municipal utility through a "Boulder rate," representing a continuing relationship that would serve both parties. For any of the municipal utility options, Xcel could provide power purchase agreements to suit the city's desired resource mix. The range of costs used for resources includes Xcel's forecasts in the development of ranges. There would need to be other shifts to the relationship related to mutual goal-setting, collaboration, and information exchange, but the selecting of municipal utility options does not preclude a continuing, innovative relationship with Xcel Energy distinct from the Xcel Baseline option that was modeled.

The modeling does not currently allow for course change.

Each option represents a set of decisions that are committed to over a 20-year period. In reality, if a municipal utility were formed, changing circumstances would lead to shifting strategies over time, resulting in the pursuit of a mixture of these potential paths. For example, based on policies set forth at the time of creation of a municipal utility, staff could begin developing a roadmap for startup based on the Low Cost option. If there are cost savings within five years, the utility could pursue a cleaner energy portfolio. Staff is investigating how to incorporate changing decisions over time in the models.

Rate or cost parity was not modeled as a separate option at this time.

The working groups recommended modeling an option that looked specifically at the reduction in GHG emissions, or other added values that could be achieved, based on matching the Xcel Baseline rates over the 20-year period. However, because this analysis incorporates probabilistic analysis, a municipalization option that matches Xcel's rates for a single set of inputs may not match Xcel's rates once the outcome is adjusted for risk, including legal risks (see description of probabilistic modeling beginning on page 18). An alternative way to get to a similar result is to consider the relative revenue requirements of the various options; i.e., how much funding each option needs to cover its costs over 20 years, discounted to net present value. If a municipalization option is expected to have cost savings compared to the Xcel Baseline option, the City Council could choose to set rates in ways that better serve customers while keeping rates comparable to Xcel's. As will be shown below, even under a middle case of stranded and acquisition costs, the Low Cost option would provide more than $200 million over 20 years that could be reinvested based on the utility's priorities. These include, but are not limited to, even higher reliability; grid intelligence; microgrid capabilities and islanding; an increasingly renewable energy portfolio; non-fracked natural gas resources; local distributed generation and energy efficiency incentives; research and development; and pilot projects with local entrepreneurs.

The risks inherent in the Xcel Baseline option have not been modeled as completely as in the municipalization options.

Carbon prices were modeled as uncertainties in all of the options; however, there are two variables that could significantly increase the amount of risk associated with the Xcel Baseline that have not been modeled. These are the impacts of Xcel's large coal investments, and whether the company's projected $3.5 billion capital expansion costs from 2012 to 2017 have been fully incorporated into its rate projections. These factors will affect Xcel's projected costs, potentially resulting in higher rates than modeled for the Xcel Baseline.

- Coal Costs: In 2004, coal costs across the country began rising significantly. According to the US Energy Information Administration (EIA), every state in the country has seen coal costs escalate at least 4.5 percent per year since 2004, and coal costs in many states are escalating at a rate greater than 10 percent per year. Because Xcel generates roughly half of its energy from coal, and fuel costs are passed through to ratepayers, the cost of coal has a significant impact on rates, especially when it makes up a large part of the resource mix. Recent projections indicate that their forecasts may be underestimated.

  As an example, coal costs at Xcel's newest and largest Colorado coal plant, Comanche 3, are currently increasing by more than 10 percent per year; however, Xcel projects its coal costs increasing by less than two percent per year when making its consumer rate projections.[8]

  Modeling the Xcel Baseline with rate increases that represent increased coal costs would likely impact the differential substantially. In addition, two of the municipalization options (Phase Out and Low Cost) have a portion of energy purchased from either Xcel or the market, and therefore would contain some small amount of energy generated from coal. As a result, volatility in coal costs is anticipated to have an impact on some of the municipalization options as well, but to a much lesser degree. In Phase II of the modeling, staff may be able to model future fuel costs from historic trends and a number of industry forecasts.

- Capital Costs: Xcel has forecasted its estimated capital expenditure programs for the years 2013 through 2017. Over the next five years Xcel Energy is expecting to spend close to $3.5 billion on electric generation, transmission and distribution. This includes $793 million for projects associated with Colorado "Clean Air-Clean Jobs" Act. Xcel's capital expenditure projections are as follows:

  Xcel Energy Forecasted Capital Expenditures (In Millions of Dollars)[9]

Actual	**Forecast**				
2012	**2013**	**2014**	**2015**	**2016**	**2017**
$887	$1,075	$1,000	$850	$800	$84

  Note: The above totals to $5.4 billion, $1.9 billion of which is allocated to Xcel's natural gas operations, leaving $3.5 billion for electric generation, transmission, and distribution.

  Staff is exploring how to incorporate these additional uncertainties in future stages of the modeling, but the ability to do so is constrained by the difficulty of interpreting the data that

[8] Xcel Energy in Docket No. 11A-869E, 2011 Electric Resource Plan (ERP)
[9] Xcel Energy, Year End 2012 Earnings Report (Jan. 31, 2013).

Xcel releases in PUC dockets. Overall, staff took a very conservative approach to modeling Xcel's Baseline with some additional costs and risks mentioned above.

V. RESULTS OF THE ANALYSIS

A. Summary of How the Options Meet the Charter Metrics

The Charter requirements and associated metrics that provide the floor for analyzing the question of whether the city can move forward with establishing a utility are summarized below. The full Charter section that allows for the creation of a municipal light and power utility is provided in **Attachment K** and a more detailed chart of the metrics is provided in **Attachment G**.

Charter Requirements	Metrics
Rates do not exceed Xcel's at time of acquisition	Average cost per kWh
Revenue sufficiency	Debt Service Coverage Ratio
Reliability compared to Xcel	Comparable equipment, facilities and services to achieve a SAIDI of 85 and SAIFI of .85; 15% reserve margin and NERC compliance
Reduce GHG emissions	Short and long term plan to meet or exceed Xcel
Increased renewables	Short and long term resource plan to meet or exceed Xcel

The chart below summarizes to what extent each of the Charter metrics are met for the municipal utility options that were modeled[10]. It should be noted that the Charter amendments also include language to ensure that the utility is operated in a fair, responsive and fiscally responsible manner. There are provisions that strive for competitive rates, cost effective improvements, responsible borrowing, nondiscriminatory and fair distribution of costs among rate classes, and limitations utility revenue transfers to the general fund. Additionally, the Charter envisions broad representation beyond citizens and allows employees of local businesses and institutions to serve as well (see **Attachment K**).

[10] Because the Charter metrics compare the municipalization options with how Xcel performs, the Xcel Baseline option is excluded from the chart.

Can the Charter Requirements be met on Day One and Over 20 Years?

	Phase Out[11]	Low Cost[9]	Low Cost, No Coal	Lowest GHG	Lowest GHG, Reduce Use
Reliability	●	●	●	●	●
Rate Parity	◐	◐	◐	🚫	🚫
Debt Service Coverage	●	●	●	●	●
GHG emissions	★	★	★	★	★
Renewable Energy	★	★	★	★	★

● = Yes 🚫 = No ◐ = Greater than 80% probability for at least one level of Stranded and Acquisition costs ★ = Greatly exceeds metrics

B. Key Overall Findings

1. All of the municipal utility options meet or exceed the Charter requirements of reliability, debt service coverage, GHG reductions, and more renewable sources of energy.

2. There are municipal utility options that are likely to also meet the Charter requirement of rate parity under different stranded and acquisition costs:
   a. Best-case ($150M): three have near or better than 80 percent likelihood
   b. Middle ($277.5M): one has better than 50 percent likelihood and one has better than 80 percent likelihood
   c. Worst-case ($405M): one has better than 50 percent likelihood

3. Four of the municipal utility options would allow the Boulder community to exceed the Kyoto Protocol in year one, and five would exceed it starting in year five.

4. The two most aggressive GHG reduction options meet all the Charter requirements except the rate parity metric.

5. The following variables have the highest impact on feasibility: stranded & acquisition costs, wind prices, gas prices, O&M costs, debt service coverage, a carbon tax, and interest rates for borrowing.

6. The GHG emissions differential between the Low Cost options and the Lowest GHGs options was not as significant as expected due to diminishing returns on carbon reduction per unit of cost under current resource cost assumptions.

[11] Both the Phase Out and Low Cost options can be built upon by Xcel to create a new type of partnership, but may require a change in state law.

7. The tentative conclusion from the modeling to date is encouraging. A municipal utility is highly likely to be able to:
    a. Offer all three major customer classes (residential, commercial and industrial) lower rates than what they would pay Xcel;
    b. Maintain or exceed current levels of system reliability and emergency response, and if the community chose to, use future investments to further enhance reliability and rate stability;
    c. Reduce harmful greenhouse gas emissions by more than 50 percent from current levels; and,
    d. Obtain more than 54 percent of its electricity from renewable resources.

8. Although additional modeling would need to be done in collaboration with Xcel Energy, a partnership with Xcel could:
    a. Be modeled using the Phase Out or Low Cost options and achieve potential cost savings and significant GHG reductions, assuming coal prices do not increase more than the modeled two percent a year, rates increase only 2.5 to 3 percent a year, and there is no impact above what is modeled from the $3.5 billion capital investment.
    b. Provide the enhanced service opportunities and localized choices described in the city's December 2012 memo.

C. Accounting for Risks and Uncertainties

The modeling done in 2011 provided council with financial, legal, and technical feasibility information. The current analysis takes this process a step further by not only refining assumptions based on additional research, but also by incorporating information that helps identify whether or not particular outcomes are likely, and what underlying factors drive those outcomes.

In the decision analysis process used by staff, consultants and the working groups, the results are based on the range of likelihoods associated with underlying factors (like the change in wind prices over time). This means that while many of the inputs and assumptions were modeled as a single fixed number, a smaller number were modeled as "uncertainties," using high, median, and low values on a common scale.[12] The working groups, staff, and consultants generated an extensive list of uncertainties that have been progressively narrowed for modeling. This decision analysis process and framework are more completely described in **Attachment H**.

The most significant uncertainties that were identified for modeling included:

All Options

- Price of natural gas – Gas prices have historically been volatile. The median price is based on Xcel's four-source blend, and the municipalization options and the Xcel Baseline were adjusted with higher and lower values to show comparative risk.

[12] While legal costs related to municipalization—stranded costs and acquisition costs—are uncertain, they were modeled based on publicly available information rather than a range of likelihoods to protect legal strategy.

- Price of wind power – Wind prices are uncertain due to increasing market demand and instability associated with state and federal incentives. The median value was based on Xcel's cost per mega-watt hour (MWh) for Limon II, with a lower value based on a low price with the production tax credit extended over 20 years, and with a higher value based on a high price without the production tax credit.
- Carbon proxy price – A carbon tax could shift which resources are more cost effective. The prices were based on a comparison of the range of carbon prices being used by utilities across the country for resource modeling. Some of those pricesare based on the models relied on by the federal government for forecasting the social cost of carbon resulting from climate change risk.
- Borrowing interest rate – Interest rates may vary depending on an entity's credit and the overall economy. The median interest rate was based on an A- rated municipal entity, with a slightly higher interest rate in the early years given the city-owned utility start up status and limited performance history from which a rating agency could establish a rating.

Municipal Utility Options

- Debt service coverage ratio (DSCR) – Although a utility would make a decision as to what debt service coverage ratio to maintain, this has been modeled as an uncertainty because a municipal entity's future credit rating is currently uncertain, and, therefore, so is the more desirable ratio. A range of ratios were modeled, from 1.25, which is the Charter-required minimum, to 2.00.
- Operations and maintenance costs – O&M costs are the expenses to maintain the local grid infrastructure. The median value is based on assessments from consulting engineers.
- Stranded and acquisition costs – These were modeled at the levels described above, but to protect legal strategy, were not modeled with probabilities. The information presented below is based on uncertainty analysis at best-case, middle-, and highest-case total amounts.

Including these uncertainties presents a more complete picture of where a particular option is susceptible to risks or able to capitalize on opportunities. It provides a range of values and the risk associated with high, nominal, and low costs. The analysis that follows is based on two types of outputs:

- Expected values: An expected value is an average of possible outcomes weighted by their likelihoods. Options with better expected values are more likely to achieve the desired outcomes. For example, the option with the lowest expected value for rates is the most likely to yield the lowest rates.
- Confidence ranges: Risk cannot be effectively modeled by showing a single output at a single point in time. Therefore, some of the results below attach 80 percent confidence ranges. This means that there is 80 percent confidence that the actual result will fall within that range. In places, this is measured around a median.

D. Summary of Outcomes by Option

The following tables show the expected values for a portion of the Charter metrics when comparing municipalization options to the Xcel Baseline option, modeled at best-case, middle, and highest-case combined stranded and acquisition costs. The outputs are as follows:

Revenue requirements: The total revenue that must be collected each year to cover all the costs of operating the utility by year, summed over 20 years, and discounted to calculate a net present value (NPV). The net present value of the yearly revenue requirements is the most common single measure of a utility's financial performance.

- Revenue requirements compared to Xcel: The revenue requirements for each municipalization option minus those of the Xcel Baseline option. By definition, it is zero for the Xcel Baseline. A positive number indicates that it is likely that the municipalization strategy will financially benefit Boulder customers because it would be cheaper to run a local electric utility under that option. Notably, the better the differential, the more likely it is that rates equal or less than Xcel's could be sustained long term rather than just at the time of acquisition, as is required by the Charter.
- Average rates: Average rates are calculated across all customer classes and are discounted to maintain consistency with the revenue requirement calculations. Total revenues are discounted over 20 years and divided by the total 20-year discounted load.
- Carbon intensity: The amount of GHGs emissions produced each year per unit of electric power consumed. They are shown for the beginning and end of the 20-year period.[13]
- Percent renewables: The percent of electric power consumed that come from renewable resources such as wind, solar, small hydroelectric, geo-thermal, and renewable biomass or waste. Wind is the dominant renewable resource across all modeled options.

[13] Total GHG emissions: The total amount of GHG emissions produced in a given year, shown for the beginning and end of the 20-year period.

BEST-CASE STRANDED AND ACQUISITION COSTS ($150 million)	Xcel Baseline	Phase Out	Low Cost	Low Cost, No Coal	Lowest GHGs	Lowest GHGs/EE
Revenue Requirements, 2017-2037 *	$2,819	$2,620	$2,398	$2,586	$2,973	$2,849
20-Yr Revenue Require'ts vs. Xcel*	n/a	$199	$421	$233	-$155	-$30
Average Rates (cents/kWh)	16.34	15.19	13.90	14.99	17.24	17.43
Carbon Intensity in 2017**	719.13	684.23	331.61	224.66	154.78	165.40
Carbon Intensity in 2037**	481.28	209.07	212.64	209.07	146.90	149.79
Total GHG Emissions in 2017***	1,136,443	1,081,296	524,035	355,025	244,600	259,653
Total GHG Emissions in 2037***	846,919	367,905	374,186	367,905	258,498	238,228
Percent Renewables in 2017***	23.10%	24.50%	57.50%	50.40%	65.80%	63.50%
Percent Renewables in 2037	24.40%	54.10%	60.50%	54.10%	67.70%	67.00%

*In millions of dollars ** kgCO2e/MWh ***mtCO_2 e

MIDDLE STRANDED AND ACQUISITION COSTS ($277.5 million)	Xcel Baseline	Phase Out	Low Cost	Low Cost, No Coal	Lowest GHGs	Lowest GHGs/EE
Revenue Requirements, 2017-2037 *	$2,819	N/A	$2,597	$2,785	$3,172	$3,048
20-Yr Revenue Require'ts vs. Xcel*	n/a	N/A	$222	$34	-$354	-$229
Average Rates (cents/kWh)	16.34	N/A	15.06	16.15	18.39	18.64
Carbon Intensity in 2017**	719.13	N/A	331.61	224.66	154.78	165.40
Carbon Intensity in 2037**	481.28	N/A	212.64	209.07	146.90	149.79
Total GHG Emissions in 2017	1,136,443	1,081,296	524,035	355,025	244,600	259,653
Total GHG Emissions in 2037	846,919	367,905	374,186	367,905	258,498	238,228
Percent Renewables in 2017	23.10%	N/A	57.50%	50.40%	65.80%	63.50%
Percent Renewables in 2037	24.40%	N/A	60.50%	54.10%	67.70%	67.00%

*In millions of dollars ** kgCO2e/MWh *** mtCO_2 e

HIGHEST-CASE STRANDED AND ACQUISITION COSTS ($405 million)	Xcel Baseline	Phase Out	Low Cost	Low Cost, No Coal	Lowest GHGs	Lowest GHGs/EE
Revenue Require'ts, 2017-2037 *	$2,819	N/A	$2,796	$2,984	$3,371	$3,247
20-Yr Revenue Require'ts vs. Xcel*	n/a	N/A	$23	-$165	-$553	-$428
Average Rates (cents/kWh)	16.34	N/A	16.21	17.30	19.55	19.86
Carbon Intensity in 2017**	719.13	N/A	331.61	224.66	154.78	165.40
Carbon Intensity in 2037**	481.28	N/A	212.64	209.07	146.90	149.79
Total GHG Emissions in 2017***	1,136,443	1,081,296	524,035	355,025	244,600	259,653
Total GHG Emissions in 2037***	846,919	367,905	374,186	367,905	258,498	238,228
Percent Renewables in 2017	23.10%	N/A	57.50%	50.40%	65.80%	63.50%
Percent Renewables in 2037	24.40%	N/A	60.50%	54.10%	67.70%	67.00%

Figure 2

Xcel Baseline
Greater than 80% probability of meeting the Charter metrics
Greater than 50% probability of meeting the Charter metrics

N/A: Phase Out option is designed to minimize stranded costs and would not be pursued for middle or worst-case stranded/ acquisition costs

Figure 2 illustrates that in a best-case scenario for stranded and acquisition costs, three municipalization options have lower expected rates and revenue requirements than the Xcel Baseline option, making it more likely that they would perform better than Xcel[14]. Additionally, analysis shows a greater than 80 percent confidence that those options would accrue 20-year cost savings compared to the Xcel Baseline option under the best-case stranded and acquisition costs.

Under the middle case of stranded and acquisition costs, the Low Cost option, the analysis still shows more than 80 percent confidence in being able to accrue 20-year cost-savings, and over 50 percent confidence that there would be cost savings under the Low Cost, No Coal option.[15] A more detailed examination of the risks associated with the Low Cost option and the highest-case result on stranded and acquisition costs indicates a 57 percent chance that even this combination would provide lower rates than Xcel.

The two most aggressive options relating to renewable energy and GHG emissions are unlikely to allow matching of Xcel rates at any level of stranded and acquisition costs. This suggests that it would be more prudent to pursue a low-cost option early on and then consider utilizing cost savings to invest in a progressively cleaner portfolio over time. Because these options are significantly higher cost without generating proportionately greater reductions in carbon intensity than the lower-cost options, they have been excluded from some parts of the more detailed analyses below.

E. Reliability

Reliability is a term used to describe the level of uninterrupted service an electric power utility provides. Reliability depends on a combination of the quality of the physical infrastructure as well as the ability of the utility to control the system and respond to failures. Certain elements of reliability are governed by federal and regional regulations. In addition to meeting the regulations, the Charter requires that to create an electric utility, the city must provide reliable electric power comparable to or better than Xcel Energy at time of acquisition.

Given its importance to businesses and residents in the community, staff worked internally and with the Reliability Working Group to develop a separate analysis and plan provided in **Attachment F**. Specialized engineers were hired to evaluate the system and its current condition, provide recommendations on needed improvements, identify regulatory reliability requirements, and recommend best practices to ensure reliable electrical service. As described in the Assumptions section of the memo, all municipalization options were designed to meet the Charter metrics related to reliability.[16]

---

[14] It is worth noting that the average rate for the Lowest GHG, Reduced Use option is higher than the Lowest GHG option likely because less electricity is consumed due to energy efficiency. This could also translate into lower overall bills.

[15] There was also greater than 50 percent confidence that there would be cost savings for the Phase Out option compared to the Xcel Baseline at the middle level of stranded and acquisition costs, although the Phase Out option would not be paired with higher levels of costs because it was specifically designed as a risk mitigation option.

[16] Maintain comparable electric equipment, facilities and services as those of Xcel at time of acquisition, which will be designed to achieve the same System Average Interruption Duration Index (SAIDI) of 85 and a System Average Interruption Frequency Index (SAIFI) of .85; maintain an adequate reserve margin of 15%; and meet applicable North American Electric Reliability Corporation (NERC) compliance requirements.

To achieve this, analysis of reliability was considered in formulating the plan for separating from the Xcel system, start-up of the utility, the capital replacement schedule, energy resource plans as well as the human, organizational and financial resources that will be needed for ongoing administration, operation, maintenance, monitoring, control, dispatch, project management, customer service and response procedures with the intent of assuring reliable electrical service if it is decided that a municipal electric utility should be created.

A separation plan has been developed based on service area boundaries that serve the city and minimize areas of separation on existing feeders. The plan maintains the vast majority of the existing system configuration, including looping and redundancy features that are integral to maintaining high reliability. At the substations, the city would acquire the equipment on the "low-side" of the transformers and Xcel would maintain the "high-side" equipment and the transformers. This division of responsibility for equipment at substations is common where the distribution system is operated by a different entity than the transmission system. Any necessary interfaces to the external distribution grid outside of the substations would be accomplished by deploying switched, metered interconnections to provide backup and redundancy for both Xcel and city feeders. Where such interconnections are not feasible, additional infrastructure would be constructed to establish and/or maintain looping, redundancy, and reliability enhancing features.

Federal regulations have positively influenced the reliability of the interconnected transmission and generation system within the United States. Energy (generation) resource plans and associated transmission capabilities would comply with all regulations, maintain a 15 percent reserve margin and provide adequate on-line and off-line reserves with the intent of ensuring a reasonable (one day in 10 years) loss of load expectation.

F. Carbon Intensity

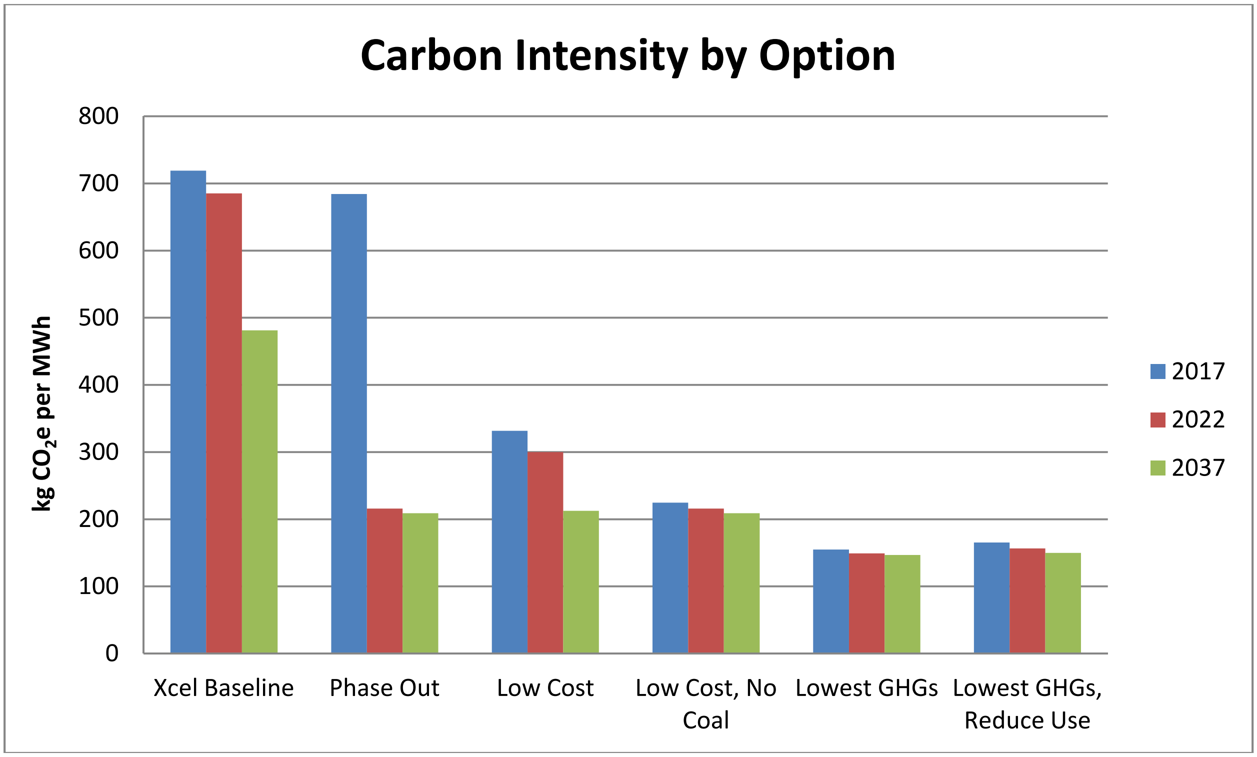


Figure 3

Figure 3 above illustrates the expected carbon intensity, or the amount of carbon by weight emitted per unit of energy consumed, of each option at three intervals in time: 2017, 2022, and 2037. Because there are several fuels assumed in each option, carbon intensity is based on their combined emissions coefficients. Figure 3 further illustrates that:

- All options, including the status quo, are expected to have declining GHG emissions over time.
- All of the municipalization options, except the Phase Out option, provide an immediate and significant reduction in emissions, which is maintained over the long term. The Phase Out option projects emissions the same as the Xcel Baseline option, because it is based on Xcel's current power mix for the first five years. The GHG emissions projection drops significantly in 2022 with a switch to the Low Cost, No Coal option.
- Projected GHG emissions are not impacted by different stranded and acquisition cost levels.
- The GHG differential between the Low Cost options and the Lowest GHGs options was not as significant as expected. This is primarily due to reaching a point of "diminishing returns." To achieve cuts in emissions beyond the Low Cost option, the modeling incorporated a large amount of solar, which is currently more expensive than wind and natural gas. This could change as the price of conventional fuels continue to rise, and the prices of local energy sources fall due to new technology breakthroughs, early adoption and economies of scale.

G. Total GHG Emissions

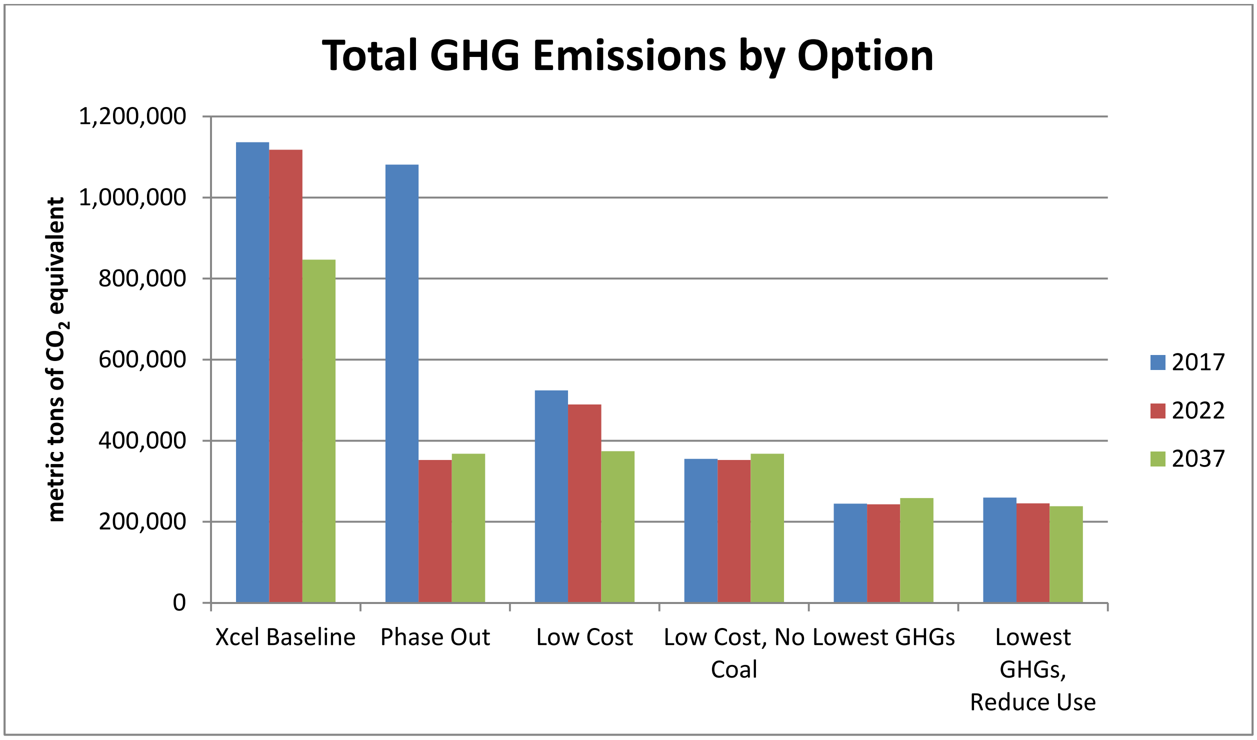


Figure 4

Figure 4 shows the total GHG emissions of the six options, as measured in metric tons of carbon dioxide equivalent. This is measured for 2017, 2022, and 2037. The findings are:

- The greatest impact comes from reducing coal-based generation as a percentage of the overall electric resource mix. The Xcel Baseline option shows a decrease in GHG emissions in 2037 based on a projected switch to a larger natural gas and smaller coal portfolio at that time.
- Total GHG emissions increase over time for several of the options despite decreasing carbon intensity because of the projected load growth that was modeled for all but the Lowest GHGs, Reduced Use option; an increasing load outweighs the decreasing intensity. For the Lowest GHGs, Reduced Use option, GHG emissions decrease over time, showing the impact of energy efficiency reducing Boulder's load.
- The Lowest GHGs, Reduced Use option actually has slightly lower levels of renewable energy and higher levels of natural gas than the Lowest GHGs option, creating slightly higher overall GHG emissions in initial years despite its reduced load.

H. Renewable Mix for Each Option

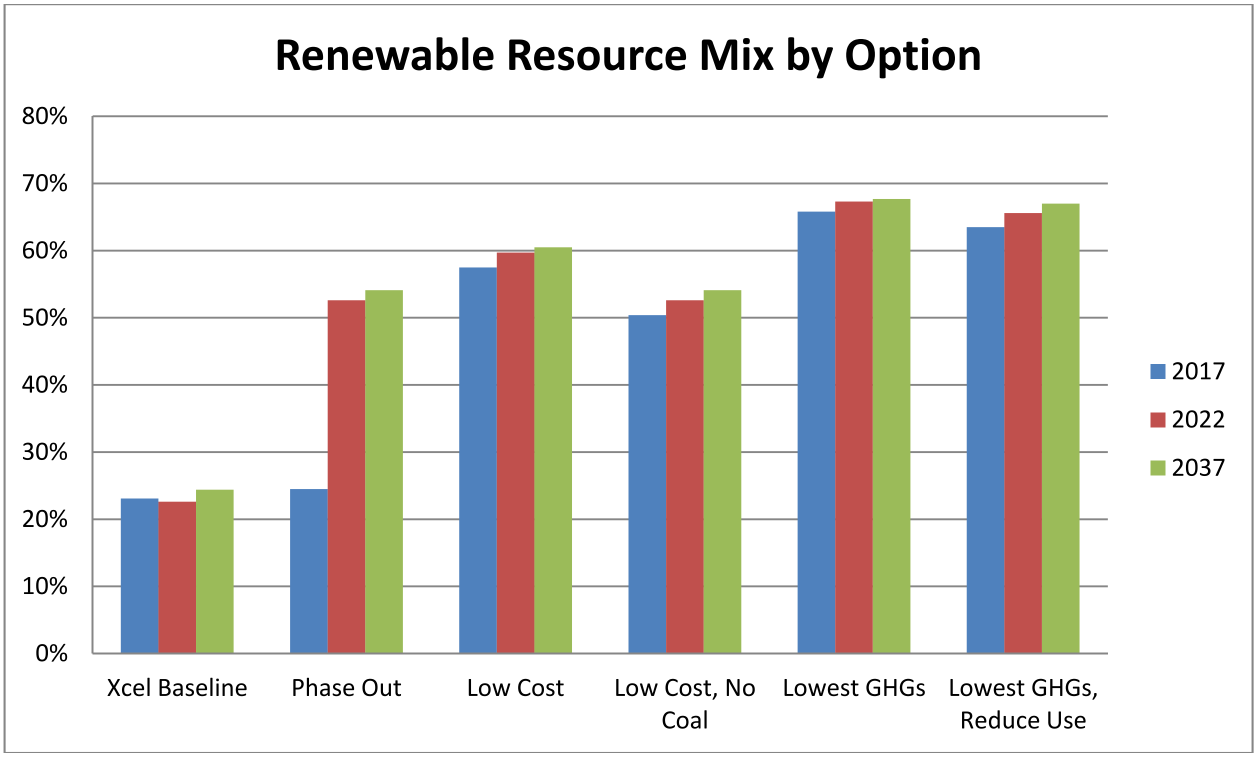


Figure 5

In order to create an electric utility, the Charter requires a plan for reducing GHG emissions and other pollutants as well as increased renewable energy. Figure 5 illustrates the percentage of renewable energy associated with each option in 2017, 2022 and 2037. As expected, the percentage of renewables in each portfolio (due to purchasing large amounts of renewable energy such as wind, solar and hydroelectricity[17]) directly influences the overall carbon intensity of each option (shown in Figure 3).

All municipalization options, except the Phase Out option, result in more than a doubling of the amount of renewable energy in Boulder's portfolio. This is primarily due to large purchases of available wind power.

All of the options were modeled without the benefit of the wind Production Tax Credit (PTC) (scheduled to expire at the end of 2013), or the solar Investment Tax Credit (ITC) (scheduled to expire at the end of 2016). The PTC and ITC are incentives that lower the overall price of wind and solar energy.

Importantly, while the Lowest GHG option is indicating that just below 70 percent of Boulder's portfolio would be from clean energy sources, it is feasible that the actual percentage could be even higher. The Lowest GHG options were not calculated as a theoretical portfolio, but rather as a realistic portfolio considering current cost and availability. To increase the portfolio above

[17] All municipalization options assume incorporating the city's hydroelectric generation into the portfolio. Currently, this electricity is produced at the city-owned facilities and sold directly to Xcel Energy.

this level requires the inclusion of more expensive generation and storage technologies. This will likely change with advances in technology that will be driven by the rising cost of fossil fuels and/or future carbon regulations.

Additional findings related to Figure 5:

- Xcel has projected the percentage of renewables in its portfolio in its most recent seven-year resource acquisition period (RAP) and 40-year planning period. While Xcel's carbon intensity is predicted to decrease over time due to increases in natural gas (see Figure 3), Xcel has projected that its percentage of renewables will stay at approximately 24 percent through 2037.[18]
- The Phase Out option shows a significant jump in renewables in year five. That is due to the fact that the option includes purchasing energy from Xcel for five years, then switching to the Low Cost option.
- All of the municipalization options show a significant increase in renewables in the early years, with little change in the later years because the renewable resources do not become significantly more cost effective.

[18] Colorado's renewable energy standard (RES) requires Xcel to purchase or generate 30% of its portfolio from renewable energy sources by 2020. However, under current law, for every kilowatt-hour of electricity provided by an in-state renewable resource it counts as one and one quarter hour toward Colorado's 30% renewable mandate. Therefore, Xcel's actual mandate without the 125% in-state multiplier is 24 percent. Xcel has not projected any additional renewables beyond the RES requirement. To ensure an accurate comparison to the Xcel Baseline, none of the other options modeled apply the in-state multiplier.

I. Options Compared to the Kyoto Protocol Goal

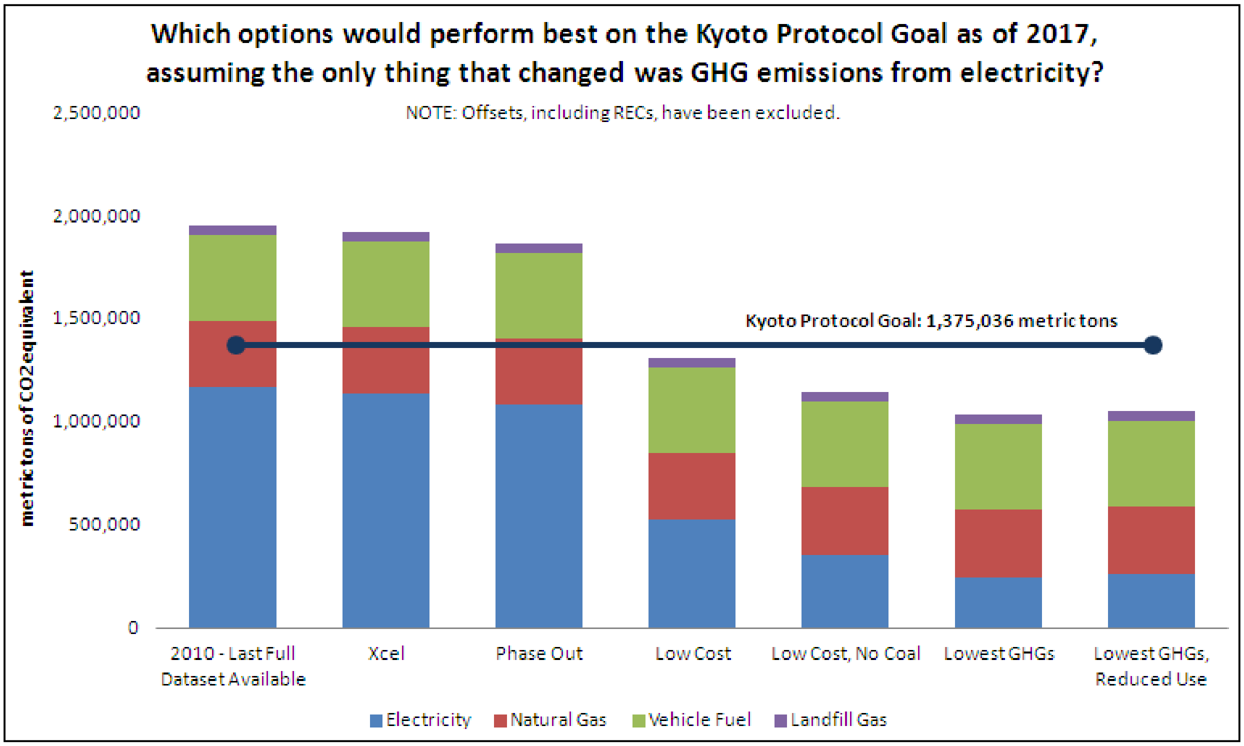


Figure 6

As shown in Figure 6, all municipalization options exceed the GHG emission reduction levels associated with the Kyoto Protocol levels[19] immediately except for the Phase Out option, which would meet Kyoto after the switch to the Low Cost, No Coal option in year five. The primary reason for the immediate and significant GHG emissions decrease relates to the replacement of coal projected in Xcel's portfolio, with available cleaner energy sources, including natural gas. To illustrate, generating one kilowatt-hour of electricity from coal releases roughly twice as much carbon dioxide (CO_2) to the atmosphere as generating the same amount from natural gas,[20] so a slight shift in the use of coal to natural gas can result in a sharp drop in GHG emissions. Xcel could potentially reach these same targets by reducing the percentage of coal in its resource portfolio, and the Low Cost option is an example of how that could be achieved.

---

[19] Boulder's Kyoto Protocol target was to reduce community emissions seven percent below 1990 levels by the end of 2012.

[20] Over its full cycle of production, distribution, and use, natural gas emits just over half as many greenhouse gas emissions as coal does for equivalent energy output, according to a new study from the Worldwatch Institute and the Deutsche Bank (www.worldwatch.org).The analysis clarifies the role of methane releases in the calculation of comparative emissions between the two fossil fuels and explores how the growing share of natural gas production from shale formations could change that fuel's footprint.

J. Average Rates Over Time By Option

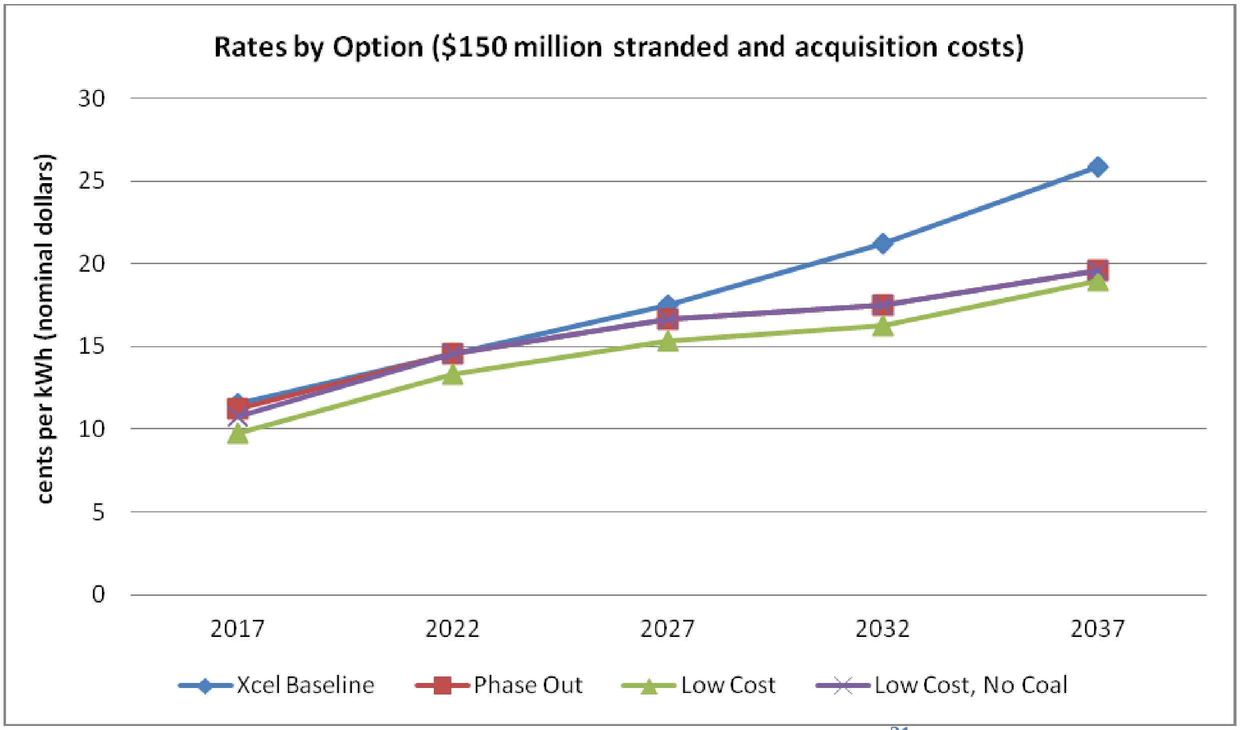


Figure 7: Average Rates Each Year by Option ($150 million stranded and acquisition costs)[21]

[21] In Figure 7, the Phase Out option and the Low Cost, No Coal option overlap since these options are identical beginning in 2022 after the phase-out period is over.

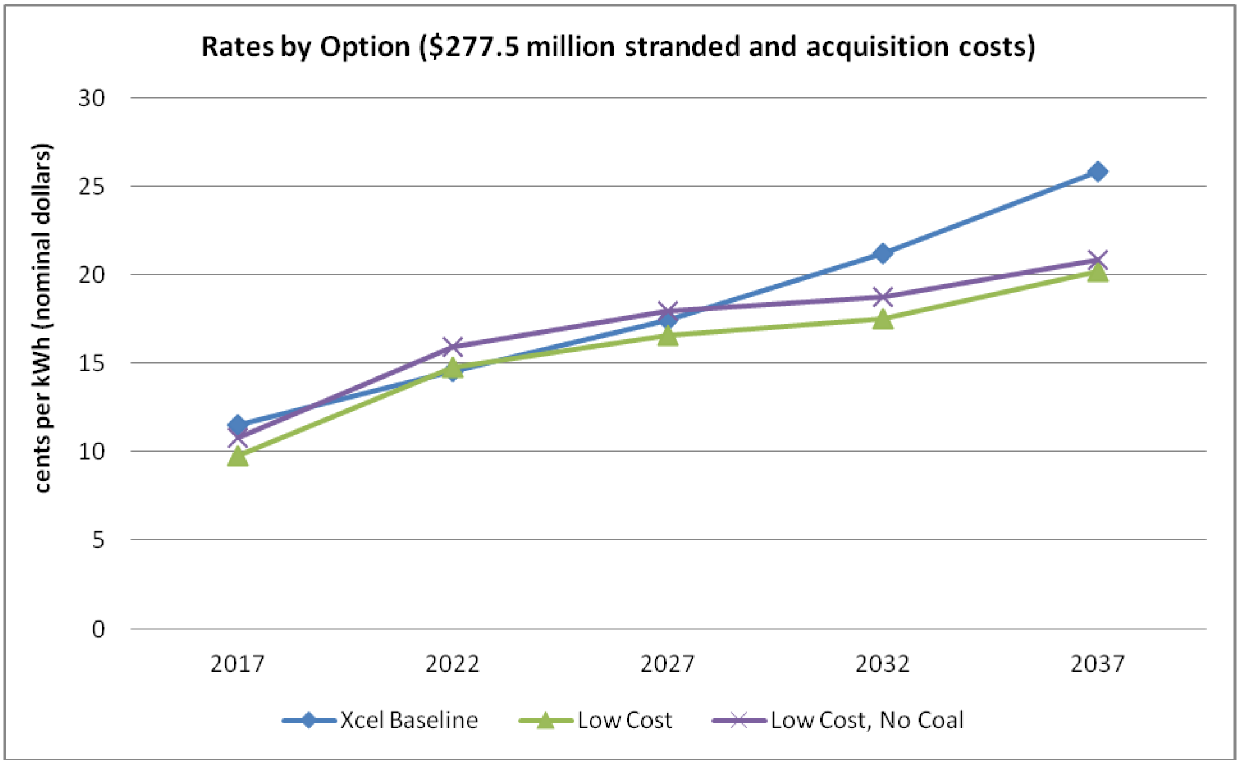


Figure 8: Average Rates Each Year by Option ($277.5 million stranded and acquisition costs)

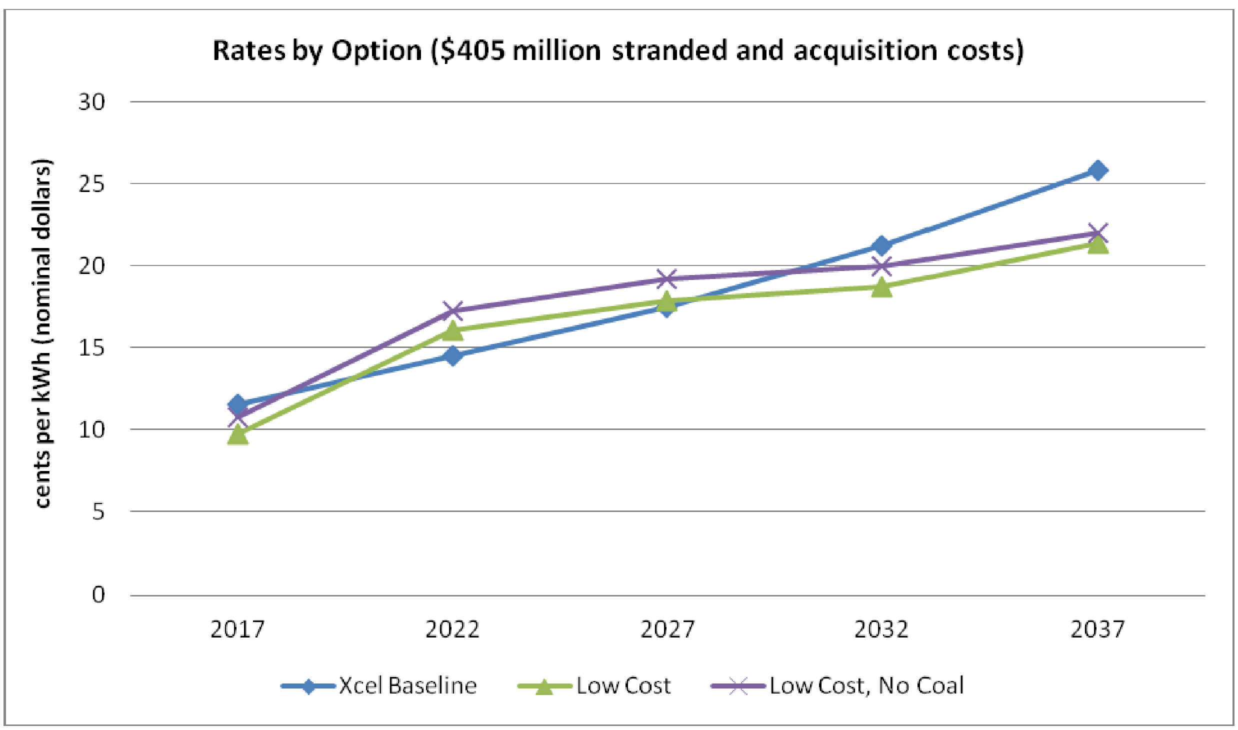


Figure 9: Average Rates Each Year by Option ($405 million stranded and acquisition costs)

In order to create an electric utility, the Charter includes a requirement that rates do not exceed those charged by Xcel at the time of acquisition. The metric to show if this Charter requirement is met compares the average cost per kilowatt hour (kWh) of the municipal utility to Xcel on day one. The charts in Figures 7 through 9, above, show average rates by option at three different levels of stranded and acquisition costs over time for the top performing municipal options (i.e., those that have a greater than 50 percent likelihood of meeting the Charter metrics) in comparison to the Xcel Baseline. In Figure 7, the Phase Out option and the Low Cost, No Coal option overlap since these options are identical beginning in 2022 after the phase-out period is over. The Phase Out option is not shown in Figures 8 and 9 since it is a strategy to reduce stranded costs and would not be relevant under the middle and high cost cases. In all three figures (7 through 9), the rates in the options shown are at or below Xcel's rates at the time of acquisition (2017). Importantly, rates for the municipal utility are not modeled as stabilized[22] in this analysis. Ultimately, the governing board of the utility could decide whether or not to stabilize rates, which could mean initially setting rates at the Xcel level, using the excess revenues to build a reserve, and accessing that reserve to keep rates stable in higher cost years.. Looking at the 20-year revenue requirements in Figure 2 provides a better proxy for what the rates would look like should they be stabilized to track Xcel's over time.

As mentioned earlier, the Xcel Baseline rates are modeled based on Xcel's projected uniform increases over the major cost categories plus inflation, whereas the rates in the municipal utility options are determined through the modeling process, reflecting changes over time. It should also be noted that the model includes a carbon proxy price as an uncertainty in later years, which would have a greater impact on Xcel's rates than on the municipal utility options.

Figure 7 shows that under the best case for stranded and acquisition costs, the Phase Out and Low Cost, No Coal options are expected to have rates equivalent to Xcel in the short-term and better than Xcel in the long-term. The Low Cost option is expected to have lower rates throughout the 20-year modeled period. Figure 8, showing the middle case of stranded and acquisition costs, illustrates that the Low Cost option performs better than Xcel throughout the 20-year period while the Low Cost, No Coal option performs the same as Xcel initially, goes above Xcel from approximately 2019 to 2027, and then performs better than Xcel again from 2027 to 2037. This is due to the fact that these rates have not been stabilized to match Xcel's growth trajectory. As seen in Figure 2, the Low Cost, No Coal option still performs better than Xcel over the 20-year period in the middle case. In Figure 9, the highest-case stranded and acquisition costs, only the Low Cost option is expected to have an overall advantage in rates as compared to Xcel.

These results show some of the future possibilities but are not intended to define the exact path forward. In any of the stranded and acquisition cost cases, the municipal utility could begin with the Low Cost option and perform better than Xcel on day one, and change course over time to any of the other options and still perform better. Another possibility would be to create a rate stabilization fund that charged the same rates as Xcel under the Low Cost option and use the additional revenues to invest in other priorities such as even higher reliability, more renewable

[22] Rate stabilization in this context refers to matching Xcel's rates from day one by creating a similar revenue requirement and using the excess revenues to keep rates lower in later years. Since the debt for the municipal utility is capitalized over the first 18 months, as is standard with most municipal debt issues, debt payments are not made during that time, resulting in a lower revenue requirement than periods of time when debt payments are made. Rate stabilization can be modeled to show a more level rate increase overtime, but looking at the revenue requirement differential over 20 years shows a more accurate picture of the rates over time compared to Xcel.

resources or grid intelligence. The Low Cost option could most closely mirror an Xcel option, given the makeup of the resources.

K. Revenue Requirements/ Costs for the Top Performing Options

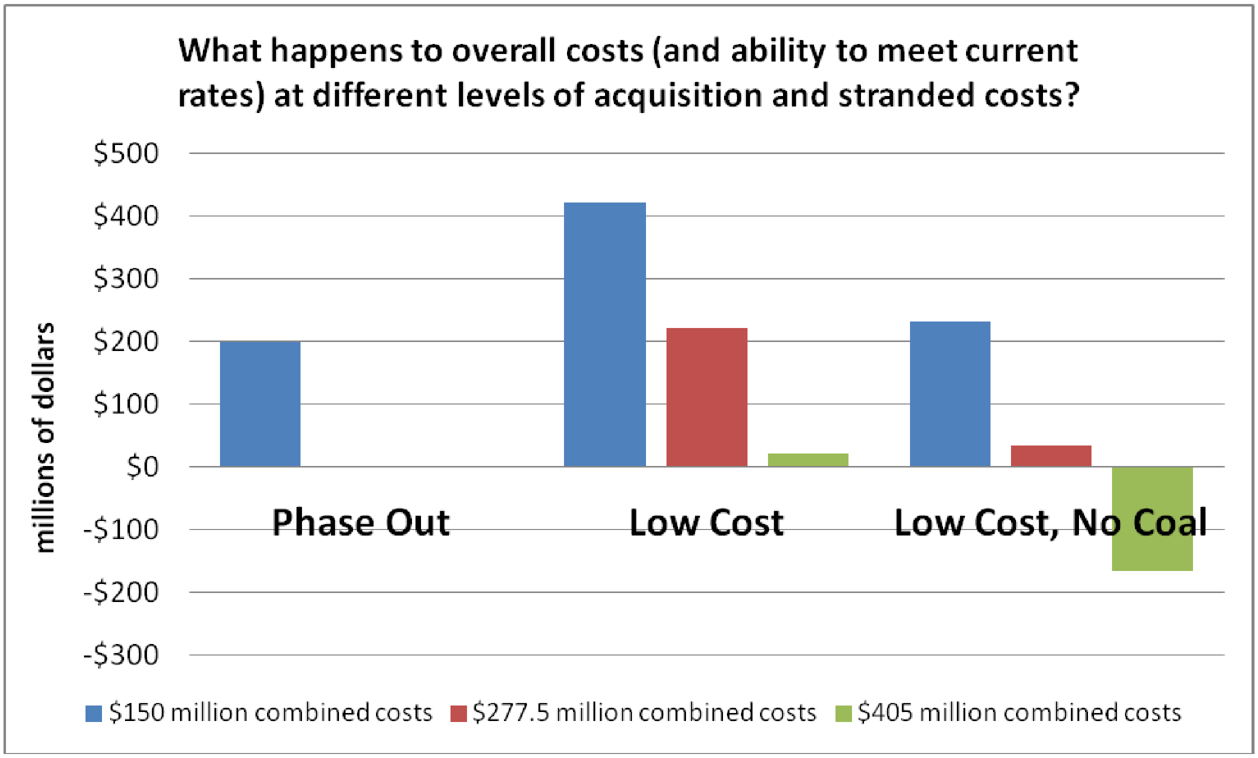


Figure 10

Figure 10 depicts the expected value cost savings or losses compared to the Xcel Baseline option for the three best-performing municipalization options. The savings or losses are based on comparing the cost of running a municipal utility over 20 years to the Xcel Baseline, in net present value. This can provide a more complete picture than looking at simply the first year's rates. Three levels of stranded and acquisition costs are shown. Only the best-case stranded and acquisition cost case is shown for the Phase Out option because it would only be chosen as part of a negotiation with Xcel that eliminated stranded costs and minimized acquisition costs. For both the best-case and middle stranded and acquisition cost levels, the Low Cost and Low Cost, No Coal options are likely to have significant cost advantages over the Xcel Baseline.

The subsequent charts below in Figures 11 and 12 extend this comparison to provide a range around the median value. Because many aspects of the future are uncertain, revenue requirements and rates cannot be predicted exactly. These graphs provide indicators of how accurately the city can currently predict outcomes. They show the interval around the median in which the city is 80 percent confident the actual differential in revenue requirements will fall.

This focuses on the two options that perform best over 20 years compared to the Xcel Baseline option: Low Cost and Low Cost, No Coal.

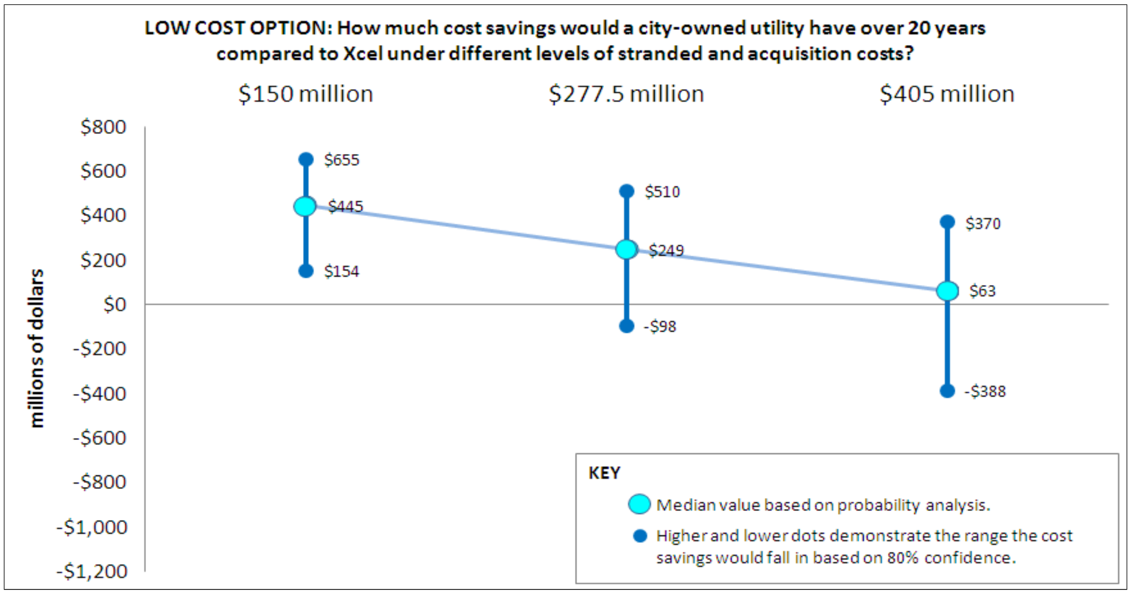


Figure 11

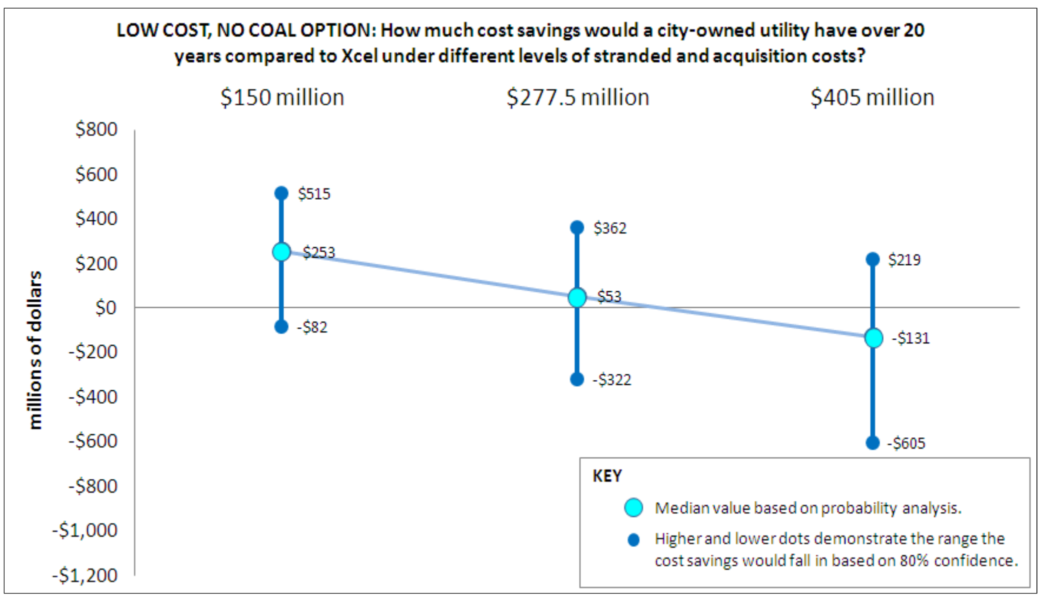


Figure 12

Figure 11 shows the median value of cost savings for the Low Cost option when compared to the Xcel Baseline over 20 years, at three different levels of stranded and acquisition costs. Cost savings are shown as positive numbers. Under the Low Cost option, the 80 percent range around the median value is fully positive for best-case stranded and acquisition costs, indicating greater than 90 percent confidence that cost savings, and therefore lower rates, could be attained.[23] At the middle level of costs, a portion of the range around the median shows cost losses, but there is still a greater than 80 percent likelihood of savings. This drops to approximately 57 percent confidence in cost savings under worst-case stranded costs, as slightly less than the bottom half of the distribution of the results are negative (losses).

[23] An 80 percent confidence range includes an additional 10 percent of the results are distributed on each of the high and low ends.

Figure 12 shows a similar trajectory of median values decreasing. With the best-case stranded and acquisition costs, most of the range around the median is positive and there is over 80 percent confidence that the Low Cost, No Coal strategy would be at or below the rates in the Xcel Baseline. At middle stranded and acquisition costs, the median value is positive and there is over 50 percent confidence that cost savings over 20 years can be achieved. At highest-case stranded and acquisition costs, most of the bar is in the negative region. The results indicate less than 50 percent confidence in being able to achieve cost savings, and therefore lower long-term rates.

There are two takeaways from these figures. The first is that the distribution curves of the modeled results are relatively normal, with the mean and median being similar. The second is that the Low Cost option is flexible enough to provide cost savings under a large range of legal costs, with a high degree of confidence.

L. Sample Customer Costs

Attachment I includes a comparison between the Xcel Baseline and each of the top three modeled options, showing a sample residential, business and industrial customer's expected total electric bill including: consumption (kWh), rate ($/kWh), total cost ($/month), greenhouse gas ($mtCO_2$) and renewable energy (%) information. The bill calculations were done using expected values, meaning that they are based on the average of possible outcomes weighted by their likelihoods rather than being the exact rates that would necessarily be charged under any option. The Xcel Baseline rates for each customer class in years one, five and twenty; as well as the average over the twenty years; are based on the current rate structure by customer class: residential, commercial and industrial, including Xcel's current tariff riders, projected out for the modeled year. The electric rates do not attempt to mirror Xcel's complex rate design by cost area; and they do not include separate demand charges because the city does not have enough detail about Xcel's rate structure to model these. However, it is still useful to look at sample bills, so this attachment shows the range of possible costs for each option in years one, five and twenty for the low, medium and high end estimates for stranded and acquisition costs.

VI. UPDATE ON DISCUSSIONS WITH XCEL

Last December, city staff prepared a paper that outlined possible ways that Xcel Energy could choose to partner with Boulder to meet the city's Energy Future goals. The options included many alternatives to municipalization. Most of these options would require PUC approval. Some would require changes to state law. All of them would require Xcel Energy working with the city to effect a change in the status quo of electric utility operations.

Staff members have met with Xcel's representatives several times since the city issued its paper. Xcel Energy's representatives have expressed a willingness to work with the city to bring about change throughout the entire Xcel Energy system but have not yet indicated what ideas the company might be willing to consider. As a result, city staff, at the direction of City Council, asked Xcel Energy to state which, if any, of the ideas in the paper the company would be interested in pursuing. In response, Xcel made a confidential proposal to work with the city to study community goals and develop a list of community priorities and options. City staff invited Xcel Energy to present this proposal in more detail in public at the Feb. 26 study session. As of the date of this printing, it is unclear whether Xcel Energy will participate in the study session. However, in a letter received Feb. 20 (**Attachment J**), Xcel officials have stated they are willing to work with the city to evaluate and pursue partnership options by establishing a joint city–Xcel working group that would include representatives from the community. If council agrees, staff will begin this process after the Feb. 26 work session.

VII. PUBLIC INPUT

In addition to the robust working group process and consultant involvement described previously, staff felt it was important to reach out to key business leaders to not only discuss the city's process and approach but to hear more about their concerns and ideas. The staff team also wanted to engage them in reviewing preliminary findings. Consequently, a small group of business and academic leaders was formed for the specific purpose of vetting the draft outcomes. Members of this group were not strong proponents of municipalization; instead, they provided a perspective that is important to consider as the city moves forward in choosing its form of electric service provider.

Lastly, the city took additional steps to make members of the more general community aware that there is new information related to the city's analysis and encouraging individuals to tune in to the Feb. 26 study session. This included print and digital advertising in The Daily Camera and the Boulder County Business Report, as well as information made available through press releases and social media.

VIII. NEXT STEPS

A. Public Input

While interested individuals are welcome and likely to provide feedback between Feb. 21, when this memo is made public, and a council decision on April 16, the city is planning a focused period of outreach and feedback-gathering about the presented options between March 6 and March 15. The overall strategy is to leverage existing platforms, such as local media, Channel 8, social media, InspireBoulder and the project website to encourage engagement, while also providing unique opportunities geared toward distinct audiences. Highlights of the plan include:

- **A business community-oriented conference call**
  The city is planning to pilot an approach that has been used by business organizations successfully in the past, inviting interested participants to call in from the convenience of their offices or other locations. The proposed format will be a one-hour panel discussion with a robust question and answer period moderated by a professional call facilitator. The conversation will be recorded so those who cannot participate can listen to it later. This is scheduled for noon to 1 p.m. on Tuesday, March 12. The city is contracting with TelSpan to provide this service. Part of the goal is to pilot the approach and evaluate its value in relation to other city initiatives. While any member of the public will be welcome to take part in the call, the topics for discussion by panelists will be the options' possible impacts on rates and reliability, as these have been identified as the areas of the most concern for

Boulder businesses. Heather Bailey and other Energy Future staff members have also offered to attend existing meetings of any business organizations that would like to host a presentation and question and answer session with their members.

- **A general community open house**
  The city is working with community partners to host an open house targeted toward potential residential city electric utility customers who wish to provide feedback about the energy future options. The session has been scheduled for 6:30 to 8:30 p.m. on Wednesday, March 13, at the West Senior Center. The format is likely to include a short video presentation, followed by a self-guided walk through stations that feature each of the options. One-page information sheets and at least one staff member will be available to further explain the options, and participants will be asked to indicate through dot voting which of the opportunities and challenges associated with each option most represent the feedback they would like to provide council.

- **An informal quantitative questionnaire, coupled with more long-form comment opportunities**
  The city is working to develop a short questionnaire that asks people to provide quantitative feedback, likely on a scale of 1 to 5, about each of the options. Due to resource constraints and in recognition that council input at this stage, while important and relevant to the expenditure of resources, is not likely to represent a final decision about whether to create an electric utility. Staff is proposing to make this questionnaire available through digital and web-based channels as opposed to a formal telephone survey. The results will be limited, therefore, by the individuals who choose to participate. However, the city intends to use a tool that will ensure that those providing feedback are either residents or people who own businesses or work in Boulder or would be covered as customers under the proposed service area plan. The value of this approach is that it will provide more of a numeric snapshot about the issues that are rising to the top from the public's perspective. This survey would not replace the comment form option that this project has provided so far. Individuals who wish to write more qualitative feedback will be welcome to do so. Both the quantitative and qualitative input will be summarized for council as part of the April 16 meeting packet.

The city is also working with local media in hopes of encouraging in-depth coverage of the options either immediately before or during this time period. Several of the ads placed in local media in advance of the Feb. 26 study session outlined ways members of the public can learn more about and evaluate the options during this focused outreach period.

Lastly, building on an effort made earlier this year, the city will be emailing an update to neighborhood groups in hopes of reaching a broader residential audience than has been achieved in the past.

B. April 16 Council meeting

At the April 16 council meeting, staff will respond to any issues that were raised at this study session and report on the results of the public input process outlined above. Assuming that council agrees that it is appropriate to consider possible next steps, the agenda item will be a public hearing and consideration of a motion to:

- Authorize the city attorney to complete the due diligence efforts that are required before City Council can take formal action to acquire property for a municipal electric utility;
- Authorize the city attorney to initiate and pursue or intervene in any action necessary to determine any potential rights or obligations of the city and means of separating from Xcel Energy's system under state or federal law, including without limitation the Federal Power Act and "Public Utilities," Title 40, C.R.S.;
- Authorize the city manager to pursue meetings with rating agencies and potential bond purchasers to further analyze financing options for creation and operation of a municipal electric utility; and,
- Authorize the city manager to develop a process for hiring an independent third-party expert to verify that a municipal utility could meet the requirements in Section 198 of the Boulder Home Rule Charter.

Council can decide to stop the major steps outlined above if they result in costs in excess of what the city can afford to still meet the Charter metrics.

C. Legal Steps

If council authorizes the city attorney and city manager to complete its due diligence efforts, the City Attorney's Office will initiate the steps described below after the April 16 city council meeting.

<u>Acquisition</u>: Prior to starting the legal process to acquire property, including by eminent domain, the city must define the scope of the acquisition. This includes defining the precise boundaries of the new utility; and creating s an inventory of all of the real property interests and equipment to be acquired. Consulting engineers reviewed the electrical system as it exists and available records. Legal professionals have searched recorded real property documents, and appraisers prepared estimates of value for the system. Engineers evaluated separation options and recommended a service area plan that allows both the new utility and Xcel to operate as well as or better than before separation.

The next phase will require formal appraisals and further study of the precise location of the outer boundaries for separation. In addition, environmental investigation work and other due diligence is necessary before staff can present to council a sufficiently specific definition of the project and an appraisal of fair market value required for an eminent domain action. If council elects to proceed with these steps on April 16, *and if the additional due diligence confirms that the city should create an electric utility,* staff intends to present to council an ordinance to authorize acquisition of the real and personal property necessary to create an electric utility at its August 6, 2013 meeting. Thereafter, the process starts with the city performing good faith negotiations with Xcel to attempt to reach agreement on the fair market value. If those negotiations fail, the city will file a petition in condemnation with the court.

Regulatory Actions:
There are a number of potential issues that will need to be addressed to insure compliance with federal regulatory requirements. In particular, there is the issue of potential stranded costs that the city may owe to Xcel. Stranded costs are "any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide [generation] service to…[a] retail customer that subsequently becomes, either directly or through another wholesale transmission purchaser, an unbundled wholesale transmission services customer of such public utility or transmitting utility." 18 C.F.R. § 35.26(b)(1)(ii). The term "stranded costs" refers to generation-based stranded costs associated with generating units built to serve customers, which costs may become stranded if, as a result of open access, these customers left the utility's system to take power service from a competing power supplier. The federal stranded cost regulations are intended to protect incumbent utilities against the risk that they would lose the ability to recover costs they incurred to serve retail customers that they lose through a municipalization made possible by the FERC's open access transmission rule.

In general terms, the stranded cost obligation is calculated on a FERC adopted formula based on anticipated revenue from the lost customer, less the estimated value of that released power in competitive markets for the reasonable length of time the utility could have reasonably expected to continue to serve the departing generating customer. See 18 C.F.R. § 35.26(c)(2)(iii). The city will seek to minimize or eliminate its exposure to stranded costs as we go forward in the process. As necessary the city will file appropriate cases with the FERC in order to protect the city's interests going forward.

In addition to FERC, it may be necessary to explore the role the Colorado PUC might play in a successful transition. Separation of the new utility from Xcel will require cooperation between the city and Xcel for the benefit of the customers receiving electric service. The PUC is the overseer for the protection of customers of Xcel and therefore may have an interest in how such a transfer occurs. The City Attorney's Office plans to proceed with examining opportunities related to this question as part of the due diligence in the further exploration of municipalization.

D. Phase II of the Work Plan

If City Council directs staff to move forward on April 16, the team will refine and check in with council on Phase II of the Work Plan. Phase II will be a continuation of the municipalization exploration project with an intention of moving toward specific actions (whether it is negotiating with Xcel or identifying alternative service providers). Staff will return to council in July or August with a work plan that details the tasks and schedule for this phase.

In addition, the process for bringing in a third-party independent evaluator will be initiated. The goal is to have a review conducted during second or third quarter of 2013 to allow for adjustments to the process in the event there are any significant findings.

If directed to move forward the Phase II work plan will include the following:

1) Proceed with the legal steps listed above
2) Proceed with the hiring process for an independent evaluation to review staff process for Phase 1
3) Continue to work with the community to develop their priorities for the Energy Future goals, and quantifying those priorities, their benefits and risks
4) Continue to engage working groups to develop a plan for achieving a utility of the future, including creating and articulating the vision
5) Initiate discussions with bond rating agencies and develop financing strategies.
6) Explore resource options in further detail
7) Identify service providers and initiate discussions, issue RFPs
8) Develop a formal implementation plan, to include transition and staging of the system, in the event of municipalization
9) Initiate discussions on utility governance structures
10) Continue to work with Xcel on a potential partnership

If council's direction on April 16 is to move forward with the pursuit of municipalization, this will be an important step in the process, but not the final one, as council will be asked to provide direction at many of the steps above, and off-ramps will remain available.

ATTACHMENTS

A. Working Groups
B. Modeling Process
C. Background
D. Modeling Inputs and Assumptions
E. Service Territory Map
F. Reliability
G. Charter Metrics Approved by City Council
H. Decision Analysis Process
I. Typical Customer Electricity Bill: Xcel Baseline Compared to Three Municipal Utility Options in 2017, 2022 and 2037
J. Xcel Letter
K. City Charter, Article XIII

ATTACHMENT A

Decision Analysis Working Group

Purpose and Scope

The Decision Analysis Working Group was tasked with reviewing the framework of the decision analysis model and with vetting data and assumptions to be included within it. This working group is intended to be a small team of experts with significant academic and/or career experience related to decision analysis and risk assessment. The city has hired a decision analysis consultant who will be providing overall project guidance, and this group evaluated aspects of that consultant's work and carried out tasks from it by providing expert feedback. This group reviewed modeled strategies and outcomes, with the exception of confidential and privileged material.

The tasks with which the working group would assist will likely include the following:

- December:
  - Review the overall framework for the decision analysis model, which is intended to demonstrate whether particular municipalization strategies, and non-municipalization strategies where identified, will achieve the Boulder community's Energy Future goals.
  - Review preliminary findings related to modeling needs.
  - If available, discuss preliminary findings from working groups on key decisions and uncertainties.
  - Determine list of information gaps and assign research related to assessment of probabilities, where not already assigned within a working group.
- January:
  - Review non-confidential decision trees and/or influence diagrams (i.e., municipalization or non-municipalization strategies) to the extent feasible.
  - Determine list of information gaps and assign research related to assessment of probabilities, where not already assigned within a working group.
- January and/or February:
  - Review model outputs, identify any data gaps.
  - Provide suggestions on how to clearly convey complex process to Council and the public in the February and March memos; and how to develop effective, cross-referenceable materials for staff.

These tasks are subject to alteration depending on the outputs of the other working groups.

Working Group Meetings

This group met three times between November and February: December 14, January 23, and February 13, as part of a joint working group session. Group members were also invited to joint meetings of the financial and resource modeling working groups to understand data collection and evaluation practices. Group members also provided feedback online through Basecamp.

ATTACHMENT A

Working Group Members

COMMUNITY MEMBERS
Pete Baston – IDEAS, LLC
Tom Feiler – Clipper Windpower, Inc.
David Kline – National Renewable Energy Laboratory
Tom Leifer – QI Path
Frank Selto – University of Colorado
Zane Selvans – Clean Energy Action
JoAnn Silverstein – University of Colorado
Edith Zagona – University of Colorado

CONSULTANTS
Greg Hamm – Stratelytics, LLC

STAFF
Kelly Crandall – Sustainability Specialist
Sarah Huntley – Media Relations/Communications Coordinator

SUMMARY OF KEY INPUT FROM THE FINANCIAL WORKING GROUP:

- It is important to explain that the 10-50-90 ranges are intended to convey distributions and may look higher or lower than what people familiar with the numbers typically see. The 50% value should be a median rather than the "most likely" or average number.
- It will be key to describe the "status quo" with Xcel Energy effectively, and to allow it to be varied with the different uncertainties as does the municipalization case – otherwise it looks like the municipalization options bear all the risk.
- The ideal is to test sensitivities on a lot of things and then reduce the modeling to only cover a handful of significant uncertainties.
- When the results are conveyed, we should be open to positive surprises, not just negatively/risk-focused.
- Evaluated the influence diagram underpinning the decision analysis model to ensure that significant factors weren't being missed.
- Proposed good documentation methods for tracking the process of identifying and evaluating uncertainties.
- Made suggestions on presentation of results to Council and the public. Any explanatory materials should be a "smart distillation," not a "101."

Financial Working Group

Purpose and Scope

The Financial Working Group was tasked with vetting certain data inputs and assumptions for inclusion in the financial model. They were also asked to research and find certain data points to use in the model. The financial model includes information on the operations of a municipal utility, including debt structures. The model also takes inputs from other sources, such as the resource modeling tool, and provides, for example, the following outputs to test certain charter requirements of forming a municipal utility:

- Total cost of service, average cost per kwh
- Debt service coverage ratio
- Comparison to Xcel Energy's average cost per kwh

The financial model is a 20-year forecast of cash flows with the ability to calculate financial attributes above and beyond the charter requirements. This model is the base tool for supporting any possible future financing. Therefore it includes several financial tests to meet rating agency tests. In addition, the model is a tool to determine various trade-offs for where policy makers may want to shift their financial resources over time to achieve the goals.

The city hired a financial advisor whose expertise lies in municipal utility finance that the financial working group was able to pose questions through throughout the process in relation to the financial assumptions, timing, and debt structures.

Data and assumptions vetted by this group were limited to the following areas[1]:

- Operations of a municipal utility (examples: various scenarios for operating a utility, functions required to operate a distribution system)
- Financial parameters assumed in the model (examples: how net present value is calculated, debt service coverage, debt structures and parameters, growth and inflation)
- Economic benefits and/or detriments of owning and operating a municipal utility (example: jobs, economic development)

Working Group Meetings

This group met formally approximately 4 times from November through February. They also performed tasks and received updates in between meetings via e-mail and through the Basecamp web application. Two joint meetings with the resource modeling group were held to review

[1] This group did not discuss assumptions and strategies related to acquisition of the assets or stranded costs as these topics are confidential and privileged attorney client matters. Additionally, this group did not discuss the metrics as they relate to the charter requirements discussed with City Council in November, 2012.

overall assumptions as they relate to resources and financial parameters and the results of the analysis.

Working Group Members

COMMUNITY MEMBERS
Jim Barrett – Applied Solutions
David Becker – EFAA
Alison Burchell – Geologic consultant
Lynda Gibbons – Gibbons White
Steve Pomerance – Community member
Dan Powers – Western Disposal Services
Joshua Putterman – Community member
Nick Rancis – CU Cleantech
Frank Selto – University of Colorado
Sam Weaver – Cool Energy, Inc.
Bob Greenlee – Community Member

STAFF
Yael Gichon – Residential Sustainability Coordinator
Kelly Crandall – Sustainability Specialist
Cheryl Pattelli - Director of Fiscal Services
Sarah Huntley – Media Relations/Communications Coordinator

SUMMARY OF KEY INPUT FROM THE FINANCIAL WORKING GROUP:

The financial working group provided input in the following areas:

- Financing considerations that were discussed in a joint session with the financial advisor including: the structure of financing and power purchase agreements, discount rates, risk, and debt service coverage calculations.
- Researched and vetted key assumptions related to start up costs, operations and maintenance, and financing.
- Vetted the options to model in the analysis.
- Identified assumptions that would be impactful to the model outcomes that were treated as uncertainties in the decision analysis process.
- Coordinated with the resource working group on the interface between the financial and resource mix models and assumptions.
- Vetted the preliminary results and conclusions.

ATTACHMENT A

Reliability Working Group

Purpose and Scope

02/21/2013

The Reliability Working Group was tasked with vetting the reliability issues associated with the city's municipalization exploration work plan.

Reliability is a combination of physical and process requirements to ensure that the electric system meets both federal and regional reliability requirements, customer demands for uninterrupted service and meet or exceed existing Xcel Energy reliability. Because reliability is such a high priority, the staff team included a major task focused on the various aspects of achieving this objective.

The goal of the working group was to help city staff identify what is required to meet the expected reliability requirements and associated costs. Considerations include not only reliability in the design, operations and maintenance of the system but in the delivery of power from suppliers.

The City hired engineering consulting firms (Exponential Engineering and Schneider Electric) and Warren Wendling (former chief engineer for the Colorado Public Utilities Commission) for specialized expertise to perform the primary analysis work. The working group was asked to help inform the scope of this analysis and review consultant work products and vet assumptions with respect to reliability driven costs.

Reliability is an important aspect in determining the best method of separating from Xcel. However, the separation analysis is confidential and was not included in the scope of the working group goals.

Working Group Meetings

The working group communicated through the Basecamp web application met on the following dates:

November 8, 2012
December 12, 2012
January 9, 2013
February 6, 2013

Working Group Members

COMMUNITY MEMBERS

Pete Baston, Community Member, IDEAS iQA
David Corbus, Community Member, NREL
Burrell Eveland, Community Member, Western Area Power Administration
Jim Look, Community Member, IEEE
Puneet Pasrich, Community Member, Colorado State University

STAFF

Robert Harberg – Utilities Project Management Coordinator
Kathy Haddock – Assistant City Attorney
Andrew Barth – Communication Specialist

CONSULTANTS

Tom Ghidossi – Exponential Engineering
Bob Lachenmayer – Schneider Electric
Warren Wendling – Wendling Consulting, LLC

ATTACHMENT A

SUMMARY OF KEY INPUT FROM THE RELIABILITY WORKING GROUP:

The following questions were considered by the reliability working group and their input has been summarized in Attachment G of this memo. There is significant expertise among the working group members and consultants and the exchange of information and discussion served to refine the understanding and analysis of the reliability issues associated with potential municipalization.

1. Existing Xcel Energy System Reliability Considerations
    a. What are the strengths and weaknesses of the existing Xcel Energy electric utility system infrastructure in Boulder?
    b. How does Xcel Energy provide reliability through on-going administration, operations, maintenance, monitoring, control, dispatch, project management, customer service and response procedures?
    c. How does Xcel Energy provide power generation and transmission reliability?
    d. What is the existing level of Xcel Energy reliability as measured by the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI)?
    e. Are there other reliability aspects of the existing Xcel Energy system that should be considered?
    f. How and to what extent has Xcel Energy incorporated and considered redundancy, firm capacity, power quality controls, reserve margins, common-mode failure scenarios?
    g. How will the plan for physical separation from Xcel Energy address reliability issues?
2. Reliability Regulation Considerations
    a. What are the reliability requirements based on North American Energy Reliability Corporation (NERC)?
    b. What are the reliability requirements based on the Western Energy Coordinating Council (WECC)?
3. Future Reliability Goals and Factors to be Considered
    a. What methods do other communities and utilities use to assure reliability?
    b. How would power generation and transmission reliability be assured?
    c. What are the reliability expectations and desires of residential and business customers?
    d. Are there other industry reliability indices or standards that should be considered?
    e. What procedures and investments should the city consider to increase the level of reliability?
    f. How should reliability be assured based on future growth and redevelopment?
    g. How will future distributed generation and demand management affect reliability?
    h. What are the human, organizational and financial resources that will be needed for on-going administration, operation, maintenance, monitoring, control, dispatch project management, customer service and response procedures to assure reliable electrical service?
    i. What types of natural and man-made hazards should be considered including frequency and magnitude of extreme events?
    j. How and to what extent should redundancy, firm capacity, power quality controls, reserve margins, common-mode failure scenarios be considered by the city to increase the level of reliability?
    k. Are there other reliability issues that should be considered?

Resource Modeling Working Group

Purpose and Scope

The role of the Resource Modeling working group was to provide industry-specific expertise about a variety of resource options and help vet assumptions that were used in the Load Profile and the HOMER resource model, used to develop the possible portfolio scenarios. The group was tasked with the following types of responsibilities:

- Researched and evaluated the economic and technical feasibility of a number of technology options, accounting for variations in costs and energy resource availability.
- Evaluated critical inputs to the model including resource availability, energy efficiency and demand-side management, transmission constraints and local generation potential.
- Recommended resources and strategies for managing future risks to assure adequate supplies of electric energy will be available at affordable prices.
- Explicit consideration of energy efficiency and load management programs as alternatives to wholesale power purchases.
- Consideration of environmental factors as well as direct economic costs.
- Analyzed the uncertainties and risks posed by different resource portfolios and by external factors.
- Identified the barriers to developing and securing electric resource and generating assets necessary for Boulder's energy future and evaluate possible policy changes. Some of these may require legislation; others may require Colorado Public Utilities Commission action.

Working Group Meetings

The working group met approximately once each month between October and February. In addition, an assumption sub-committee met numerous times outside of regularly scheduled working group meetings. Other tasks and updates in between meetings took place via e-mail and through the Basecamp web application.

Current Working Group Members

COMMUNITY MEMBERS
Tom Asprey – Community Modeling Team
Alison Burchell – Community Modeling Team
David Corbus – NREL
David Cohen – Evolution 7
Brad Davids – Enernoc
Steve Drouilhet – Sustainable Power Systems
Gregg Eisenberg – Eisenberg Energy

ATTACHMENT A

Thomas Feiler – Clipper WindPower
Leslie Glustrom – Clean Energy Action
Wayne Goss – Spinnaker Energy, LLC
Joshua Kuhn – Community Member
Puneet Pasrich – Colorado State University
Ken Regelson – Five-Star Consultants
David Rhodes – Southwest Generation
Debra Sandor – NREL
Sam Weaver – Cool Energy
Ted Weaver – First Tracks Consulting

CONSULTANTS
John Glassmire – HOMER
Peter Lilienthal – HOMER
Nils Tellier – EPSIM Corp

SUMMARY OF KEY INPUT FROM THE RESOURCE WORKING GROUP:

The Resource Modeling working group provided input in the following areas:

- Developed the initial options to model in the analysis.
- Reviewed the modeling methodology for accuracy and consistency.
- Researched and vetted key assumptions and inputs related to resource types, availability, and their associated costs.
- Identified sensitivities that would be potentially impactful to the model outcomes that were treated as uncertainties in the decision analysis process.
- Coordinated with the Financial working group on the interface between the financial and resource mix models and assumptions.
- Coordinated with the Reliability working group on potential impacts to reliability related to resources and specific assumptions around the planning and operating reserves.
- Vetted the preliminary results and conclusions.

Communications and Outreach Working Group

Purpose and Scope

The Communications and Outreach Working Group was tasked with providing strategic counsel to city staff about best practice and/or innovative ways of engaging a broad cross-section of the community in the ongoing discussion about whether the city should form an electric utility.

This group will be tasked with the following types of specific responsibilities:

- Vetting ongoing communications and outreach efforts to help ensure that we are reaching a wide and varied audience;
- Identifying and examining alternate strategies and low-cost tactics to expand our reach beyond those who are currently engaged in this issue; and
- Providing city staff with feedback from the public's perspective about what is and is not working in terms of communication related to the municipalization exploration effort.

Final determinations about the most effective strategies and the ability to implement them based on staff and other resources will be made by Heather Bailey and City of Boulder staff. Communications and outreach strategies and tactics will likely have to be adjusted and honed as the overall project team's recommendations to City Council become more clear.

Working Group Meetings

This group met formally once a month from November through February and is planning to participate in the March 13 Open House. Members also participated in email communication, phone conference calls and subgroup meetings during this timeframe.

Working Group Members

COMMUNITY MEMBERS
Craig Cox - Lyght Co
Angelique Espinoza - Boulder Chamber
Chris Hoffman – Hoop and Tree; community member
Robert O'Herron – community member
Jennifer Pinsonneault – Boulder Economic Council
Julie Zahniser – community member

CONSULTANTS
John Egan – Egan Energy Communications, Inc.
Robb Shurr - WaldenHyde

ATTACHMENT A

STAFF
Sarah Huntley – Media Relations/Communications Manager
Andrew Barth – Communications Specialist
Kristen Hartel – Sustainability Specialist
Wynne Adams – Energy Future Intern

SUMMARY OF KEY INPUT FROM THE FINANCIAL WORKING GROUP:

ACCOMPLISHED TASKS (SOME OF THESE WERE ACCOMPLISHED BY THE FULL GROUP; OTHERS WERE ASSSIGNED TO SUBGROUPS THAT MADE SIGNIFICANT CONTRIBUTIONS TO STAFF WORK):

- Review of existing city messages and materials
- Review of overall communications plan with some revisions suggested for getting somewhere between the basic 101 version of information but not as far as the 301 versions that some members of the community are seeking and more differentiations based on audience
- More specific discussions about different audiences and their different needs, with an emphasis on the business community and ways to engage with this segment more effectively
- Creation of an updated business liaison contact list
- Research into communications efforts conducted by Winter Park, Fla., during its exploration and ultimate decision to create a municipal utility
- Assistance boiling down one-page letter to neighborhood associations
- Brainstorming about possible earned media opportunities
- Developed plan to update design and streamline content of project website in phases between Feb. 26 and April 15
- Development of a targeted outreach plan for the period between Feb. 26 and April 16
    - (Ongoing) Concept design, logistical planning and help with spreading the word for March 13 open house (ongoing)
    - (Ongoing) Concept design, logistical planning and help with spreading the word for March 12 business call (a new concept recommended by the advisory group as a pilot for other city outreach efforts)
    - (Ongoing) Assistance with survey preparation
    - Creation of advertisements related to target outreach and participation opportunities

Model Integration and Quality Control

MODELS USED

The models used in this phase include a mix of spreadsheet and software models. Microsoft Excel spreadsheets provided the flexibility to develop load models and the core financial model (upgraded from the 2011 version). HOMER, a resource modeling software developed out of NREL, was used to generate optimized annual resource packages based on forecast energy demand and cost or greenhouse gas constraints. DPL, a decision analysis software, was used to run multiple permutations of the financial model associated with different load profiles, resource packages, and other uncertainties to generate risk profiles for the modeled options. Integrating these models required careful interaction among consultants and city of Boulder Information Technology (IT) staff, who assisted with information transfer, business process, and quality control. Fig. 1 shows how the models interface.

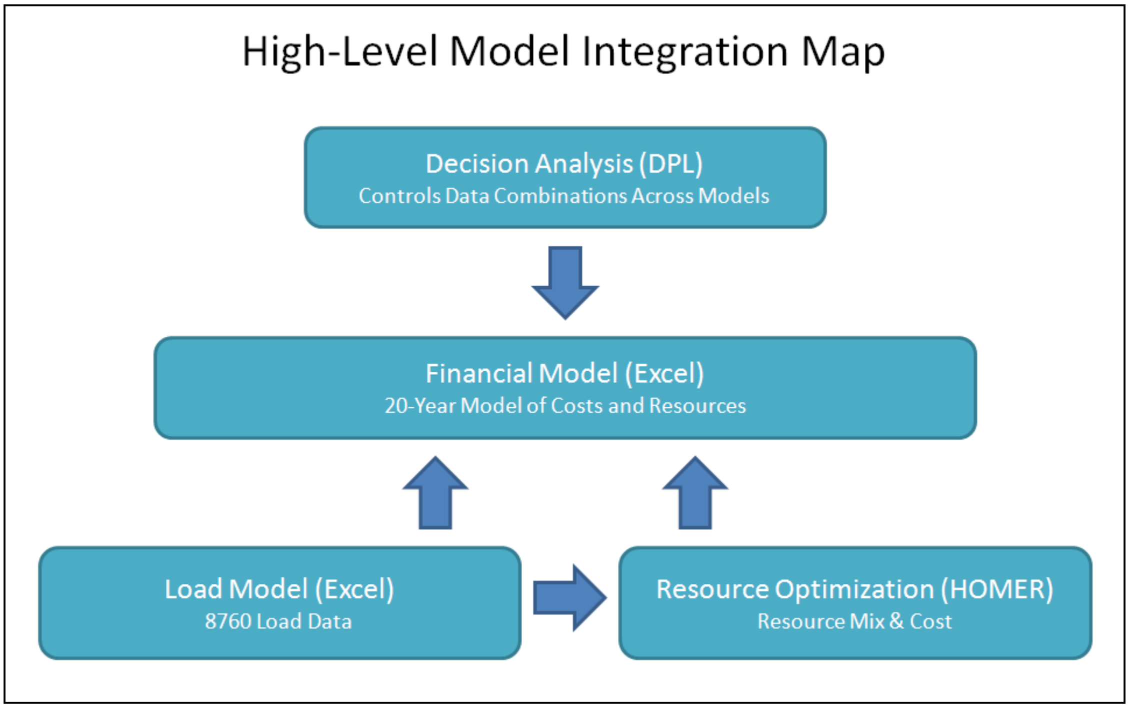


Fig. 1: Model Integration Map

QUALITY CONTROL

City IT staff used a tool called Validate to perform a technical audit to help assess the soundness of the modeling from a technical perspective. Validate identifies logical and mathematical errors in formulae. It was run in stages and found a limited number of logical and mathematical errors, only one of which impacted the model outputs. All errors were fixed prior to the final model runs. All of the interfaces between the model components are programmatic rather than manual, and the audit found that they do provide expected data in the appropriate places. Assuming the outputs from the models are themselves sound, IT found the financial model to be technically sound.

BACKGROUND

Energy Future Goals

Phase I of the municipalization exploration project has focused on the specific tasks necessary to determine whether the Charter requirements to create a local electric utility can been met; and furthermore, how and if municipal utility options would achieve the community's broader energy future goals. These broader goals were defined in early 2011 through a public process and enumerate the distinct, tangible outcomes important to those who live and work in Boulder. The six goals identified at that time were:

- Ensure a stable, safe and reliable energy supply
- Ensure competitive rates, balancing short-term and long-term interests
- Significantly reduce carbon emissions and pollutants
- Provide energy customers with a greater say about their energy supply
- Promote local economic vitality
- Promote social and environmental justice

A stable, safe and reliable energy supply, along with competitive electric rates, are the most important factors articulated by members of the business community, when considering whether or not to change their electric utility provider. For some members of the business community, forming a city-owned utility would need to demonstrate a clear economic benefit that outweighs the risk associated with changing energy providers.

These goals have guided city staff's work to develop a coordinated and viable strategy. However, when voters supported the continued exploration of municipalization, they (and City Council) emphasized the need to set specific measures that must be met before council could issue bonds to acquire Xcel Energy's system and create a city-owned utility.

Charter Requirements and Metrics

The Charter provisions related to a possible Light and Power Utility are summarized below, and the full Charter language in Article XIII, Section 178 is included as **Attachment K**. These provisions set the floor such that if they cannot be fulfilled, municipalization cannot occur.

To set quantitative measures for the Charter provisions, the city and community stakeholders developed a set of metrics that were approved by City Council in November 2012 (see **Attachment G**). The metrics should be thought of as a means of eliminating municipalization options that would not meet the Charter provisions so that focus can be directed toward the most viable option or options. Importantly, while the Charter articulates the conditions under which municipalization is possible (i.e., "could we?")[1], the Energy Future goals describe the conditions under which it is also desirable (i.e., "should we?").

---

[1] The Charter amendments also include language to ensure that the utility is operated in a fair, responsive and fiscally responsible manner. There are provisions that strive for competitive rates, cost effective improvements, responsible borrowing, nondiscriminatory and fair distribution of costs among rate classes, and limitations utility revenue transfers to the general fund. Additionally, the Charter envisions broad representation beyond citizens and allows employees of local businesses and institutions to serve as well.

Work Done Since the December Study Session

Since the update provided to City Council at its Study Session on Dec. 11, work has continued on all areas of the work plan, including:

- Developing and analyzing six options to achieve Boulder's Energy Future goals
- Incorporating Charter metrics into modeling and analyses
- Evaluating reliability of the system and power supply
- Integrating new data into the resource model
- Integrating work plan outputs into the financial modeling analysis
- Integrating financial and resource modeling outputs into the decision analysis tool (DPL) to analyze risks and opportunities of each potential option
- Identifying and appraising specific assets to be acquired
- Refining financial parameters surrounding bonding, acquisition, operating and maintenance (O&M) and capital costs and other areas
- Determining the service area boundaries for a system that is the most technically optimal
- Working with FERC attorneys to develop strategies, options, and planning for compliance with federal regulatory requirements.

Working Groups

More than 50 people from the Boulder community and beyond have volunteered their time to help staff and consultants with the extensive research and vetting process necessary to refine and build upon the feasibility studies that were completed in 2011. The five working groups that these community volunteers have served on are:

- Financial modeling
- Reliability
- Resource modeling
- Decision Analysis
- Communications & Outreach

Their input and expertise has been invaluable and helped ensure that a cross-section of the community had a voice during this important phase of the analysis. Information on the make-up of the working groups, their backgrounds, roles and a summary of their input is provided in **Attachment C**.

Consultants

To ensure the modeling process was objective and informed, the city utilized a number of consultants with expertise in literally every aspect of electric grid design and performance. The consultants provided specific expertise in utility areas such as:

- Transmission and Distribution Engineering
- Reliability
- Utility Management
- Resources and Portfolio Management
- Utility Finance
- Decision Analysis

- Communications and Outreach

The consultant team worked closely with staff and the Working Groups to provide specific industry expertise, and included the following firms and individuals:

Appraisers
Hegarty and Gerken, Inc., Charlie Hegarty
NewGen Strategies and Solutions, LLC, Nancy Heller-Hughes
The Rothweiler Group, Steve Rothweiler

Communications and Engagement
Egan Energy Communications, Inc., John Egan
Walden Hyde LLC, Robb Shurr

Engineering
Excergy Corporation, Andy Owens
Exponential Engineering Company, Tom Ghiodossi
NewGen Strategies and Solutions, LLC, Nancy Heller-Hughes
Schneider Electric, Bob Lachenmayer
Wendling Consulting, LLC, Warren Wendling

Financial
Piper Jaffray Companies, Jonathan Heroux
Public Financial Management (PFM), Inc., Mike Berwanger, Eric Espino, Will Frymann, Dan Hartman

Legal
Duncan and Allen
Duncan, Ostrander and Dingess, P.C., Don Ostrander
Kutak Rock, LLP, Jennifer Barrett

Modeling
EPSIM Corporation, Nils Tellier
HOMER Energy, LLC, Dr. Peter Lilienthal, John Glassmire, Tom Asprey
Stratelytics, LLC, Dr. Gregory Hamm

ATTACHMENT D

Key Assumptions and Inputs for the 2012/ 2013 Modeling

Staff coordinated with consultants and the working groups to define the modeling assumptions and key inputs, utilizing a wide range of relevant sources and industry expertise. The key assumptions and inputs are described below, followed by the full list, including data sources. Many assumptions are unique to Xcel as an operating utility; some apply to both Xcel and a municipal utility; and others apply only to a city-owned utility (e.g., start-up costs, stranded costs).

A number of the assumptions and inputs in the modeling were also used in the 2011 modeling effort. Besides simply updating the inputs to reflect current conditions, there are a number of differences in the modeling efforts. First, the modeling performed in 2011 was not performed using a Resource Specific tool such as HOMER[1]. This refinement provides a closer look of the actual resource options, their availability and projected costs. Second, the 2011 modeling was a deterministic approach, which has been refined in this effort to include a probabilistic analysis. The 2011 modeling effort only looked at a few potential options, while this process looks at a wide number of options. Finally, many of the previous modeling inputs were calculated using broad ranges. The numbers have been refined considerably in this effort to narrow the realistic financial outputs.

Key Assumptions for All the Options

1. Planning Horizon: All modeled options assume a 20-year period beginning in 2017. The 20-year load profile (see below) was developed using annual load data modeled at 5-year increments.

2. Load Growth: All options assume Boulder- specific load growth rates over the 20 year planning horizon as provided by Xcel Energy.[2] The Low GHGs/EE Option models aggressive energy efficiency and conservation or demand-side management (DSM) and therefore uses a modified load profile based on local energy use reductions. Losses related to transmission and distribution were included in the load model projections to account for additional costs and generation.

3. Resource Costs: The modeled options use the same fuel cost projections that Xcel used in recent Public Utilities Commission (PUC) rate and resource proceedings.

4. Reliability: All utilities, whether municipally owned or investor owned, are subject to the same reliability requirements and penalties by the National Energy Reliability Corporation (NERC) and the Western Area Coordinating Council (WECC). All modeled options assume a system configuration and resource mix that meets these across-the-board reliability requirements.

[1] HOMER is the Resource simulation software that was used to run simulations of different energy systems, compare the results and get a realistic projection of their capital and operating expenses.
[2] Boulder specific load growth was provided by Xcel Energy in Docket No. 11A-869E, Electric Resource Plan (ERP)

ATTACHMENT D

Key Assumptions for the Xcel Baseline

The Xcel Baseline provides the status quo to provide both a comparison point for municipalization options—which are required to meet or exceed Xcel Energy's performance to be feasible—and to explore to what degree the community's energy goals could be met under current and potential future conditions.

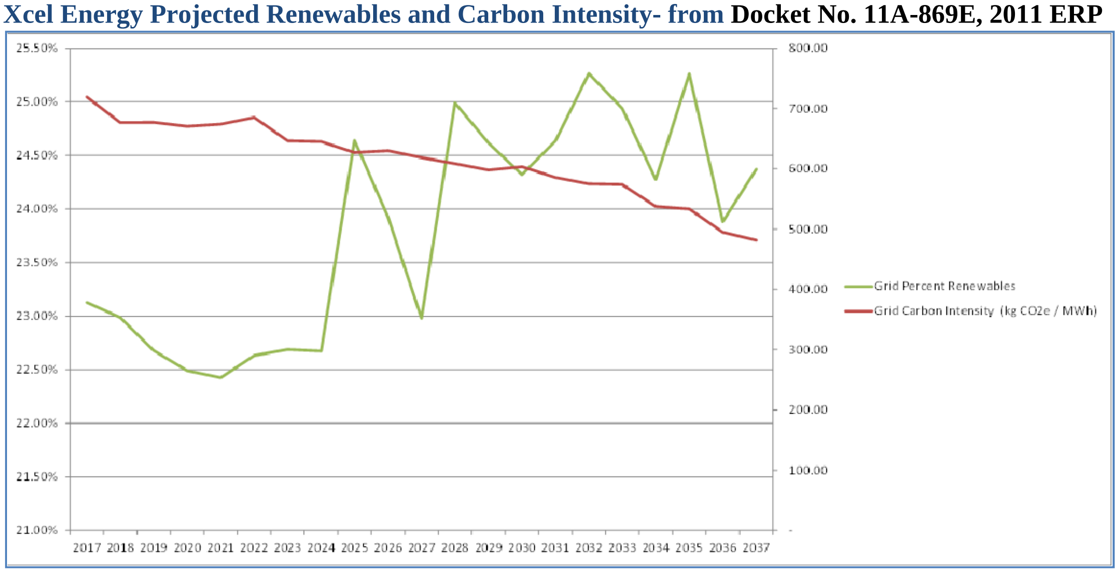
To ensure accuracy in measuring the differential between the Xcel Baseline and the municipalization options, the models used Xcel's own projections for inputs such as fuel costs, load growth, The assumptions related to the Xcel baseline were derived from recent and publicly available information such as Public Utility Commission documents, annual reports and Federal Energy Regulatory Commission (FERC) filings.

The assumptions that are unique to the Xcel Baseline Option include:

- **Revenue Requirement & Rates:** The modeling uses Xcel's revenue requirement from its most recent PUC rate cases. Xcel's rates were modeled based on the current cost allocation by customer class (commercial, industrial and residential) and rate schedule, including Xcel's current tariff riders. The rates were assumed to increase over time at a growth rate of 2.5-3% based on Xcel's projections. [3]

- **Resource Mix:** The modeling uses Xcel's current and projected resource mix they project for the next 20 years[4]. To account properly for energy production of local solar added in the Xcel baseline, production was included back into the system load models on an hourly basis and then modeled for cost in the financial model. The figure below shows Xcel's forecasted renewables percentage and resultant carbon intensity.

Xcel Energy Projected Renewables and Carbon Intensity- from Docket No. 11A-869E, 2011 ERP



[3] investors.xcelenergy.com/Cache/1500046219.PDF?D=&O=PDF&IID=4025308&Y=&T=&FID=1500046219
[4] Xcel projected their resource mix in Docket No. 11A-869E, 2011 Electric Resource Plan (ERP).

ATTACHMENT D

Key Assumptions for the Five Municipal Utility Options

The following inputs and assumptions are either unique to a municipal-owned utility (e.g., service territory) or were developed to determine the costs, rates and resource mix for a municipal utility.

1. Service Territory: The modeling assumes that the utility would serve an area that has been defined by the reliability and acquisition engineering consultants as the most technically optimal. [5]. The consultants considered the cost and reliability of a number of separation options. The optimal separation area is at substations and on feeders where interconnections exist. The six substations serving Boulder are interconnected to provide redundancy and other overlap to provide the reliability that currently serves the city and surrounding areas. Reliability at least at current levels is a value the community has said is absolute. Separating any of the six substations from the area serving the city negatively affects reliability and requires building duplicate facilities. The engineers developed a map **(Attachment F)** that shows the area served by the six substations with (a) the minimal number of new interconnectors required to maintain the existing reliability for both Xcel and the new utility and (b) 75 to 80% of the interconnections being at existing normally-open switches. The line on the map is wavy around the periphery because pinpointing exact locations of the interconnectors will require additional field work.

2. Electric Power Providers: The modeling assumes that electricity requirements outside of local distributed generation will be acquired through power purchase agreements (PPAs). While staff and the Resource Working Group agree that there will be advantages to owning and operating generation resources in the long run, the city's financial advisor (PFM) has cautioned that this could negatively affect the city's credit rating in the short run. Therefore, for this phase, all model runs assume that existing and available resources would be procured primarily through negotiated power contracts. Existing local generation resources (e.g., hydroelectric, combined heat & power and solar), are assumed to continue to be utilized under all the modeled options. All but one of the options use a load model that assumes that the amount of local generation will continue to grow gradually based on historical percentages. The Low GHGs/Reduced Use Option assumes approximately 5% of Boulder's electricity needs coming from local small-scale renewable energy (currently less than 1%), escalating to 8% by 2037.

3. Load Profile: Load is simply defined as electricity consumption. The load profile looks at the amount of energy used throughout each day of the year for each of the major rate classes (i.e., residential, commercial, and industrial). The modeling forecasts the community's load profile on an hourly basis over a 20-year period using existing load data from Xcel Energy at hourly increments throughout the year[6], along with proxy information from similar jurisdictions. The impact of Boulder's current energy efficiency or demand-side management (DSM) [7] programs on the load was integrated into the model by customer class based on data

---

[5] Exponential Engineering and Reliability Working Group

[6] The load model was developed using actual electricity sales and annual 8,760-hour consumption data by customer class.

[7] Demand-side management (DSM) involves reducing electricity use through activities or programs that promote electric energy efficiency or conservation, or more efficient management of electric energy loads. In this stage of the modeling process, staff and the working groups agreed to only look at the potential load impact from energy

from national and state studies and research that incorporates best practices for determining savings. Other utilities utilize this same methodology when calculating the potential savings attributed to DSM. The Low GHGs/ Reduced Use Option utilizes a modified load profile that includes projected load reduction attributed to DSM.

4. Resource (fuel source) Mix: The resource model applies current market fuel and emission prices to select the best resource mix associated with a specific load profile. Those prices are then escalated using standard inflationary percentages and applied to the 20-year load forecast to develop a long-term resource portfolio for each option. The price projections for wholesale power sources such as natural gas, wind, solar and emission prices were based on a comprehensive set of costs specific to the Western Electricity Coordinating Council (WECC) Region. The working group also considered a wide-range of resource portfolios and contingency plans that analyzed both the environmental and cost impacts associated with each plan.

5. Reliability: Maintaining or improving system reliability is a Charter requirement; therefore, the modeling assumes a system configuration and resource mix that meets minimum reliability requirements set forth in the Charter metrics[8]. Each resource's proximity, availability and technical attributes were evaluated to determine the potential to impact negatively or improve system reliability. Specific resources were selected for their ability to maintain or improve system reliability and were vetted with the Reliability Working Group. See **Attachment F** for additional information on reliability.

6. Utility Reserves: Various types of generation for electric system capacity and reserves were considered for this modeling. In practice, there are two major types of reserves: planning reserve and operating reserve (spinning and non-spinning). A utility will have access to reserves to ensure that power is available if there are disruptions to the power supply for short periods (i.e., less than an hour) and extended periods (i.e., longer than an hour).

    a) Planning Reserves: A utility must have sufficient dispatchable (i.e. on demand) power generating capacity available to meet their peak load plus a planning margin. A reserve margin of 15% was used in the resource modeling process to compensate for uncertainty surrounding future load forecast changes and resource contingencies such as generation or transmission-forced outages.

    The sources used as a basis for a planning reserve margin varies based on many operational considerations such as region, whether or not the utility maintains its own generation, participation and membership in reserve groups like the Rocky Mountain Reserve Group (RMRG), the utility's largest single contingency loss possible, utility operational policies, variation in the load (customer energy usage) being served, variable resources in the generation mix, reserve credits for wind and solar, etc. The North American Electric Reliability Corporation (NERC) sets reference levels for planning reserve margin. While the Western Electricity Coordinating Council

---

efficiency and distributed generation. The impact of Demand Response (DR) strategies will be evaluated in a subsequent phase of modeling.

[8] Maintain comparable electric equipment, facilities and services as those of Xcel at time of acquisition, which will be designed to achieve the same System Average Interruption Duration Index (SAIDI) of 85 and a System Average Interruption Frequency Index (SAIFI) of .85; maintain an adequate reserve margin of 15%; and meet applicable North American Electric Reliability Corporation (NERC) compliance requirements.

(WECC) does not have an interconnection-wide formal Planning Reserve Margin standard, the Rocky Mountain sub-region of WECC recommends levels of 14.65%/15.68% for summer/winter seasons (NERC, *2012 Long-Term Reliability Assessment*). The WECC's target margins are developed using a building block method that has four elements:

- Contingency reserves
- Operating reserves
- Reserves for forced outages
- Reserves for one-in-ten-year weather events

The assumption for a Boulder utility planning reserve identifies a capacity need of 115% of the planning year's expected peak usage to set a 15% planning reserve margin. The Boulder City peak load is in summer, so the NERC reference would provide a slightly better margin.

The planning reserve is developed by determining the amount of generation that can be considered "firm", or available on demand. In this phase of planning, a credit for 15% of the solar name plate capacity and 10% of nameplate wind capacity was counted as firm capacity towards the planning reserve requirements. For reference, in their 2011 Electric resource Plan (ERP), Xcel used 12.5% for wind's Effective Load Carrying Credit (ELCC) and 13.8% for solar PV's ELCC (page 2-223, volume 2). Hydroelectric power was credited for 50% of the 13 MW typically available, based on the assumption that Boulder Canyon would be able to provide at least this power during peak season.

Several other sources of planning reserves available to Boulder are not included due to limited time for assessment or required agreements to include them, ensuring a conservative approach focused on reliability with potential planning reserves available in more detailed planning for later phases. These untapped sources include demand response (DR) agreements and reduction through demand side management (DSM), credits for agreements to utilize customer backup capacity to provide peak capacity during extreme events, and capacity sharing with partner utilities. The one case customer resources were counted is the 16MW of the University of Colorado's 33MW generation capacity that was included as firm capacity, based on the expectation that the university would continue providing reserve capacity to their electric utility provider. All other capacity was purchased in the form of firm power purchase agreements with natural gas independent power producers (PPAs). These assumptions will be examined in greater detail should Boulder progress to phase-2 planning in discussions on reserve group membership requirements.

b. Operating Reserves: To ensure reliable electricity, system operators maintain a buffer of generating capacity to meet demand in the event of an unexpected increase in demand or the failure of a generating or transmitting unit. This buffer, referred to as operating reserve margin, is met with generation capacity that is on-line, or that can be brought on-line and synchronized to the grid within a short period of time (i.e., less than an hour). Operating reserves are commonly provided through agreements with neighboring utilities and the Balancing Authority (BA)[9]. In this sense, the utility must ensure that it reserves sufficient capacity to meet its planning reserve requirements (the typical largest need plus a planned margin), but can rely on cost sharing agreements with neighboring utilities to meet their operating reserve requirements. The modeling assumes that all the municipalization options maintain levels of reserve capacity prescribed by the North American Electric Reliability Corporation (NERC).

Large wholesale/retail electricity providers in the state of Colorado maintain operating reserve margins via a reserve sharing group, the Rocky Mountain Reserve Group (RMRG). RMRG membership is based on a multilateral agreement in which the members "obligate themselves to maintain defined levels of reserves, coordinate reserve sharing and activation, and reserve transmission capacity for such purposes" (Rocky Mountain Reserve Group, 2002). RMRG defines the reserve capacity requirements, which have been included in the modeling process.

Operating reserves have been accounted for in the resource PPAs as capacity costs only, given that fuel costs associated with operating reserves would only be incurred if generation is actually needed during localized outage events related to generation or transmission.

7. <u>Operating & Maintenance Costs:</u> The financial model includes a set of ongoing operating and maintenance costs that are annual costs required to ensure the utility can meet, operate and maintain the distribution system with a high level of reliability and efficiency. The functions include general administration, customer service and accounts, billing, metering, scheduling and distribution. Additionally, revenues are collected annually to fund capital improvements, replace aging infrastructure and moving overhead electrical lines underground. Data and assumptions for the operations and maintenance of the system was updated from previous city studies (2007 and 2011) and then benchmarked against select Colorado municipal utilities and data from the American Public Power Association. The data was vetted through the working groups, and inputs were coordinated with the engineers and staff working on the system reliability to ensure the costs are sufficient to achieve targeted reliability levels.

8. <u>Start-up Costs:</u> These are costs that would be needed in the period preceding and the first two years of operation of a new utility. This category of costs includes building a utility service center including maintenance facilities, offices and warehouses; new information systems that would be needed at start-up; control centers; vehicles; mobile communications; spare parts inventory needed on hand at start-up; and capital for system replacements in the first two years of the utility.

9. <u>Credit Rates:</u> Staff has been working closely with the city's financial advisors (PFM) to develop a model that ensures a municipal utility would be creditworthy, has considered timing for issuing debt, and is using realistic, yet conservative assumptions for the bond parameters. PFM has completed an in-depth analysis of the city's financial model to ensure

[9] Balancing Authorities integrate resource plans ahead of time and maintain in real time the balance of electricity resources and electricity demand. They continuously balance the area's net scheduled interchange with its actual interchange by dispatching generation units used for regulation and help the entire interconnection regulate and stabilize the alternating current frequency that can be caused by intermittent resources such as wind and solar.

accuracy of the calculations, assumptions, as well as overall integrity of the model. The work with PFM and the resulting structure and assumptions of the financial model is designed to lay a solid foundation should the city pursue meetings with rating agencies and potential investors to further investigate financing options for creation and operation of a municipal electric utility. The financial assumptions are based on an estimate from PFM of an "A-" bond rating for the municipal utility. The rating would be highly dependent on the final structure at the time of credit rating, but this is currently believed to be a good assumption.

10. Stranded Costs: Stranded costs were modeled using three separate figures: (a) the number Xcel provided in its estimate of stranded costs provided to the city in June 2011 is estimated to be $255 M in 2017, (b) the city's 2011 estimate that there is no stranded cost obligation, and (c) one point between (a) and (b).

11. Acquisition Price: In June 2011, Xcel provided the city with an analysis that shows acquisition of its distribution system would cost $150 million. While the city is not conceding this figure, Xcel's number was used for all of the models to be as conservative as possible. The city believes that number drastically overestimates the value of the system, but since it represents Xcel's estimate, and therefore a "worst-case scenario," any other modeling would include a smaller number and simply increase financial feasibility.

Specific Resource Assumptions

1. Hydroelectric Energy: A daily average model from 2010 was used for flow rates and therefore power generated by the City in flow electrical generation. The cost used was the rate Xcel paid the city to purchase that energy wholesale. This keeps the water department costs covered with the same revenue for the same electric power produced in a typical year and transfers that equivalent cost from Xcel to the Boulder utility. Only 50% of the Boulder hydroelectric capacity was credited as firm for operating capacity and planning reserve margin.

2. Solar Energy: The cost of the 20 MW of solar that will exist by 2017 under the current Xcel programs is assumed to be priced in the financial model under acquisition. Incremental solar beyond the existing 20 MW was accounted for by assuming costs for a mix of 80% rooftop, 20% commercial through 2027, transitioning to a 60%/40% mix by 2037 after that. No utility scale solar (>100kW) projects were assumed, although this is lowest cost.

   Prices for installed PV for various scales were taken from reports from NREL (*Residential, Commercial, and Utility-Scale Photovoltaic (PV) System Prices in the United States: Current Drivers and Cost-Reduction Opportunities*, Alan Goodrich, Ted James, and Michael Woodhouse, Feb. 2012), Lawrence Berkeley National Laboratory (*Tracking the Sun V, An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2011,* Galen Barbose, Naïm Darghouth, Ryan Wiser, November 2012) and the U.S Department of Energy SunShot Program (*Photovoltaic (PV) Pricing Trends: Historical, Recent, and Near-Term Projections,* November 2012).

   A cost profile was based on installed costs from these reports and then compared to local reference pricing from a vendor in Boulder for 2013. The costs were then blended into an average cost based on the portion of projects at the rooftop and commercial scales (<100kW) included in the mix. The 2017 median price of $0.186/kWh for the rooftop/commercial blend compares to \$0.195/kWh for "10% Investment tax Credit (ITC) Solar PV" in Xcel's 2011 ERP in their generic renewable resource cost and performance table when converted to equivalent 2011\$'s and a Capacity Factor (CF) of 18%.

The price range included was meant to represent different types of solar PV: rooftop, community garden and larger central installations. Some of the range captures the issue that the ITC may be gone in 2017, or reduced. For pricing validation, we used a couple of different sources. The LA dept of Water and Power just launched a 100MW solar PV program for larger systems, and will start its Feed-in tariff (FIT)[10] at 17.5 cents/kWh, dropping by a penny per kWh for each 20MW step. This represents current market PPA pricing for solar.

Reference pricing was also gathered from some local solar companies for installations - large commercial at \$2-\$3 per watt. This translates (20 year system life, \$0.01/kWh O&M, 7% cost of financing, 30% ITC through 2016) to 9.3 cents/kWh to 13.7 cents/kWh-AC produced. The ITC is expected to expired prior to a 2017 start, in which case the price range represented would be 13.1 cents/kWh to 19.4 cents/kWh. If we now include roof-mounted residential systems, current pricing is \$3-\$4.50/ Watt installed from local reference pricing, leading to a solar energy price range of \$0.137/kWh to \$0.23/kWh with the ITC at 30%, \$0.194/kWh to \$0.288/kWh without.

A wide range was chosen for a low end with a 10% probability that costs might be lower to a high end with a 90% probability that cost will be lower. The ranges were chosen based on the understanding that solar panel costs are well under half of solar system costs today. The factory door prices for Chinese crystalline solar panels are currently in the \$0.70/Watt range (Mercom Solar Report, January 2013), meaning that permitting, distribution charges, balance of system, and labor costs are the dominant drivers for PV system installed costs today. One risk captured in the high case is that if demand rises, this may cause panel prices to increase. This may seem unlikely but the high end of the range represents a 90% probability the actual cost will be below this amount.

The costs modeled represent the fully-installed cost that the utility would pay for solar energy production in the utility's energy mix. Even the optimistic end of the solar pricing range did not by itself cause solar to be included in a cost optimized mix so a program to include solar would be required. A solar program was included in the aggressive scenarios where emission reductions were emphasized for a mix of 1.9%, 5%, 6%, 7% and 8% in years 2017, 2022, 2027, 2032 and 2037 through either utility ownership or incentives for private ownership. Full cost to the utility was assumed because even with private ownership and cost sharing, the utility pays an equivalent cost through lost revenue for feed in tariffs or other programs.

A standard, non-tracking configuration was assumed for performance. A relatively low 80% de-rating factor was used to account for panel performance variation in orientation,

---

[10] A feed-in tariff (FIT) is often called a standard offer contract or renewable energy payments is a policy mechanism designed to accelerate investment in renewable energy technologies. It achieves this by offering long-term contracts to renewable energy producers, typically based on the cost of generation of each technology. Technologies such as wind power, for instance, are awarded a lower per-kWh price, while technologies such as solar PV are offered a higher price, reflecting higher costs.

maintenance and shading that lowers production on a portion of the installed base.

3. Wind Energy: The energy provided by wind was modeled using a single location (Spring Canyon near Peetz, CO). This location is a wind resource at the low end of the middle of 5 areas with 100 meter anemometer data available so that an average Colorado wind resource would be considered. In an actual system, turbines from various locations would be included depending on cost and availability. The wind turbine assumed was the same GE 1.6-100 assumed in Xcel's 2011 ERP (42.3% CF) at 100m hub height.

   The cost of wind energy was based on U.S. DOE data on historical wind power prices (*2011 Wind Technologies Market Report*, Ryan Wiser and Mark Bolinger et al of Lawrence Berkeley National Laboratory, August 2012). Prices for wind energy are from long term projects, including RECs and the PTC, and had a capacity weighted average cost of $32/MWh in 2011 for the "Wind Belt" states (that includes Colorado). The distribution of costs from a sample of 113 contract prices set from 2004 through 2011 in the Wind Belt states was analyzed to estimate wind contract price volatility.

   The high end cost was calculated using the distribution's median and standard deviation to scale the 2011 average price up with $22/MWh added to remove the PTC from the discounted prices. The low end was scaled down from the average 2011 prices using one standard deviation below the median. The 2011 average price of $32/MWh and high end of $67/MWh, not including transmission costs, compares to assumptions of $33/MWh for PTC wind and $59/MWh and $66/MWh (all discounted from 2017$'s to 2011$'s at 2.5%) used for non-PTC wind for generic sources and LEC source assumptions used in the Xcel 2011 ERP.

   Transmission for all wind energy is paid through one Balancing Authority in the resource model based on schedules in the 2013 Xcel OATT. Assuming that wind is generated in another Balancing Authority's area and requires transmission through the local Balancing Authority to Boulder, the financial model would include that additional cost.

   All excess wind was assumed to be curtailed and all transmission costs are still paid. This amounts to about $0.0057/kWh curtailed. No value is assumed for this energy but is an opportunity for cost reduction.

4. Natural Gas Fuel: The median natural gas price assumptions are based on the assumptions used in the Xcel 2011 ERP. The gas prices for 2017, 2022, 2027, 2032 and 2037 were deflated using an inflation rate of 1.78% used in the ERP for "General Inflation." These median prices were then compared with EIA reported data for delivered gas prices to the electrical sector versus Xcel's assumptions. The Xcel assumption was 41.6% higher in 2017, 38.4% higher in 2022, 28.0% higher in 2027, 0.2% higher in 2032 and 4.5% lower in 2037 than the EIA estimates.

   To calculate the range of 90% probability high values and 10% probability low values, the volatility was calculated for Colorado's gas price history in 2011 $'s from 1997 through 2011 from the U.S. Government's Energy Information Administration (EIA) with the median falling on the 2011 price. Using the ratio of 1.281552 x one standard deviation from the median as a percentage variation from the median for the 10%-90% ranges, this ratio was applied to the Xcel gas prices assuming they are the median price as intended. This assumes a normal distribution for gas price variation.

5. Gas Power Purchase Agreements (PPA's): Natural gas Power Purchase Agreements (PPAs) serve to provide firm backup when renewable energy resources are unavailable. Three PPAs were considered with varying power capacity ($/kW) versus improving cost for efficiency to produce energy ($/kWh). Which PPAs are chosen for the dispatchable power mix depends on many factors, including what is being optimized (cost versus emission), whether the PPA is needed for reserve capacity at lowest cost with infrequent operation or higher efficiency for frequent operation for operating capacity, etc. The assumptions for PPAs reflect this variation for the modeling optimization to use. The costs were based on industry reference pricing and supported as reasonable using a cost model combining mixes of Combustion Turbine (CT) and Combined Cycle (CC) configurations for generating power using natural gas. The model used cost assumptions from the 2011 Xcel ERP.

   The PPA assumptions were $10/kW-mo, $7/kW-mo and $5/kW-mo for financial heat rates of 8,000 Btu/kWh, 9,000 Btu/kWh and 10,000 Btu/kWh. For example, to procure access to 1000 kW of power for one month for the $10/kW-mo versus the $5/kW-mo PPA would cost $10,000 versus $5,000 but using them to generate 10,000 kWh (using them for 10 hours) would be an additional cost of $400 versus $500 for each assuming a natural gas price of $5.00/MMBTU (1,000,000 Btu's). This works out to $1.04/kWh and $0.54/kWh for each but if the purchase had been for 600,000 kWh, these would be $0.057/kWh and $.058/kWh. Even higher usage shifts the costs even more. So, final energy costs will depend on how the PPA is used. The HOMER optimization selects the best mix of these to give the best outcome.

   As part of the reserve calculations, the generation from these PPA's was assumed to be firm, meaning that the provider is required to maintain sufficient reserves to ensure supply. Transmission costs were not included and will be discussed below.

   For the emissions for these PPA's, a mix of turbine types using 4% CT's and 96% CC's was assumed for 2017. The CO2 equivalent emission rate of 417.6 g/kWh for the CT and CC generators came from the Xcel 2011 ERP rate for each generic type as a 4%/96% blend. The component blend is determined by many factors and will be reassessed to consider available technologies in a later phase if the process moves forward. The assumption for CT and CC emissions are from the Xcel ERP Table "*Attachment 2.8-2 Strategist Modeled Emissions Projected Emission Rates for Generic Resources*" for a Post-Resource Acquisition Period Combustion Turbine (1,322 lb/MWh = 600 g/kWh) and the Post-RAP 2x1 Combined Cycle Turbines (903 lb/MWh = 410 g/kWh).

   The option of modeling these PPA's as local generation was considered for several significant opportunities to reduce cost and increase efficiency with lower emissions. Local generation reduces losses and does not incur any transmission OATT costs. In addition, local generation gives opportunity to use waste heat from cogeneration to be used to heat and cool local businesses and possibly homes. However, estimating the costs and value of using this waste energy (and excess wind energy above) were beyond the scope of this analysis. The modeling currently does not include any value for the possibility of cogeneration and is reserved for any future phase of analysis.

6. Market Purchases: An hourly market cost profile for the Colorado area was created for buying and selling energy. It was assumed for modeling purposes that Boulder would not sell energy to avoid the complexity of pricing the value of excess wind energy. The market price tends to be the cheapest resource but carries with it higher emissions because it is assumed to match the Xcel mix and contains coal as a significant part of the generation supplying the energy. It is possible to contract specifically for lower emissions gas or even excess renewable energy but the cost is typically higher or available when energy is not needed.

   Because Xcel controls the Balancing Authority the Boulder market would make purchases in and Xcel supplies the majority of generation in the Balancing Authority, it is assumed that any market purchases of energy will have the emissions that Xcel assumes for its mix in the Xcel 2011 ERP ("*Attach Climax1-1.A1 SO - --PUBLIC VERSION-- 1-BASELINE*" spreadsheet had values of 652, 622, 561, 521 and 437 g/kWh for years 2017, 2022, 2027, 2032 and 2037). These assumptions were also used for the Xcel baseline and Phase Out Option when purchasing from Xcel.

7. Regulatory Carbon: The cost of carbon was based on a report on the possible cost to utilities for CO_2 emissions from Synapse Energy Economics Inc. (*2012 Carbon Dioxide Price Forecast*, Rachel Wilson, Patrick Luckow, Bruce Biewald, Frank Ackerman and Ezra Hausman, October 4, 2012). This report's basic assumption is that there will be action at the Federal or State level through legislative, executive or judicial levels that will put a price on carbon in the next 5 years by 2017. The authors see three likely trajectories of pricing for carbon from 2017 through 2040.

   The low path forecast is characterized by limited Congressional action through a national Renewable Portfolio Standard (RPS) or efficiency standards for utilities. This path starts at $15 (2012 $'s per ton) in 2020 to about $35 in 2040. The middle case forecast assumes significant but reasonable goals will be pursued with a cap-and-trade program or flexible policies to meet the goals. This path starts at $20 in 2020 and climbs to $65 per ton in 2040. Finally, the high forecast assumes high costs from aggressive emission standards, restrictions on emissions offsets or higher costs for alternative technologies to achieve more aggressive goals. This path ranges from $30 to $90 per ton over the same 20 year period.

   The assumption for this modeling assumed that the middle forecast would be the most likely high end for carbon costs. It was assumed that 90% of the probability distribution would be below 90% of this middle forecast, the middle of the range from $0 would be the median and 10% of the forecast would be exceeded 90% of the time. This gave ranges of high: $10.58 to $46.47, a median of $5.88 to $25.82, and a low range of $1.18 to $5.16 from 2017 to 2037 (2011 $'s).

   Boulder has already imposed a carbon tax on itself, although this is paid by customers and not the utility so it is not a true incentive for Xcel but motivates real changes from its customers and can fund efficiency programs. These can lead to real costs for the utility so the low range of carbon costs seems likely.

8. Transmission: Transmission costs were taken from the 2013 Xcel Open Access Transmission Tariff (OATT) issued by Xcel's Transmission subsidiary (*XCEL ENERGY*

ATTACHMENT D

OPERATING COs JOINT OATT Version: 0.0.0 Effective: 7/30/2010. These include costs for:

Schedule 1: scheduling, system control and dispatch services,
Schedule 2: Reactive Supply and Voltage Control from Generation Sources Service
Schedule 3: Regulation and Frequency Response Service
Schedule 5: Operating Reserve - Spinning Reserve Service
Schedule 6: Operating Reserve - Supplemental Reserve Service
Schedule 7: Long-Term and Short-Term Firm Point-to-Point Transmission Service
Schedule 8: Non-Firm Point-to-Point Transmission Service
Attachment H - Annual Transmission Revenue Requirement for Network Integration Transmission Service (NITS)

Transmission losses are included in the load models as extra load that must be supplied by generation. As mentioned, the natural gas generation PPA's include transmission costs through the Xcel Balancing Authority in the financial model. Wind energy used includes these transmission costs plus an additional cost of $20.64/kW-yr for transmission through an additional Balancing Authority and is included in the HOMER generation model. Excess wind only includes costs for the additional Balancing Authority in the HOMER model.

Resource Inputs and Assumptions

Model Settings and Assumptions Summary	(Units, comments)	Input to Model:	Range Entry	2017 Input Value	2022 Input Value	2027 Input Value	2032 Input Value	2037 Input Value
Project Starting Year Projected	(yr)			2017	n/a	n/a	n/a	n/a
Project Timeframe for Calculations	(yrs)			20	n/a	n/a	n/a	n/a
Planning Reserve Margin	(% of annual)	HOMER		0.15	0.15	0.15	0.15	0.15
Solar firm capacity	(% based on nameplate)	HOMER		0.15	0.15	0.15	0.15	0.15
Wind firm capacity	(% based on nameplate)	HOMER		0.1	0.1	0.1	0.1	0.1
Solar Operating Reserve Derated	(% of solar OR req.)	HOMER	High	0%	0%	0%	0%	0%
Wind Operating Reserve Derated	(% of wind OR req.)	HOMER	High	0%	0%	0%	0%	0%
Boulder Load Model Baseline	(files with 8760 load model)	(located in load model)						
Boulder Load Model with Aggressive DSM	(files with 8760 load model)	(located in load model)						
Existing Boulder Hydro Production	(kWh/yr)			45,617,288	45,617,288	45,617,288	45,617,288	45,617,288
Hydro Hourly Production Model	(files with load model)		Model	2010 model	2010 model	2010 model	2010 model	2010 model
Hydro Cost (Equal to Current PSCo Cost)	($/y, excludes transmission)			$1,969,740	$1,969,740	$1,969,740	$1,969,740	$1,969,740
Hydro Capacity to Transmission	(kW)			13000	13000	13000	13000	13000
Hydro Total Annual Cost	($/yr, transmission in financial model)	HOMER		$1,969,740	$1,969,740	$1,969,740	$1,969,740	$1,969,740
Existing Installed Solar Capacity Rating	(MW, pre-2017 solar PV)	Fin./HOMER	pre 2017 solar	20	20	20	20	20
PPA-S Solar Production Cost (added post 2017)	($/KWh produced, excludes transmission)		High	0.228	0.203	0.19	0.166	0.166
			Nom	0.186	0.162	0.15	0.146	0.146
			Low	0.133	0.113	0.105	0.103	0.103
PPA-S Total Solar Cost	($/kWh, no transmission needed)	HOMER	High	0.228	0.203	0.19	0.166	0.166
			Nom	0.186	0.162	0.15	0.146	0.146
			Low	0.133	0.113	0.105	0.103	0.103
PPA-S PV Capacity Subject to Transmission	(%)			0%	0%	0%	0%	0%
Solar Source Model	(NREL profile data in Boulder)		Model	TMY3 for Boulder (TMY #724699, Broomfield/Jeffco [Boulder - Surfrad]	TMY3 for Boulder (TMY #724699, Broomfield/Jeffco [Boulder - Surfrad]	TMY3 for Boulder (TMY #724699, Broomfield/Jeffco [Boulder - Surfrad]	TMY3 for Boulder (TMY #724699, Broomfield/Jeffco [Boulder - Surfrad]	TMY3 for Boulder (TMY #724699, Broomfield/Jeffco [Boulder - Surfrad]
Solar Derating Factor	(% to AC)	HOMER		0.8	0.8	0.8	0.8	0.8
Solar Panel Slope	(degrees, at latitude)	HOMER		40	40	40	40	40
Solar Azimuth	(degrees W of S)	HOMER		0	0	0	0	0
Solar Fixed		HOMER		no tracking	no tracking	no tracking	no tracking	no tracking
Solar Ground Reflectance	(%)	HOMER		0.2	0.2	0.2	0.2	0.2
PPA-W Wind Production Contract Price	($/kWh, excludes transmission)		High	0.067	0.067	0.067	0.067	0.067

ATTACHMENT D

			Nom	0.032	0.032	0.032	0.032	0.032
			Low	0.025	0.025	0.025	0.025	0.025
PPA-W Total Wind Cost	($/kWh, includes transmission)	HOMER	High	0.072568016	0.072568016	0.072568016	0.072568016	0.072568016
			Nom	0.037568016	0.037568016	0.037568016	0.037568016	0.037568016
			Low	0.030568016	0.030568016	0.030568016	0.030568016	0.030568016
PPA-W Wind Turbine Capacity for Transmission	(kW)			1600	1600	1600	1600	1600
PPA-W Wind Turbine Annual Production	(kWh/yr)			5,930,771	5,930,771	5,930,771	5,930,771	5,930,771
PPA-W Wind Turbine to Model	(type, hub height&wind speed/power profile)	HOMER	Turbine	GE1.6-100	GE1.6-100	GE1.6-100	GE1.6-100	GE1.6-100
PPA-W Wind Turbine Hub Height	(m)	HOMER	Fixed	100	100	100	100	100
PPA-W Wind Source Models	(NREL 100m anemometer height [mps])		Model	SpgCn100m	SpgCn100m	SpgCn100m	SpgCn100m	SpgCn100m
Natural Gas Cost Used in HOMER	($/m3, delivered, 2012 $)		High	0.252	0.288	0.316	0.321	0.327
			Nom	0.183	0.209	0.229	0.232	0.237
			Low	0.113	0.129	0.142	0.144	0.147
Natural Gas Cost Equivalent MMBTU Cost	($/MMBTU, delivered, MMBTU=29.678 m3)		High	$7.48	$8.55	$9.38	$9.51	$9.71
			Nom	$5.42	$6.19	$6.80	$6.89	$7.04
			Low	$3.36	$3.84	$4.22	$4.27	$4.36
Natural Gas CO2-e content in fuel	(g-CO2-e/BTU)	unused		0.0770	0.0770	0.0770	0.0770	0.0770
PPA-D Dispatchable Contract 1 Fixed Cost	($/kW-yr)	HOMER		$120.00	$120.00	$120.00	$120.00	$120.00
PPA-D Dispatchable Contract 1 Financial Heat Rate	(BTU/kWh)			8000	8000	8000	8000	8000
PPA-D Dispatchable Contract 1 Contract Price	($/kWh)	HOMER	High	0.05984	0.0684	0.07504	0.07608	0.07768
			Nom	0.04336	0.04952	0.0544	0.05512	0.05632
			Low	0.02688	0.03072	0.03376	0.03416	0.03488
PPA-D Dispatchable Contract 1 CO2e(100)	(g/kWh)	HOMER		417.60	417.60	417.60	417.60	417.60
PPA-D Dispatchable Contract 2 Fixed Cost	($/kW-yr)	HOMER		$84.00	$84.00	$84.00	$84.00	$84.00
PPA-D Dispatchable Contract 2 Financial Heat Rate	(BTU/kWh)			9000	9000	9000	9000	9000
PPA-D Dispatchable Contract 2 Contract Price	($/kWh)	HOMER	High	0.06732	0.07695	0.08442	0.08559	0.08739
			Nom	0.04878	0.05571	0.0612	0.06201	0.06336
			Low	0.03024	0.03456	0.03798	0.03843	0.03924
PPA-D Dispatchable Contract 2 CO2e(100)	(g/kWh)	HOMER		417.60	417.60	417.60	417.60	417.60
PPA-D Dispatchable Contract 3 Fixed Cost	($/kW-y)	HOMER		$60.00	$60.00	$60.00	$60.00	$60.00

PPA-D Dispatchable Contract 3 Financial Heat Rate	(BTU/kWh)			10000	10000	10000	10000	10000
PPA-D Dispatchable Contract 3 Contract Price	($/kWh)	HOMER	High	0.0748	0.0855	0.0938	0.0951	0.0971
			Nom	0.0542	0.0619	0.068	0.0689	0.0704
			Low	0.0336	0.0384	0.0422	0.0427	0.0436
PPA-D Dispatchable Contract 3 CO2e(100)	(g/kWh)	HOMER		417.60	417.60	417.60	417.60	417.60
PPA-D Contract Minimum (Must Take)		HOMER		0	0	0	0	0
PPA-D Contract Length	(years)	HOMER		20	20	20	20	20
Market CO2e(100)	(g/kWh) from ERP Mix	HOMER	Nom	652.39	621.67	561.33	521.49	436.61
Market (NG Portion)	(%) from ERP Mix			0.2198	0.3296	0.3746	0.4063	0.5548
Market (Renewable Portion)	(%) from ERP Mix			0.2313	0.2263	0.2298	0.2526	0.2437
Market Price Multiplier (based on wind)	(%, ratio)	HOMER	High	100.00%	100.00%	100.00%	100.00%	100.00%
			Nom	100.00%	100.00%	100.00%	100.00%	100.00%
			Low	100.00%	100.00%	100.00%	100.00%	100.00%
Market Price Multiplier (based on natural gas)	(%, ratio)	HOMER	High	108.35%	112.57%	114.21%	115.45%	121.04%
			Nom	100.00%	100.00%	100.00%	100.00%	100.00%
			Low	91.65%	87.49%	85.79%	84.55%	78.88%
Trade Margin	($/kWh)	HOMER	High	0.006	0.006	0.006	0.006	0.006
			Nom	0.004	0.004	0.004	0.004	0.004
			Low	0.002	0.002	0.002	0.002	0.002
Water Use	(gallons/KWH)	unused	High					
Regulatory: Carbon Tax	($/t, 2011 $'s/metric tonne)	HOMER	High	10.58	19.55	28.52	37.49	46.47
			Nom	5.88	10.86	15.85	20.83	25.82
			Low	1.18	2.17	3.17	4.17	5.16
Additional Transmission Wheeling Cost	($/kW-yr, 2013 OATT)	HOMER	Nom	$20.64	$20.64	$20.64	$20.64	$20.64
Additional data used in modeling								
Total PPA-S Annual Cost	($/kWh, no transmission needed)	HOMER	High	$356.56	$317.47	$297.14	$259.60	$259.60
			Nom	$290.88	$253.35	$234.58	$228.33	$228.33
			Low	$207.99	$176.72	$164.21	$161.08	$161.08
Total PPA-W Annual Cost	($/turbine, includes transmission)	HOMER	High	$430,384	$430,384	$430,384	$430,384	$430,384
			Nom	$222,807	$222,807	$222,807	$222,807	$222,807
			Low	$181,292	$181,292	$181,292	$181,292	$181,292
PPA-D Dispatchable Contract 1 Carbon Intensity	(dag/kWh, CO2e to C based on molecular mass)	HOMER		11.389091	11.389091	11.389091	11.389091	11.389091

ATTACHMENT D

PPA-D Dispatchable Contract 2 Carbon Intensity	(dag/kWh, CO2e to C based on molecular mass)	HOMER		11.389091	11.389091	11.389091	11.389091	11.389091
PPA-D Dispatchable Contract 3 Carbon Intensity	(dag/kWh, CO2e to C based on molecular mass)	HOMER		11.389091	11.389091	11.389091	11.389091	11.389091
Xcel Negotiated Cost (High Wind High NG)	($/kWh, excludes transmission)	HOMER		0.0656	NA	NA	NA	NA
Xcel Negotiated Cost (Nom Wind High NG)	(ECA + Levelized RSE)	HOMER		0.0626	NA	NA	NA	NA
Xcel Negotiated Cost (Low Wind High NG)		HOMER		0.0612	NA	NA	NA	NA
Xcel Negotiated Cost (High Wind Nom NG)		HOMER		0.0623	NA	NA	NA	NA
Xcel Negotiated Cost (Nom Wind Nom NG)		HOMER		0.0593	NA	NA	NA	NA
Xcel Negotiated Cost (Low Wind Nom NG)		HOMER		0.0579	NA	NA	NA	NA
Xcel Negotiated Cost (High Wind Low NG)		HOMER		0.0591	NA	NA	NA	NA
Xcel Negotiated Cost (Nom Wind Low NG)		HOMER		0.0561	NA	NA	NA	NA
Xcel Negotiated Cost (Low Wind Low NG)		HOMER		0.0546	NA	NA	NA	NA

ATTACHMENT D

Financial Inputs and Assumptions				
GROUP	**ITEM**	**VALUE**	**DESCRIPTION OF INPUT**	**SOURCE**
Set up Parameters	Model Start Year:	2017	Values entered will be in 2011 dollars and adjusted for inflation. This start year is for modeling purposes and not an indication of actual estimated start time.	City Staff
Set up Parameters	Operations Start Date:	3/1/2017	For modeling purposes, not an indication of actual estimated start time.	City Staff
Set up Parameters	Annual Inflation:	2.50%	Percentage of inflation applied to all dollar values over the time span of the model	Boulder Cost Model 2011
Set up Parameters	Public Purpose Program (P^3 Fund):	0.00%	Previously represented percentage of revenues used for demand side management (DSM) and demand response programs, including those currently funded through the city's Climate Action Plan (CAP) tax. This is now covered in the on-going O+M costs under customer accounts.	-
Set up Parameters	Annual Property Tax Reimbursement	$2,000,000	This represents payments to other governmental entities to replace taxes currently paid by Xcel. Payments to the school district are mandatory in the city charter. Based on 2010 numbers, this is approximately $1.6M. This is entered into the model as a value in dollars. The number is updated with a conservative estimate.	Appendix E of August 2, 2011 city council memo and city finance department
Set up Parameters	City Overhead (PILOT):	3.00%	The city charter allows **up to** four percent of total revenues to be paid to the general fund as a replacement for existing revenues currently generated through a franchise fee or an occupation tax from the incumbent utility. Council would decide the appropriate amount each year based on the revenues and the need to replace existing revenues.	City Charter

Set up Parameters	Target Debt Service Coverage:	1.25	The ratio of net revenues available to pay debt service to the debt service requirements. The city charter requires the utility to have a minimum 1.25 coverage ratio. The actual target will vary depending on target rating. The model is being analyzed by exploring the sensitivity of higher target debt service coverage ratios.	PFM/City Charter
Set up Parameters	Working Capital (Months):	6	The cash available for day-to-day operations of an organization. Calculated value: working capital in months multiplied by the average monthly O&M cost during the first year. O&M includes energy, transmission and operations. This fund builds over time to serve as a reserve fund.	PFM
Set up Parameters	5-YR SAVINGS/(LOSSES) NPV ($000's)	5.00%	The value represents the discount rate in the NPV calculation. The discount rate is the rate of return that could be earned on an investment in the financial markets with similar risk. This assumption assumes a 5-year NPV calculation.	PFM
Set up Parameters	20-YR SAVINGS/(LOSSES) NPV ($000's)	7.50%	The value represents the discount rate in the NPV calculation. The discount rate is the rate of return that could be earned on an investment in the financial markets with similar risk. This assumption assumes a 20-year NPV calculation.	PFM
Taxable Bond	Term (years)	30	The time period the bonds would be outstanding (generally this would be the same time as the expected life of the asset).	PFM
Taxable Bond	Interest Pmt/year:	2	The number of interest payments made on the bond annually.	PFM
Taxable Bond	Bond Interest Rate:	6.50%	The estimated interest rate on a 30-year taxable bond, given the entity's anticipated bond rating. This rate is used as a nominal value and the model is being analyzed by exploring the sensitivity of higher and lower interest rates on the debt issues.	PFM

ATTACHMENT D

Taxable Bond	Debt Service Reserve:	Maximum annual debt payment	When revenue bonds are issued a Debt Service Reserve Fund (DSRF) is established to provide a reserve source of payment for principal and interest in the event that revenues are unable to cover bond obligations when due. DSRFs are usually sized at the lessor of 10% of Par, 125% of Average Annual Debt Service or Maximum Annual Debt Service. If using one test, PFM suggests using Maximum Annual Debt Service.	PFM
Taxable Bond	Cap. Interest (Years):	1.5	Capitalized interest is the portion of the bond proceeds that will be reserved to be available to make the initial interest payments on the bonds. The number inserted is the number of years for which capitalized interest is included in the bonds (1.5 means a year and one-half or 18 months).	City Bond Counsel
Taxable Bond	Underwriter Discount:	0.75%	The differential between the price paid to the issuer and the prices at which the securities are initially offered to the investing public. It is the fee an underwriter charges when purchasing bonds for resale to the public. The underwriter assumes the risk of ownership until the bonds are sold.	PFM
Taxable Bond	Issuance Cost:	$1,500,000	The expenses incurred in the process of issuing bonds. This may include registration with regulators, marketing the issue to investors, bond rating costs, legal fees, and so forth.	PFM
Taxable Bond	Interest Rate of Return:	1.00%	The rate of return expected on the city's investments.	PFM
Non-Taxable Bond	Term (years)	30	The time period the bonds would be outstanding (generally this would be the same time as the expected life of the asset).	PFM
Non-Taxable Bond	Interest Pmt/year:	2	The number of interest payments made on the bond annually.	PFM
Non-Taxable Bond	Bond Interest Rate:	5.50%	The estimated interest rate on a 30-year tax exempt bond, given the entity's anticipated bond rating. This rate is used as a nominal value and the model is being analyzed by exploring the sensitivity of higher and lower interest rates on the debt issues.	PFM

Non-Taxable Bond	Debt Service Reserve:	Maximum annual debt payment	When revenue bonds are issued a Debt Service Reserve Fund (DSRF) is established to provide a reserve source of payment for principal and interest in the event that revenues are unable to cover bond obligations when due. DSRFs are usually sized at the lessor of 10% of Par, 125% of Average Annual Debt Service or Maximum Annual Debt Service. If using one test, PFM suggests using Maximum Annual Debt Service.	PFM
Non-Taxable Bond	Cap. Interest (Years):	1.5	Capitalized interest is the portion of the bond proceeds that will be reserved to be available to make the initial interest payments on the bonds. The number inserted is the number of years for which capitalized interest is included in the bonds (1.5 means a year and one-half or 18 months).	PFM
Non-Taxable Bond	Underwriter Discount:	0.75%	The differential between the price paid to the issuer and the price paid to the issuer and the prices at which the securities are initially offered to the investing public. It is the fee an underwriter charges when purchasing bonds for resale to the public. The underwriter assumes the risk of ownership until the bonds are sold.	PFM
Non-Taxable Bond	Issuance Cost:	$1,000,000	The expenses incurred in the process of issuing bonds. This may include registration with regulators, marketing the issue to investors, bond rating costs, legal fees, and so forth.	PFM
Non-Taxable Bond	Interest Rate of Return:	1.00%	The rate of return expected on the city's investments.	PFM
Bridge Loan	Term (years)	2	2 years is being used for modeling purposes as the maximum time for the bridge loan	PFM
Bridge Loan	Interest Pmt/year:	12	The number of interest payments made on the loan annually	PFM
Bridge Loan	Bond Interest Rate:	8.00%	The estimated interest rate on a short-term bridge loan. This rate is used as a nominal value and the model is being analyzed by exploring the sensitivity of higher and lower interest rates on the debt issues.	PFM
Bridge Loan	Debt Service Reserve:	N/A	Assume no Debt Service Reserve	PFM

Bridge Loan	Cap. Interest (Years):	0.0	For bridge loan, only interest payments will be made; principal will be repaid from bond proceeds. Therefore there is no capitalized interest	PFM
Bridge Loan	Underwriter Discount:	0.75%	The anticipated fee charged to underwrite a bridge loan	PFM
Bridge Loan	Issuance Cost:	$750,000	The expenses incurred in the process of receiving a bridge loan. This may include marketing the issue to investors, legal fees, and so forth	PFM
Stranded Costs		$ 255,204,000	Funded through taxable debt. Xcel energy provided estimates of stranded costs for different time periods if the city of Boulder left their system. Stranded costs are being modeled with this number as aligned with the model start date of 2017 as the worst case scenario. The city believes there will be no stranded costs caused by the city leaving Xcel's system. Analysis includes sensitivity analysis on other values ranging from $0 to $255M.	Xcel Energy letter to the city June, 2011
Acquistion Costs		$ 150,000,000	Funded through taxable debt. Includes all costs associated with acquistion. Xcel energy provided an estimate of the system value in a study completed by their consultant, Utilipoint. This value is being modeled as the worst case sceanrio with a sensitivity analysis on this input.	Xcel Energy Utilipoint study, 2011
Utility Start-up	Working Capital:	6 months	Calculated value: working capital in months multiplied by the highest monthly O&M cost during the first year. O&M include energy, transmission and operations.	PFM
Utility Start-up	Logistics pre-acquisition:	$4,933,859	This is a one-time cost that includes start-up capital costs necessary in advance of a condemnation ruling. The costs include building expanded facilities at the City Municipal Service Center, purchase of specialized vehicles (with long lead order times), information systems, critical substation and feeder separation components,and inventory. This cost would be funded through some type of bridge financing in advance of acquisition.	Peer cities, Schneider Engineering, Exponential Engineering, City of Boulder FAM

Utility Start-up	Logistics at time of acquisition:	$19,475,307	This is a one-time cost that includes the remaining capital costs necessary to begin utility operations. Costs include expansion of facilities, warehouse, customer information systems, land acquistion, information systems, vehicles, substation and feeder separation components, inventory, and inital capital investments to replace aging infrastructure.	Peer cities, Schneider Engineering, Exponential Engineering, City of Boulder FAM
Other start-up costs	Capital improvements and undergrounding	$22,876,750	Tax-exempt bond issuance in year 3 to upgrade aging infrastructure and undergrounding.	Exponential Engineering
Other start-up costs	Capital improvements and undergrounding	$17,120,250	Tax-exempt bond issuance in year 8 to upgrade aging infrastructure and undergrounding.	Exponential Engineering
Other start-up costs	Capital improvements and undergrounding	$15,513,750	Tax-exempt bond issuance in year 13 to upgrade aging infrastructure and undergrounding.	Exponential Engineering
Other start-up costs	Capital improvements and undergrounding	$9,308,250	Tax-exempt bond issuance in year 18 to upgrade aging infrastructure and undergrounding.	Exponential Engineering
OATT (Open Access Transmission Tariff)	Scheduling, SC and Dispatch	$ 0.070	Monthly Cost/KW of load	2011 FERC filing from XCEL Energy.
OATT	Reactive Supply and Voltage Control	$ 0.08	Monthly Cost/KW of load	2011 FERC filing from XCEL Energy.
OATT	Regulation and Frequency Response	$ 6.74	Monthly Cost/KW of load	2011 FERC filing from XCEL Energy.
OATT	Operating Reserve - Spinning Reserve	$ 6.88	Monthly Cost/KW of load	2011 FERC filing from XCEL Energy.

OATT	Operating Reserve - Supplemental Reserve	$ 3.72	Monthly Cost/KW of load	2011 FERC filing from XCEL Energy.
OATT	Network Integration	$ 1.98	Monthly Cost/KW of load	2011 FERC filing from XCEL Energy.
GENERAL ADMIN	General Manager:	$325,000	General Manager of Utility: Staff includes 1 Electric Utility Director ($250,000 + 30% loading factor) based on high and low range from salary.com and 2007 Operations Report estimates updated in 2011.	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and Cost Model. Benchmarked through peer utilities and APPA
GENERAL ADMIN	Operations Management:	$507,000	Division management of utility: Staff includes 1 Operation Manager ($144,000 + 30% loading factor), 0.5 Public Works Utilities & Maintenance Coordinator (50% of $111,500+ 30% loading factor), 0.5 Director of Public Works (50% of $170,000+ 30% loading factor), and 0.5 Senior Financial Manager (50% of $210,000+ 30% loading factor), based on maxium salaries from salary.com and 2007 Operations Report estimates updated in 2011.	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and Cost Model. Benchmarked through peer utilities and APPA
GENERAL ADMIN	Board:	$100,000	Identified as $100,000 in annual expenses related to boards and meetings in RBI Feasibility Study at p. 23.	Feasibility Study by RBI, 2011. Benchmarked through peer utilities and APPA

GENERAL ADMIN	Reg. Compliance and Reports:	$253,500	3 Administrative Specialists ($65,000 each + 30% loading factor), based on maximum salaries from salary.com and 2007 Operations Report estimates updated in 2011.	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and Cost Model. Benchmarked through peer utilities and APPA
GENERAL ADMIN	Legal:	$600,000	Client LSE at 580 in 2011, includes lobbyist for GHG/Carbon efforts. Estimated at $600,000 per year in RBI Feasibility Study at p. 23.	Feasibility Study by RBI, 2011. Benchmarked through peer utilities and APPA
GENERAL ADMIN	Human Resources:	$176,800	Staff includes 2 Compensation Analysts ($68,000 each + 30% loading factor) based on maximum salaries from salary.com and 2007 Operations Report estimate updated in 2011.	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and Cost Model. Benchmarked through peer utilities and APPA
GENERAL ADMIN	Insurance:	$1,000,000	Estimated at 1% of operating cost or $1,000,000 per year in RBI Feasibility Study at p. 23.	Feasibility Study by RBI, 2011. Benchmarked through peer utilities and APPA
GENERAL ADMIN	Insurance:	$100,000	Distribution operation insurance (linemen). Identified as $100,000 per year in RBI Feasibility Study at p. 23.	Feasibility Study by RBI, 2011. Benchmarked through peer utilities, APPA

GENERAL ADMIN	Office Supplies:	$100,000	Includes telecom, printing, office rental, etc. Identified as $100,000 per year in RBI Feasibility Study at p. 22. Costs for furniture and equipment estimated at $85,500 in 2007 Operations Report at p. 33.	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and Cost Model. Benchmarked through peer utilities and APPA
GENERAL ADMIN	Audits:	$50,000	Identified as $50,000 per year in RBI Feasibility Study at p. 23.	Feasibility Study by RBI, 2011. Benchmarked through peer utilities and APPA
GENERAL ADMIN	Dues and NERC:	$100,000	Identified as $100,000 per year in RBI Feasibility Study at p. 23.	Feasibility Study by RBI, 2011. Benchmarked through peer utilities and APPA
GENERAL ADMIN	Allocation to city overhead	$1,482,375	The costs allocated to the utility from other city departments for admininstrative support. Based on an estimated 2013 cost allocation from city water utilities proportional to the number of FTEs.	City of Boulder
GENERAL ADMIN	Staff support	$126,230	Support for staff- includes trainings, additional office expenses. Calculated as additional 10% on labor costs	City of Boulder
GENERAL ADMIN	Rental of administrative facility	$505,920	Annual costs to rent a facitility for administrative services	City of Boulder
GENERAL ADMIN	Repayment to Transportation and Utilities	$91,476	Annual repayment to transportation and utilities departments for use of land and facilities.	City of Boulder

CUSTOMER SERVICE AND ACCOUNTS	Energy Services	$520,000	Staff includes 5 Conservation and Energy Services ($80,000) + 30% loading factor	City of Boulder and Benchmarked through peer utilities and APPA
CUSTOMER SERVICE AND ACCOUNTS	Energy rebates	$2,230,000	Energy rebates	Energy Baseline Report, 2011 , Appendix E of August 2, 2011 city council memo and Benchmarked through peer utilities and APPA
CUSTOMER SERVICE AND ACCOUNTS	Energy Programs	$1,710,000	Includes overhead, marketing, planning, program delivery, indirect programs, etc.	Energy Baseline Report, 2011 , Appendix E of August 2, 2011 city council memo and Benchmarked through peer utilities and APPA
CUSTOMER SERVICE AND ACCOUNTS	Staff support	$52,000	Support for staff- includes trainings, additional office expenses. Calculated as additional 10% on labor costs	City of Boulder and Benchmarked through peer utilities and APPA
BILLING	Key Accounts & Rates:	$773,400	Staff includes 1 Electric Utility Rate Analyst ($87,000 + 30% loading factor), 5 Key Accounts Specialists ($84,000 + 30% loading factor), and 0.5 Utility Financial Manager (50% of $210,000 + 30% loading factor), based on maximum salaries at salary.com and 2007 Operations Report estimates.	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and Cost Model. Benchmarked through peer utilities and APPA

ATTACHMENT D

BILLING	Billing & Paying:	$557,700	Staff includes 3 Billing Services Representatives ($65,000 each + 30% loading factor), 0.5 Billing Supervisor (50% of $78,000 + 30% loading factor), and 3 Billing Customer Service (50% of $65,000 each + 30% loading factor), based on maximum salaries at salary.com.	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and Cost Model. Benchmarked through peer utilities and APPA
BILLING	Software:	$50,000	Billing software license identified as $50,000 per year in RBI Feasibility Study at p. 22. Costs to upgrade existing city utility Customer Information System (CIS) estimated as $30-50,000 in 2007 Operations Report at p. 25.	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and Cost Model. Benchmarked through peer utilities and APPA
BILLING	Staff support	$133,110	Support for staff- includes trainings, additional office expenses. Calculated as additional 10% on labor costs	City of Boulder and Benchmarked through peer utilities and APPA
METERING	Supervisors:	$182,650	Staff includes 1 Meter Supervisor ($73,000+ 30% loading factor), 1 Standards Engineer ($74,000+ 30% loading factor), and 0.5 Materials Management Supervisor (50% of $61,000+ 30% loading factor), based on maximum salaries from salary.com and 2007 Operations Report estimates updated in 2011.	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and

				Cost Model. Benchmarked through peer utilities and APPA
METERING	Technicians:	$611,169	Staff includes 2 Meter Specialists ($57,500 each), 0.5 Instrument & Control Specialists (50% of $67,500), 0.5 Materials Management Specialist (50% of $52,000), 2 Materials Inventory Technicians ($48,500 each), 2 Meter Service Technicians ($65,000 each) and 3 Meter Readers ($38,960) based on maximum salaries from salary.com and 2007 Operations Report estimates updated in 2011	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and Cost Model. Benchmarked through peer utilities and APPA
METERING	Software:	$50,000	Metering software license identified as $50,000 per year in RBI Feasibility Study at p. 22.	Feasibility Study by RBI, 2011. Benchmarked through peer utilities and APPA
METERING	Meter Maintenance:	$21,095	Material costs for on-going meter maintenance. Estimated at 2.5% of metering costs.	Feasibility Study by RBI, 2011. Benchmarked through peer utilities and APPA
METERING	Staff support	$79,382	Support for staff- includes trainings, additional office expenses. Calculated as additional 10% on labor costs	City of Boulder and Benchmarked through peer utilities and APPA

SCHEDULING/ MARKET	Energy Manager:	$228,800	Called Resource Supply Supervisor in 2011. Based on maximum salary from salary.com + 30% loading factor and 2007 Operations Report estimates updated in 2011.	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and Cost Model. Benchmarked through peer utilities and APPA
SCHEDULING/ MARKET	Schedule Coordinator:	$431,600	Based on maximum salary from salary.com+ 30% loading factor and 2007 Operations Report estimates updated in 2011.	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and Cost Model. Benchmarked through peer utilities and APPA
SCHEDULING/ MARKET	Settlement:	$195,000	Based on maximum salary from salary.com + 30% loading factor and 2007 Operations Report estimates updated in 2011.	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and Cost Model. Benchmarked through peer utilities and APPA

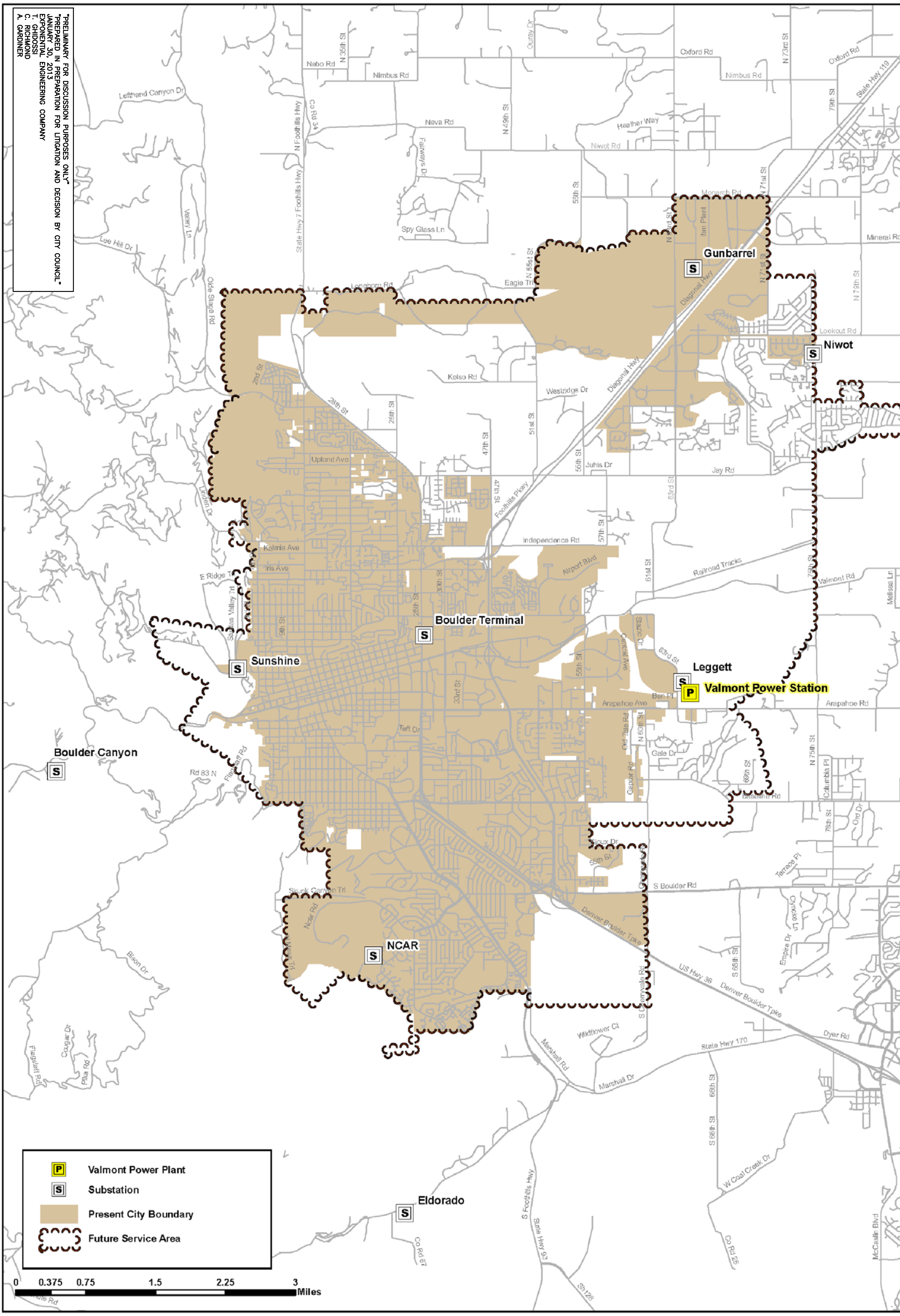
SCHEDULING/ MARKET	Software:	$50,000	Scheduling software license identified as $50,000 per year in RBI Feasibility Study at p. 22.	Feasibility Study by RBI, 2011. Benchmarked through peer utilities and APPA
SCHEDULING/ MARKET	Staff support	$85,540	Support for staff- includes trainings, additional office expenses. Calculated as additional 10% on labor costs	City of Boulder and Benchmarked through peer utilities and APPA
DISTRIBUTION	Engineering:	$1,392,950	Staff includes 2 Engineering Supervisors ($113,000 each+ 30% loading factor), 2 Project Engineers ($98,000 each + 30% loading factor), 3 Electric Engineer ($85,000 + 30% loading factor), 1 Field Engineering Supervisor ($114,000 + 30% loading factor), 3 Field Engineer Specialists ($71,000 each + 30% loading factor), 0.5 Standards Engineer (50% of $74,000 + 30% loading factor), and 0.5 Materials Management Supervisor (50% of $61,000 + 30% loading factor), based on maximum salaries at salary.com and 2007 Operations Report estimates updated in 2011	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and Cost Model. Benchmarked through peer utilities and APPA
DISTRIBUTION	Field & Line Staff:	$5,895,825	Staff includes 2 Substation Supervisor ($75,000+ 30% loading factor), 2 Substation Specialists ($63,000 each+ 30% loading factor), 1 Field Service Manager ($112,000+ 30% loading factor), 2 Line Supervisors ($81,000 each+ 30% loading factor), 4 Line Crew Supervisors ($69,000 each+ 30% loading factor), 9 Line Specialists ($66,000 each+ 30% loading factor), 9 Line Technicians ($67,000 each+ 30% loading factor), 2 Electric Ground Workers ($50,000 each+ 30% loading factor), 2 Line Equipment Operators ($60,000 each+ 30% loading factor), 2 Electric Service Supervisor ($85,000+ 30% loading factor), 1 Safety/Training Coordinator ($74,000+ 30% loading factor), 1 Inspector ($54,000+ 30% loading factor), 1 Dispatcher ($62,000+ 30% loading factor), 1 Fleet Mechanic ($64,000)+ 30% loading factor, 0.5 of 8 Fleet Services (50% of $55,000 each+ 30% loading factor), 1 Instrument & Control Specialist ($67,500+ 30% loading factor), 1 Materials Management Specialist ($52,000+ 30% loading factor), and 2 Materials Inventory Technician ($48,500 each+ 30% loading factor), based on maximum salaries at salary.com and 2007 Operations Report estimates updated in 2011.	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and Cost Model. Benchmarked through peer utilities and APPA

DISTRIBUTION	GIS & IT Support:	$468,650	Staff includes 3 GIS Mapper ($55,500+ 30% loading factor) and 3 Developers/Programmers ($97,000 each+ 30% loading factor), based on maximum salaries from salary.com and 2007 Operations Report estimates updated in 2011	Electric Municipalization Project Administrative and Operational Report, 2007. Updated in 2011 RBI Feasibility Study and Cost Model. Benchmarked through peer utilities and APPA
DISTRIBUTION	SCADA:	$120,000	Estimated at $120,000 per year in RBI Feasibility Study at p. 22.	Feasibility Study by RBI, 2011. Benchmarked through peer utilities and APPA
DISTRIBUTION	Fuel:	$50,000	Vehicle fuel identified as $50,000 per year in RBI Feasibility Study at p. 22.	Feasibility Study by RBI, 2011. Benchmarked through peer utilities and APPA
DISTRIBUTION	Distribution Maintenance Materials	$223,829	Materials for on-going distribution maintenance = 2.5% of overall distribution costs	City of Boulder and Benchmarked through peer utilities and APPA
DISTRIBUTION	Research and Development	$250,000	On-going cost for research and development of new technology.	City of Boulder
DISTRIBUTION	Staff support	$775,743	Support for staff- includes trainings, additional office expenses. Calculated as additional 10% on labor costs	City of Boulder and Benchmarked through peer utilities and APPA

ATTACHMENT D

CAPITAL IMPROVEMENT	Distribution Capital & Undergrounding	$1,500,000	Annual fund for capital investments to replace aging infrastructure and undergrounding. This is augmented by additional tax-exempt debt issued in years 3,8,13, and 18.	Exponential Engineering

ATTACHMENT E
Service Territory Map



Drawn	TAG
Designed	DMS
Checked	TAG
Approved	TAG
Scale: 11x17	NTS
22x34	NTS
Date Created	1-30-13
Proj. No.	BLDR-1201
Reference Drawing No.	BASE 2

Exponential
Engineering
Company
328 Airpark Drive
Fort Collins, Colorado 80524
Phone: (970) 207-9648
Fax: (970) 207-9657

CITY OF BOULDER

PRELIMINARY SEPARATION CONCEPTS

No	Revisions	Date	By

ATTACHMENT F

Reliability Considerations for Municipalization

02/20/13

I. INTRODUCTION

One of the criteria of Section 198 of the Charter is that the city would provide reliable electric power as set forth in the Charter metrics[1]. Given the importance of this issue, a separate analysis and working group was formed to address questions about reliability. Specialized engineers were hired to evaluate the system and its condition, provide recommendations on needed improvements, identify regulatory reliability requirements, and recommend best practices to ensure reliable electrical service.

Reliability is a term used to describe the level of uninterrupted service an electric power utility provides. Reliability depends on a combination of the quality of the physical infrastructure as well as the ability of the utility to control the system and respond to failures. Certain elements of reliability are governed by federal and regional regulations. The staff has worked internally and with the Reliability Working Group to develop a plan that would allow a city-owned electric utility to provide better reliability than currently provided by Xcel, as well as meeting regulatory requirements.

The analysis of reliability has been considered in terms of formulating the plan for separating from the Xcel system, start-up of the utility, the capital replacement schedule and energy resource plans. In addition, the human, organizational and financial resources that would be needed for ongoing administration, operation, maintenance, monitoring, control, dispatch, project management, customer service and response procedures have been addressed in the modeling of municipal utility options with the intent of assuring reliable electrical service if a municipal electric utility is created.

A separation plan has been developed based on service area boundaries that serve the city and minimize areas of separation on existing feeders. The plan maintains the vast majority of the existing system configuration, including looping and redundancy features that are integral to maintaining high reliability. At the substations, the city would acquire the equipment on the "low-side" of the transformers and Xcel would maintain the "high-side" equipment and the transformers. This division of responsibility for equipment at substations is common where the distribution system is operated by a different entity than the transmission system. Any necessary interfaces to the external distribution grid outside of the substations would be accomplished by deploying switched, metered interconnections to provide backup and redundancy for both Xcel and city feeders. Where such interconnections are not feasible, additional infrastructure would be constructed to establish and/or maintain looping, redundancy, and reliability enhancing features.

Federal regulations have positively influenced the reliability of the interconnected transmission and generation system within the United States. Energy (generation) resource plans and associated transmission capabilities would comply with all regulations, maintain a 15 percent

[1] Maintain comparable electric equipment, facilities and services as those of Xcel at time of acquisition, which will be designed to achieve the same System Average Interruption Duration Index (SAIDI) of 85 and a System Average Interruption Frequency Index (SAIFI) of .85; maintain an adequate reserve margin of 15%; and meet applicable North American Electric Reliability Corporation (NERC) compliance requirements.

reserve margin and provide adequate on-line and off-line reserves with the intent of ensuring a reasonable (one day in 10 years) loss of load expectation.

Appendix F-1 presents a compilation of the various issues and analysis considered by the Reliability Working Group in a question and answer format. The following is a summary of some of the important aspects of the analysis.

II. RELIABILITY INDICES

Electric power system reliability is commonly measured based on the following indices:

The System Average Interruption Duration Index (SAIDI) measures the total interruption duration over a given time period (typically one year) for the average customer:

SAIDI = Σ(ri * Ni) / NT
Where,
SAIDI = System Average Interruption Duration Index
Σ = Summation function
ri = Restoration time, minutes
Ni = Total number of customers interrupted
NT = Total number of customer served

The System Average Interruption Frequency Index (SAIFI) is defined as the average number of times that a typical customer is interrupted during a specific time period (typically one year). SAIFI is determined by dividing the total number of customers interrupted in a time period by the average number of customers served. The resulting unit is "average number of interruptions per customer."

SAIFI = Σ(Ni) / NT
Where,
SAIFI = System Average Interruption Frequency Index
Σ = Summation function
Ni = Total number of customers interrupted
N_T *= Total number of customers served*

Based on Xcel Energy Quality of Service (QSP) reports, the following metric indices were established by City Council in November 2012.

- SAIDI: 85
- SAIFI: 0.85

These metric indices are slightly better than the four-year average for the Xcel Energy Boulder region. Appendix F-2 is a copy of the Xcel Energy QSP Report dated Jan. 17, 2012.

ATTACHMENT F

The electric power system may be categorized as:

1. Distribution - less than100 kilovolts (kV)
2. Transmission -100 kV and greater
3. Generation or Resource mix

The distribution system is defined as that portion of the electrical power system downstream of the substation high-side disconnect switch. Within the United States, distribution systems have the greatest impact on overall system performance as measured by SAIDI and SAIFI. Distribution systems constitute the vast majority of the "mileage" of the electric system and thus offer the greatest exposure to hazards, faults and failures. The interconnected transmission system and generation are designed for failure contingencies that would be uneconomical for distribution systems. The influence of extreme weather events is generally quantified separately (not included in SAIDI and SAIFI) due to the low probability of occurrence and economic and practical constraints preventing design of systems to withstand such events.

City staff interviewed and collected data from other Northern Colorado Front Range Public Power Utilities including Longmont and Fort Collins. These agencies use a variety of performance indices and metrics, some of which are targeted at reliability. Table 1 presents an abbreviated summary of this information. Appendix F-3 presents the data compiled to date.

Table 1 – Comparison Data

	Longmont	Fort Collins	Boulder
Service Area Population	86,000	147,000	111,000
Service Area Employment	49,000	97,000	97,000
Service Area (square miles)	49	56	44
Metered customers	37,000	64,000	62,000
Circuit Miles	594	855	569
Miles Overhead	149	17	213
Miles Underground	445	838	356
SAIDI	38	17	85
SAIFI	0.69	0.45	0.85

As shown, Longmont and Ft. Collins report better overall distribution system reliability as measured by SAIDI and SAIFI than Xcel Energy in the Boulder region.

A 2011 Institute of Electrical and Electronics Engineers (IEEE) benchmarking study attempted to help utilities quantify and improve their system reliability. This study reported a wide range of performance across the United States as measured by SAIDI and SAIFI. Figures 1 and 2 present the survey results for the day-to-day distribution system performance as measured by SAIDI and SAIFI without considering the influence of extreme events. The colors represent different regions of the United States and the dark blue represents the southwest region of which Colorado is a part.

Figure 1 - SAIDI Index Survey, Distribution Only
(2011 IEEE Benchmarking Study)

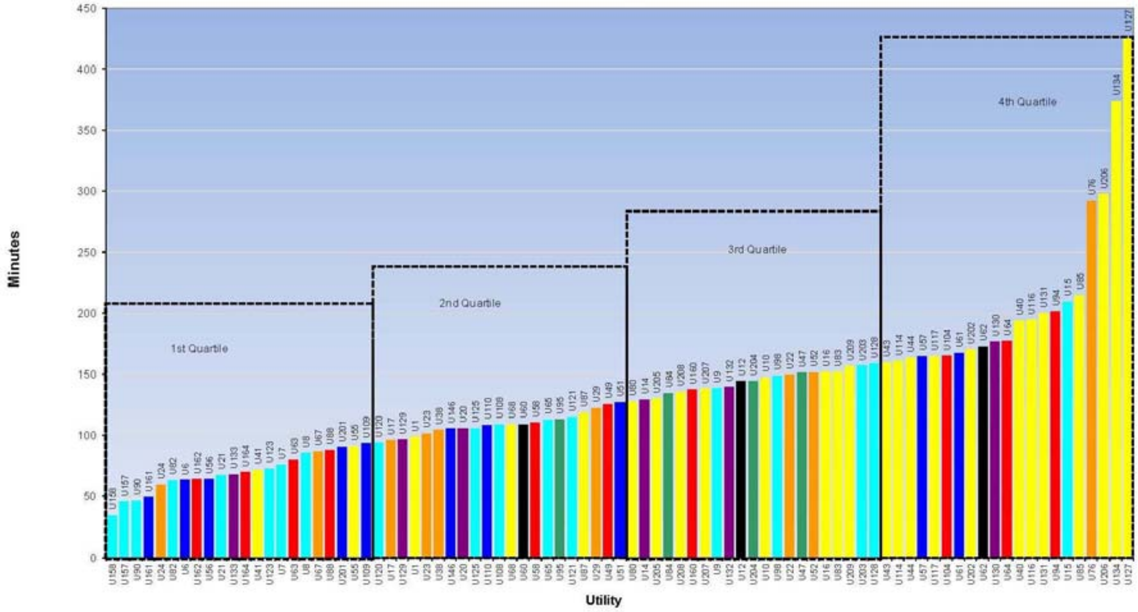
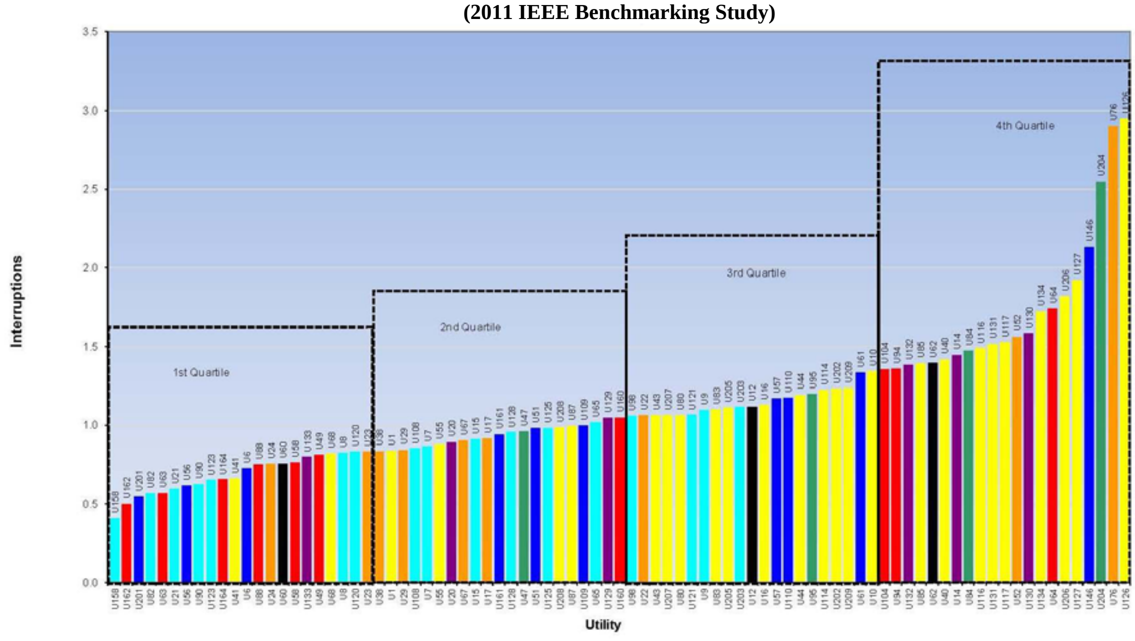


Figure 2 - SAIFI Index Survey, Distribution Only
(2011 IEEE Benchmarking Study)



Figures 3 and 4 present the influence of transmission and extreme events. As depicted in pink, transmission system impacts are relatively insignificant whereas the impacts of extreme weather events (as depicted in gray) are significant and vary considerably across the United States with the northeast and mid-Atlantic regions being more highly impacted by extreme weather events, such as hurricanes and ice storms.

Figure 3 - SAIDI Index Survey, Including Transmission and Extreme Events
(2011 IEEE Benchmarking Study)

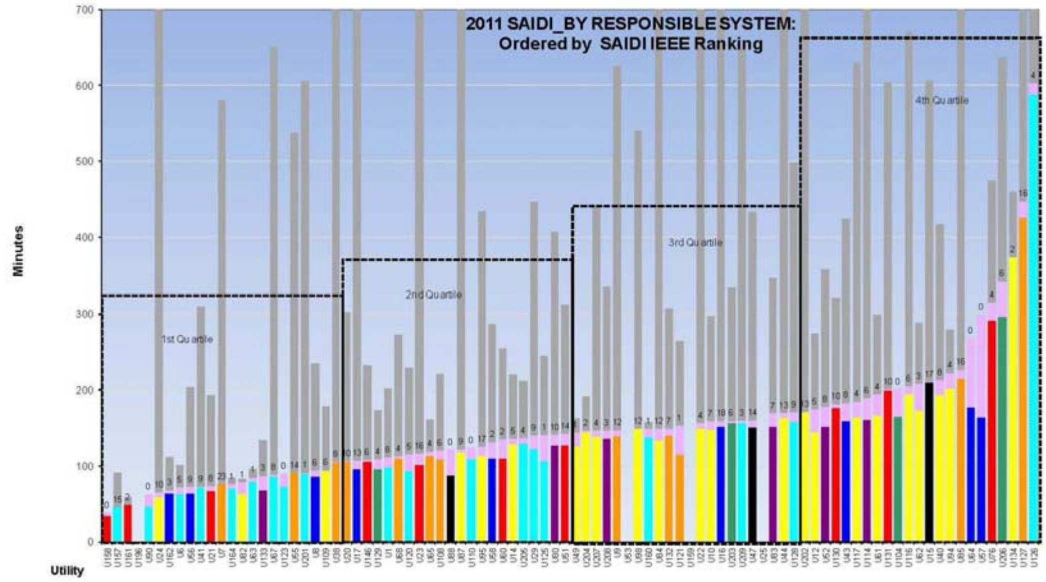
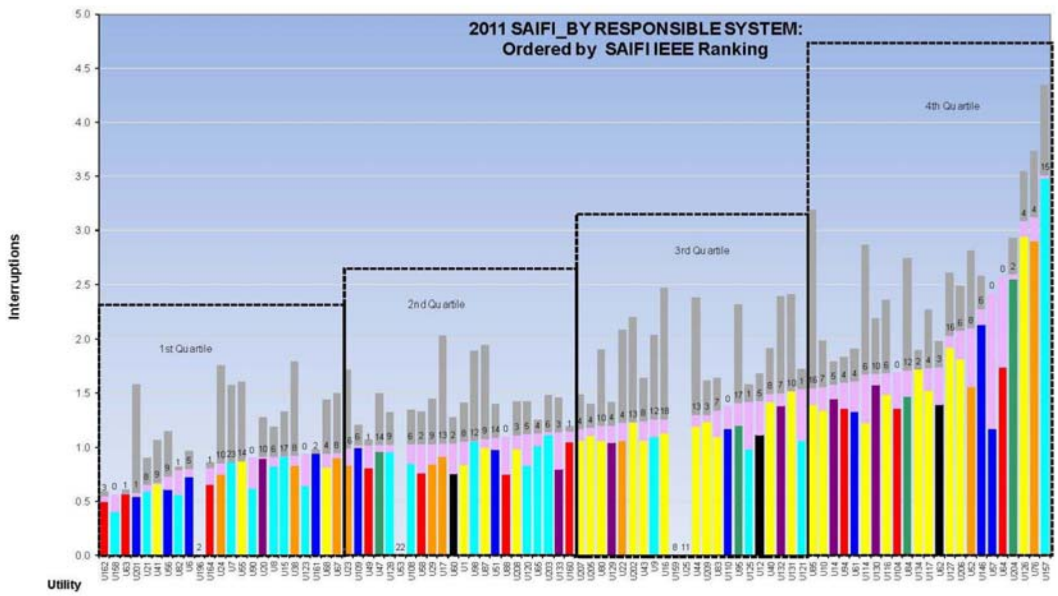


Figure 4 - SAIFI Index Survey, Including Transmission and Extreme Events
(2011 IEEE Benchmarking Study)



III. OTHER INDUSTRY RELIABILITY BENCHMARKS AND PROGRAMS

The American Public Power Association (APPA) has developed and hosts the Reliable Public Power Provider ($RP_3^{®}$) Program. The purpose of the RP3 Program is to encourage public power utilities to operate an efficient and reliable distribution system by demonstrating proficiency in four important disciplines: reliability, safety, work force development and system improvement. Utilities submit an application to the RP3 program for a peer-evaluation review.

Key elements of the Reliability section include reliability indices, a mutual aid agreement, a system-wide disaster management plan (emergency response plan), and both cyber and physical security. Please see Appendix F-4 for a copy of the RP3 Program Procedure Manual.

In 2012, 94 of the nation's more than 2,000 public power utilities earned RP3 recognition from the American Public Power Association for providing consumers with the highest degree of reliable and safe electric service. In Colorado, only the City of Longmont and the City of Fort Collins earned this distinction.

IV. DISTRIBUTION SYSTEM RELIABILITY

According to a January 2013 report by the Electric Power Research Institute titled "Enhancing Distribution Resiliency," the majority of electrical outages are related to failures in the local distribution portion of the electrical grid. The report indicates that the leading cause of failure is weather events. The primary contributing factor is woody vegetation coming into contact with live portions of the electrical system due to snow, ice and wind. Other outage causes include distribution equipment failure, animal intrusion and unintentional acts of the public.

Sufficient resources must be dedicated to the ongoing operation and maintenance of the distribution system, including response to failures. The assumptions used for modeling of ongoing operation and maintenance have been compared with APPA benchmarks as well as benchmarks reported by Fort Collins. Fort Collins was chosen for comparison because it is regarded as an organization that employs best management practices. In all cases, the modeling assumptions used are intended to be conservative in order to provide a higher level of reliability than Xcel Energy currently provides.

The following two APPA benchmark categories were used for comparison purposes:

Category 10 - Total Operation and Maintenance Expense (Excluding Power Supply Expense) per Retail Customer

Definition: The ratio of total electric utility operation and maintenance expenses, excluding all costs of power supply, to the total number of ultimate customers. Operation and maintenance expenses include the costs of transmission, distribution, customer accounting, customer services, sales and administrative and general expenses. The costs of power supply (generation and purchased power) are excluded from the ratio. This ratio may be affected by population density and the mix of customers between various classes (residential, commercial, industrial or other). Also, the extent that a utility services a large number of resale customers will influence the ratio.

Category 10 = Total O&M Expense (Excluding Power Supply Expense)							
	Boulder Modeled $/year	Boulder Modeled $/customer	Estimated Xcel Energy Base Case $/year	Estimated Xcel Energy Base Case $/customer	Ft. Collins (2009 $)	APPA Median West Region (2012 $)	APPA Median 50K-100K customers (2012 $)
1st Quartile	NA	NA	NA	NA	NA	$340	$319
Median	$22,656,744	$362.51	$19,709,313	$315.35	$260	$480	$402
3rd Quartile	NA	NA	NA	NA	NA	$617	$498

Based on this benchmark, the modeled funding for total O&M expense is lower than the APPA median but higher than Fort Collins. The anticipated Boulder service area (estimated 62,500 customers over approximately 44.4 square miles and 569 circuit miles) is more densely populated than the Fort Collins service area (reported 64,200 customers over 56 square miles and 855 circuit miles) and may be more densely populated than the median APPA comparison base. For this reason, an additional comparison is made based on circuit mile.

Category 15 - Distribution Operation and Maintenance Expenses per Circuit Mile

Definition: The ratio of total distribution operation and maintenance expenses to the total number of circuit miles of distribution line. This measures the total distribution costs associated with each circuit mile of distribution line used to deliver power to customers. Distribution costs include expenses associated with labor, supervision, engineering, materials and supplies used in the operation and maintenance of the distribution system. The ratio will be affected by population density, the mix of customer classes served by the utility, the dispersion of customers within the utility's service territory, and the proportion of underground and overhead distribution lines.

Category 15 = Distribution O&M Expenses per Circuit Mile							
	Boulder Modeled $/year	Boulder Modeled $/circuit mile	Estimated Xcel Energy Base Case $/year	Estimated Xcel Energy Base Case $/circuit mile	Ft. Collins (2009 $)	APPA Median West Region (2012 $)	APPA Median 50K-100K customers (2012 $)
1st Quartile	NA	NA	NA	NA	NA	$4,270	$6,678
Median	$9,176,997	$16,128	$4,949,548	$8,699	$10,284	$6,088	$9,426
3rd Quartile	NA	NA	NA	NA	NA	$13,494	$12,910

Based on this benchmark, the modeled funding for distribution O&M expense is significantly higher than for either Fort Collins or the APPA comparison base.

In addition to the conservative modeling assumptions for ongoing O&M, an aggressive capital replacement schedule has been formulated that would provide for accelerated replacement of system components because of age and deterioration. Undergrounding of existing overhead electrical infrastructure would also continue under the modeling assumptions.

Attachment E presents the start-up and ongoing operation and maintenance cost assumptions used in the financial modeling. These cost assumptions can be compared to APPA benchmarking data as presented in Appendix F-5 - APPA Selected Financial and Operating Ratios of Public Power Systems, 2011 Data.

A utility start-up work plan would be developed that, if executed, would provide for a smooth transition of electric service to the customers. Appendix F-6 presents an outline of steps necessary to assure reliability during the transition, start-up and first several years of operation of a potential new municipal electric utility.

V. FEDERAL AND REGIONAL RELIABILITY REGULATIONS

The North American Electric Reliability Corporation's (NERC) mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards for the bulk power system. The bulk power system is made up of three main parts: generation, transmission, and load (i.e. customer electric demand).

Meeting the reliability expectations of consumers requires the bulk power system to be planned, designed, constructed, operated, maintained, and restored (as necessary following the loss of electric infrastructure) as described by specific, pre-determined tests or criteria. As such, the bulk power system is evaluated, assessed, and planned to ensure that an adequate supply of electricity is available to meet current and future needs.

The distribution system of a city-owned electric utility is typically classified as Load-Serving Entity (LSE) and as a Distribution Provider (DP). The city could contract with Public Service Company of Colorado or another entity to receive Network Integration Transmission Service meeting federal standards.

NERC is comprised of ten separate regional councils. The city would become either directly or indirectly a member of the Western Electricity Coordinating Council (WECC). The WECC is one of the ten NERC regional councils established to promote the reliable operation of the interconnected bulk power system of the western United States and Canada.

WECC does not publish a recommended or required planning reserve criterion for its member systems, but rather allows individual member systems (including regulatory commissions) to adopt their own planning reserve criteria. WECC does, however, perform Power Supply Assessments (PSAs) of its member systems annually. The purpose of the PSAs is to identify WECC sub-regions that have the potential for electricity supply shortages based on reported demand, resource, and transmission data. During these annual PSA reviews, the city would provide WECC with detailed information regarding its electric system. Municipal power utilities are exempt from the jurisdiction of the state PUC.

VI. TRANSMISSION AND RESOURCE MIX RELIABILITY

Transmission reliability, as mentioned above, is covered by WECC requirements. The city's distribution system would be served by a transmission provider (most likely Public Service Company of Colorado) governed by those requirements to maintain the present level of transmission system reliability. The city would pay a network interconnection cost that would include the transmission provider's capital and O&M costs.

Staff has proposed energy (generation) resource plans based on a 15 percent reserve margin as well as adequate on-line and off-line reserves with the intent of ensuring a reasonable (one day in 10 years) loss of load expectation. As discussed above, generation and transmission are regulated through the Federal Energy Regulatory Commission and the energy resource and separation plans have been formulated with the intent to comply with all these regulations.

In WECC, the reference Reserve Margins differ by sub-region and by season. For the Rocky Mountain sub-region of WECC, the reported NERC Reference Margin Level for years 2013-2022 summer peak is 14.65 percent and for winter peak it is 15.68 percent.

The modeling assumes that electricity requirements outside of local distributed generation will be acquired through power purchase agreements (PPAs). Model runs assume that existing and available resources would be procured primarily through negotiated PPAs. The portfolio of PPAs would be structured to meet the regulatory, reserve margin and loss of load expectation requirements. Additional analysis of the resource mix reliability is needed once a desired scenario has been established.

APPENDICES:

Appendix F-1:	Reliability Considerations – Questions and Answers
Appendix F-2:	Xcel Energy QSP Report – January 17, 2012
Appendix F-3:	Northern Colorado Front Range Comparative Data
Appendix F-4:	APPA RP3 Program Procedures Manual
Appendix F-5:	APPA Selected Financial and Operating Ratios of Public Power Systems, 2011 Data
Appendix F-6:	Reliability Work Plan Outline

Appendix F-1

Reliability Considerations - Questions and Answers

02/20/13

The following is a compilation of the various issues and analysis considered by the Reliability Working Group in a question and answer format.

I. EXISTING XCEL ENERGY SYSTEM RELIABILITY CONSIDERATIONS

A. What are the strengths and weaknesses of the existing Xcel Energy electric utility system infrastructure in Boulder?

Distribution Infrastructure Strengths

1. Cross-connections between substations - Each substation and its feeders are interconnected with other subs to allow for alternate feeds during maintenance or in the event of equipment failure.
2. Feeders sized for efficient distribution - Main feeder exits from substations are larger wire sizes, moving down to smaller conductor as the feeders branch out. In general, conductors have been sized to provide sufficient capacity, reduce voltage drop, and reduce power losses.
3. Steel poles in several areas - The use of steel poles in certain areas reduces the potential for pole failure and requires less maintenance.
4. Switching and sectionalizing equipment - Overhead and pad mount switches, re-closers, fuses, and pad mount sectionalizing cabinets allow for flexible configuration of feeders, isolation of faulted sections, and reducing maintenance outages.
5. Protection coordination - While the specifics to protection coordination are not known, such coordination if implemented is effective in isolating faulted equipment while maintaining service to healthy areas. Various coordination and sectionalizing philosophies can be applied to systems and further analysis is merited.
6. Underground/Overhead - In general, underground installations perform more reliably than overhead over the course of time. However, overhead faults are typically temporary, while underground faults are generally permanent, leading to longer outage durations on underground circuits when they occur.
7. Automatic throw over switches (ATOs) installed at some locations enable service to be maintained to critical loads such as hospitals; if one feeder source is lost, the switch transfers to another feeder, generally fed from a different substation.

Infrastructure Weaknesses

1. Overhead and underground construction in back lots - Access to facilities in the rear of properties is restricted and difficult, especially as properties are filled in. Vegetation management is also a problem. In the event of a wind, ice, or heavy snow event, restoring service to neighborhoods would take significant time.
2. ROW clearing has fallen behind - Removing danger trees and growth into overhead lines that can cause faults and failures appears to be behind typical progress. Safe access to pad mounted equipment for maintenance and operation is also blocked in many cases.
3. Age of equipment - In general, much of the equipment has been in place for a significant time and may be approaching the end of its predicted useful life.

4. Overhead construction crowded with joint use pole Attachments - The large number of communications and cable Attachments to overhead poles is cause for concern due to limiting access and additional pole loading and potential failure.
5. Overhead clearances - Clearances to ground and structures are of concern in a number of areas.

Typical Substation Transformer Loading

1. Two 115/13.2kV (or 230/13.2kV) step-down transformers each rated 30/40/50 MVA
2. Two metal clad switchgear each with four feeders with a bus tie to other switchgear for a total of eight total feeders each capable of 10 MVA but only loaded to 7.5-8 MVA maximum

Each transformer bank is generally loaded to 80 percent capacity at peak; as a result, if a bank is lost, the remaining bank can only pick up another 20 percent. Switching feeders to other substations would then be necessary to pick up the remaining load. If one bank is lost – 40 MVA would need to be picked up – 16 MVA could be quickly switched to other feeders via ties; the other bank would be loaded to 50 + MVA; the hope is that the outage would occur at something other than the one hour out of the 8,760 that is the peak. If the outage is during the summer peak then additional temporary efforts would be employed [load shedding, etc.]

This practice contrasts with the City of Fort Collins which loads its substation transformers and feeders at approximately 50 percent to allow one of the transformers to support the entire load during repairs or maintenance.

Transformer overheating can significant reduce the life of this equipment. This issue needs to be further investigated since the City does not understand when this may have occurred or have access to any of Xcel Energy's test data.

B. How does Xcel Energy provide reliability through on-going administration, operations, maintenance, monitoring, control, dispatch, project management, customer service and response procedures?

Information is limited and based on observations only:

1. Assessment of system performance from grid data - Data from substation and feeder monitoring equipment provides more accurate and timely information with which to assess equipment loading and performance. This information allows utility staff to make modifications and configuration changes over time in advance of potential overloads. It does not appear that such modifications or configuration changes can be made automatically at this time.
2. SCADA at Substations - Substation equipment monitoring and control speeds up the process of locating disturbances and addressing and repairing them.
3. Local crews - Locally based crews are familiar with the system and can respond effectively to outages and operations.
4. Pole testing - A regular and consistent pole testing program can identify equipment prior to actual failure and can identify trends in materials and service areas.

5. Line patrol - Regular line patrol and observation helps to identify potential failures or issues before they become outages. However, this process is really only effective for overhead facilities.
6. Maintenance - A planned maintenance program can be very effective, especially if directed to preventive and condition based considerations. Further research into Xcel's specific practices is warranted.

C. How does Xcel Energy provide power generation and transmission reliability?

Supply – Generation

Xcel Energy is required to provide reliability for its generation system by maintaining an adequate supply of electric generation to meet the expected maximum demand of its customers (i.e., the "peak" demand or load) for a reasonable set of unforeseen events (power plant outages, higher than expected load etc.). To maintain service to firm customers, Xcel Energy has utilized a combination of measures and practices, each focusing different time horizons: real-time, mid-term, and long-term.

Real-time

Ultimately it is the real-time status of the system that determines whether supply is sufficient to maintain service to firm load customers. Real-time in this context refers to the presumed measures and practices Xcel Energy employs on a daily basis in operating the electric system. These entail carrying sufficient operating reserves to ensure that adequate resources are available to serve load. Operating reserves are generation capacity that is either on-line and unloaded, i.e., spinning, or that can be brought on-line and synchronized to the grid in short order.

Xcel Energy is a member of the Rocky Mountain Reserve Group ("RMRG".) RMRG is a NERC registered Sharing Group and thus is subject to NERC standards and enforcement. Xcel Energy carries operating reserves in accordance with the RMRG established methodology.

Mid-term

To better ensure sufficient resources are available to meet the real-time needs of the system, Xcel Energy evaluates the need for short-term capacity and energy several months (but generally less than a year) in advance of each summer peak season. In the event that this mid-term supply adequacy evaluation determines that the installed reserves for the upcoming summer peak are likely to fall below the desired reserve level, Xcel Energy has historically pursued purchasing short-term capacity.

Long-term

Long-term activities involve the acquisition of additional generation resources or demand reduction to meet the long-term electric demand projections. The amount of installed generation capacity in excess of the annual system peak demand is commonly referred to as "planning reserve margin" or "planning reserves". Long-term in this context refers to a future period up to 10 years (or longer) over which Xcel Energy acquires additional resources. The reserve margin target used in the long-term planning of the system influences Xcel Energy's ability to meet the future mid-term and, ultimately, the real-time capacity needs of the system.

Note: FERC, NERC and WECC have as yet not adopted a specific Planning Reserve percentage but could require a higher level in the future.

The reserve margin target used by Xcel Energy in Resource Planning:

1. "standard for reliable systems within the electric utility industry" – the resource should only be unable to serve firm load customers approximately 1 day in 10 years[1] Xcel needs a Planning Reserve Margin of 16.3 percent to reach that standard
2. "It is typical to use a 1-day-in-10-year Loss of Load Probability (LOLP) when determining the needed Planning Reserve Margin. This level of LOLP is equivalent to failing to serve the energy requirements of the system for 2.4 hours each year or 24 hours during a 10-year period."[2]
3. Xcel's most recent Loss of Load Probability study uses historical forced outage rates as the expected levels of forced outage rates going forward[3]
4. Xcel receives Reserve Support from the Rocky Mountain Reserve Group Support[4]
   - Without this Reserve Support group; Xcel's reserve margin requirement would be 17.8 percent (compared to 16.3 percent)
5. Xcel is able to use expected unused transmission capacity to reduce its Planning Reserve Margin
   - Without being able to use this expected unused transmission capacity; Xcel's reserve margin requirement would be 19.2 percent (compared to 16.3 percent)[5]
6. Planning Reserve Margin = (Resources – Peak Load) / Peak Load[6]
   - Peak Load: peak hour for the entire system
   - Resources: Peak capacity of generation, accounting for lower generation rate of some renewable generation. "Interruptible loads and demand side management programs are included as resources but for load and resource balance purposes, they are subtracted from the peak load"
7. Capacity Need: [7]
   - Electric Demand Forecast
     - MINUS Demand avoided by DSM
     - MINUS Demand avoided by Load Management/DR programs
     - PLUS Demand to cover Planning Reserve Margin
     - MINUS Existing Generation
     - EQUALS Demand in Excess of Existing Generation

Xcel Energy separately analyzes its reserve margin needs by season: summer and winter. While the summer peak has historically been significantly higher than the winter peak, operating

[1] http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/Xcel Energy-ERP-2011/Appendix-2.10-1-LOLP-Study.pdf Page 5
[2] Page 6
[3] Page 11
[4] Page 12
[5] Page 15
[6] Page 16
[7] http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/PSCo-ERP-2011/Exhibit-No-KJH-1-Volume-1.pdf Page 30

experience has shown that at the time of the winter peak a number of simultaneous and related forced outages can occur, impacting resource availability, and that there is the possibility of restriction on types of fuel supply. These common-mode failure scenarios are analyzed over the planning horizon.

A balancing authority is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time. Xcel Energy is its own Balancing Authority and thus is subject to the NERC standards and enforcement.

Transmission Reliability - 115kV and 230kV Looped transmission system
Xcel Energy is a Transmission Service Provider and is subject to NERC and WECC standards and enforcement. Xcel Energy adheres to NERC & WECC Reliability Criteria, as well as internal Company criteria for planning studies. During system intact conditions, criteria are to maintain transmission system bus voltages between 0.95 and 105 percent of nominal, and steady-state power flows below the thermal ratings of all facilities. Operationally, Xcel Energy has tried to maintain a transmission system voltage profile ranging from 102 percent or higher at regulating (generation) buses to 100 percent or higher at transmission load buses. Following a single contingency, transmission system steady state bus voltages must remain within 90 percent to 105 percent, and power flows within 100 percent of the facilities' continuous thermal ratings.

Xcel Energy participates in Regional (WECC) and subregional (Colorado Coordinated Planning Group) planning activities. They conduct near term (next peak season) as well as mid and long term planning studies of the bulk power transmission system to verify compliance for the various disturbance Categories as required.

To meet these Reliability Criteria for example, Xcel Energy has constructed the looped 115kV and 230kV Bulk Power transmission systems that serve the city of Boulder's loads.

D. What is the existing level of Xcel Energy reliability as measured by the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI)?

The System Average Interruption Duration Index (SAIDI) measures the total interruption duration over a specific time period (typically one year) for the average customer:

$$SAIDI = \Sigma(ri * Ni) / NT$$

Where,
SAIDI = System Average Interruption Duration Index
Σ = Summation function
ri = Restoration time, minutes
Ni = Total number of customers interrupted
NT = Total number of customer served

The System Average Interruption Frequency Index (SAIFI) is defined as the average number of times that a typical customer is interrupted during a specific time period (typically one year).

Appendix F-1

SAIFI is determined by dividing the total number of customers interrupted in a time period by the average number of customers served. The resulting unit is "average number of interruptions per customer."

> ***SAIFI = Σ(Ni) / NT***
> *Where,*
> *SAIFI = System Average Interruption Frequency Index*
> *Σ = Summation function*
> *Ni = Total number of customers interrupted*
> *N_T = Total number of customers served*

Xcel Energy filed its application for an electric Quality of Service (QSP) Monitoring and Reporting Plan on July 1, 2005. On March 22, 2006, Public Service, Staff, OCC, and Denver filed a joint motion for approval of the Partial Stipulation and Settlement Agreement (SAIDI Settlement). The SAIDI Settlement was approved by Decision No. C06-1303.

Xcel Energy filed its annual QSP report on April 1, 2011 – see Appendix F-2. Based on this and similar reports for the past four years, the following metric indices were developed which are slightly better than the Xcel Energy four-year average for the Boulder region.

- SAIDI: 85
- SAIFI: 0.85

E. Are there other reliability aspects of the existing Xcel Energy system that should be considered?

1. Adaptability of the infrastructure to Distributed Generation at significant penetration levels
    - The existing feeder network (conductor sizes, routing, trunks and branches) should provide capacity for distributed generation at most locations with minimal modifications. However, additional protection and control devices will be necessary to provide reliable isolation of faulted elements and interconnected generators for customer and personnel safety.
2. Fiber optic network - groundwork for Smart Grid
    - The installed infrastructure includes cellular, radio, and fiber optic communications systems. These systems should be readily convertible to new purposes to interact with feeder devices, meters, and control systems. The existing communications infrastructure is also suitable for connection to a new control center for the city. The existing broadband over power line equipment is proprietary and no longer supported by the manufacturer. This equipment bridges distribution transformers and could be considered a liability with respect to reliability. Some of the existing voltage and current sensing equipment may be of functional use; at this time the usefulness and potential benefits cannot be determined as it is not clear what equipment is in place.

Appendix F-1

F. How and to what extent has Xcel Energy incorporated and considered redundancy, firm capacity, power quality controls, reserve margins, common-mode failure scenarios?

1. Redundancy
    - Multiple feeder connections appear to be provided between substations and two or three transformers in most substations Therefore the system can be reconfigured to adapt to equipment failures and faults within a relatively short time.
2. Capability
    - The feeders appear to be sized for the capacity to feed more than their normal load in the event of failure of a component in an adjacent feeder. Feeder conductor sizes appear to be adequate to maintain customer voltage within acceptable limits even at heavy load. Transformers are sized to be adequate to take on the load of an adjacent transformer during maintenance or repair.
3. Power Quality Controls
    - Capacitors - Capacitor banks appear to be placed on various feeders to support voltage during heavy load; these banks can be switched automatically (typical for daily operation) or manually (typical for seasonal operation).
    - Lightning Protection - Lightning arresters appear to be provided for all distribution transformers, as well as some feeder applications. Lightning arresters will clamp the voltage surge due to lightning striking a feeder conductor and generally prevent or at least minimize damage to more expensive equipment and customer facilities. System grounding practice is also critical for limiting damage and proper operation of arresters and protective equipment.
    - Voltage Regulators - Voltage regulators appear to be provided on only a few of the longer feeders into the foothills. Load-tap-changing substation transformers provide voltage regulation at the substation bus which is generally effective to maintain adequate voltage on feeders of similar length and loading.

G. How will the plan for physical separation from Xcel Energy address reliability issues?

A separation plan has been developed based on service area boundaries that serve the city and minimize areas of separation on existing feeders. The plan maintains the vast majority of the existing system configuration, including looping and redundancy features that are integral to maintaining high reliability. At the substations, the city would acquire the equipment on the "low-side" of the transformers and Xcel would maintain the "high-side" equipment and the transformers. This division of responsibility for equipment at substations is common where the distribution system is operated by a different entity than the transmission system. Any necessary interfaces to the external distribution grid outside of the substations would be accomplished by deploying switched, metered interconnections to provide backup and redundancy for both Xcel and City feeders. Where such interconnections are not feasible, additional infrastructure would be constructed to establish and/or maintain looping, redundancy, and reliability enhancing features.

II. RELIABILITY REGULATION CONSIDERATIONS

A. What are the reliability requirements of the North American Energy Reliability Corporation (NERC)?

The North American Electric Reliability Corporation's (NERC) mission is to ensure the reliability of the North American **bulk power system**. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards for the bulk power system. The **bulk power system** is made up of three main parts: generation, transmission, and load (i.e. customer electric demand).

Meeting the reliability expectations of consumers requires the bulk power system to be planned, designed, constructed, operated, maintained, and restored (as necessary following the loss of electric infrastructure) as described by specific, pre-determined tests or criteria. As such, the bulk power system is evaluated, assessed, and planned to ensure that an adequate supply of electricity is available to meet current and future needs.

Definition of "Adequate Level of Reliability"

Adequate Level of Reliability (ALR) is the performance state that the design, planning, and operation of the Bulk Electric System (BES) will achieve when certain reliability objectives and associated performance outcomes are met. The intent of the set of NERC Reliability Standards is to deliver an Adequate Level of Reliability defined by the following bulk power system characteristics:

1. The system is controlled to stay within acceptable limits during normal conditions.
2. The system performs acceptably after credible contingencies.
3. The system limits the impact and scope of instability and cascading outages when they occur.
4. The system's facilities are protected from unacceptable damage by operating them within facility ratings.
5. The system's integrity can be restored promptly if it is lost.
6. The system has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.

NERC develops and enforces reliability standards. Basic reliability principles are developed so that the:

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.
2. Information necessary for planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the system reliably.
3. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented
4. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.

5. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified and have the responsibility and authority to implement actions,
6. The security (operational reliability) of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.

A Load-Serving Entity (LSE) secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers. A Distribution Provider (DP) provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. A city-owned electric utility may be classified as LSE and as a DP. The city may contract with Public Service Company of Colorado (PSCo) to receive Network Integration Transmission Service. This Service allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner (PSCo) serves Native Load customers.

NERC does not set required planning reserve criteria but does publish a Reliability Assessment Guidebook. Thus NERC's standards are primarily operational in nature.

B. What are the reliability requirements of the Western Energy Coordinating Council (WECC)?

NERC is comprised of ten separate regional councils. The city would become either directly or indirectly a member of the Western Electricity Coordinating Council ("WECC"). The WECC is one of the ten NERC regional councils established to promote the reliable operation of the interconnected bulk power system of the western United States and Canada.

1. Spot checks that require reporting/documentation of performance
2. Most requirements focus on the bulk transmission system;
3. WECC has a specific Contingency Reserve standard applicable to Balancing Authorities and Reserve Sharing Groups. This standard is applicable to real-time operations and is not a reserve margin standard.
4. WECC does not publish a recommended or required planning reserve criterion for its member systems, but rather allows individual member systems (including regulatory Commissions) to adopt their own planning reserve criteria. WECC does, however, perform Power Supply Assessments ("PSA") of its member systems annually. The purpose of the PSAs is to identify WECC subregions that have the potential for electricity supply shortages based on reported demand, resource, and transmission data. During these annual PSA reviews, the city would provide WECC with detailed information regarding the company's electric supply system including:
    - Generation rating data
    - Actual and Forecasts of demand
    - Characteristics of Demand
    - General System data

III. FUTURE RELIABILITY GOALS AND FACTORS TO BE CONSIDERED

A. What methods do other communities and utilities use to assure reliability?

City staff interviewed and collected data from other Northern Colorado Front Range Public Power Utilities including Longmont, Fort Collins and Loveland. These agencies use a variety of performance indices and metrics, some of which are targeted at reliability. Appendix F-3 presents a summary of this information.

The American Public Power Association (APPA) has developed and hosts the Reliable Public Power Provider (RP_3®) Program. The purpose of the RP3 Program is to encourage public power utilities to operate an efficient and reliable distribution system by demonstrating proficiency in four important disciplines: reliability, safety, work force development, and system improvement. Utilities submit an application to the RP3 program for a peer-evaluation review.

Key elements of the Reliability section include reliability indices, a mutual aid agreement, a system-wide disaster management plan (emergency response plan), and both cyber and physical security. Please see Appendix F-4 for a copy of the RP3 Program Procedure Manual.

In 2012, 94 of the nation's more than 2,000 public power utilities earned Reliable Public Power Provider (RP3®) recognition from the American Public Power Association for providing consumers with the highest degree of reliable and safe electric service. In Colorado, only the City of Longmont and the City of Fort Collins earned this distinction.

APPA defines Service Reliability as follows:

The degree of performance of the elements of the bulk electric system that results in the delivery of electricity to customers in accordance with accepted industry standards. Reliability can be addressed by considering two basic qualities: availability and resiliency.

Availability – The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably unscheduled outages of system elements.

Resiliency – The ability of the electric system to withstand sudden disturbances such as short circuits or unanticipated losses of system components.

APPA recommends that utilities should demonstrate awareness of its system performance by using reliability indices. Also, the utility should be using those indices to maintain or improve system reliability. Industry standard indices (IEEE 1366) are the preferred method of tracking performance. In addition, indices should reflect at least one year of data, at least three indices should be tracked, and documentation of the use of indices is required.

APPA provides additional information regarding Reliability Indices, Types of Faults and Outage Types as follows:

Appendix F-1

Reliability Indices Reliability indices are the measures used to track and evaluate system performance. The frequency of system failures, number of customers affected and duration of outages are three basic metrics used in measuring reliability. Reliability indices may further be classified as component reliability indices, load-point reliability indices, and system reliability indices.

1. Component reliability indices measure the continuity of service provided by system components.
2. Load-point reliability indices measure the continuity of service to individual loads.
3. System indices measure the continuity of service to groups of loads.

Factors affecting reliability include feeder length, exposure, sectionalizing, conductor type and number of customers on the feeder. Some utilities exclude major events and storm-related outages from their evaluation of reliability indices as they may give inaccurate predictions for the probabilistic failure rates of the system components.

Types of Faults Types of faults that can occur on a typical distribution system are:

1. Transient (Temporary) Faults: These are the faults that occur on the system and do not require corrective action to remove the fault from the system. The majority of faults on most overhead distribution systems are transient in nature.
2. Permanent Faults: These faults generally occur on the system as a result of a permanently damaging event. These faults typically require some form of repair before service can be restored to the customers.

Outage Types

IEEE Std. 1366 classifies interruptions on the distribution system into four types:

1. Momentary Interruption: These are the outages that occur on the system and last five minutes or less until the fault is cleared and service to all customers is restored. The major causes for this type of outage are trees, animals and lightning.
2. Sustained Interruption: These are the outages that occur on the system and last more than five minutes until the fault is cleared and service to customers is restored. Partial service restoration may be performed through technical switching procedures and field ties.
3. Major Event (Catastrophe): These are abnormal conditions that the system encounters resulting in service disruption to 10 percent or more of customers on the electric system for 24 hours or more. Severe weather conditions (e.g. hurricanes, tropical storms, ice storms, etc.) and cascading outages resulting from the loss of one or more major transmission lines are the major cause for these types of outages.
4. Planned Interruption: A loss of electric power that results when a component is deliberately taken out of service at a selected time, usually for the purposes of construction, preventive maintenance, or repair.

Typically, utilities exclude scheduled outages, partial power, customer-related problems, and qualifying major events from the reliability indices calculations.

The APPA RP_3 Program also requires best management practices for physical infrastructure security and cyber security. Physical infrastructure security can range from a substation with camera, locks, and fences to equipment tracking systems, such as Radio Frequency Identification (RFID) tags on all of your equipment or bar code scanning systems. These types of security measures have been implemented by the city for other critical infrastructure including the drinking water system.

Although NERC Critical Infrastructure Protection (CIP) standards may not specifically apply to a Boulder municipal electric utility, cyber security issues should still be addressed by employing mechanisms such as passwords, firewalls, protocols against using non-company issued USB drives (foreign device protocols), etc. Similar cyber security protocols have been implemented by the city for other critical systems, including the Supervisory Control and Data Acquisition System for drinking water and in the case of the public safety and criminal justice system in accordance with the Federal Bureau of Investigation Criminal Justice Information Services Security Policy of 2011.

B. How would power generation and transmission reliability be assured?

For comparison purposes and according to NERC's 2012 Long-Term Reliability Assessment [released Nov. 2012] the NERC Reference Margin Level for ERCOT (TEXAS) is 13.75 percent, while in the west WECC does not have an interconnection-wide formal Planning Reserve Margin standard. The WECC's annual PSA summer and winter reserve target margins are developed using a building block method that has four elements:

1. Contingency reserves
2. Operating reserves
3. Reserves for forced outages
4. Reserves for one-year-in-ten weather events

In WECC the reference Reserve Margins differ by sub-region and by season. For the Rocky Mountain Sub-Region of WECC the reported NERC Reference Margin Level for years 2013-2022 SUMMER peak season is 14.65 percent and for WINTER peak it is 15.68 percent [see page 256 of 335 of the 2012 Long-Term Reliability Assessment].

The need for reserves based on item 3 above "Reserves for forced outages" is illustrated by the following example. Assume a Utility system has a load of 200 MW and it is being served by 4 – 50 MW purchases that are each unit specific (meaning that the purchase is from an individual named generating unit and the purchase is therefore unit contingent.) If one of the 50 MW units is forced out of service, then the utility would have to replace that unit's lost output by dispatching 50 MW of generation from its reserve.

Municipal utilities are required to have a certain percentage of the energy they serve supplied by renewable energy sources although the amount is much less than Xcel Energy. The percentage grows over time.

Municipal utilities are exempt from the jurisdiction of the state PUC, which has requirements for filing of plans. The State of California does have requirements for filing of plans by Municipal Utilities and CCAs. While not required to file plans, the municipal utilities in Colorado do engage in prudent planning practices. For example: Platte River Power Authority is the supplier of power and energy for the cities of Ft. Collins, Longmont and Loveland. According to their 2012 Integrated Resource Plan their Resource Criteria is to use a 15 percent planning reserve with additional criteria:

1. Ensure loss of load probability (LOLP) of less than 5 percent at peak hour;
2. Ensure loss of load EXPECTATION (LOLE) of less than one day in ten years;
3. Future resource capacity to cover outage of Rawhide without relying on market spot purchase at peak; and
4. No on-peak capacity credit to Renewable Intermittent Resources. [based on operational experience]

PRPA's IRP treats the majority of Distributed Generation (premise solar) like negative load. Xcel Energy's resource planning assigns a 10 percent of nameplate rating as a capacity credit at time of system peak to large wind projects and a 12.5 percent credit to large solar projects. In contrast, based upon measured past operating experience, PRPA assigns zero capacity credit to its Medicine Bow Wind project.

Additional analysis of the resource mix reliability is needed once the desired scenario has been established.

C. What are the reliability expectations and desires of residential and business customers?

It is understood that all residential and business customers expect and desire a high level of electrical reliability. City staff has not completed a customer survey to quantify the expectations and desires. However, several large energy users in Boulder are either satisfied or very satisfied with the existing Xcel Energy reliability based on interviews conducted to date with the following companies:

- IBM
- Corden Pharma
- Boulder Community Hospital
- Lockheed Martin
- Covidien
- City of Boulder 75th St. Wastewater Treatment Facility
- City of Boulder 63rd St. Water Treatment Facility

Several of the large users that cannot tolerate an outage of any kind have indicated they have on-site backup power generation facilities to support critical loads. Other business customers whose equipment load is not as significant (computers, data centers, telecommunications equipment, etc.) typically deploy uninterruptible power sources (UPS). Several large users with critical loads have secured a fully redundant feeder circuit through negotiation and/or payment to Xcel Energy. This includes IBM and the City of Boulder 75th St. Wastewater Treatment Facility.

Appendix F-1

The cost of power outages is calculated by analyzing Value of Service surveys. Below is a list of costs due to poor power quality/lost power:

- Lost experiments
- Lost production line run
- Electric Shock
- Employee/customer injury
- Health Problems
- Flood damage
- Spoiled food
- Lost sales
- Reduced productivity
- Reduced motor life
- Housing relocation

Source: Joseph M Juran Center for Quality at the University of Minnesota Carlson School of Management

The information below is based on the Tobit model. The Tobit model is a statistical model (describes the relationship between dependent and independent variables. (similar to regression). The underlying data is based on eight Value of Service studies.

The Tobit models predict that the average cost experienced by an "average" customer for a single summer afternoon outage of one hour is approximately:

- $3 for residential
- $1,200 for small-medium commercial and industrial
- $82,000 for large commercial and industrial

The outage costs increase substantially, but not linearly, as the outage duration increases from one to eight hours. Outage costs are generally higher in the winter than in the summer for an outage of a given duration or time of day. The Tobit models also reveal important differences in outage costs across regions, time of day, customer size, and business type.

Source: A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys. http://certs.lbl.gov/pdf/54365.pdf

D. Are there other industry reliability indices or standards that should be considered?

Besides the SAIDI and SAIFI indices previously defined, other indices may be considered as follows:

Customer Average Interruption Duration Index (CAIDI) measures the average interruption duration for those customers interrupted during the year.

CAIDI = Σ(ri * Ni) / Σ(Ni)
Where,
CAIDI = Customer Average Interruption Duration Index
Σ = Summation function
ri = Restoration time, minutes
Ni = Total number of customers interrupted

Customer Average Interruption Frequency Index (CAIFI) measures the average number of interruptions per customer interrupted per year.

CAIFI = Σ(No) / Σ(Ni)
Where,
CAIFI = Customer Average Interruption Frequency Index
Σ = Summation function
No = Number of interruptions
N_i = Total number of customers interrupted

Momentary Average Interruption Frequency Index (MAIFI) represents the average frequency of momentary customer interruptions (usually less than a 5 minute limit) divided by the total number of customers served.

MAIFI = Σ(IDi * Ni) / NT
Where,
MAIFI = Momentary Average Interruption Frequency
Σ = Summation function
IDi = Number of interrupting device operations
Ni = Total number of customers interrupted
NT = Total number of customers served

Average Service Availability Index (ASAI) represents the fraction of time (often in percentage) that a customer has received power during a predefined period of time (typically a year).

ASAI = [1 – (Σ(ri * Ni) / (NT * T))] * 100
Where,
ASAI = Average System Availability Index, percent.
Σ = Summation function
T = Time period under study, hours.
ri = Restoration time, hours
Ni = Total number of customers interrupted
NT = Total number of customers served

E. What procedures and investments should the city consider to increase the level of reliability?

As reported by Transmission & Distribution World - Vegetation Management Resource Center, two key strategies to improve reliability and power quality to customers are:

1. Minimize the effect of faults on customers – This can be achieved by sectionalizing and restoring circuits more quickly (automation), using more protective devices (fuses, reclosers, sectionalizers), reclosing more quickly and improving device coordination.
2. Eliminate faults – Better tree maintenance, animal protection, equipment replacement programs and arrester application, as well as thorough construction work audits to ensure quality and line inspections.

Other considerations include:

1. Capital replacement of assets on a regular basis
2. Undergrounding cables
3. Vegetation management: 3-5 year cycle
4. Smart-Grid implementation
5. Audit Pole Joint-Use Attachment Agreements (impact of pole Attachments e.g. phone, cable Attachments)
6. Implementation of transmission and distribution system GIS
7. Customer requested reliability improvements. Create tariffs that allow customers with high reliability needs to request improvements and contribute financially to accelerate those improvements.
8. Regularly collect and analyze reliability performance of overhead and underground systems to better prepare for response to outages.

Cost data is available for construction of overhead and underground circuit based on customer density, defined as:

1. Urban: 150+ customers per square mile
2. Suburban: 51 to 149 customers per square mile
3. Rural: 50 or fewer customers per square mile

Cost per Mile: New Construction Transmission

	Overhead			Underground		
	Urban	Suburban	Rural	Urban	Suburban	Rural
Minimum	$377,000	$232,000	$174,000	$3,500,000	$2,300,000	$1,400,000
Maximum	$11,000,000	$4,500,000	$6,500,000	$30,000,000	$30,000,000	$27,000,000

Cost per Mile: New Construction Distribution

	Overhead			Underground		
	Urban	Suburban	Rural	Urban	Suburban	Rural
Minimum	$126,900	$110,800	$86,700	$1,141,300	$528,000	$297,200
Maximum	$1,000,000	$908,000	$903,000	$4,500,000	$2,300,000	$1,840,000

Cost per Mile: Converting Overhead to Underground Transmission

	Urban	Suburban	Rural
Minimum	$536,760	$1,100,000	$1,100,000
Maximum	$12,000,000	$11,000,000	$6,000,000

Cost per Mile: Converting Overhead to Underground Distribution

	Urban	Suburban	Rural
Minimum	$1,000,000	$313,600	$158,100
Maximum	$5,000,000	$2,420,000	$1,960,000

Material and Labor Percentages

	Transmission		Distribution	
	Overhead	Underground	Overhead	Underground
Material	46.3%	53.5%	43.4%	45.9%
Labor	53.7%	46.5%	56.6%	54.1%

http://www.eei.org/ourissues/electricitydistribution/Documents/UndergroundReport.pdf

Geographic Information System and Mapping

The city currently has significant GIS and mapping resources available to leverage if a new municipal electric utility is created. GIS datasets are primarily stored in an enterprise spatial database using ESRI's ArcSDE technology. The enterprise database is managed by the IT department. The updating and maintenance of the GIS datasets remains the responsibility of the appropriate department.

Two applications are currently used to interact with these GIS datasets. ESRI's ArcGIS Desktop is a Microsoft Windows application that requires installation and licensing on each users workstation. ArcGIS Desktop is the primary application used to create, edit, and analyze these GIS datasets. Increasingly, web browser applications that interact with a central GIS Server are being used to provide easy to use GIS viewers. With data and map viewer functionality being centrally managed and no additional software required, these viewers are also a cost effective way to provide GIS access to internal staff and the public. These web viewers currently have limited GIS analysis and printing capability. However, ESRI has indicated that the browser application capabilities will continue to evolve and may one day match those of the ArcGIS Desktop application. Some of the major GIS and records resources are listed include:

1. **Aerial Photography and Terrain dataset**
   Merrick and Co. delivered 6-inch digital aerial photography and 1-foot contours covering Boulder planning area I and II in 2003. Subsequent aerial photography projects have been coordinated by DRCOG. These projects have produced 1-foot photography for 2006, 2008, 2010 and will produce photography for 2012. Utilizing ArcGIS software, any of the GIS datasets can be superimposed on the aerial photography. Aerial photography has become an essential element for Public Works planning, maintenance, and asset management.
2. **Utility Infrastructure GIS datasets**
   The utility infrastructure datasets are stored in the enterprise GIS database. The datasets include; water distribution, water transmission, storm drainage, wastewater collection, and city owned telecommunications. These GIS datasets provide detailed utility system information used to support hydraulic modeling, utility asset management, water main replacement, maintenance record keeping, utility master planning, and utility map book production.
3. **Property and Easement GIS Layer**
   The city maintains a property boundary dataset in the enterprise GIS. Tabular data comes from Boulder County Assessor's Office and includes address, owner and physical information concerning the land and related development. In addition to this information, the city maintains an easement dataset. Easements of which the city is party are mapped along with easement descriptions and recording information. Many of the easements are

hot-linked which allows a user to open the recorded documents by simply selecting the easement in a GIS application like ArcGIS Desktop.

F. How should reliability be assured based on future growth and redevelopment?

Reliability can be assured with proper land use, financial and organizational planning and execution. The Boulder Valley Comprehensive Plan (BVCP) provides a vision for future land use, urban service and development within the Boulder Valley. The city's Design and Construction Standards, Building Codes and right-of-way permitting processes assure the proper design and construction of new urban services and facilities.

The future development of the power system would be integrated with the city's annual capital budget process and in consideration of proposed development consistent with the BVCP. Outage and reliability data would indicate areas of the power system where additional capital expenditure should be considered. Proposed urban development projects must be evaluated for impact on the grid as well as opportunities for electric system optimization. Large integrated developments would be opportunities for co-generation and micro-grids.

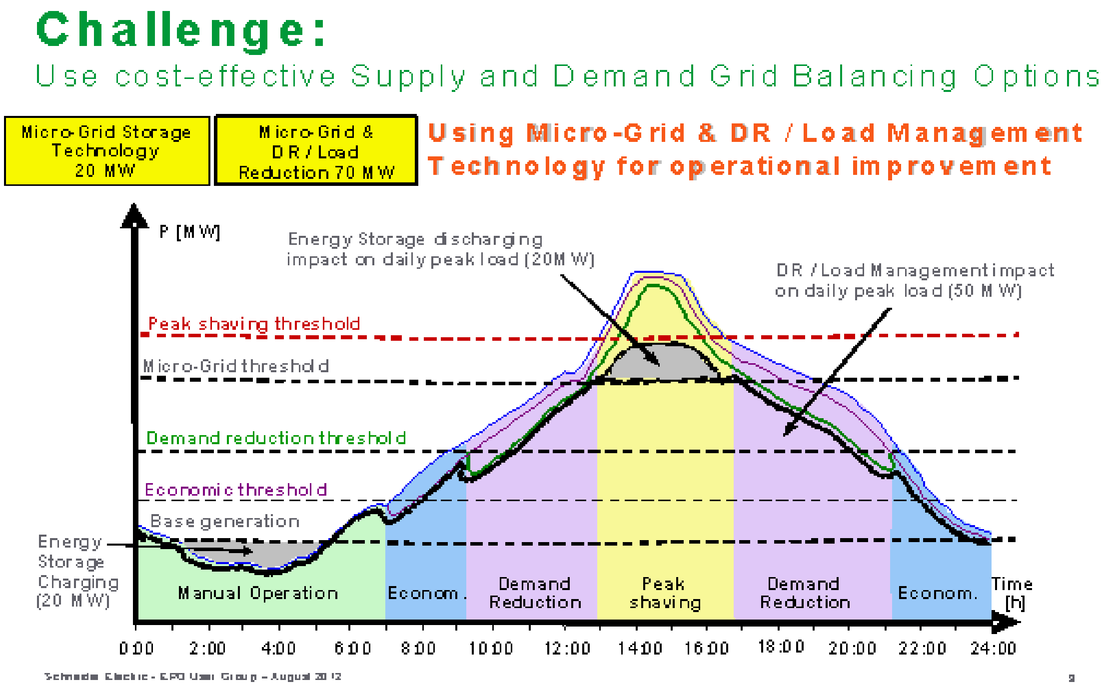
G. How will future distributed generation and demand management affect reliability?

1. Demand management (in the form of basic load shedding) is a simple yet fundamental requirement for reliability plans. Ranging from curtailment to black-outs, these contingencies are generally calculated in a multi-level plan whereby the utility could implement a particular stage of load curtailment based on local or even regional system conditions.
2. One cannot consider Distributed Generation and Demand Management separately. The presence of variable generation sources dispersed through the distribution network will cause power quality and reliability issues thus requiring the effective management of loads, other generation sources, energy storage, and even the medium voltage network itself. The complexity of such a system is daunting, but with proper modeling and software tools that are available, utilities are able to manage quality and reliability.
3. Ideally, the utility of the future would engage in the development of public and private micro-grids that provide a means to improve reliability. Legacy utilities will have a varied mix of vendor and vintage software and hardware. A trend for progressive utilities is to eliminate the integration complexities and the user interface differences by applying an Advanced Distribution Management System.
4. The ability to manage this complex network efficiently, cost effectively and sustainably, is directly related to the ability to understand the economics of demand management from both the supplier and the end-user perspective. Managing loads on the utility network without an understanding of the user's needs, can aid in reliability indices, but these improvements simply reflect 'lights-out' scenarios. Understanding reliability from the end user perspective is key to helping them manage their energy spend, participate in utility programs as a revenue stream, and enable their sustainability efforts. All within the context of each users specific reliability requirements. Ultimately this directly impacts a Cities Economic Development objectives since the city that successfully

deploys this strategy will create a more competitive environment in which businesses will operate.

5. Utilities have the opportunity to be an enabler and service provider for reliability zones and micro-grids (both utility scale and private) to help their customers meet their reliability targets and to encourage investment in energy efficiency and distributed renewable energy as well as rate designs that reflect potential different levels of reliability and environmental stewardship objectives of the community.
6. Load density may be an issue for securing substantial demand management. However, CU, federal Facilities and other major power users represent an opportunity to enhance the future reliability and efficiency of both the city and the attached entities. Dialogue between the city and these entities would ensure that all parties have a common vision, have identified areas of common interest and have the ability to coordinate future power system developments.
7. Demand aggregation is defined as the condition where many interruptible loads are combined through the use of a distributed control system so that they all could be shutdown simultaneously for short periods of time. This is a concept that has been implemented in urban areas on the East coast (Manhattan) and by large corporations (Walmart). In these cases, large numbers of A/C chillers or hundreds refrigeration units have been rewired to allow for remote control. Once you can control several tens of megawatts of demand (for a short time), you have a valuable, marketable energy product. Boulder is unlikely to have such a large block of interruptible load so as to make economic sense. The one exception may be CU. If the university could aggregate all of the A/C chillers on campus it might have a large enough load to make aggregation worthwhile (at least in the summer).
8. Distributed generation is already being deployed in the city. At current penetration, however, the issues of excessive local generation, voltage and VAR control are not a problem because Xcel has limited PV generation to 50 percent of usage. Should the city allow higher penetration levels of PV or other technologies (fuel cells, micro turbines), control of distributed generation could become an issue. Obviously, redesigning the distribution system using micro-grids would address both of these issues.
9. The utility of the future will have the opportunity to utilize ADR 2.0 solutions and grid balancing technologies and strategies that will include customer assets (loads) which are controllable or dispatchable. Those would include the PV systems that are currently in place for commercial / industrial customers as well as all those city-owned facilities and Biomass generation. Other gird technologies could be incentivized to encourage customers to use compressed air storage, battery storage, ice storage, and / or several new breed of fuel cell technologies for commercial facilities as part of its grid balancing, demand management, “green” portfolio mix. These grid balancing / demand management programs provide the municipal utility with a better, more reliable and more cost-effective supply portfolio mix to manage their system loads than the traditional IOU business model.
10. Based on actual interval data for a similar sized municipal utility with similar size customers (305MW Peak) showed there were significant opportunities to leverage customer loads for a demand management / grid balancing / DR solution through a focused deployment approach. For this utility, only 34 of the largest customers could provide over 17 MWs of curtailable / control demand management load. Expanding such

a program to other smaller customers could ultimately provide upwards of 50 MWs of demand management load. That utility expected to save over $3.5 million dollars annually in operating costs and an increase in system reliability by having access to these curtailable/controllable customer loads and selected micro-grid technologies.



H. What are the human, organizational and financial resources that will be needed for on-going administration, operation, maintenance, monitoring, control, dispatch project management, customer service and response procedures to assure reliable electrical service?

Industry data indicates that distribution system problems have the most profound effect on overall electric utility system reliability. Therefore sufficient resources must be dedicated to the on-going operation and maintenance of the distribution system. The assumptions used for modeling of ongoing operation and maintenance have been compared with American Public Power Association benchmarks as well as benchmarks reported by other Northern Colorado public power utilities including the cities of Ft. Collins, Loveland and Longmont. These utilities report better overall distribution system reliability as measured by the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) than Xcel Energy. In all cases, the modeling assumptions used are intended to be conservative in order to provide a higher level of reliability than Xcel Energy currently provides.

Attachment E presents the start-up and on-going operation and maintenance cost assumptions that are being used in the financial modeling. These cost assumptions can be compared to APPA benchmarking data as presented in Appendix F-5 - APPA Selected Financial and Operating Ratios of Public Power Systems, 2011 Data.

Appendix F-1

An aggressive capital replacement schedule has been formulated that would provide for ongoing replacement of system components because of age and deterioration. In addition, undergrounding of existing overhead electrical infrastructure would continue.

Appendix F-6 presents a work plan outline of steps necessary to assure reliability during the transition, start-up and first several years of operation of a potential new municipal electric utility. The work plan has been developed that if executed would provide for a smooth transition of electric service to the customers.

Energy resource plans assume a 15 percent reserve margin as well as adequate on-line and off-line reserves with the intent of ensuring that loss of load probability is within acceptable levels. Generation and transmission are regulated through the Federal Energy Regulatory Commission and the energy resource and separation plans have been formulated with the intent to comply with all regulations.

I. What types of natural and man-made hazards should be considered including frequency and magnitude of extreme events?

Defining Major Events

1. Traditional, non statistical definitions:
    - Any event that has more than 10 percent of the utility customers out of service for 24 hours.
    - Any 15 percent of the customers for the duration of the storm.
2. IEEE proposed definition of Major Event Days
    - Any day that exceeds a daily SAIDI threshold called TMED.
    - Daily SAIDI values for the past five years are used to calculate TMED
    - The natural log (ln) of each SAIDI value is found and the log-average (α) is found.
    - The standard deviation of the logarithms is found (β).
3. Cooperative agreements with other utilities
    - Provide mutual support during major events
4. Outage event and contingency plans (non-disaster)
    - Most utilities will have a five-stage outage plan to prevent complete blackout
        - Self-imposed curtailment
        - Voltage and frequency control
        - Selected circuit outages
        - Public request for curtailment
        - Mandatory outages (brownouts and outages)
5. Disaster and recovery planning
    - Command center
6. Asset inventory reserve
    - Backup inventory assets for common cause (e.g. poles, transformers, fuses, switchgear, wires, cables)
7. Public outreach efforts
8. Post major event data collection and analysis

In addition to the capability of potential City of Boulder electric utility resources and staff to respond directly to an extreme event, the city's Purchasing Division would provide for additional external resources through on-call service contracts. These contracts provide pre-negotiated prices for labor, material and equipment. There are also other collective resources that should be considered including existing emergency management capabilities and mutual aid agreements.

City of Boulder Emergency Management Functions

Boulder Office of Emergency Management
The Boulder Office of Emergency Management (OEM) was established under a joint agreement between Boulder County and the City of Boulder in 1984. This office leads a comprehensive emergency management program designed to provide an efficient response to, and effective recovery from emergencies and disasters. Emergency Management is the function that plans, coordinates and supports a wide range of activities that help communities to reduce vulnerability to hazards, prepare for and cope with disasters.

The Boulder OEM has emergency management responsibilities for both the City of Boulder and Boulder County. In addition, Boulder OEM coordinates with state and federal partners, many city and county departments, public safety agencies, municipalities, non-governmental organizations and private businesses throughout Boulder County in order to facilitate coordinated planning and response to emergency situations.

City/County Emergency Operations Center (EOC)
The Emergency Operations Center (EOC) is a special central location for disaster management and communications. The EOC is opened when it becomes apparent that a particular event has or will have major effects on the community exceeding the capabilities available from routine operations. It is located at 3280 Airport Road.

During a crisis/disaster situation, information from all available resources regarding weather, hazard areas, incident situation and other pertinent information is discussed and decisions are made. This centralized organization allows for all information to go through the EOC, allowing for the most effective and efficient allocation of resources to be disbursed.

National Incident Management System (NIMS) and the Incident Command System (ICS)
The National Incident Management System (NIMS) provides a systematic, proactive approach to guide departments and agencies at all levels of government, nongovernmental organizations, and the private sector to work seamlessly to prevent, protect against, respond to, recover from, and mitigate the effects of incidents, regardless of cause, size, location, or complexity, in order to reduce the loss of life and property and harm to the environment. The Boulder Incident Command System (ICS) is a standard local management system under NIMS for controlling incidents. The ICS consists of personnel, facilities, equipment, communications and procedures, all operating within a common organization structure to gain control and resolve any type of incident.

Appendix F-1

City of Boulder Public Works Department Incident Command Center

The City of Boulder Public Works (PW) Incident Command is established as the central point for essential Public Works information coordination concerning a disaster situation. The PW Incident Command stays in contact with the EOC and is located at the Municipal Service Center in the conference room.

The Municipal Service Center also serves as Public Works' Resource Allocation Center (RAC), which is responsible for allocating and documenting city resources (personnel, equipment and supplies) needed in a disaster situation.

Multi-Hazard Mitigation Plan

The Disaster Mitigation Act of 2000 (DMA) requires local communities to have a FEMA-approved MHMP in place in order to maintain eligibility for certain federal pre- and post-disaster mitigation funding. The purpose of the plan is to identify natural hazards that affect a community and the people and places that are at risk. The plan then provides a framework for actions that may be applied to reduce or eliminate long-term risk associated with priority hazards.

The City of Boulder first developed a Multi-Hazard Mitigation Plan in 2008. To remain eligible for federal funding and CRS points, the Federal Emergency Management Agency (FEMA) requires the plan to be updated every five years. The city in conjunction with AMEC consulting firm and the Hazard Mitigation Planning Committee (HMPC) recently developed the 2012 five-year plan update. The HMPC is comprised of key city, county and other government and stakeholder representatives. The basic goals of the plan have remained unchanged and include:

- Increasing community awareness
- Reducing vulnerability to natural hazards
- Increasing interagency capabilities and coordination

The five-year update includes updated natural hazard risks and capabilities and developing a new list of mitigation actions. Ranking of the city's natural hazard risks was revisited based on current information such as new floodplain maps and the city's wildland fire risk map in conjunction with a profile of the hazards including likely geographic extent of each hazard, probability of future occurrences and anticipated magnitude of damage.

Mutual Aid

Utilities establish mutual aid agreements with neighboring and regional utilities in order to improve service restoration efforts during power outages. Mutual aid agreements are part of a utility's response plan during power outages that enable them to use the help of other utilities (manpower, tools, spare parts and mobile equipment, etc). Establishing a mutual aid agreement requires advance sharing of information among member utilities. Furthermore, having a national mutual aid agreement is a beneficial precaution, especially if your utility encounters a situation where it requests Federal Emergency Management Agency (FEMA) funding.

The City of Boulder is currently a member of the Colorado Water/Waste Water Agency Response Network (CoWARN), a network of utilities helping one another to prepare for natural or man-made disasters, organize response according to requirements and share personnel and other resources statewide by agreement. The agreement is consistent with the National Incident Management System (NIMS) and contains indemnification provisions to protect the city and provide for reimbursement of costs as needed.

If a new municipal electric utility is formed, the existing emergency management functions and mutual aid agreements would be expanded and adapted accordingly.

J. How and to what extent should redundancy, firm capacity, power quality controls, reserve margins, common-mode failure scenarios be considered by the city to increase the level of reliability?

1. All of these are fundamental components to reliability. The implementation and management of these are the core business of a utility. DG and DM integration make these considerations more complicated as the balance equation becomes far more complex. Technology will need to be utilized and new measurements and methods of managing reliability will need to be adopted if all system assets are to be leveraged and all user energy needs are to be met.

2. Operation of the utility distribution network needs to be managed in an ‘energy optimized’ mode versus operating in a ‘peak management’ mode.

3. All available concepts, new and old, should be deployed to help manage reliability.
    - Smart switching (self-healing)
    - Volt/VAR control
    - Microgrids
    - Undergrounding
    - Loop design for OH
    - Outage Management System
    - Cyber Security assessment that address reliability by eliminating or mitigating identified vulnerabilities and addressing the gaps
    - Weather Intelligence Services – offers predictive capabilities in order to minimize the impact of weather on overall system efficiency and reliability
    - Protection schemes
    - Fusing
    - Design standards (e.g. Covered conductor to prevent animal caused outages, spacing between conductors, etc)

K. Are there other reliability issues that should be considered?

According to a 2009 Transmission and Distribution benchmark study, the United States lags behind in reliability standards when compared to other countries. Some studies estimate power interruptions cost the US economy about $150 billion each year, or 4 cents per kilowatt (KW) hour. Table 1 presents the average SAIDI and SAIFI indices for various countries.

Table 1 – Electrical System Reliability

Country	SAIDI	SAIFI
United States	244	1.49
Austria	31.77	0.66
Denmark	16.95	0.49
France	95.1	0.98
Germany	19.27	0.3
Italy	88.84	2.27
Netherlands	33.7	0.38
Spain	133.86	2.19
UK	81.42	0.72

Table 2 presents information about the causes of electrical outages and their relative impact on system reliability.

Table 2 – Causes of Outages

Causes of Outages	Relative Impact
Major Events	80.60%
Trees	5.60%
Distribution Equipment Failure	4.00%
Other	2.60%
Planned Interruptions	1.30%
Acts of Public	1.20%
Weather-Related	1.10%
Transmission Outages	1.10%
Lightning	1.10%
Substation Outages	0.90%
Animals	0.50%
Generation Outages	0.00%

Potential Impact of Grid Measured Reliability on Economic Development

1. Often the grade school, hospital and datacenter are all fed off the same circuit, yet they have vastly different needs around power availability / reliability.
2. If you simply provide the lowest level of availability required by the grade school, then the hospital and datacenter need to invest significant money in their own backup and mitigation strategies.
3. If they have to do this, they may decide to build in the town down the road, bringing jobs, tax revenue and quality of life somewhere else.

4. Even if they do decide to build or stay in the territory, they must now staff a high degree of competency around electrical distribution systems: areas that may not be a core part of their business mission.
5. Conversely, if you provide the level of power quality mandated by the hospital application, the school is essentially subsidizing the business model of the hospital.
6. Today, the efficiency, sustainability, and reliability aspects of an electron are often "bundled" in a flat cost to the user.
7. If the city/utility of the future unbundles these aspects and provides a cafeteria plan to their end users, it would augment the minimum level of reliability with infrastructure and professional services that extend their reach beyond the meter.

In a Smarter Grid:

1. A conserved kWh is valued at (or above) the market rate of a generated kWh
2. Consumers understand their total energy consumption as well as the flexibility that they have in instantaneous demand, and are empowered to optimize to their desired outcomes around cost, reliability, and sustainability
3. All generation (including intermittent renewable) and storage mechanisms can seamlessly contribute to supplying the grid requirements.
4. The system "self heals" responding quickly and surgically to power distribution events, physical and cyber attacks.
5. New products, services, and markets power our 21st century economy while helping energy providers and consumers meet their business objectives
6. Reliability Considerations from the Integration of Smart Grid (http://www.nerc.com/files/SGTF_Report_Final_posted.pdf)

Xcel Energy[SM]
PUBLIC SERVICE COMPANY

P.O. Box 840
Denver, Colorado 80201-0840

January 17, 2012

Doug Dean, Director
Public Utilities Commission
of the State of Colorado
1560 Broadway, Suite 250
Denver, Colorado 80202

RE: Docket No. 05A-288E - Public Service Company Quality of Service Plan (SAIDI Settlement requirements for RWT exceedance)

Mr. Dean:

Public Service filed its application for an electric Quality of Service Monitoring and Reporting Plan on July 1, 2005. On March 22, 2006, Public Service, Staff, OCC, and Denver filed a joint motion for approval of the Partial Stipulation and Settlement Agreement (SAIDI Settlement). The SAIDI Settlement was approved by Decision No. C06-1303.

Within that SAIDI Settlement there are five Performance Thresholds: 1) Customer Complaints, 2) Telephone Response, 3) Regional System Reliability, 4) Electric Service Continuity and 5) Electric Service Restoration. The primary measure of system average reliability is the SAIDI associated with ODI for each operating region. The Company agrees to strive to maintain reliability in each operating region so that SAIDI-ODI in a performance year does not exceed the established RWT. The parties also agree that if the annual SAIDI-ODI for an operating region exceeds the RWT in a performance year, that Company would file a monthly report for the region until such time as the Company's annual QSP report shows that SAIDI-ODI for the affected region was below the RWT.

Appendix F-2

Public Service filed its annual QSP report on April 1, 2011, which shows that Western region exceeded its RWT in the 2010 performance year. Please find attached the December 2011 Reliability Summary reports for the Western region.

If you have any questions, please call me.

Sincerely,

Jennifer Baker
Regulatory Administrator
Xcel Energy Services, Inc.
1800 Larimer St., Suite 1400
Denver, Colorado 80202
303 294-2495

Attachment

Cc: Steve Brown

Appendix F-2

Xcel Energy

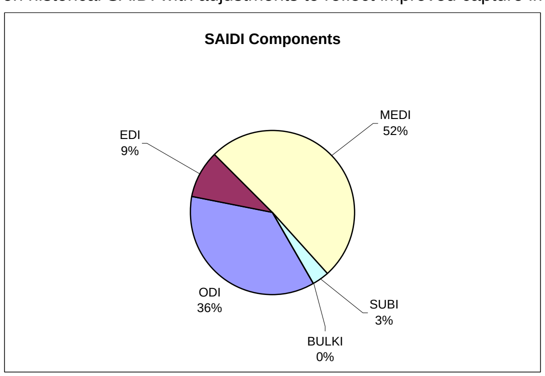
Public Service Company of Colorado Electric Reliability Summary

Report Revision Date:		1/15/2012	
Region:		**Denver**	
Reporting Period:		**Dec-11**	
OMS Region?		**Yes**	
Customer Count:		**943,251**	active meters
Major Event Day Threshold:	TMED	**3.02**	(Daily SAIDI-DSI Threshold Value, in minutes, Based on data from 2006 - 2010)
Number of MED's Identified:	#MED	**1**	(MED's are those days whose daily SAIDI-DSI value exceeds TMED)
MED Dates:		**12/31**	
SAIDI-ODI Reliability Warning Threshold:	RWT*	**107.4**	(Based on data from 1998 - 2010)

Electric Reliability Results

Description	Metric	SAIDI	SAIFI	CAIDI	ECT	ERT	Notes
		(System Average Interruption Duration Index, in minutes per month)	(System Average Interruption Frequency Index, in interruptions per month)	(Monthly Customer Average Interruption Duration Index, in minutes)	Electric Continuity Threshold (Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months)	Electric Restoration Threshold (Customers experiencing an interruption greater than 24 hours)	
Ordinary Distribution Interruptions	**ODI**	**3.7**	0.04	93.5			
Extraordinary - Catastrophic	ECATI	0.0	0.00	0.0			
Extraordinary - Government request	EGOVI	0.0	0.00	0.0			
Extraordinary - Emergency	EMERGI	0.0	0.00	0.0			
Extraordinary - Properly Planned	EPLANI	0.1	0.00	87.7			
Extraordinary - Public Damage	EPUBI	0.9	0.01	69.4			
Extraordinary - PUC Declare	EPUCI	0.0	0.00	0.0			
Extraordinary - Safety	ESAFTI	0.0	0.00	0.0			
Extraordinary - Vandalism	EVANI	0.0	0.00	85.5			
Extraordinary Distribution Interruptions	EDI	0.9	0.01	70.2			(EDI = ECATI+EGOVI+EMERGI+EPLANI+EPUBI+EPUCI+ESAFTI+EVANI)
Common Distribution Interruptions	CDI	4.6	0.1	87.5			(CDI = ODI + EDI)
DSI Major Event Day Interruptions	MEDI	5.2	0.02	329.7			
Distribution System Interruptions	DSI	9.8	0.07	142.7			(DSI = CDI + MEDI)
Substation Interruptions	SUBI	0.3	0.01	27.1			
Bulk Supply Interruptions	BULKI	0.0	0.00	0.0			
Sustained Electric System Interruptions	SESI	10.1	0.08	124.6			(SESI = DSI + SUBI + BULKI)
					593		> 5 (SESI-MEDI-EPUBI)
						0	> 24hours (SESI-MEDI-EPUBI-BULKI)

* These numbers are based on historical SAIDI with adjustments to reflect improved capture improvement and customer counts.



Appendix F-2

Xcel Energy

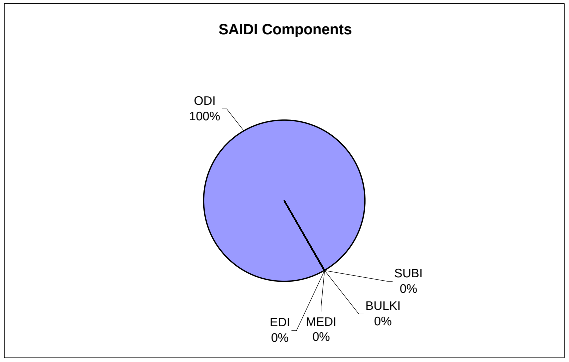
Public Service Company of Colorado Electric Reliability Summary

Report Revision Date:		1/15/2012	
Region:		**Boulder**	
Reporting Period:		**Dec-11**	
OMS Region?		**Yes**	
Customer Count:		**120,024**	active meters
Major Event Day Threshold:	TMED	**13.97**	(Daily SAIDI-DSI Threshold Value, in minutes, Based on data from 2006 - 2010)
Number of MED's Identified:	#MED	**0**	(MED's are those days whose daily SAIDI-DSI value exceeds TMED)
MED Dates:			
SAIDI-ODI Reliability Warning Threshold:	RWT*	**101.1**	(Based on data from 1998 - 2010)

Electric Reliability Results

Description	Metric	SAIDI	SAIFI	CAIDI	ECT	ERT	Notes
		(System Average Interruption Duration Index, in minutes per month)	(System Average Interruption Frequency Index, in interruptions per month)	(Monthly Customer Average Interruption Duration Index, in minutes)	Electric Continuity Threshold (Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months)	Electric Restoration Threshold (Customers experiencing an interruption greater than 24 hours)	
Ordinary Distribution Interruptions	**ODI**	**5.8**	0.08	69.1			
Extraordinary - Catastrophic	ECATI	0.0	0.00	0.0			
Extraordinary - Government request	EGOVI	0.0	0.00	0.0			
Extraordinary - Emergency	EMERGI	0.0	0.00	0.0			
Extraordinary - Properly Planned	EPLANI	0.0	0.00	0.0			
Extraordinary - Public Damage	EPUBI	0.0	0.00	125.0			
Extraordinary - PUC Declare	EPUCI	0.0	0.00	0.0			
Extraordinary - Safety	ESAFTI	0.0	0.00	0.0			
Extraordinary - Vandalism	EVANI	0.0	0.00	0.0			
Extraordinary Distribution Interruptions	EDI	0.0	0.00	125.0			(EDI = ECATI+EGOVI+EMERGI+EPLANI+EPUBI+EPUCI+ESAFTI+EVANI)
Common Distribution Interruptions	CDI	5.8	0.1	69.1			(CDI = ODI + EDI)
DSI Major Event Day Interruptions	MEDI	0.0	0.00	0.0			
Distribution System Interruptions	DSI	5.8	0.08	69.1			(DSI = CDI + MEDI)
Substation Interruptions	SUBI	0.0	0.00	0.0			
Bulk Supply Interruptions	BULKI	0.0	0.00	0.0			
Sustained Electric System Interruptions	SESI	5.8	0.08	69.1			(SESI = DSI + SUBI + BULKI)
					142		> 5 (SESI-MEDI-EPUBI)
						0	> 24hours (SESI-MEDI-EPUBI-BULKI)

* These numbers are based on historical SAIDI with adjustments to reflect improved capture improvement and customer counts.



Appendix F-2

Xcel Energy

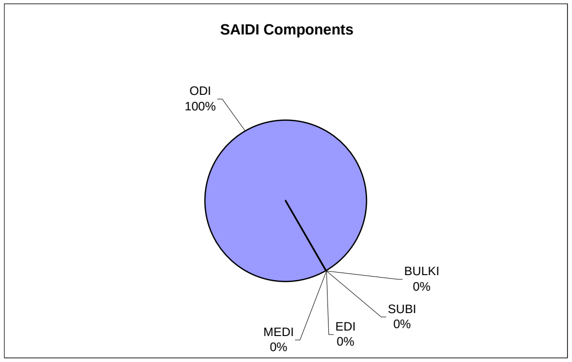
Public Service Company of Colorado Electric Reliability Summary

Report Revision Date:		1/15/2012	
Region:		**Front Range**	
Reporting Period:		**Dec-11**	
OMS Region?		**Yes**	
Customer Count:		**17,718**	active meters
Major Event Day Threshold:	TMED*	**14.51**	(Daily SAIDI-DSI Threshold Value, in minutes, Based on data from 2006 - 2010)
Number of MED's Identified:	#MED	**0**	(MED's are those days whose daily SAIDI-DSI value exceeds TMED)
MED Dates:			
SAIDI-ODI Reliability Warning Threshold:	RWT*	**115.6**	(Based on data from 1998 - 2010)

Electric Reliability Results

Description	Metric	SAIDI	SAIFI	CAIDI	ECT	ERT	Notes
		(System Average Interruption Duration Index, in minutes per month)	(System Average Interruption Frequency Index, in interruptions per month)	(Monthly Customer Average Interruption Duration Index, in minutes)	Electric Continuity Threshold (Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months)	Electric Restoration Threshold (Customers experiencing an interruption greater than 24 hours)	
Ordinary Distribution Interruptions	**ODI**	**8.1**	0.18	44.6			
Extraordinary - Catastrophic	ECATI	0.0	0.00	0.0			
Extraordinary - Government request	EGOVI	0.0	0.00	0.0			
Extraordinary - Emergency	EMERGI	0.0	0.00	0.0			
Extraordinary - Properly Planned	EPLANI	0.0	0.00	0.0			
Extraordinary - Public Damage	EPUBI	0.0	0.00	0.0			
Extraordinary - PUC Declare	EPUCI	0.0	0.00	0.0			
Extraordinary - Safety	ESAFTI	0.0	0.00	0.0			
Extraordinary - Vandalism	EVANI	0.0	0.00	0.0			
Extraordinary Distribution Interruptions	EDI	0.0	0.00	0.0			(EDI = ECATI+EGOVI+EMERGI+EPLANI+EPUBI+EPUCI+ESAFTI+EVANI)
Common Distribution Interruptions	CDI	8.1	0.2	44.6			(CDI = ODI + EDI)
DSI Major Event Day Interruptions	MEDI	0.0	0.00	0.0			
Distribution System Interruptions	DSI	8.1	0.18	44.6			(DSI = CDI + MEDI)
Substation Interruptions	SUBI	0.0	0.00	0.0			
Bulk Supply Interruptions	BULKI	0.0	0.00	0.0			
Sustained Electric System Interruptions	SESI	8.1	0.18	44.6			(SESI = DSI + SUBI + BULKI)
					0		> 5 (SESI-MEDI-EPUBI)
						0	> 24hours (SESI-MEDI-EPUBI-BULKI)

* These numbers are based on historical SAIDI with adjustments to reflect improved capture improvement and customer counts.



Appendix F-2

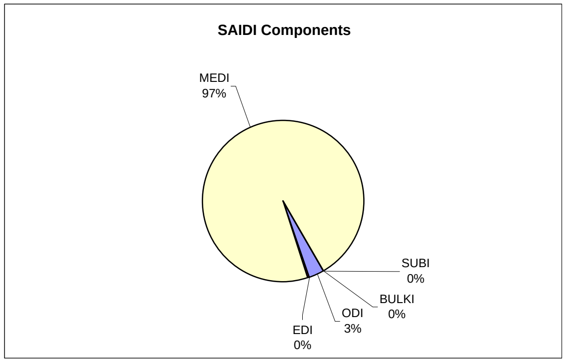
Xcel Energy
Public Service Company of Colorado Electric Reliability Summary

Report Revision Date:		1/15/2012	
Region:		**Greeley**	
Reporting Period:		**Dec-11**	
OMS Region?		**Yes**	
Customer Count:		**56,631**	active meters
Major Event Day Threshold:	TMED*	**4.55**	(Daily SAIDI-DSI Threshold Value, in minutes, Based on data from 2006 - 2010)
Number of MED's Identified:	#MED	**1**	(MED's are those days whose daily SAIDI-DSI value exceeds TMED)
MED Dates:		**12/31**	
SAIDI-ODI Reliability Warning Threshold:	RWT*	**59.2**	(Based on data from 1998 - 2010)

Electric Reliability Results

Description	Metric	SAIDI	SAIFI	CAIDI	ECT	ERT	Notes
		(System Average Interruption Duration Index, in minutes per month)	(System Average Interruption Frequency Index, in interruptions per month)	(Monthly Customer Average Interruption Duration Index, in minutes)	Electric Continuity Threshold (Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months)	Electric Restoration Threshold (Customers experiencing an interruption greater than 24 hours)	
Ordinary Distribution Interruptions	**ODI**	**0.8**	0.01	70.0			
Extraordinary - Catastrophic	ECATI	0.0	0.00	0.0			
Extraordinary - Government request	EGOVI	0.0	0.00	0.0			
Extraordinary - Emergency	EMERGI	0.0	0.00	0.0			
Extraordinary - Properly Planned	EPLANI	0.0	0.00	0.0			
Extraordinary - Public Damage	EPUBI	0.1	0.00	193.1			
Extraordinary - PUC Declare	EPUCI	0.0	0.00	0.0			
Extraordinary - Safety	ESAFTI	0.0	0.00	0.0			
Extraordinary - Vandalism	EVANI	0.0	0.00	0.0			
Extraordinary Distribution Interruptions	EDI	0.1	0.00	193.1			(EDI = ECATI+EGOVI+EMERGI+EPLANI+EPUBI+EPUCI+ESAFTI+EVANI)
Common Distribution Interruptions	CDI	0.8	0.0	73.6			(CDI = ODI + EDI)
DSI Major Event Day Interruptions	MEDI	23.6	0.05	450.2			
Distribution System Interruptions	DSI	24.4	0.06	383.5			(DSI = CDI + MEDI)
Substation Interruptions	SUBI	0.0	0.00	0.0			
Bulk Supply Interruptions	BULKI	0.0	0.00	0.0			
Sustained Electric System Interruptions	SESI	24.4	0.06	383.5			(SESI = DSI + SUBI + BULKI)
					38		> 5 (SESI-MEDI-EPUBI)
						0	> 24hours (SESI-MEDI-EPUBI-BULKI)

* These numbers are based on historical SAIDI with adjustments to reflect improved capture improvement and customer counts.



Appendix F-2

Xcel Energy

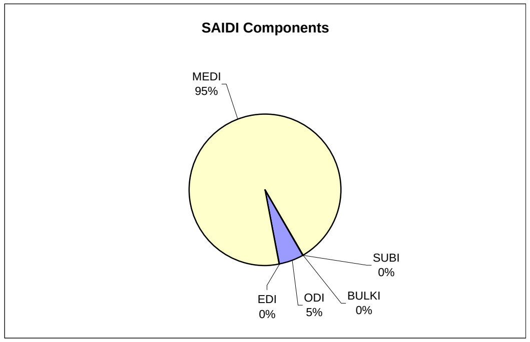
Public Service Company of Colorado Electric Reliability Summary

Report Revision Date:		1/15/2012	
Region:		**High Plains**	
Reporting Period:		**Dec-11**	
OMS Region?		**Yes**	
Customer Count:		**11,599**	active meters
Major Event Day Threshold:	TMED*	**9.52**	(Daily SAIDI-DSI Threshold Value, in minutes, Based on data from 2006 - 2010)
Number of MED's Identified:	#MED	**1**	(MED's are those days whose daily SAIDI-DSI value exceeds TMED)
MED Dates:		**12/31**	
SAIDI-ODI Reliability Warning Threshold:	RWT*	**55.5**	(Based on data from 1998 - 2010)

Electric Reliability Results

Description	Metric	SAIDI	SAIFI	CAIDI	ECT	ERT	Notes
		(System Average Interruption Duration Index, in minutes per month)	(System Average Interruption Frequency Index, in interruptions per month)	(Monthly Customer Average Interruption Duration Index, in minutes)	Electric Continuity Threshold (Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months)	Electric Restoration Threshold (Customers experiencing an interruption greater than 24 hours)	
Ordinary Distribution Interruptions	**ODI**	**2.0**	0.02	104.2			
Extraordinary - Catastrophic	ECATI	0.0	0.00	0.0			
Extraordinary - Government request	EGOVI	0.0	0.00	0.0			
Extraordinary - Emergency	EMERGI	0.0	0.00	0.0			
Extraordinary - Properly Planned	EPLANI	0.0	0.00	0.0			
Extraordinary - Public Damage	EPUBI	0.0	0.00	0.0			
Extraordinary - PUC Declare	EPUCI	0.0	0.00	0.0			
Extraordinary - Safety	ESAFTI	0.0	0.00	0.0			
Extraordinary - Vandalism	EVANI	0.0	0.00	0.0			
Extraordinary Distribution Interruptions	EDI	0.0	0.00	0.0			(EDI = ECATI+EGOVI+EMERGI+EPLANI+EPUBI+EPUCI+ESAFTI+EVANI)
Common Distribution Interruptions	CDI	2.0	0.0	104.2			(CDI = ODI + EDI)
DSI Major Event Day Interruptions	MEDI	35.3	0.22	161.4			
Distribution System Interruptions	DSI	37.3	0.24	156.8			(DSI = CDI + MEDI)
Substation Interruptions	SUBI	0.0	0.00	0.0			
Bulk Supply Interruptions	BULKI	0.0	0.00	0.0			
Sustained Electric System Interruptions	SESI	37.3	0.24	156.8			(SESI = DSI + SUBI + BULKI)
					0		> 5 (SESI-MEDI-EPUBI)
						0	> 24hours (SESI-MEDI-EPUBI-BULKI)

* These numbers are based on historical SAIDI with adjustments to reflect improved capture improvement and customer counts.



Appendix F-2

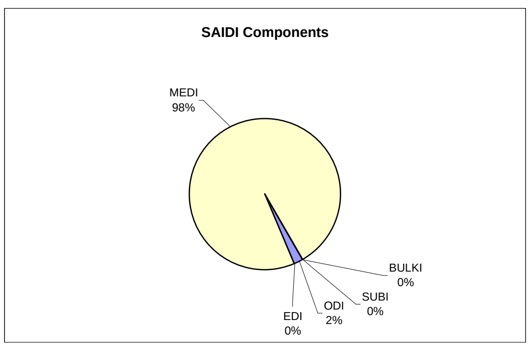
Xcel Energy
Public Service Company of Colorado Electric Reliability Summary

Report Revision Date:		1/15/2012	
Region:		**Mountain**	
Reporting Period:		**Dec-11**	
OMS Region?		**Yes**	
Customer Count:		**36,305**	active meters
Major Event Day Threshold:	TMED*	**12.60**	(Daily SAIDI-DSI Threshold Value, in minutes, Based on data from 2006 - 2010)
Number of MED's Identified:	#MED	**1**	(MED's are those days whose daily SAIDI-DSI value exceeds TMED)
MED Dates:		**12/31**	
SAIDI-ODI Reliability Warning Threshold:	RWT*	**154.2**	(Based on data from 1998 - 2010)

Electric Reliability Results

Description	Metric	SAIDI	SAIFI	CAIDI	ECT	ERT	Notes
		(System Average Interruption Duration Index, in minutes per month)	(System Average Interruption Frequency Index, in interruptions per month)	(Monthly Customer Average Interruption Duration Index, in minutes)	Electric Continuity Threshold (Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months)	Electric Restoration Threshold (Customers experiencing an interruption greater than 24 hours)	
Ordinary Distribution Interruptions	**ODI**	**1.2**	0.01	165.4			
Extraordinary - Catastrophic	ECATI	0.0	0.00	0.0			
Extraordinary - Government request	EGOVI	0.0	0.00	0.0			
Extraordinary - Emergency	EMERGI	0.0	0.00	0.0			
Extraordinary - Properly Planned	EPLANI	0.0	0.00	0.0			
Extraordinary - Public Damage	EPUBI	0.0	0.00	0.0			
Extraordinary - PUC Declare	EPUCI	0.0	0.00	0.0			
Extraordinary - Safety	ESAFTI	0.0	0.00	0.0			
Extraordinary - Vandalism	EVANI	0.0	0.00	0.0			
Extraordinary Distribution Interruptions	EDI	0.0	0.00	0.0			(EDI = ECATI+EGOVI+EMERGI+EPLANI+EPUBI+EPUCI+ESAFTI+EVANI)
Common Distribution Interruptions	CDI	1.2	0.0	165.4			(CDI = ODI + EDI)
DSI Major Event Day Interruptions	MEDI	63.4	0.17	365.2			
Distribution System Interruptions	DSI	64.6	0.18	357.4			(DSI = CDI + MEDI)
Substation Interruptions	SUBI	0.0	0.00	0.0			
Bulk Supply Interruptions	BULKI	0.0	0.00	0.0			
Sustained Electric System Interruptions	SESI	64.6	0.18	357.4			(SESI = DSI + SUBI + BULKI)
					0		> 5 (SESI-MEDI-EPUBI)
						0	> 24hours (SESI-MEDI-EPUBI-BULKI)

* These numbers are based on historical SAIDI with adjustments to reflect improved capture improvement and customer counts.



Appendix F-2

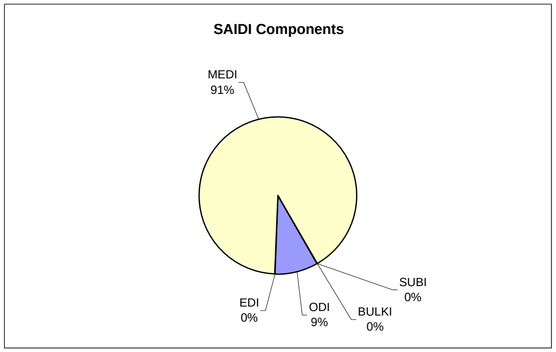
Xcel Energy
Public Service Company of Colorado Electric Reliability Summary

Report Revision Date:		1/15/2012	
Region:		**Northern**	
Reporting Period:		**Dec-11**	
OMS Region?		**Yes**	
Customer Count:		**27,316**	active meters
Major Event Day Threshold:	TMED	**15.28**	(Daily SAIDI-DSI Threshold Value, in minutes, Based on data from 2006 - 2010)
Number of MED's Identified:	#MED	**1**	(MED's are those days whose daily SAIDI-DSI value exceeds TMED)
MED Dates:		**12/31**	
SAIDI-ODI Reliability Warning Threshold:	RWT*	**97.4**	(Based on data from 1998 - 2010)

Electric Reliability Results

Description	Metric	SAIDI	SAIFI	CAIDI	ECT	ERT	Notes
		(System Average Interruption Duration Index, in minutes per month)	(System Average Interruption Frequency Index, in interruptions per month)	(Monthly Customer Average Interruption Duration Index, in minutes)	Electric Continuity Threshold (Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months)	Electric Restoration Threshold (Customers experiencing an interruption greater than 24 hours)	
Ordinary Distribution Interruptions	**ODI**	**5.5**	0.06	91.6			
Extraordinary - Catastrophic	ECATI	0.0	0.00	0.0			
Extraordinary - Government request	EGOVI	0.0	0.00	0.0			
Extraordinary - Emergency	EMERGI	0.0	0.00	0.0			
Extraordinary - Properly Planned	EPLANI	0.0	0.00	0.0			
Extraordinary - Public Damage	EPUBI	0.1	0.00	135.8			
Extraordinary - PUC Declare	EPUCI	0.0	0.00	0.0			
Extraordinary - Safety	ESAFTI	0.0	0.00	0.0			
Extraordinary - Vandalism	EVANI	0.0	0.00	0.0			
Extraordinary Distribution Interruptions	EDI	0.1	0.00	135.8			(EDI = ECATI+EGOVI+EMERGI+EPLANI+EPUBI+EPUCI+ESAFTI+EVANI)
Common Distribution Interruptions	CDI	5.6	0.1	92.1			(CDI = ODI + EDI)
DSI Major Event Day Interruptions	MEDI	56.6	0.14	395.0			
Distribution System Interruptions	DSI	62.2	0.20	305.1			(DSI = CDI + MEDI)
Substation Interruptions	SUBI	0.0	0.00	0.0			
Bulk Supply Interruptions	BULKI	0.0	0.00	0.0			
Sustained Electric System Interruptions	SESI	62.2	0.20	305.1			(SESI = DSI + SUBI + BULKI)
					0		> 5 (SESI-MEDI-EPUBI)
						0	> 24hours (SESI-MEDI-EPUBI-BULKI)

* These numbers are based on historical SAIDI with adjustments to reflect improved capture improvement and customer counts.



Appendix F-2

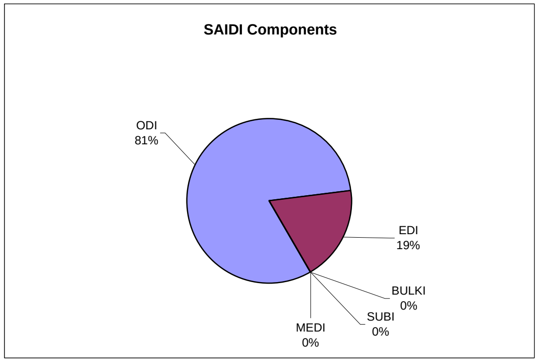
Xcel Energy
Public Service Company of Colorado Electric Reliability Summary

Report Revision Date:		1/15/2012	
Region:		**SLV**	
Reporting Period:		**Dec-11**	
OMS Region?		**Yes**	
Customer Count:		**22,695**	active meters
Major Event Day Threshold:	TMED*	**4.93**	(Daily SAIDI-DSI Threshold Value, in minutes, Based on data from 2006 - 2010)
Number of MED's Identified:	#MED	**0**	(MED's are those days whose daily SAIDI-DSI value exceeds TMED)
MED Dates:			
SAIDI-ODI Reliability Warning Threshold:	RWT*	**62.9**	(Based on data from 1998 - 2010)

Electric Reliability Results

Description	Metric	SAIDI	SAIFI	CAIDI	ECT	ERT	Notes
		(System Average Interruption Duration Index, in minutes per month)	(System Average Interruption Frequency Index, in interruptions per month)	(Monthly Customer Average Interruption Duration Index, in minutes)	Electric Continuity Threshold (Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months)	Electric Restoration Threshold (Customers experiencing an interruption greater than 24 hours)	
Ordinary Distribution Interruptions	**ODI**	**4.6**	0.09	54.3			
Extraordinary - Catastrophic	ECATI	0.0	0.00	0.0			
Extraordinary - Government request	EGOVI	0.0	0.00	0.0			
Extraordinary - Emergency	EMERGI	0.0	0.00	0.0			
Extraordinary - Properly Planned	EPLANI	0.0	0.00	0.0			
Extraordinary - Public Damage	EPUBI	1.1	0.01	99.8			
Extraordinary - PUC Declare	EPUCI	0.0	0.00	0.0			
Extraordinary - Safety	ESAFTI	0.0	0.00	0.0			
Extraordinary - Vandalism	EVANI	0.0	0.00	0.0			
Extraordinary Distribution Interruptions	EDI	1.1	0.01	99.8			(EDI = ECATI+EGOVI+EMERGI+EPLANI+EPUBI+EPUCI+ESAFTI+EVANI)
Common Distribution Interruptions	CDI	5.7	0.1	59.3			(CDI = ODI + EDI)
DSI Major Event Day Interruptions	MEDI	0.0	0.00	0.0			
Distribution System Interruptions	DSI	5.7	0.10	59.3			(DSI = CDI + MEDI)
Substation Interruptions	SUBI	0.0	0.00	0.0			
Bulk Supply Interruptions	BULKI	0.0	0.00	0.0			
Sustained Electric System Interruptions	SESI	5.7	0.10	59.3			(SESI = DSI + SUBI + BULKI)
					4		> 5 (SESI-MEDI-EPUBI)
						0	> 24hours (SESI-MEDI-EPUBI-BULKI)

* These numbers are based on historical SAIDI with adjustments to reflect improved capture improvement and customer counts.



Appendix F-2

Xcel Energy

Public Service Company of Colorado Electric Reliability Summary

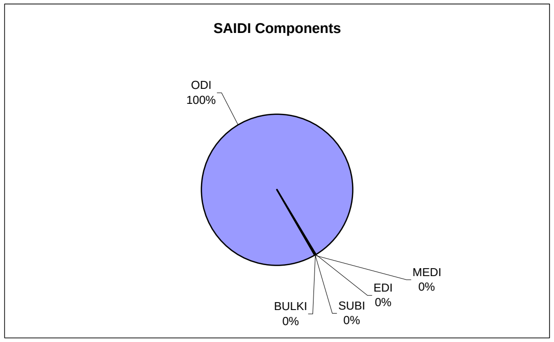
Report Revision Date: 1/15/2012

Region:		**Western**	
Reporting Period:		**Dec-11**	
OMS Region?		**Yes**	
Customer Count:		**67,407**	active meters
Major Event Day Threshold:	TMED	**8.84**	(Daily SAIDI-DSI Threshold Value, in minutes, Based on data from 2006 - 2010)
Number of MED's Identified:	#MED	**0**	(MED's are those days whose daily SAIDI-DSI value exceeds TMED)
MED Dates:			
SAIDI-ODI Reliability Warning Threshold:	RWT*	**51.4**	(Based on data from 1998 - 2010)

Electric Reliability Results

Description	Metric	SAIDI	SAIFI	CAIDI	ECT	ERT	Notes
		(System Average Interruption Duration Index, in minutes per month)	(System Average Interruption Frequency Index, in interruptions per month)	(Monthly Customer Average Interruption Duration Index, in minutes)	Electric Continuity Threshold (Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months)	Electric Restoration Threshold (Customers experiencing an interruption greater than 24 hours)	
Ordinary Distribution Interruptions	**ODI**	**3.9**	0.05	82.3			
Extraordinary - Catastrophic	ECATI	0.0	0.00	0.0			
Extraordinary - Government request	EGOVI	0.0	0.00	0.0			
Extraordinary - Emergency	EMERGI	0.0	0.00	0.0			
Extraordinary - Properly Planned	EPLANI	0.0	0.00	65.0			
Extraordinary - Public Damage	EPUBI	0.0	0.00	163.0			
Extraordinary - PUC Declare	EPUCI	0.0	0.00	0.0			
Extraordinary - Safety	ESAFTI	0.0	0.00	0.0			
Extraordinary - Vandalism	EVANI	0.0	0.00	0.0			
Extraordinary Distribution Interruptions	EDI	0.0	0.00	114.0			(EDI = ECATI+EGOVI+EMERGI+EPLANI+EPUBI+EPUCI+ESAFTI+EVANI)
Common Distribution Interruptions	CDI	3.9	0.0	82.3			(CDI = ODI + EDI)
DSI Major Event Day Interruptions	MEDI	0.0	0.00	0.0			
Distribution System Interruptions	DSI	3.9	0.05	82.3			(DSI = CDI + MEDI)
Substation Interruptions	SUBI	0.0	0.00	0.0			
Bulk Supply Interruptions	BULKI	0.0	0.00	0.0			
Sustained Electric System Interruptions	SESI	3.9	0.05	82.3			(SESI = DSI + SUBI + BULKI)
					45		> 5 (SESI-MEDI-EPUBI)
						0	> 24hours (SESI-MEDI-EPUBI-BULKI)

* These numbers are based on historical SAIDI with adjustments to reflect improved capture improvement and customer counts.



Appendix F-2

Xcel Energy

Public Service Company of Colorado Electric Service Continuity Target Exceedance Summary

Report Revision Date:	1/15/2012	
Region:	**Denver**	
Reporting Period:	**Dec-11**	
OMS Region?	**Yes**	
Customer Count:	**943,251**	active meters

Electric Service Continuity Target Exceedance List
Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months
Premise I.D.

Appendix F-2

Xcel Energy

Public Service Company of Colorado Electric Service Continuity Target Exceedance Summary

Report Revision Date:	1/15/2012	
Region:	**Boulder**	
Reporting Period:	**Dec-11**	
OMS Region?	**Yes**	
Customer Count:	**120,024**	active meters

Electric Service Continuity Target Exceedance List
Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months
Premise I.D.

Appendix F-2

Xcel Energy

Public Service Company of Colorado Electric Service Continuity Target Exceedance Summary

Report Revision Date:	1/15/2012	
Region:	**Front Range**	
Reporting Period:	**Dec-11**	
OMS Region?	**Yes**	
Customer Count:	**17,718**	active meters

Electric Service Continuity Target Exceedance List
Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months
Premise I.D.

Appendix F-2

Xcel Energy

Public Service Company of Colorado Electric Service Continuity Target Exceedance Summary

Report Revision Date: 1/15/2012

Region:	**Greeley**
Reporting Period:	**Dec-11**
OMS Region?	**Yes**
Customer Count:	**56,631** active meters

Electric Service Continuity Target Exceedance List
Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months
Premise I.D.

Appendix F-2

Xcel Energy

Public Service Company of Colorado Electric Service Continuity Target Exceedance Summary

Report Revision Date:	1/15/2012	
Region:	**High Plains**	
Reporting Period:	**Dec-11**	
OMS Region?	**Yes**	
Customer Count:	**11,599**	active meters

Electric Service Continuity Target Exceedance List
Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months
Premise I.D.

Appendix F-2

Xcel Energy

Public Service Company of Colorado Electric Service Continuity Target Exceedance Summary

Report Revision Date:	1/15/2012	
Region:	**Mountain**	
Reporting Period:	**Dec-11**	
OMS Region?	**Yes**	
Customer Count:	**36,305**	active meters

Electric Service Continuity Target Exceedance List
Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months
Premise I.D.

Appendix F-2

Xcel Energy

Public Service Company of Colorado Electric Service Continuity Target Exceedance Summary

Report Revision Date: 1/15/2012

Region:	**Northern**
Reporting Period:	**Dec-11**
OMS Region?	**Yes**
Customer Count:	**27,316** active meters

Electric Service Continuity Target Exceedance List
Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months
Premise I.D.

Appendix F-2

Xcel Energy

Public Service Company of Colorado Electric Service Continuity Target Exceedance Summary

Report Revision Date:	1/15/2012	
Region:	**SLV**	
Reporting Period:	**Dec-11**	
OMS Region?	**Yes**	
Customer Count:	**22,695**	active meters

Electric Service Continuity Target Exceedance List
Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months
Premise I.D.

Appendix F-2

Xcel Energy

Public Service Company of Colorado Electric Service Continuity Target Exceedance Summary

Report Revision Date: 1/15/2012

Region:	**Western**
Reporting Period:	**Dec-11**
OMS Region?	**Yes**
Customer Count:	**67,407** active meters

Electric Service Continuity Target Exceedance List
Customers experiencing more than 5 interruptions for calendar year that were not reported in previous months
Premise I.D.

Appendix F-2

Xcel Energy

Public Service Company of Colorado Electric Service Restoration Target Exceedance Summary

Report Revision Date:	1/15/2012	
Region:	**Denver**	
Reporting Period:	**Dec-11**	
OMS Region?	**Yes**	
Customer Count:	**943,251**	active meters

Electric Service Restoration Target Exceedance List
Customers experiencing an interruption greater than 24 hours
Premise I.D.
None to report

Appendix F-2

Xcel Energy

Public Service Company of Colorado Electric Service Restoration Target Exceedance Summary

Report Revision Date:	1/15/2012	
Region:	**Boulder**	
Reporting Period:	**Dec-11**	
OMS Region?	**Yes**	
Customer Count:	**120,024**	active meters

Electric Service Restoration Target Exceedance List
Customers experiencing an interruption greater than 24 hours
Premise I.D.
None to report

Appendix F-2

Xcel Energy

Public Service Company of Colorado Electric Service Continuity Target Exceedance Summary

Report Revision Date: 1/15/2012

Region:	**Front Range**
Reporting Period:	**Dec-11**
OMS Region?	**Yes**
Customer Count:	**17,718** active meters

Electric Service Restoration Target Exceedance List
Customers experiencing an interruption greater than 24 hours
Premise I.D.

Appendix F-2

Xcel Energy

Public Service Company of Colorado Electric Service Restoration Target Exceedance Summary

Report Revision Date: 1/15/2012

Region:	**Northern**
Reporting Period:	**Dec-11**
OMS Region?	**Yes**
Customer Count:	**27,316** active meters

Electric Service Restoration Target Exceedance List
Customers experiencing an interruption greater than 24 hours
Premise I.D.
None to report

Appendix F-2

Xcel Energy

Public Service Company of Colorado Electric Service Restoration Target Exceedance Summary

Report Revision Date:	1/15/2012
Region:	**Western**
Reporting Period:	**Dec-11**
OMS Region?	**Yes**
Customer Count:	**67,407** active meters

Electric Service Restoration Target Exceedance List
Customers experiencing an interruption greater than 24 hours
Premise I.D.
None to report

Appendix F-3

Northern Front Range Public Power Utilities	Longmont (1)		Fort Collins (2)		Loveland (3)		Boulder - Base Scenario (4)	
Comparative Data	Actual	Goal/Projected	Actual	Goal/Projected	Actual	Goal/Projected	Current Estimate	Goal/Projected
Information compiled and calculated by Robert Harberg and Kara Mertz - City of Boulder								
1/27/2013								
General Utility Characteristics	**2010**		**2010**	**2012**	**2010**		**2010**	**Future**
Distribution Voltage (kV)	12.4		13.8		12.4		13.2	
Service Area Population	**86,270**		**143,986**	**146,870**	**66,859**		**111,000**	
Service Area Employment	**48,503**		**97,238**		**126,657**		**96,800**	
Service Area (square miles)	**49**		**56**		**61**		**44.4**	
Housing Units	**35,008**		**60,503**				**43,620**	
Residential customers (inside/outside)	34,173		57,034	59,406	28,110 / 644		55,734	
Commercial customers (inside/outside)	2,624		7,168		3,778 / 278		5,765	
Industrial customers (inside/outside)	12		21		339 / 10		1,009	
Total metered customers	**36,809**		**64,223**		**33,158**		**62,508**	
Street lights overhead			0		1076		3080	
Street lights underground			10766		4431		1660	
Total street lights	**7238**		**10766**		**5507**		**4740**	
System Characteristics								
Total Line (Circuit) Miles	**594**		**855**		**561**		**569**	
Total Line (Primary Distribution Circuit) Miles Overhead	149		17		81		213	
Total Line (Primary Disribution Circuit) Miles Underground	445		838		480		356	
Transmission ROW Miles					34		29	
Main Distribution Circuits	46		100				29	
Substations	6		6		6		6	
Substation transformers	12		12		12		12	
Loads and Fuels								
Maximum Demand (MW)	**175**		**282**		**140**		**244**	
Annual Energy Consumption (KMWH)	**826**		**1473**				**1484**	
Average Residential Customer's per day Electric use (kWh)			23.36	22.49	24			
Summer Peak demand (kW)					140,399			
Winter Peak demand (kW)					103,908			
System Load Factor	53%		62%		55.42%			
System Power Factor			98%	98%	95.90%			
Resource Mix								
Coal %	69.1%				68.0%			
Hydropower %	26.0%				25.9%			
Wind %	3.1%				4.4%			
Natural Gas %	0.4%				0.4%			
Other %	1.4%				1.3%			
TOTAL OWNED Hydropower (kW)					700			
TOTAL Net Metered DG (kW)					2396			
Performance Indices and Metrics	**2011**	**2012**	**2012**	**2012**	**2011**	**2013**		**Future**
APPA RP3 Reliability Indices								
System Average Interruption Duration Index (SAIDI) minutes	38.2	<30	17.27				>85	<85
Customer Average Interruption Duration Index (CAIDI) minutes	55.8	<60	38.00	<60	68.53	75.25		
Average System Availability Index (ASAI) percent	99.995%	99.995%	99.9967%	99.9886%	99.9930%	99.9930%		
Momentary Average Interruption Frequency Index (MAIFI)	0.10	0.50	0.09		0.018	0.022		
System Average Interruption Frequency Index (SAIFI)	0.69	0.50	0.45	<1.0	0.042	0.04	>.85	<0.85
Other (Specific Fuse Operation)		3 in last 12 months						
Reliability Survey	Yes							
Mutual Aid	Yes							
FEMA/DHS NIMS	Yes		Yes					
Disaster Plan	Yes		Yes					
NERC Registration	Yes, DP - 2007		Yes, DP					
Physical Infrastructure Security	Yes		Yes					
Cyber Security	Yes, NERC CIP 001-009		Yes, NIST SP 800-53					
Other Objectives and Metrics	**2011**		**2010**	**2012**	**2011**	**2013**		
Reduce greenhouse gas emissions	see 2012 Focus on Longmont Plicy 3.3 - Emphasis on built environment		Avoided annual carbon emissions from efficiency programs of over 14,900 metric tons—and over 41,000 metric tons since 2006	20% by 2020				
Distribution O&M Expense per Circuit Mile	$6,136		$ 9,455	$ 10,284				
Line Loss Percentage	2.25%			2.8%				
Number of hours spent responding to power quality complaints	300				450	450		
Percent of system capacity used to meet peak demand	60%				55.4%	55.0%		
Average annual residential power per capita usage (kWh/person/year)	764		3433	3329	3650	3633		
Percent of unaccounted/unmetered distribution losses (includes line losses)	3%		1.47%	2.80%	3.25%	3.25%		
O&M cost per 100 miles	$97,558				$ 464,553	$ 610,466		
Average residential electric cost for 700 kWh per month summer ($)	51.65		$ 67.00		$ 59.49			
Average residential electric cost for 700 kWh per month winter ($)	51.65		$ 60.00		$ 56.36			
Financial Information	**2011**	**2013**		**2013**	**2011**	**2013**		**Future**
Purchased power	72%				74%			
Distribution System	11%							
Franchise Fee	8%							
Transfer to General Fund	3%							
Administrative	4%							
Capital Improvement	2%							
Revenues								
Service Charges		$ 62,961,000		$ 109,235,769	$ 46,591,219	$ 52,790,060		
2013 Interest Earnings		$ 50,000		$ 507,000	$ 570,585	$ 286,360		
Miscellaneous		$ 400,224		$ 3,403,949	$ 1,794,531	$ 1,032,940		
PIF					$ 2,233,023	$ 1,799,500		
Total Revenues	**$ -**	**$ 63,411,224**		**$ 113,146,718**	**$ 51,189,358**	**$ 55,908,860**		
Expenses								
Personnel Services		$ 5,924,996			$ 2,331,272	$ 2,686,930		
Operating and Maintenance		$ 54,290,492						
Operations				$ 8,001,652	$ 358,168	$ 593,850		
Payments & Transfers				$ 13,343,919	$ 586,691	$ 117,970		
Power Purchase				$ 81,295,555				
System Additions				$ 8,963,546				
Capital Projects		$ 1,232,200		$ 681,129	$ 5,124,567	$ 6,411,170		
Energy Services				$ 5,324,247		$ 120,300		
Non-operating		$ 801,070						
Purchased Services					$ 37,591,625	$ 46,453,720		
Total Expenses	**$ -**	**$ 62,248,758**	**$ -**	**$ 117,610,048**	**$ 45,992,323**	**$ 56,383,940**		
Average Residential Electric Rate ($/kWh)					$ 0.0787			
Rate Increase		7.50%		4.33%				
FTEs		72.75		99.95	42.72	42.95		
Administration & General Staff					7.05	5.94		
Administration & General Budget					$ 37,728,269.00	$ 45,469,600.00		
Electric Distribution Operations Staff		29.25			34.77	35.19		
Electric Distribution Operations Budget		$ 4,260,265			$ 3,021,911.00	$ 3,439,680.00		
Electric Engineering Staff		12.00						
Electric Engineering Budget		$ 1,753,416						
Meter Reading Staff (water and electric)		5.05						
Meter Reading Budget (water and electric)		$ 377,407						
Utilities Warehouse Staff (water and electric)		4.00						
Utilities Warehouse Budget (water and electric)		$ 488,369						
Energy Services Staff		6.00						
Energy Services Budget		$ 946,741						
Hydroelectric Generation Staff					0.9	0.32		
Hydroelectric Generation Budget					$ 38,590.00	$ 88,160.00		
Customer Relations Staff					1	1.5		
Customer Relations Budget					$ 78,986.00	$ 975,330.00		
Capital Improvements Budget (maintenance)		$ 911,000			$ 5,124,567.00	$ 6,411,170.00		
Capital Improvements Budget (growth)		$ 990,000						

Appendix F-4

American Public Power Association

Reliable Public Power Provider

Procedure Manual

Reliable Public Power Provider Procedure Manual

May 2012

Published by the
American Public Power Association
1875 Connecticut Avenue, NW
Suite 1200
Washington, D.C. 20009-5715
www.PublicPower.org

Table of Contents

About APPA

The American Public Power Association (APPA) is the service organization for the nation's more than 2,000 community owned electric utilities. APPA member utilities serve some of the nation's largest cities. Several state public power agencies also provide electric power to many communities within their states. However, the majority of APPA member utilities are located in small and medium-sized communities. Combined, public power utilities serve more than 45 million Americans.

APPA was created in 1940 as a non-profit, non-partisan organization with the purpose of advancing the public policy interests of its members and their consumers, and providing member services to ensure adequate, reliable electricity at a reasonable price while considering proper protection of the environment.

Reliable Public Power Provider (RP_3 ®) Program Overview

RP_3 is APPA's program to encourage public power utilities to demonstrate basic proficiency in four important disciplines:

- Reliability
- Safety
- Work Force Development
- System Improvement

Being recognized by the RP_3 program demonstrates to community leaders, governing board members, suppliers and service providers a utility's commitment to its employees, customers, and community. Additionally, an RP_3 designation is a sign of a utility focused on operating an efficient and reliable distribution system.

In the RP_3 program, applicants can earn up to 100 points for their practices and accomplishments in each of the four disciplines. Criteria within each category are based on sound business practices and are intended to represent a utility-wide commitment to safe and reliable delivery of electricity. A list of the specific scoring criteria is provided in the following sections and summarized in the back of this manual.

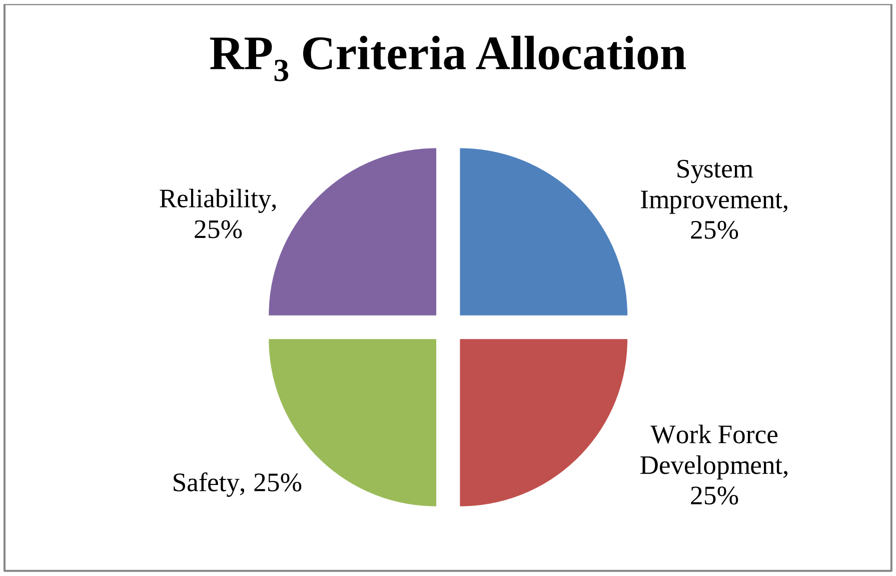


Figure 1: Percentage allocation of points by discipline

Reliability

The term "reliable" is defined by Webster's Dictionary as an adjective that means: can be relied on; dependable; trustworthy; and worthy of confidence. Although these are all true in context, reliability of an electric system goes deeper than just defining the results that are evident through reliable day-to-day service.

Key elements of the Reliability section include reliability indices, a mutual aid agreement, a system-wide disaster management plan (emergency response plan), and both cyber and physical security. To attain the full 25% rating in this section, please see the detailed Reliability section and Scoring Criteria Summary in this manual.

Safety

Workers' safety starts with the utility's safety program. A culture of safety must be created. This commitment to safety must begin with top management and include safety in all aspects of operations from generation to line work, and all utility services in between. Benchmarking of safety statistics by tracking industry-accepted OSHA incident rates, along with focusing on frontline workers, is crucial to the delivery of safe and reliable electricity. In the RP_3 program, each utility must prove that it uses an accepted safety manual and follows safe work practices, among other requirements. To attain the full 25% rating in this section, please see the detailed Safety section and Scoring Criteria Summary in this manual.

Work Force Development

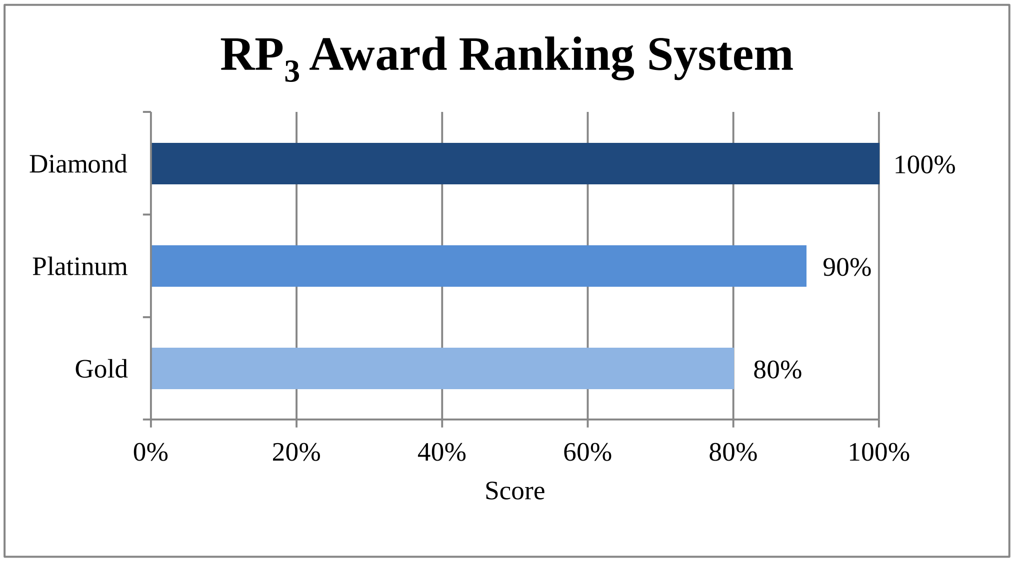
Training employees, whether through traditional avenues such as workshops and college courses or through in-house programs, demonstrates that a utility values its work force. However, education alone is only one of the important considerations a utility should embrace when developing and maintaining a sound work force. This section intends to cover this broader scope of work force development. Utilities benefit from providing opportunities for staff to network with other utility representatives throughout the nation and encourage them to get involved in the national perspective of utility relations. Utility staff knowledge increases through membership in state, regional, and nationally focused committees, as well as attendance in conferences and training. RP_3 applicants must demonstrate that their utility staff attend applicable industry conferences and workshops, are provided educational and career development opportunities, are active either directly or indirectly on industry committees, and that the utility has engaged in work force development and succession planning initiatives. To attain the full 25% rating in this section, please see the detailed Work Force Development section and Scoring Criteria Summary in this manual.

System Improvement

Stewardship of utility assets is essential to ensuring long term system reliability and performance. Keeping an electric utility system well maintained and up-to-date by mandating an improvement program that includes both an eye on the future through research and development (R&D) and a commitment to system betterment programs can help utilities provide reliable services in the future. Important items in this section include demonstrating that your utility participates in a national, regional, or local R&D program, involvement in energy efficiency or conservation programs, descriptions of system planning and betterment projects to maintain your system's integrity and efficiency. To attain the full 25% in this section, please see the detailed System Improvement section and Scoring Criteria Summary in this manual.

Becoming a Reliable Public Power Provider

By completing the application checklists and providing the requested documentation and application fee, participating utilities may be recognized as a Gold, Platinum or Diamond Reliable Public Power Provider. The Diamond designation is awarded to the utility if it successfully meets 100% of the defined criteria. The Platinum designation is awarded if the utility meets 90-99% of the criteria. The Gold designation is awarded if the utility meets 80-89% of the RP_3 Program criteria. An RP_3 designation is valid for a two year period; therefore, utilities that wish to maintain their RP_3 status must re-apply every other year. The intent of the re-application process is to ensure RP_3 utilities are consistently striving to improve the quality of their system based on the four criteria covered in the application.



About the Application and Awards Process

The enrollment period for the program begins in early May every year. At that time, program materials are posted to APPA's website (www.PublicPower.org/RP3); hard copy packets may also be requested.

The applicant shall submit information and data on the application that is representative of the most recent two-year period. For the reliability section, the data must be current, representing the most recent twelve-month period of data collections and calculations for your utility (i.e. rolling, fiscal or calendar). For the safety, work force development, and system improvement sections, the information and data must have occurred over the past two years.

Applications must be submitted by the last day in September every year. Review of all applications received will be conducted by the RP_3 Review Panel and facilitated by APPA Engineering Services staff. All applications will be treated as confidential.

All applicants will receive notification of their application's outcome in January or February of the award year. RP_3 Award winners will be formally announced at the Engineering & Operations Technical Conference during the first general session.

2012-2013 Award Year Schedule	
May 1, 2012	RP_3 Enrollment Period Opens
September 30, 2012	Deadline to submit an RP_3 Application for being designated from May 1, 2013 to April 30, 2015
January - February, 2013	Applicants notified of their status
March 24-27, 2013	RP_3 Award Winners announced at the APPA Engineering & Operations Technical Conference
May 1, 2013 - April 30, 2015	RP_3 Award Designation Period
May 1, 2014 - September 30, 2015	Re-apply for RP_3 designation

About the RP_3 Review Panel

The RP_3 Review Panel has 18 members. There are six panel seats for two representatives each from small, medium and large systems. One seat represents either a joint action agency or a state association. Six of the panel members are the officers (chair and vice chair) of three of APPA's Engineering and Operations Section Committees: Safety, Transmission & Distribution and System Planning. The five remaining seats are held by subject matter experts in the following areas: reliability; safety; system improvement; and human resources (two representatives).

Once elected to the panel, panel members serve two year terms with the option of choosing to serve a second and third term. When a vacancy on the panel occurs, a call for nominees is issued by newsletter, website posting, and e-mail notification.

2012-2103 RP_3 Review Panel

Small Systems – APPA Members with less than 5,000 customers

Jason Bird
City of Princeton, IL

Charles (Mel) Davis
Lawrenceburg Municipal Utilities, IN

Medium Systems – APPA Members with between 5,000 and 30,000 customers

Kenneth Stone*
Braintree Electric Light Department, MA

Tim Reed
Muscatine Power and Water, IA

Large Systems – APPA Members with more than 30,000 customers

Neil James
Santee Cooper, SC

Richard Anderson
Fayetteville Public Works Commission, NC

Joint Action Agency or State Association Representative

Michelle Palmer*
American Municipal Power, OH

APPA Safety Committee

Bob Rumbaugh
American Municipal Power, OH

Marlin Bales, Vice Chair
Colorado Springs Utilities, CO

APPA System Planning Committee

David Lynch
Marquette Board of Light & Power, MI

Committee Vice Chair [TBA]

APPA Transmission & Distribution Committee

Ramon Abueg
Glendale Water & Power, CA

Reggie Bowlin, Vice Chair
Memphis Light, Gas & Water, TN

Reliability Representative

Brent McKinney*
City Utilities of Springfield, MO

Safety Representative

Jon Beasley
Electric Cities of Georgia, GA

System Improvement Representative

Phillip T. Solomon, P.E.
City of St. George, UT

Human Resources Representatives

Janet McTague
Fort Collins Utilities, CO

Danette Scudder
Tennessee Valley Public Power Association, TN

* Denotes RP_3 Executive Committee

RP_3 Application, Payment, and Verification Forms

The **RP_3 application form** serves two purposes. First, the form asks for a primary contact. This individual will be contacted with any questions the RP_3 Review Panel or APPA Engineering Services staff may have concerning the application. All correspondence relating to the application will also be sent to this individual. Second, the form asks for utility demographics and membership status. This information is used during the assessment of your RP_3 application. The number of customers and employees must be filled out to the best of your ability. Utilities that offer more than electric service (e.g. gas, water, and sewer) should account for all electric-side only employees (operations, engineering, etc.). If the electric side of the utility is not distinctly separated from the other services, anybody that supports the electric side of your operations should be included in the final number of utility employees. For example, if your utility offers three services, one third (or the equivalent proportion of employee time devoted to electric services) of the shared support staff (accounting, reception, etc.) should be included in your final number of electric employees. It is helpful for the RP_3 Panel to understand the employee breakdown of your system. Any documents attached should clearly illustrate the number of employees in electric operations side of your utility, including engineering, line work, metering, human resources, accounting, or any other area that contributes to the electric division.

The **RP_3 payment form** is used to complete the application fee to cover costs associated with processing, examining, and scoring all submissions. This fee must be paid each time you apply for RP_3 status. The fee structure is dependent on your utility size based on the number of customers your utility serves. The application fee is not refundable if the RP_3 criteria are not met. However, if you do not receive the RP_3 designation for any reason, you may re-apply the year immediately following your initial application without paying the application fee again. You may pay the fee online, by check, by credit card, or APPA bill your utility directly (APPA members only for this option). Online payments can be made at www.PublicPower.org/RP3 by following the instructions on the "Application" page.

<u>Appendix F-4</u>

The **<u>RP_3 verification form</u>** is intended to demonstrate support of the application by the utility's management. This form does not need to be notarized but it **must** be signed and witnessed. Generally, a utility will choose to have their General Manager, CEO, Electric Superintendent, or equivalent sign the form to ensure that they are aware of their utility's intent to participate in the RP_3 program and the benefits participation may add to their system.

All three forms must be submitted with the application for it to be considered official and complete.

Information For Submitting Your RP_3 Application

A – Application Assembly

You only need to send one copy of your application to APPA by the **September 30, 2012** deadline. We do suggest, however, that you keep a hard copy of your application in case the FedEx, UPS, DHL or postal delivery should go astray. Please be advised APPA will NOT return any portion of copy submitted.

APPA recommends that applications be submitted in the following manner:

- 3-ring binder with tab dividers for each of the RP_3 sections.
- 2-pocket folder to hold the application together.
- Properly identify the location of attachments using the designated area under each question in the RP_3 Checklists.
- If you submit a digital application, it must be on a USB drive with each section and its attachments placed in electronic folders. CD-ROM's will not be accepted.

REMEMBER: If the RP_3 Panel cannot easily find attached or referenced materials, they will be unable to score your utility's application properly.

B – Application Submittal Checklist

- ☐ All five checklists are complete and supplemental documents have been attached.
- ☐ The verification form is complete and signed.
- ☐ The application form is complete with proper documentation for utility demographics.
- ☐ The payment form is complete and your fee method has been checked off with the necessary information corresponding to your payment choice.
- ☐ Your completed package is addressed to:

  Alejandra Franco
  Engineering Services Coordinator
  ATTN: RP_3 PROGRAM
  American Public Power Association
  1875 Connecticut Avenue, NW Suite 1200
  Washington, DC 20009-5715

All applications must be postmarked by September 30, 2012.

If you have questions about the application or submittal process please contact APPA's Engineering Services Department at (202) 467-2900 or via email at RP3@PublicPower.org.

C – After the Application Submittal

Receipt of RP_3 applications will be acknowledged by APPA Engineering Services staff. You may be contacted by APPA Engineering Services staff with questions or requests concerning your application during the review process. You will be notified of your application's outcome in early 2013.

Reliability Section

Reliability is a term that takes on various meanings. For most customers, reliability means dependability; trustworthiness; and "keeping the lights on." Although these are accurate in context, electric system reliability is broader than the results that are evident through reliable day-to-day service. A utility's membership in a mutual aid network to help with the burden of major storms is crucial. In addition, utility preparation for major disasters, NERC compliance and security are important.

A – Reliability Indices Collection (0-9 points)

The term "Service Reliability" may be defined as the degree of performance of the elements of the bulk electric system that results in the delivery of electricity to customers in accordance with accepted industry standards. Reliability can be addressed by considering two basic qualities: availability and resiliency.

> Availability – The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably unscheduled outages of system elements.
>
> Resiliency – The ability of the electric system to withstand sudden disturbances such as short circuits or unanticipated losses of system components.

Tracking Reliability Data

An RP_3 utility should demonstrate awareness of its system performance by using reliability indices. Also, the utility should be using those indices to maintain or improve system reliability. Industry standard indices (IEEE 1366) are the preferred method of tracking performance. In addition, indices should reflect at least one year of data, at least three indices should be tracked, and documentation of the use of indices is required.

Reliability Indices

Reliability indices are the measures used to track and evaluate system performance. The frequency of system failures, number of customers affected and duration of outages are three basic metrics used in measuring reliability.

Reliability indices may further be classified as component reliability indices, load-point reliability indices, and system reliability indices.

- Component reliability indices measure the continuity of service provided by system components.
- Load-point reliability indices measure the continuity of service to individual loads.
- System indices measure the continuity of service to groups of loads.

Factors affecting reliability include feeder length, exposure, sectionalizing, conductor type and number of customers on the feeder. Some utilities exclude major events and storm-related outages from their evaluation of reliability indices as they may give inaccurate predictions for the probabilistic failure rates of the system components.

Types of Faults

Types of faults that can occur on a typical distribution system are:

- Transient (Temporary) Faults: These are the faults that occur on the system and do not require corrective action to remove the fault from the system. The majority of faults on most overhead distribution systems are transient in nature.

- Permanent Faults: These faults generally occur on the system as a result of a permanently damaging event. These faults typically require some form of repair before service can be restored to the customers.

Appendix F-4

Outage Types

IEEE Std. 1366 classifies interruptions on the distribution system into four types:

- Momentary Interruption: These are the outages that occur on the system and last five minutes or less until the fault is cleared and service to all customers is restored. The major causes for this type of outage are trees, animals and lightning.

- Sustained Interruption: These are the outages that occur on the system and last more than five minutes until the fault is cleared and service to customers is restored. Partial service restoration may be performed through technical switching procedures and field ties.

- Major Event (Catastrophe): These are abnormal conditions that the system encounters resulting in service disruption to 10% or more of customers on the electric system for 24 hours or more. Severe weather conditions (e.g. hurricanes, tropical storms, ice storms, etc.) and cascading outages resulting from the loss of one or more major transmission lines are the major cause for these types of outages.

- Planned Interruption: A loss of electric power that results when a component is deliberately taken out of service at a selected time, usually for the purposes of construction, preventive maintenance, or repair.

Typically, utilities exclude scheduled outages, partial power, customer-related problems, and qualifying major events from the reliability indices calculations.

Appendix F-4

The RP_3 program allows utilities to provide any and all acceptable indices such as: SAIDI, CAIDI, ASAI, SAIFI and MAIFI. Whether it's an index that calculates the average yearly length of interruption for a customer, or one that indicates the number of interruptions along a circuit, the intent of these criteria is for utilities to track outages, calculate indices, and better understand electric system reliability. Remember to include the time period for each tracked index as it gives the RP_3 Panel a better understanding of the value. Although your utility goal or target is optional, it provides valuable insight to the Panel and may become a required section in future applications. The intent of this section is not to compare your utility's index values against other utilities, or even against your utility's goal or targets; instead, it is to ensure that your utility is monitoring and tracking this data to maintain or improve its system.

Appendix F-4

Reliability Indices Calculation

System Average Interruption Duration Index (SAIDI):

Measures the total interruption duration for the average customer.

$$\frac{\sum No.of\ Customers\ Interrupted \times Outage\ Duration\ in\ Minutes}{Total\ No.of\ Customers\ Served}$$

$$SAIDI = \frac{\sum Customer\ Interruption\ Duratons}{Total\ No.of\ Customers\ Served}$$

Customer Average Interruption Duration Index (CAIDI):

Measures the average interruption duration for those customers interrupted during the year.

$$\frac{\sum No.of\ Customers\ Interrupted \times Outage\ Duration\ in\ Minutes}{Total\ No.of\ Customers\ Interrupted}$$

$$CAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ No.of\ Customers\ Interrupted}$$

Average Service Availability Index (ASAI):

Represents the fraction of time (often in percentage) that a customer has received power during a predefined period of time (typically a year).

$$ASAI = \frac{Customer\ Hours\ of\ Available\ Service}{Customer\ Service\ Hours\ Demanded}$$

$$= 1 - \frac{Customer\ Hours\ of\ Interruption}{Total\ Hours\ in\ Period \times Total\ No.of\ Customers\ Served}$$

Reliability Indices

Momentary Average Interruption Frequency Index (MAIFI):

Represents the average frequency of momentary customer interruptions (usually less than a 5 minute limit) divided by the total number of customers served.

$$MAIFI = \frac{Total\ No. Customer\ Interruptions\ (Momentary)}{Total\ Number\ of\ Customers\ Served}$$

System Average Interruption Frequency Index (SAIFI):

This index is defined as the average number of times that a typical customer is interrupted during a specific time period. SAIFI is determined by dividing the total number of customers interrupted in a time period by the average number of customers served. The resulting unit is "average number of interruptions per customer."

$$SAIFI = \frac{Total\ Number\ of\ Customers\ Interrupted}{Total\ Number\ of\ Customers\ Served}$$

Reliability Software

Tracking indices provides a utility with valuable information. Many utilities have developed in-house reliability tracking systems, some of which are computer based. For those systems that currently are not tracking outages, APPA's Research & Development Program Demonstration of Energy-Efficient Developments (DEED), offers utilities a software program that enables a utility to develop reliability indices including ASAI, CAIDI, SAIDI and SAIFI reports. This software is one tool available for electric systems to evaluate their operations based on the results of the reports created. APPA's Reliability Software can be purchased through the APPA Product Store, (202) 467-2926, or online at www.PublicPower.org/Store.

B – Reliability Indices Use (0-2 points)

Not only is it important to track reliability indices, it is equally important to use the data collected to maintain and improve your utility's system reliability. Some systems may use the data to decrease the amount of time between tree trimming cycles, as trees could have been linked to higher momentary outages. The checkboxes on the checklist are only a sampling of ways that your utility may have used reliability indices. If applicable, please provide information on other ways your utility may use indices. It is critical to provide supporting documentation for each checked or “other” method to receive full points in this area.

Reliability Survey

Participation in a reliability survey is important to understand where your system stands in terms of benchmarking and improvement. This information can help your utility maintain or improve its system, which is vital to the health of a dependable public power utility.

C – Mutual Aid and NIMS (0-4 points)

Utilities establish mutual aid agreements with neighboring and regional utilities in order to improve service restoration efforts during power outages. Mutual aid agreements are part of a utility’s response plan during power outages that enable them to use the help of other utilities (manpower, tools, spare parts and mobile equipment, etc). Establishing a mutual aid agreement requires advance sharing of information among member utilities. Furthermore, having a national mutual aid agreement is a beneficial precaution, especially if your utility encounters a situation where it requests Federal Emergency Management Agency (FEMA) funding.

Example Information to Have Available for Aid Crews

- Contact information of utility staff and contractors
- One-line diagrams and circuit maps for the distribution system
- Load data and system/equipment capacities
- Inventory quantities for poles, transformers, cross-arms, connectors, fuses, etc.
- Availability of written switching procedures on both the substation and circuit level
- Equipment availability including number of derrick trucks, bucket trucks, and excavators
- Personnel availability including classification
- Compensation and insurance arrangements

Having mutual aid agreements in place has proven beneficial to utilities as they improve their reliability by reducing the ”down time” for power outages, especially during catastrophic events. An example of the nationally accepted APPA/NRECA mutual aid form is included with the forms and applications in this packet and is available on the APPA website. If your utility does not currently have this agreement on file with APPA, submitting it with your completed application will satisfy the mutual aid section.

Appendix F-4

National Incident Management System (NIMS)

The National Incident Management System (NIMS) provides a systematic, proactive approach to guide departments and agencies at all levels of government, nongovernmental organizations, and the private sector to work seamlessly to prevent, protect against, respond to, recover from, and mitigate the effects of incidents, regardless of cause, size, location, or complexity, in order to reduce the loss of life and property and harm to the environment.

Learn more about NIMS

NIMS works hand in hand with the National Response Framework (NRF). NIMS provides the template for the management of incidents, while the NRF provides the structure and mechanisms for national-level policy for incident management.

The Secretary of Homeland Security, through the National Integration Center (NIC), Incident Management Systems Integration (IMSI) Division (formerly known as the NIMS Integration Center), publishes the standards, guidelines, and compliance protocols for determining whether a Federal, State, tribal, or local government has implemented NIMS.

The NIMS implementation and compliance guide by fiscal year is located at the following website:
http://www.fema.gov/emergency/nims/CurrentYearGuidance.shtm

The intent of the NIMS section is to verify that your system has addressed NIMS and, if needed, has acted appropriately. The RP_3 Panel understands that some systems may not participate in the NIMS process.

D – Disaster Plan (0-5 points)

Disaster plans are used by utilities to help coordinate their response to emergency situations of various kinds that include large outages of customers. These plans include information on the roles that the utility's employees will assume during a disaster.

Example Information and Procedures to be Included in a Disaster Plan

- Outlining outside resources that are available to the utility to rebuild the system
- Plans to provide food and lodging for crews
- Listing electric supply companies that can be called on to provide materials
- Outlining the communication responsibilities to inform the public, government agencies, and the media on restoration efforts
- Providing a priority list of restoration efforts (hospital, police, water/sewer plants, etc.)

For some utilities, one city-wide comprehensive plan may suffice. Other utilities may have individual plans for each type of disaster that address information technology, weather, terrorism, transmission, generation, etc.

Disaster plans should be revised and/or reviewed on a regular basis. An outdated plan will become stale and unusable should a disaster occur after conditions have changed. It is also important to perform periodic disaster drills to ensure the effectiveness of the plan. Although it is recommended that the plan be available to the public, employees, government officials and the media, it is understood that confidentiality may apply to certain security sensitive sections of a well-developed plan.

To meet the requirements of this portion of the RP_3 criteria, the RP_3 Panel recommends that the utility provide the index or table of contents of the plan(s), as they should provide an accurate sampling of your utility's plan coverage. Plans should include but are by no means limited to:

- Damage assessment procedures
- List/contact information of all employees
- List/contact information of critical customers
- List/contact information of suppliers – including food, fuel, housing of mutual aid lineworkers, etc.
- Location of Emergency Operations Center (EOC) and possible back up locations
- Priority of Restoration
- Radios/communication plans and policies
- Your system's coordination with and role in a city-wide emergency plan

If the index or table of contents does not demonstrate a strong disaster plan you may be asked to provide written portions of your plan.

E – Standards, Security, and Compliance (0-5 Points)

North American Electric Reliability Corporation (NERC) Registration

Close to 300 municipally owned electric utilities across the nation are required to comply with the NERC standards. Most of these utilities have been notified of their requirements and are in the process of implementing a compliance plan. If your utility is designated as an entity that affects the Bulk Electric System you will need to submit an outline of your compliance plan. If your utility currently does not need to comply you must contact your region to verify your status and provide supporting documentation to that effect.

Is your utility required to be NERC Compliant?

NERC developed a Statement of Compliance Registry Criteria (click here or go to http://www.nerc.com/page.php?cid=3|25 for more information and a copy of the criteria) that delineates the selection criteria employed by NERC and the regional entities to determine which organizations should be registered as owners, operators, or users of the bulk power system. In particular, the statement proposes criteria for smaller or relatively (electrically) isolated organizations as load-serving entities, distribution providers, generation owners, generation operators, or transmission owners and transmission operators.

Appendix F-4

Physical Infrastructure Security

Utilities should be constantly mindful of threats due to security breaches such as vandalism and terrorist attacks. A utility's critical infrastructure such as substations, control centers, personnel, and other facilities should be included in a plan to prevent such outages. Utilities must develop the best available mitigation practices to address such attacks. Physical infrastructure security can range from a substation with camera, locks, and fences to equipment tracking systems, such as Radio Frequency Identification (RFID) tags on all of your equipment or bar code scanning systems.

Cyber Security

In the past few years, cyber threats have surfaced as a significant and diverse set of concerns within public power communities. It is imperative for utilities to know what type of cyber security they require to help avoid unauthorized access and cyber attacks. NERC Critical Infrastructure Protection (CIP) standards do not apply to all utilities, but even exempt utilities should address cyber security issues by employing mechanisms such as passwords, firewalls, protocols against using non-company issued USB drives (foreign device protocols), etc. In this question, supporting documentation for each checked item is required.

Safety Section

Worker safety is at the core of a utility's commitment to service. This dedication to safety must be utility-wide and be evident in all aspects of utility operations. The use of a designated safety manual, regular safety meetings, and management involvement in the establishment of a culture of safety are all critical elements in ensuring the delivery of safe and reliable electricity.

In the RP_3 program, each utility must prove that it has implemented a nationally accepted safety program (by adherence to a safety manual or other innovative approach), calculates and tracks benchmarking information as it relates to safety, and utilizes safe work practices in order to attain the full 25% rating.

A – Safety Manual (0-5 points)

The ultimate source for safety compliance information lies within a good safety manual. Using a safety manual, whether APPA's, your utility's, or an outside source's, is not only a recognized best practice, but in fact can provide the foundation of a utility-wide safety program. A safety manual that addresses safe practices for every utility employee (lineworker, office worker, meter reader, etc.) is essential.

The quality of the safety manual that is used is equally important; keeping your safety manual up-to-date with appropriate revisions is critical to maintaining a safe work environment.

Adoption

Adopting your safety manual, whether APPA's or one developed by another source, and formally acknowledging required adherence to its guidelines is a method of documenting that your utility has formally designated that manual to be followed for all employee safety-related work practices.

Please show that your utility has formally adopted your safety manual by providing documentation such as a city council resolution, utility board approval, or equivalent that acknowledges that your utility uses your current safety manual.

NOTE: Adoption forms from earlier RP_3 applications will not be accepted.

Directive

It is also just as important that the utility management communicate to utility employees the accepted safety-related work practices, which are expected to be adhered to when working for the utility. A directive can take the form of a letter or other formal communication from the general manager/city council member/highest ranking member of your utility addressed to all utility employees. Ideally, this directive will be issued on regular basis (for example, every year) and/or when a new safety manual or approach is updated and/or adopted.

It is important to have a safety culture that starts from the top of the utility and goes all the way down the ladder to reach all employees.

B – Safe Work Practices (0-17 points)

Safety and reliability are at the core of a well-functioning utility. Providing a safe environment for both employees and the public contributes to the overall reliable service of an RP_3 designated public power utility.

Accordingly, the RP_3 safe work practices category is intended to provide a method to document some of the more important aspects of the training efforts at each participating system. The initial requirements checklist summary that follows is intended to describe those efforts that contribute to a safe work environment. In certain cases, an electric utility may use other creative, non-standard methods that work well. The RP_3 program is intended to include these methods, as explained in the following nine category descriptions.

Regular Safety Meetings

Regularly scheduled safety meetings are a key to establishing and maintaining an effective safety program. Well-planned and executed safety meetings provide a forum for management and employees to have a dialogue related to pertinent issues affecting the company's operations. If your utility hosts safety meetings of different frequencies and lengths for different employees (e.g. lineworkers may have three 30 minutes safety meetings per week or a 15 minute "kick off the day" meeting every morning, whereas office engineers may meet for one hour per month), supporting documentation for each type of group should be supplied to ensure proper scoring.

Accident Investigations/Near-miss Reports

Performing accident investigations and filing near-miss reports are critical towards preventing repeat accidents. A well-documented accident or near-miss report could provide invaluable information to other employees who may not have been at the scene of the accident. Sample near-miss reports may be found at http://www.PublicPower.org/Safety.

Safety Training Provider

In addition to conducting regular safety meetings, it is also important that a skilled and competent individual is overseeing the safety training and that this person has the support of the management function of the utility. This individual should have significant experience in the safety field, as well as up-to-date training certifications and credentials.

Management Participation

Safety training is often carried out by staff employees, but safety programs are most effective when utility management is involved in the planning and/or execution of the safety training function. Management participation is one of the major components of an effective program.

Safety Recognition

Employees have long demonstrated positive response to the recognition of safe practices in the workplace. Recognition coupled with excellent content and well-executed training sessions adds value to safety training programs. Because good safety programs can help lower contact-injury related claims, many workers compensation insurance providers willingly participate in electric system safety incentive programs. These programs may include safety recognition breakfasts or luncheons, financial and in-kind contributions, “attaboy” boards, “shout-outs” in meetings, or other forms of recognition. Safety recognition programs must exclude any incentive or response that retaliates against any worker for reporting dangerous conditions, injury or illness.

Annual Refresher Training for OSHA-type Issues

An electric safety program includes but is not limited to well planned and delivered safety meetings. The RP_3 Panel understands that many utilities will not fall under Occupational Safety and Health Administration (OSHA) jurisdiction. However, electric utilities should be informed and up to date on OSHA-type issues. The core intent of this question is to encourage electric utilities to conduct annual refresher training in certain areas including CPR/AEDs, pole-top rescue, bucket-truck rescue, etc. Many of these issues are significant and important enough to focus additional resources that are above and beyond monthly safety meetings.

Automated External Defibrillators (AEDs)

Ensuring that employees are CPR certified may help save a life. An additional life-saving tool is the Automated External Defibrillator (AED), also referred to as a Portable Defibrillator (PD). Defibrillators are available from numerous medical equipment providers. When maintained and used properly, AEDs can mean the difference between life and death. A utility that provides defibrillators gives a clear indication of management's commitment to a safe work environment. The RP_3 Panel has determined that AEDs should be available at all times at every work location to ensure employee safety. Work locations include office locations, operations/field work-site locations, and power plant locations. Depending on how a utility configures its work force, AEDs may be needed on every truck in the field to meet these criteria.

Arc Hazard Assessments

According to the 2012 National Electrical Safety Code (IEEE C2), employers are required to ensure that an assessment has been performed to determine potential exposure to an electric arc for employees who work on or near energized lines, parts, or equipment. It is important to indicate how you chose the proper level of FR clothing for your employees.

Disaster Drills

Disaster preparation is a clear indication that the utility will be reliable because the more prepared employees are when an unexpected disaster strikes, the less time the customers will be without critical services. Preparation for a disaster may also uncover weaknesses in the system or process that may be corrected before an actual incident occurs.

Categorizing your drills as table top or field (including emergency drills in administrative buildings) is important to understand the variety of your drills. Keeping track of when your last drill was performed is important. In addition, a well prepared utility will identify when and in what areas future drills need to be conducted to be sure its staff is ready in the event of an emergency.

C – Benchmarking (0-3 points)

Safety index benchmarking allows individual utilities to analyze their safety performance, to define and track long-term trends, and to review the effectiveness of their safety program. Benchmarking provides an opportunity for utilities to compare and contrast their programs with those of their peers.

Appendix F-4

APPA's annual Safety Awards of Excellence showcases APPA member utilities that have the lowest incident rate within a group of their peers categorized by the number of worker-hours of exposure. Awards winners enjoy valuable public relations benefits. Data submitted for the Awards is used to compile the annual statistical publication, *An Evaluation of Data Submitted to APPA's Safety Awards of Excellence*. This publication is available on APPA's website under the member-protected Engineering & Operations section and is distributed to all Awards participants. For more information on participating in APPA's Safety Awards, or to verify your utility's past participation, please contact the Engineering Services department at (202) 467-2900.

The data used to determine APPA's Safety Awards recipients is similar to that reported on the OSHA 300 form. If you do not participate in APPA's Safety Awards, submitting your OSHA 300 log will satisfy the requirement of this section.

Whether you complete APPA's Safety Awards or the OSHA 300 log, please indicate your incidence rate based on the formula used on both forms (see below). The RP_3 Panel has determined that tracking incidents at your utility contributes to a better understanding of your utility's commitment to safety.

$$Incidence\ Rate = \frac{Total\ number\ of\ cases\ x\ 200{,}000}{Total\ worker\ hours\ of\ exposure}$$

Work Force Development Section

Employees are a utility's finest asset. Training employees —whether through APPA utility education courses, local college instructions, or through in-house programs such as vendor-specific training— demonstrates that a utility values its work force. In the world of public power, traditional education should also be accompanied by opportunities for utility staff to network with other industry representatives throughout the nation. Utility staff knowledge increases through membership in state, regional, and nationally focused committees. This knowledge allows employees to get involved in national utility issues and participate in industry dialogue.

To attain the full 25% available in this section of the RP_3 program, each applicant must demonstrate that utility staff attends applicable industry conferences and workshops, are provided with opportunities for education, have addressed work force and succession planning and are active directly or indirectly on industry committees. Utilities must complete the Work Force Development Checklist and provide detailed attendance logs or equivalent. **Electronic versions of the logs are accessible from APPA's RP_3 website.**[1] The RP_3 Panel recommends that you use the logs; however if you choose not to please ensure that all items on the log are incorporated in your alternative submission.

A – Networking (0-5 points)

The U.S. electric system is an intricate connection of generating plants, transmission lines, distribution circuits and metered customers. In order to operate effectively, utility personnel must understand the system, build relationships with those who own and operate the transmission grid, and get to know representatives from other public power utilities facing similar concerns. Combine these concerns with the increased complexity of the electric system, and it is clear that to maintain a reliable, safe and efficient system, utility personnel must network with other professionals to share, debate, and create new ideas and work processes.

Attendance at conferences and workshops fosters interaction, networking capabilities, and idea-sharing. The networks formed during conferences and workshops become the glue that holds utility systems together when faced with disasters such as storms, or discovering common problems in equipment used throughout the industry. Whether national, regional, or local in scope, networking efforts of individual staff—based on the support of utility management—can

[1] http://www.PublicPower.org/RP3

bolster the strength of the utility's entire work force. Furthermore, it is important to ensure that a diverse representation of employees attend these types of events; not always the same person or small group of people.

For the RP_3 application, your utility must provide the number of the different conferences/workshops (events) that your utility personnel and, where applicable, governing body representatives attended between October 1, 2010 to September 30, 2012. Also note the total number of utility personnel and, where applicable, governing representatives (individuals) that attended the above conferences/workshops during the same period. For verification purposes, the Conference & Workshop Attendance Log[2] or equivalent document must be submitted.

[2] Available as a Microsoft Excel spreadsheet in the RP_3 application packet zip file at PublicPower.org/RP3

Appendix F-4

Work Force Networking Examples

- *APPA Conferences & Workshops*

  The APPA hosts a variety of conferences for every member of your utility staff – including legal, engineering, operations, or safety personnel. For more information or to register for any conferences or workshops listed below, visit the APPA website: http://www.PublicPower.org.

  - Engineering & Operations Technical Conference
  - Public Power Lineworkers Rodeo
  - National Conference
  - Business & Financial Conference
  - Customer Connections Conference
  - Legal Seminar
  - Joint Action Agency Workshop
  - Legislative Rally
- *EPRI Conferences*

  An EPRI conference may provide utility staff with research and development updates, especially considering the constant developments and new technology emerging in the industry.
- *IEEE Conference*

  IEEE conferences may help your utility conform to new NESC standards, which are vital to maintain the most updated safety standards and practices for your employees and customers.
- *State association conference or workshop*

  As a member of a state association, it is always beneficial to take advantage of any development opportunities they may offer.
- *Regional association conference or workshop*

  As a member of a regional association, it is always beneficial to take advantage of any development opportunities they may offer.
- *Joint Action Agency meetings*

  Joint action agency meetings are an excellent place to discuss issues such as power supply and system planning in general. Developing a network to discuss these issues is vital to maintaining a reliable system.
- *Other conferences or workshops*

B – Education (0-10 points)

Successful utilities seeking to provide reliable and customer-focused service recognize that their employees are the key to their success. Employees—crews in the field, call center staff, billing clerks, back-office accountants, IT professionals, customer service and key account representatives, and others—are the face of the utility in the eyes of the customers and the community they serve.

Investment in employee training and professional development is vital for public power utilities to attract and retain the employees needed to serve utility customers and maintain the utility's reputation for reliable and customer-focused service. Many utilities at the forefront of our industry have recognized the benefits of ensuring that their employees are properly trained in both the technical aspects of their jobs and in providing consistent and high-quality customer service.

Utilities can demonstrate their commitment to work force development and training through a program offering a variety of opportunities best suited to their organizations.

For the RP_3 application, you must provide a numerical value of the different continuing education courses that your utility personnel and, where applicable, governing body representatives attended between October 1, 2010 to September 30, 2012. Also, provide the total number of utility personnel and, where applicable, governing representatives (individuals) that attended the above education courses during the same period. For verification purposes, the Continuing Education Log[3] or equivalent document must be submitted.

[3] Available as a Microsoft Excel spreadsheet in the RP_3 application packet zip file at PublicPower.org/RP3

Appendix F-4

Work Force Education Examples

- *In-house Training*
  Using in-house personnel and resources to provide staff training programs.
- *Outside Training*
  Training presented by vendors, non-utility trainers, or other professionals with a knowledge of the utility industry to train on specific needs (i.e., safety practices, customer service), on the utility's premises.
- *Webinars*
  Webinars are hosted regularly by a variety of organizations (including APPA) on many different subjects. This mode of learning is an excellent way to educate a large group of employees, without costs associated with travel and lodging.
- *College, University or Online studies*
  Reimbursing staff for utility-approved courses taken locally or online.
- *Certificate or other Professional Development Programs*
  Examples include apprentice programs and professional development programs.
- *Local, regional, or national education programs*
  Includes state, regional and other courses and seminars that apply to utility organization topics.
- *User Groups*
  Includes groups that meet on a specific topic that will improve work skills or the utility's performance.
- *Other*
  Includes developing a library of printed, video, audio or computer based training, establishing mentoring programs, etc.

Employee development programs must identify gaps in performance or desired performance that can be addressed by training to achieve desired performance and service. Understanding the value of all employees and encouraging their input on programs or topics contributes to the performance, service and pride that define public power.

Written Education Policies/Procedures/Programs

Written education policies, procedures, and/or programs help highlight the importance of and place emphasis on career growth within the utility. Your utility will be required to provide a copy of its policy, procedure, or program so that the RP_3 Panel can review the quality and provide feedback. Also, it is equally important to *regularly* communicate this policy to your employees so that they are reminded to take advantage of this benefit. This will help both the employee and the knowledge base of your entire utility grow, which can lead to higher productivity and innovative approaches within your utility. When describing how you communicate your policy/procedure/program to your employees, include the frequency of these communications along with any supporting documentation such as a memo to all employees, a note in a weekly newsletter, etc.

C – Succession Planning and Recruitment (0-5 points)

The electric utility industry is facing increased competition in recruiting and hiring management, back-office support, skilled technical and craft labor personnel. In addition, these utilities are having difficulty finding entry-level personnel to replace those retiring. Lack of skilled workers will threaten a utility's ability to meet its customers' future needs.

Succession Plan

Succession planning is an important element of work force planning because the integrity of your utility operations depends on your employees. A formal succession plan is a tool that your utility should use to ensure continuity of operations when unexpected vacancies occur. Along with having a plan, it is also important to regularly review and/or revise your plan, in order to prepare in the event that key personnel suddenly retire or leave your utility.

Demographics

By keeping track of employee demographics, your utility can be prepared to identify when a large group of employees may retire and in which departments you are most likely to lose key personnel. This analysis allows the utility to focus training and hiring in areas where you will have gaps in the future. Being proactive in this area could pay back dividends in terms of having employees ready to swiftly take over new responsibilities. At a minimum, your utility should track the number of employees that are eligible to retire.

Appendix F-4

Recruitment Procedure or Practice

Having a written recruitment procedure allows your utility to focus its recruitment efforts on those positions in need of covering future staffing shortfalls. Formally developing a procedure or practice ensures that everyone in your utility, or at least key personnel in your human resources department, have a plan of action to quickly act on vacancies.

Development Plans

Employee development plans provide tailored training program to meet the career development paths of your utility's employees you currently have and tailor their. Implementation of a written plan shows current employees how their career track is tied to their training. There are a variety of ways to tackle development plans, some utilities review the career development path with their employees during an annual review while others have a more formal procedure that involves sitting down with the employee on a quarterly basis. The composition of these plans will depend on a variety of factors, including the size of your utility, how progression works within your utility, utility/council rules, etc. Regardless of these policies, giving employees this opportunity at least once a year will encourage them to grow with your utility.

Importance of Performance Recognition

While establishing goals within an employee development plan is critical to objectively benchmarking and tracking individual progress, the process is not complete unless achievement of those goals is acknowledged. Performance recognition can take many forms. Program elements can include written acknowledgement, presentation of certificates or awards, monetary incentives, or appreciation luncheons. Employee commitment, loyalty and support of the utility's mission are typically strengthened if they feel their accomplishments and contributions to the utility are recognized. Such programs serve to create an environment that facilitates motivation for continued growth.

D – Committee Participation (0-5 Points)

As discussed earlier, the utility industry is a vast network of individual systems operating in unison to provide electric power. In many ways this has advantages, one major disadvantage is the fact that public power entities are at times overlooked, or underrepresented in the areas of policy, engineering, certification, standardization, transmission rights, etc. Nevertheless, many of the decisions made through professional organizations such as the North American Electric Reliability Corporation (NERC), the Institute of Electrical and Electronics Engineers (IEEE), and federal agencies such the Department of Labor and the Occupational, Safety & Health Administration (DOL/OSHA), the Department of Homeland Security (DHS), the Department of Energy (DOE) and others actually impact the operation of every public power utility in the United States. To ensure that the voices of public power utilities are heard, and that pertinent concerns are raised during the rulemaking and standards-setting processes, public power employees should participate on committees, working groups, task forces, boards, and other state, regional, and national bodies. The ability of knowledgeable utility staff to provide input on issues that impact public power is crucial.

Furthermore, public power thrives on being a community-owned entity, so it’s equally important to participate in local boards and committees; this participation enhances and exemplifies the mission of public power being a member of the community.

For verification purposes, the Committee Membership Log[4] or equivalent document must be submitted.

[4] Available as a Microsoft Excel spreadsheet in the RP_3 application packet zip file at PublicPower.org/RP3

System Improvement Section

System improvement is essential for long-term electric system reliability and performance. Ensuring that your utility's electric system is well-maintained by implementing a comprehensive improvement program shows both employees and the public that your utility is committed to self-preservation and efficient operation. Funding for system improvements, whether for basic maintenance, or for research and development, is money well invested.

To attain the final 25% rating of the RP_3 program, a utility must demonstrate that it participates in a national, regional or local R&D program, regularly addresses power supply, system planning and energy efficiency issues. In addition, a top utility will perform improvement projects to maintain the system's integrity and efficiency.

A – Research & Development (0-3 points)

Research and development at public power utilities is an essential investment, and utilities can take a leadership role by pursuing cutting-edge technology and innovation as an integral part of energy delivery. This principle is embodied in public power's commitment to invest in innovative solutions and technologies to enhance energy delivery and develop their communities. Through research, development, and demonstration of new ideas, utilities can increase efficiency, reduce costs, investigate new and better technologies and services, and improve processes and practices to better serve customers.

Public power has been a leader in supporting technology breakthroughs and providing innovative services by reinvesting a portion of resources every year into research and development. The RP_3 Review Panel recognizes the value of this commitment and encourages participation in a national program. This participation gives public power access to a pool of funding opportunities, and, more importantly, access to information on a variety of projects that they can review before implementing a new technology.

APPA's Demonstration of Energy-Efficient Developments (DEED) program is public power's own research program. In 1980, APPA initiated DEED to pool members' resources to invest in the future technologies and best practices of the electric industry. DEED funds projects that provide direct, tangible and transferable benefits to members. This program enables utilities, from the smallest to the largest, with limited resources to engage in research and development activities. For more information about DEED visit APPA's website at www.PublicPower.org/DEED.

EPRI is the only science and technology consortium serving the entire energy industry—from energy conservation to end use—in every region of the world. Founded in 1973 as a private, public-interest, not-for-profit organization, EPRI provides a clear, credible voice through the development of independently verifiable scientific and technical research. For more information, visit the EPRI website at www.epri.com.

While it is important to be a member of a national R&D program, it is perhaps even more important to take advantage of the resources that the program offers to educate your employees and make informed system improvement decisions for your utility and community. Participation can range from applying for grants and conducting research projects, to reviewing the results of completed projects and considering the findings as they apply to your utility's operation.

State and regional programs are unique to your utility's location. Check with your state association or joint action agency within your region to discover what R&D opportunities there may be for your utility.

B – Energy Conservation and DSM (0-4 points)

Energy conservation and/or energy efficiency has always been a key element to reducing your system's peak load. When it comes to system improvement, having any type of energy management program can help your utility manage its public image and overall system performance.

Programs for Energy Conservation and Efficient Processes

Energy programs of all types are an important connection point that a utility can have with its customers. Having programs that are designed to help customers achieve conservation or efficiency goals can help create a personal connection between the utility and its community.

Appendix F-4

High performing utilities will have some type of program to address energy conservation and efficient processes in their communities. There are many online resources available to help a utility choose or develop a program that makes the most sense for their circumstances. In this section, utilities can submit descriptions of their particular program(s).

Example Energy Program Areas

- Demand side management
  - Residential
  - Industrial
  - Commercial
- Appliance energy efficiency incentives or rebates
- Energy audits
  - Residential
  - Industrial
  - Commercial
- Design assistance
- Light bulb exchanges
- Conservation behavior

Measurement or Verification of the Efficacy of Energy Conservation/Efficiency Programs/Plans

Measurement and verification is the best way for a utility to make sure their program is producing its intended result. This practice also helps utilities to phase out programs that are having little impact in order to concentrate their limited resources in areas that are the most meaningful. There are many good APPA and online resources available to help utilities measure or verify their programs' performance. In this section, utilities should submit descriptions of their particular methodologies for verifying the performance of their energy program(s). For more information on APPA's energy efficiency resources, visit the Energy Efficiency Resource Central at www.PublicPower.org/EERC.

Education and Outreach for Energy Conservation or Energy Efficiency Programs

In certain instances, a utility may have a good energy program that may be under-utilized because of lack of community knowledge of the program. Utilities that provide outreach for their programs are taking a good step to interact with the community and improve the performance of their program. In this question, utilities should submit descriptions of the outreach they conduct for their particular program(s).

In addition, utilities that engage in discussions with key policy/decision makers to inform them about the energy issues facing the utility are acting in the best interest of the community. The more informed decision makers are about the critical energy supply, efficiency and conservation issues the better decisions they will be able to make. In this section, utilities should also submit descriptions of their efforts to inform key policy or decision makers in their communities.

C – System Maintenance and Betterment (0-12 points)

Utilities that monitor the condition and functionality of their system are in the best position to know when and where investment is needed. Key components of this section involve: system maintenance, such as keeping records and developing inspection schedules for various equipment; system losses, including both what your losses are (numerical value) and how you calculate the value; and system betterment projects, especially for near-term projects that may just have been completed or will be completed in a span of 2-3 years, which represent the bulk of the points in the section.

System Maintenance

Efforts to track age, condition and performance of system components enable the establishment of short- and long-term planning goals. Such goals may be based on load growth, expected service life of units of property, depreciation schedules, etc. Written goals then provide support for adequate budgeting and achievement of system improvements, with the ultimate benefit of top-notch reliability and customer service.

Preventative maintenance has to begin with keeping records and setting inspection schedules. In this section, you should check each item your utility tests or has a maintenance schedule, and provide sample reports or other information to verify each checked item. Larger utilities will be expected to track more items than smaller utilities.

System Losses

Another element of system planning is to monitor system losses; it is important to have a plan or procedure to address losses right away. To receive credit for this section, your system losses must be reported along with *how* your utility calculates the losses; many utilities use the EIA 861 report, while others have in-house software that monitors systems losses on a regular basis. Once you have the information about losses, it’s important to dig deeper and find out how you can improve the reliability of your system through a variety of programs. As a reminder, specific utility information will be kept confidential with the RP_3 Review Panel and APPA staff.

Near-Term Capital and O&M Projects

Public power utilities are continually engaging in projects to maintain the integrity of their systems – their main focus is high reliability, while maintaining low electricity costs for their consumers. Therefore, each year the utility makes hard decisions on which projects to complete and which project can be put off for another year. The RP_3 Review Panel evaluates this section to ensure that your utility is being proactive in making proper near-term decisions for your system; they are evaluating projects you've recently completed and projects that are scheduled to complete in a matter of years.

The write-up in the section should include your capital improvement plan, detailed descriptions of projects with a funding breakdown, and/or a capital operations and maintenance budget. Generally, this is all information you should be presenting to your city or utility board to get approval of funds for your electric infrastructure.

The list below includes example projects to include in this area, only if they are in your near-term goals; for some systems, a project like upgrading a SCADA system may still be five years out, so that would not be included in this section. On the other hand, other utilities may be "knee-deep" in their project and would want to include a description of such a project in their write-up.

Near-Term Capital and O&M projects can be demonstrated by documentation of amounts, types and costs of equipment upgrades.

Examples include:

- Replacement of aging transformers and poles
- Installation of additional capacitor banks
- Upgrading of conductors on various circuits
- Enhancing appropriate levels of on-hand inventory
- Upgrading computer or SCADA equipment
- Funding of an adequate tree clearance program
- Conversion of overhead to underground circuits
- Use of life-cycle costing for transformer purchases
- Upgrade of substation design and/or capacity
- Purchase of a new bucket truck for better line maintenance and outage response
- Investment in environmental enhancement through use of renewable energy resources or programs, spill containment improvements, or other methods
- Loss management system reduction program
- Enhancement of system mapping with GIS
- Utilization of alternative fuel or hybrid vehicles
- Upgrades of facility security measures

The Near-Term Capital and O&M projects portion of this application should include:

- Your capital improvement plan.
  - Describing the projects in your utility's capital improvement plans is critical to the RP_3 Review Panel's review of your application.
- A list of future plans or evidence of a longer range planning activity.
- Provide a detailed description of your projects similar to what you would present to your council or board to secure funding for the project.
  - This includes a brief description of your project with budgeted amounts.
- Provide your capital and/or operating and maintenance budget.

D – Future Planning (0-6 points)

Long-term Planning for T&D

While it's important to work diligently on near-term projects, you should always have an eye on the future transmission and distribution (T&D) projects. Developing a system planning study, whether conducted by in-house staff or an outside consultant, is vital to determining the types of projects your system needs to be prepared to address. This study should have information such descriptions of the projects, why they are necessary, timelines, and the amount of funding required. These projects could include building a new substation, installing additional transmission lines, upgrading substation transformers, or upgrading distribution lines from a 4 kV to 12 kV system. For RP_3 purposes, an executive summary of the study will suffice. (Three year and five year plans should have specific dates and budgetary information, whereas a ten year—or beyond—plan may have rough dates and estimates.)

Long-term Planning for non-T&D

The goal of this section is to capture any projects that your utility is currently involved in that may not necessarily be classified as "transmission and distribution." Such projects could include installing a GIS system, upgrading a customer information system, deploying a data management system, or expanding your utility's fiber communications network. The projects listed in this section should be planned for the future (e.g., 5 to 10 years out); if your utility is currently involved in the project or if it's slated to begin within a year or two, it should be included in the *System Maintenance and Betterment* section.

Long-term T&D and Non-T&D projects could include:

- Upgrading computer or SCADA equipment
- Planning for data management
- New communications equipment
- Investment in environmental enhancement through use of renewable energy resources or programs, or spill containment improvements
- Long range system improvement and/or maintenance plan
- Loss management system reduction program
- Initiating an Automated Meter Reading program
- Enhancement of system mapping with GIS
- Utilization of alternative fuel or hybrid vehicles
- Upgrades of facility security measures

Emerging Issues Section

The electricity industry is rapidly changing due to government mandates, new technology, work force dynamics, and a variety of other reasons. Therefore, the RP_3 Panel included the Emerging Issues section for two purposes: to pave the path for the evolution of the RP_3 program as it follows with these changes; and to learn about the public power industry as it stands to provide better legislative and technical support to our members in the future. This section will not be scored.

The questions/checklists in these categories will change every year to concentrate on key issues affecting our industry or critical items that will become important within the near future. Your responses in this section will not be considered for scoring, but we encourage all applicants to complete because depending on the answers, some of the questions might be included in the scored section of future RP_3 applications.

A – Reliability

Tracking Indices

Along with tracking reliability indices, it's important to set goals/targets for your utility. These goals could be developed through benchmarking surveys or by evaluating the needs of your community. The RP_3 Review Panel would like to gain insight on how your utility sets its goals/targets.

B – Safety

Incidence Rates

Although tracking safety indices is an important component of a culture of safety, it's equally important to make regular changes to your safety programs/practices based on these indices. In this question, please describe if you've made any such changes based on your incidence rates.

Safety Meetings

Administrative and other office employees should also participate in regular safety meetings. The RP_3 Review Panel would like information on the frequency and duration of these meetings.

FR Clothing

Please describe how your utility has addressed the issue of flame resistant (FR) clothing for employees working under 1000 volts.

D – System Improvement

Distributed Generation

With the emergence of electric vehicles, solar panels, etc., please describe how your utility is preparing for this added and distributed load. Some utilities may be conducting elaborate studies, while others may be reading reports from the DEED database. Since DG is such an important issue, your answers could help shape a new question potentially scored in future cycles.

Appendix F-4

RP_3 Scoring Criteria Summary		
Criteria Area	**Scoring Area**	**Maximum Point Value**
Reliability 25%	Reliability Indices Collection	9 points
	Reliability Indices Use	2 points
	Mutual Aid	4 points
	Disaster Plan	5 points
	Standards, Security and Compliance	5 points
Safety 25%	Safety Manual	5 points
	Safe Work Practices	17 points
	Benchmarking	3 points
Work Force Development 25%	Networking	5 points
	Education	10 points
	Succession Planning and Recruitment	5 points
	Committee Participation	5 points
System Improvement 25%	Research & Development	3 points
	Energy Conservation and DSM	4 points
	System Maintenance and Betterment	12 points
	Future Planning	6 points

2012 RP_3 Industry Support Council

APPA encourages working with allied industry to achieve and maintain RP_3 status. APPA Associate Members are invited to participate on the RP_3 Industry Support Council.

For more information on the Industry Support Council and how to join please contact Pamela Cowen, APPA's Manager of Membership and Marketing at (202) 467-2903.

Industry Support Council Member

Smart solutions.
Strong relationships.

APPA Resources

APPA has several publications and products that could contribute to achieving and maintaining RP_3 status. For a detailed description of these items please visit the Product Store on the APPA's website (www.PublicPower.org/store) or by calling (202) 467-2926.

A sampling of RP_3 helpful products:

- Arc Flash Hazard Assessment Webinar
- Business Planning and Performance Measurement: A Guide for Small Public Power Systems
- Distribution System Performance Improvement Guide
- Emergency Management Checklist
- Energy Efficiency Pays: A Guide for the Small Business Owner
- Getting Customers to Pay for Efficiency: A Guide for Designing and Implementing Residential Energy Efficiency Information and Financial Programs
- How to Design and Implement a Distribution Circuit Inspection Program for Your Public Power Utility
- Performance Management for Public Power Systems: An Implementation Guide
- Primary Distribution System Optimization Guide: A Practical Guide to Maximize Efficiency and Resource Optimization
- Reliability Guidebook
- Reliability Tracker 6.2 Software
- SafetySmart Software Version 2.0
- SafetySmart DVD Video Series and Instructor's Manual
- Security Checklist and Guidance Manual
- FEMA Guidebook for Public Power Managers
- RP_3 Best Practices Guidebook
- APPA Safety Manual 14th Edition *[15th Edition to be released mid-2012]*
- Easy Steps to Energy Efficiency
- Emergency Planning Toolkit for Public Power Utilities
- Energy Services That Work
- NERC ERO Compliance Plan Guideline and Template
- Smart Grid Essentials: A Public Power Primer
- Cyber Security Essentials: A Public Power Primer *[coming Summer 2012]*

New publications and products are featured on APPA's website on a regular basis.

APPA Selected Financial and Operating Ratios of Public Power Systems, 2011 Data

Published November 2012

American Public Power Association

1875 Connecticut Ave, N.W.
Washington, D.C. 20009-5715
202/467-2900

www.publicpower.org

ABOUT THIS REPORT

This is the latest in the annual report series prepared by the American Public Power Association (APPA) on financial and operating ratios. Many of the ratios in this report were suggested by the APPA Performance Management Committee and its predecessor, the APPA Task Force on Performance Indicators.

The report was prepared by the APPA Statistical Analysis Department. See page 6 for information on where to direct comments or questions about this report.

 Published by the American Public Power Association
1875 Connecticut Ave, N.W., Suite 1200 Washington, D.C. 20009-5715

TABLE OF CONTENTS

TABLE OF CONTENTS (CONT'D.)

SELECTED FINANCIAL AND OPERATING RATIOS

OF PUBLIC POWER SYSTEMS, 2011

I. Introduction

This report presents data for 21 categories of financial and operating ratios for 137 of the largest publicly owned electric utilities in the United States. The ratios can be a useful tool in assessing electric utility performance. However, they do not provide definitive information, nor should the level of any indicator be taken as the "correct" level of performance.

It is important that users be familiar with definitions of ratios and the variables that may affect them. Although the groupings of the ratios by customer size class, region and net power generation adjust for major variables, other factors may also influence the ratios. The financial and operating ratios provide a useful starting point for analyses and may be used to pinpoint areas in need of further investigation. The ratios should be analyzed in conjunction with other information and should not be the sole basis for broad conclusions.

A. The Report Format

Summary tables listing median values of the ratios are presented in Section II by customer size class, region and net power generation. Section III presents detailed breakdowns for each ratio with the number of utilities, means, medians and first and third quartile values. The information is provided by customer size, region and generation groupings. Definitions and descriptive information precede each set of tables. A copy of the APPA Performance Indicator Survey, 2011, as well as formulas, data sources, definitions of regions, and the utilities included in the report can be found in Appendices A, B, C and D.

Medians and number of responses for each ratio are presented in the following table for all customer size classes, regions and generation classes.

Appendix F-5

Financial Ratios	Utilities	Median
1. Revenue per KWH		
a. All Retail Customers	137	$0.086
b. Residential Customers	137	$0.098
c. Commercial Customers	137	$0.089
d. Industrial Customers	129	$0.070
2. Debt to Total Assets	113	0.320
3. Operating Ratio	135	0.864
4. Current Ratio	119	2.52
5a. Times Interest Earned	113	3.40
5b. Debt Service Coverage	109	3.15
6. Net Income per Revenue Dollar	133	$0.048
7. Uncollectible Accounts per Revenue Dollar	132	$0.0019
Operating Ratios		
8. Retail Customer per Non-Power Generation Employee	132	332
9. Total O&M Expense per KWH Sold	136	$0.072
10. Total O&M Expense (Excluding Power Supply Exp.) per Retail Customer	132	$407
11. Total Power Supply Expense per KWH Sold	136	$0.058
12. Purchased Power Cost per KWH	135	$0.056
13. Retail Customers per Meter Reader	124	6,203
14. Distribution O&M Expense per Retail Customer	127	$143
15. Distribution O&M Expense per Circuit Mile	127	$5,852
16. Customer Accounting, Service, and Sales Expense per Retail Customer	127	$59
17. Administrative and General Expense per Retail Customer	127	$150
Other Ratios		
18. Labor Expense per Worker-Hour	125	$33.04
19. OSHA Incidence Rate (per 100 employees)	125	2.6
20. Energy Loss Percentage	124	3.22%
21. System Load Factor	125	55.3%

Appendix F-5

Utilities in the Report

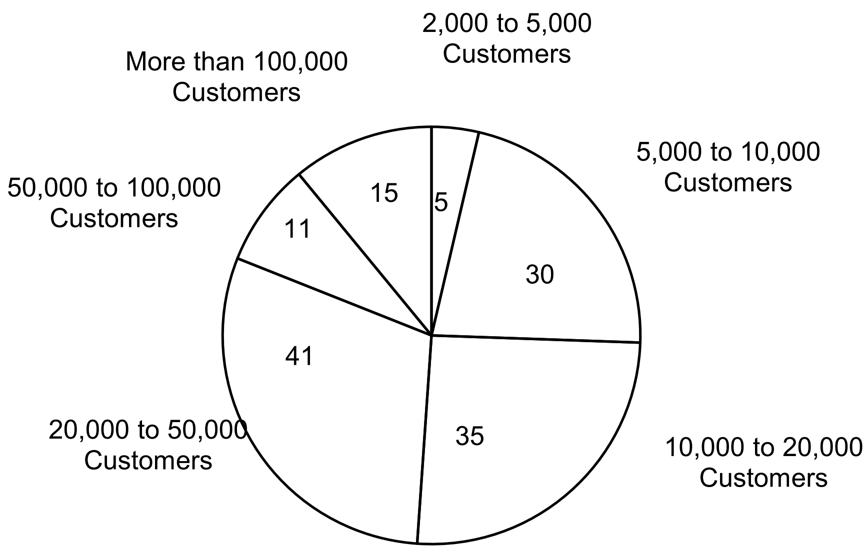
The utilities included in this report are those that responded to APPA's Performance Indicator Survey, 2011. The survey was sent to all public power utilities whose sales to consumers account for approximately 50 percent or more of their total sales, and who also have retail sales or sales for resale of 150,000 megawatt-hours or more.

Joint action agencies are not included in the report, nor are utilities that are primarily wholesalers of electric power. For purposes of this report, wholesalers are defined as those utilities whose retail sales account for approximately 50 percent or less of their total sales.

Direct comparisons with the 2010 ratio report should not be made because the composition of utilities included for each ratio may have changed. Although 137 utilities are included in this report, not all of the utilities were incorporated into each of the ratios. Many utilities did not have, or did not provide information necessary for particular ratios. Also, data are excluded from calculations if there is reason to believe the information is incorrect, e.g., extreme values, etc.

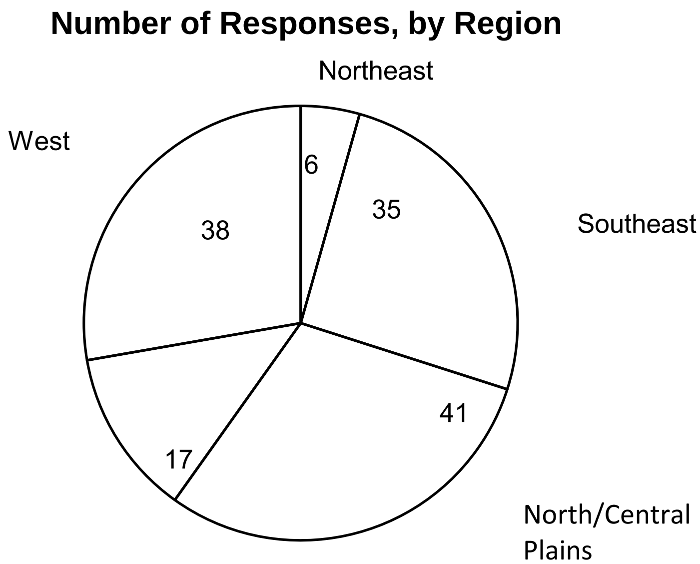
The respondents are grouped into six customer size classes. Mean, median, and first and third quartile values are calculated for each of these classes. Means are weighted means - calculated by summing the values for all utilities, and then computing the ratio from these totals. Since large utilities heavily influence the mean value (particularly when there are only a small number of utilities in the sample), median values provide a better measure of the typical utility. The class size and number of responses in each class are shown in the chart below.

Number of Responses, by Customer Size Class

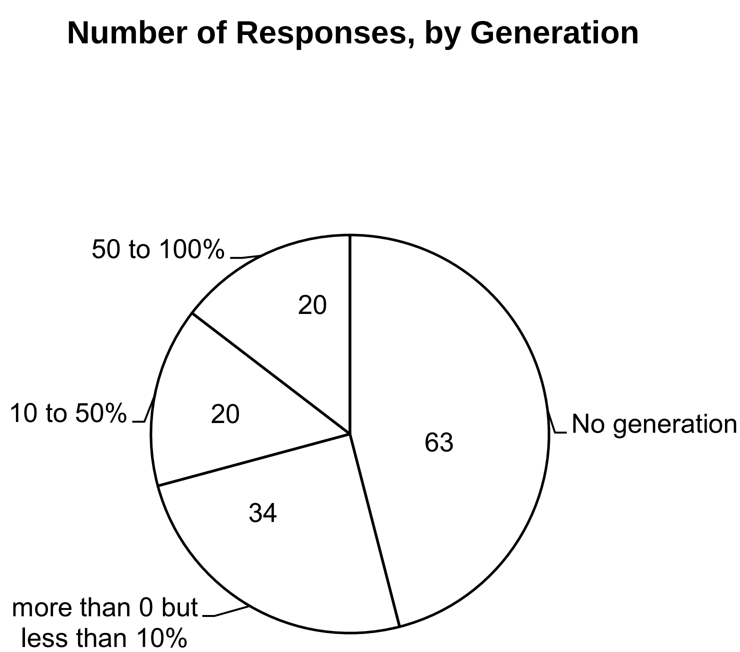


Appendix F-5

Utilities are grouped and ratios calculated based on geographic location. The five regions are based on combined NERC regions (see Appendix C). The regions and number of utilities in each are shown in the following chart.



Finally, respondents are grouped into categories based upon the percent of total power requirements generated by the utility. The classes range from "none" (or zero generation) to "50 to 100 percent" generation. The number of utilities in each category is shown in the chart below.



C. Definitions, Data Sources and Computations

Definitions of each ratio are found in Section III, "Detailed Tables," and information on data sources and computations are provided in Appendix B. The data in this report comes from the **APPA Performance Indicators Survey, 2011.** Utilities were asked to include on their survey response data on sales, revenue, and generation as reported on the U.S. Department of Energy, Energy Information Administration (EIA) Form EIA-861.

D. Factors Influencing Ratios

Each of the ratios in this report may be influenced by a variety of economic, environmental and technical factors. Aggregating the data may mask significant differences. When making comparisons, users of the data should attempt to understand the various factors that might affect a particular ratio. A high or low value for a given ratio for an individual utility, relative to the median for a group, may be due to particular policies or situations faced by a utility, and may not be indicative of a performance problem.

The groupings in this report adjust for differences in utility size based on the number of customers served, regional variations, and differences in operations related to the proportion of power requirements generated by the utility. Factors that may influence the ratios include:

*Number and composition of customers served;

*Geographic location;

*Population density;

*Source of power supply (and physical, economic, or institutional barriers to acquiring alternative power supply);

*Amount of taxes, payments in lieu of taxes, contributions and free electricity or services that a utility makes to or receives from a local government;

*Number of contract employees used by a utility (e.g., consultants, contract labor for maintenance, tree trimming, etc.);

*Financial policies (e.g., proportion of major capital expenditures financed by long-term debt versus current revenue);

*Management policies (e.g., the extent to which a utility focuses on customer service or other programs);

*Regulatory policies that may affect public power systems in some states;

***Relatively small number of utilities reporting data on a particular ratio (e.g., small numbers of utilities frequently appear in the detailed breakdowns);**

***Degree of precision of the data component, or**

***Differences in utility reporting periods.**

Ratios are calculated from fiscal year and calendar year data.

E. Comments or Questions about the Report

APPA members are encouraged to comment on the content and format of this report. Comments or questions should be directed to: **Paul Zummo, Research Analyst (PZummo@publicpower.org),** or at:

American Public Power Association
1875 Connecticut Ave, NW
Suite 1200
Washington, D.C. 20009-5715
202/467-2969

II. Summary Tables

The following tables present summary data on the 21 financial and operating ratios by customer size class (Table A), by region (Table B) and by generation class (Table C). These tables present median values for each of the ratios. Definitions and detailed data including means, medians and quartile values appear in Section III. Data sources and calculation procedures are found in Appendix B.

The average number of retail customers reported by each utility on the APPA Performance Indicators Survey determines customer size class. Responding utilities are grouped into five geographic regions: Northeast, Southeast, North Central/Plains, Southwest, and West. The regions correspond to combined regions of the North American Electric Reliability Council (NERC). See Appendix C for a detailed description of the regions.

Generation refers to the power a utility produces and is based upon the utility's net generation as a percent of total sources of energy as reported on the APPA Performance Indicators Survey.

Table A: 2011 Financial & Operating Ratios : Median Values by Customer Size Class

Ratio	2,000 to 5,000 Customers	5,000 to 10,000 Customers	10,000 to 20,000 Customers	20,000 to 50,000 Customers	50,000 to 100,000 Customers	More than 100,000 Customers
1. Revenue per KWH						
a. All Retail Customers	$0.083	$0.079	$0.088	$0.086	$0.103	$0.091
b. Residential Customers	$0.118	$0.094	$0.098	$0.094	$0.110	$0.099
c. Commercial Customers	$0.076	$0.086	$0.094	$0.087	$0.105	$0.089
d. Industrial Customers	$0.080	$0.071	$0.070	$0.069	$0.074	$0.064
2. Debt to Total Assets	a	0.233	0.363	0.271	0.285	0.587
3. Operating Ratio	0.757	0.901	0.868	0.858	0.829	0.755
4. Current Ratio	a	2.52	2.40	2.85	3.42	2.14
5a. Times Interest Earned	a	4.17	4.08	3.46	4.27	1.54
5b. Debt Service Coverage	a	2.89	4.31	2.77	4.26	1.66
6. Net Income per Revenue Dollar	$0.049	$0.039	$0.049	$0.048	$0.054	$0.046
7. Uncollectible Accounts per Revenue Dollar	$0.0015	$0.0009	$0.0023	$0.0019	$0.0023	$0.0036
8. Retail Customer per Non-Power Generation Employee	a	334	381	348	291	273
9. Total O&M Expense per KWH Sold	$0.059	$0.078	$0.077	$0.074	$0.061	$0.056
10. Total O&M Expense (Excluding Power Supply Exp.) per Retail Customer	a	$432	$362	$412	$402	$476
11. Total Power Supply Expense per KWH Sold	$0.044	$0.066	$0.062	$0.057	$0.050	$0.044
12. Purchased Power Cost per KWH	$0.044	$0.060	$0.060	$0.053	$0.048	$0.046
13. Retail Customers per Meter Reader	a	5,338	4,844	6,650	9,325	9,564
14. Distribution O&M Expense per Retail Customer	$301	$143	$148	$144	$148	$124
15. Distribution O&M Expense per Circuit Mile	$12,883	$6,297	$5,548	$4,812	$9,426	$7,422
16. Customer Accounting, Service, and Sales Expense per Retail Customer	$121	$56	$55	$55	$79	$85
17. Administrative and General Expense per Retail Customer	$280	$152	$150	$148	$141	$149
18. Labor Expense per Worker-Hour	$34.68	$30.54	$33.27	$32.32	$36.34	$40.84
19. OSHA Incidence Rate (per 100 employees)	0.0	0.0	3.4	3.0	2.9	0.9
20. Energy Loss Percentage	a	3.32%	2.74%	3.62%	2.16%	3.24%
21. System Load Factor	a	54.2%	53.8%	53.4%	56.6%	58.6%

a Medians are not calculated for fewer than 5 responses

Appendix F-5

Table B : 2011 Financial & Operating Ratios : Median Values by Region

Ratio	Northeast	Southeast	North Central/Plains	Southwest	West
1. Revenue per KWH					
a. All Retail Customers	$0.125	$0.096	$0.082	$0.086	$0.073
b. Residential Customers	$0.132	$0.101	$0.097	$0.091	$0.082
c. Commercial Customers	$0.130	$0.100	$0.087	$0.085	$0.073
d. Industrial Customers	$0.114	$0.082	$0.071	$0.063	$0.058
2. Debt to Total Assets	0.164	0.356	0.219	0.419	0.402
3. Operating Ratio	0.860	0.905	0.868	0.839	0.808
4. Current Ratio	2.23	2.15	2.55	3.54	3.09
5a. Times Interest Earned	a	4.02	3.54	3.93	2.60
5b. Debt Service Coverage	6.98	2.62	2.36	2.88	4.28
6. Net Income per Revenue Dollar	$0.049	$0.043	$0.046	$0.056	$0.058
7. Uncollectible Accounts per Revenue Dollar	$0.0024	$0.0019	$0.0011	$0.0033	$0.0020
8. Retail Customer per Non-Power Generation Employee	365	289	363	289	334
9. Total O&M Expense per KWH Sold	$0.108	$0.087	$0.074	$0.066	$0.057
10. Total O&M Expense (Excluding Power Supply Exp.) per Retail Customer	$627	$347	$412	$418	$480
11. Total Power Supply Expense per KWH Sold	$0.075	$0.074	$0.060	$0.053	$0.043
12. Purchased Power Cost per KWH	$0.035	$0.071	$0.053	$0.056	$0.037
13. Retail Customers per Meter Reader	5,880	5,963	6,176	4,526	8,978
14. Distribution O&M Expense per Retail Customer	$178	$131	$141	$156	$159
15. Distribution O&M Expense per Circuit Mile	$12,471	$5,162	$5,826	$7,023	$6,088
16. Customer Accounting, Service, and Sales Expense per Retail Customer	$56	$55	$47	$64	$88
17. Administrative and General Expense per Retail Customer	$210	$126	$157	$135	$161
18. Labor Expense per Worker-Hour	$41.11	$28.57	$33.06	$29.79	$42.14
19. OSHA Incidence Rate (per 100 employees)	3.6	1.8	0.9	2.6	3.2
20. Energy Loss Percentage	3.45%	2.53%	2.76%	4.33%	3.44%
21. System Load Factor	49.5%	52.9%	57.4%	56.9%	57.9%

a Medians are not calculated for fewer than 5 responses

Appendix F-5

Table C : 2011 Financial & Operating Ratios : Median Values by Power Generation Class*

Ratio	No Generation	more than 0 but less than 10%	10 to 50%	50 to 100%
1. Revenue per KWH				
a. All Retail Customers	$0.089	$0.088	$0.076	$0.080
b. Residential Customers	$0.097	$0.100	$0.094	$0.096
c. Commercial Customers	$0.094	$0.095	$0.082	$0.085
d. Industrial Customers	$0.076	$0.069	$0.070	$0.061
2. Debt to Total Assets	0.285	0.307	0.452	0.283
3. Operating Ratio	0.896	0.851	0.825	0.724
9. Total O&M Expense per KWH Sold	$0.078	$0.077	$0.057	$0.055
11. Total Power Supply Expense per KWH Sold	$0.067	$0.059	$0.047	$0.043
12. Purchased Power Cost per KWH	$0.062	$0.058	$0.040	$0.047
17. Administrative and General Expense per Retail Customer	$149	$127	$209	$154
18. Labor Expense per Worker-Hour	$32.83	$31.15	$40.60	$33.04
19. OSHA Incidence Rate (per 100 employees)	3.0	3.0	5.7	1.1
20. Energy Loss Percentage	2.94%	3.94%	3.28%	3.35%

* Only those ratios affected by power generation are included in this table

III. Detailed Tables

The following tables present a detailed breakdown of each of the 21 ratios. Each table includes a breakdown of the ratio by customer size class, and by customer size class and region. Some tables also include a breakdown by customer size and generation class. The numbers of responses are presented along with the mean, median and first and third quartile values of the ratio for each class.

Appendix F-5

Revenue per Kilowatt-hour

a. All retail customers – The ratio of total electric operating revenues from sales to ultimate customers to total kilowatt-hour sales. This ratio measures the amount of revenue received for each kilowatt-hour of electricity sold to all classes of customers, including residential, commercial, industrial, public street and highway lighting and other customers.

b. Residential customers – The ratio of residential revenues to residential sales. This ratio measures the amount of revenue received for each kilowatt-hour of electricity sold to residential customers.

c. Commercial customers – The ratio of commercial revenues to commercial sales. This ratio measures the amount of revenue received for each kilowatt-hour of electricity sold to commercial customers.

d. Industrial customers – The ratio of industrial revenues to industrial sales. This ratio measures the amount of revenues received for each kilowatt-hour of electricity sold to industrial customers.

The definitions of commercial and industrial customers may vary between utilities, with the resulting classification based on specific load characteristics or demand rather than on a popular definition of “commercial” or “industrial.” Revenue and sales data include only full-service (bundled sales), thus data for customers who purchase power from an alternative supplier are excluded.

Appendix F-5

Table 1A. Revenue per KWH: All Retail Customers

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	137	$0.088	$0.073	$0.086	$0.097
1. Customer Size Class					
2,000 to 5,000 Customers	5	$0.084	a	$0.083	a
5,000 to 10,000 Customers	30	0.074	0.069	0.079	0.092
10,000 to 20,000 Customers	35	0.084	0.077	0.088	0.095
20,000 to 50,000 Customers	41	0.084	0.067	0.086	0.099
50,000 to 100,000 Customers	11	0.100	0.086	0.103	0.118
More than 100,000 Customers	15	0.089	0.075	0.091	0.107
2. Region					
Northeast	6	0.108	a	0.125	a
Southeast	35	0.095	0.090	0.096	0.105
North Central/Plains	41	0.080	0.076	0.082	0.093
Southwest	17	0.083	0.073	0.086	0.088
West	38	0.085	0.061	0.073	0.095
3. Generation					
No generation	63	0.090	0.075	0.089	0.098
more than 0 but less than 10%	34	0.087	0.077	0.088	0.097
10 to 50%	20	0.079	0.065	0.076	0.089
50 to 100%	20	0.091	0.069	0.080	0.100

a Quartiles are not calculated for fewer than 9 responses

Table 1B. Revenue per KWH: Residential Customers

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	137	$0.101	$0.084	$0.098	$0.110
1. Customer Size Class					
2,000 to 5,000 Customers	5	$0.104	a	$0.118	a
5,000 to 10,000 Customers	30	0.084	0.075	0.094	0.101
10,000 to 20,000 Customers	35	0.084	0.077	0.088	0.095
20,000 to 50,000 Customers	41	0.084	0.067	0.086	0.099
50,000 to 100,000 Customers	11	0.100	0.086	0.103	0.118
More than 100,000 Customers	15	0.089	0.075	0.091	0.107
2. Region					
Northeast	6	0.114	a	0.132	a
Southeast	35	0.109	0.097	0.101	0.109
North Central/Plains	41	0.095	0.086	0.097	0.114
Southwest	17	0.095	0.081	0.091	0.099
West	38	0.083	0.073	0.082	0.107
3. Generation					
No generation	63	0.097	0.086	0.097	0.108
more than 0 but less than 10%	34	0.087	0.077	0.088	0.097
10 to 50%	20	0.079	0.065	0.076	0.089
50 to 100%	20	0.091	0.069	0.080	0.100

a Quartiles are not calculated for fewer than 9 responses

Appendix F-5

Table 1C. Revenue per KWH: Commercial Customers

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	137	$0.091	$0.074	$0.089	$0.102
1. Customer Size Class					
2,000 to 5,000 Customers	5	$0.077	a	$0.076	a
5,000 to 10,000 Customers	30	0.080	0.072	0.086	0.097
10,000 to 20,000 Customers	35	0.092	0.083	0.094	0.102
20,000 to 50,000 Customers	41	0.090	0.071	0.087	0.104
50,000 to 100,000 Customers	11	0.099	0.085	0.105	0.114
More than 100,000 Customers	15	0.091	0.073	0.089	0.100
2. Region					
Northeast	6	0.118	a	0.130	a
Southeast	35	0.102	0.096	0.100	0.106
North Central/Plains	41	0.083	0.082	0.087	0.100
Southwest	17	0.086	0.074	0.085	0.089
West	38	0.075	0.066	0.073	0.100
3. Generation					
No generation	63	0.095	0.076	0.094	0.105
more than 0 but less than 10%	34	0.092	0.083	0.095	0.102
10 to 50%	20	0.081	0.069	0.082	0.096
50 to 100%	20	0.092	0.072	0.085	0.097

a Quartiles are not calculated for fewer than 9 responses

Table 1D. Revenue per KWH: Industrial Customers

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	129	$0.067	$0.060	$0.070	$0.083
1. Customer Size Class					
2,000 to 5,000 Customers	5	$0.080	a	$0.080	a
5,000 to 10,000 Customers	30	0.065	$0.062	0.071	$0.085
10,000 to 20,000 Customers	32	0.068	0.064	0.070	0.081
20,000 to 50,000 Customers	38	0.064	0.050	0.069	0.083
50,000 to 100,000 Customers	10	0.079	0.057	0.074	0.106
More than 100,000 Customers	14	0.067	0.059	0.064	0.077
2. Region					
Northeast	6	0.099	a	0.114	a
Southeast	32	0.069	0.074	0.082	0.088
North Central/Plains	40	0.068	0.065	0.071	0.081
Southwest	15	0.060	0.061	0.063	0.068
West	36	0.066	0.048	0.058	0.076
3. Generation					
No generation	59	0.072	0.062	0.076	0.085
more than 0 but less than 10%	32	0.066	0.062	0.069	0.084
10 to 50%	20	0.067	0.054	0.070	0.076
50 to 100%	18	0.064	0.057	0.061	0.069

a Quartiles are not calculated for fewer than 9 responses

2. Debt to Total Assets

Definition: The ratio of long-term debt, plus current and accrued liabilities, to total assets and other debits. This ratio measures a utility's ability to meet its current and long-term liabilities based on the availability of assets.

Long-term debt includes bonds, advances from the municipality, other long-term debt, any unamortized premium on long-term debt and any unamortized discount on long-term debt. Current and accrued liabilities include warrants, notes and accounts payable, payables to the municipality, customer deposits, taxes accrued, interest accrued, and miscellaneous current and accrued liabilities. Total assets and other debits include utility plant, investments, current and accrued assets and deferred debits.

This ratio may be influenced by the extent to which its components include information applicable to the non-electric portion of the utility, if any (e.g., gas, water or other). In addition, the ratio may be influenced by a utility's financial policies.

Table 2. Debt to Total Assets

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	113	0.535	0.142	0.320	0.469
1. Customer Size Class					
2,000 to 5,000 Customers	4	b	a	b	a
5,000 to 10,000 Customers	24	0.311	0.097	0.233	0.423
10,000 to 20,000 Customers	29	0.330	0.118	0.363	0.430
20,000 to 50,000 Customers	36	0.326	0.163	0.271	0.326
50,000 to 100,000 Customers	11	0.766	0.246	0.285	0.510
More than 100,000 Customers	9	0.579	0.494	0.587	0.719
2. Region					
Northeast	6	0.378	a	0.164	a
Southeast	26	0.558	0.224	0.356	0.541
North Central/Plains	36	0.375	0.096	0.219	0.418
Southwest	13	0.418	0.173	0.419	0.469
West	32	0.622	0.243	0.402	0.566
3. Generation					
No generation	55	0.380	0.131	0.285	0.422
more than 0 but less than 10%	26	0.312	0.196	0.307	0.433
10 to 50%	16	0.547	0.140	0.452	0.512
50 to 100%	16	0.725	0.106	0.283	0.552

a Quartiles are not calculated for fewer than 9 responses

b Means and Medians are not calculated for fewer than 5 responses

3. Operating Ratio

Definition: The ratio of total electric operation and maintenance expenses to total electric operating revenues. This ratio measures the proportion of revenues received from electricity sales, rate adjustments and other electric activities required to cover the operation and maintenance costs associated with producing and selling electricity.

Operation and maintenance expenses include the costs of power production, purchased power, transmission, distribution, customer accounting, customer service, sales, and administrative and general expenses. This ratio may be influenced by the availability of alternative power options and the costs of purchased power.

Table 3. Operating Ratio

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	135	0.792	0.794	0.864	0.921
1. Customer Size Class					
2,000 to 5,000 Customers	5	0.781	a	0.757	a
5,000 to 10,000 Customers	30	0.947	0.858	0.901	0.948
10,000 to 20,000 Customers	35	0.890	0.814	0.868	0.915
20,000 to 50,000 Customers	40	0.859	0.800	0.858	0.919
50,000 to 100,000 Customers	11	0.782	0.720	0.829	0.865
More than 100,000 Customers	14	0.750	0.673	0.755	0.847
2. Region					
Northeast	6	0.870	a	0.860	a
Southeast	35	0.781	0.826	0.905	0.944
North Central/Plains	41	0.863	0.838	0.868	0.935
Southwest	17	0.785	0.761	0.839	0.911
West	36	0.785	0.760	0.808	0.866
3. Generation					
No generation	63	0.911	0.857	0.896	0.931
more than 0 but less than 10%	33	0.850	0.814	0.851	0.958
10 to 50%	20	0.768	0.736	0.825	0.888
50 to 100%	19	0.699	0.699	0.724	0.804

a Quartiles are not calculated for fewer than 9 responses

4. Current Ratio

Definition: The ratio of total current and accrued assets to total current and accrued liabilities. This is a measure of the utility's short-term liquidity (the ability to pay bills). The current ratio takes a snapshot of the utility's liquidity at a point in time and thus may vary considerably at other times of the year.

Total current and accrued assets include cash and working funds, temporary cash investments, notes and accounts receivable, receivables from the municipality, materials and supplies, prepayments and miscellaneous current and accrued assets. Total current and accrued liabilities include warrants, notes and accounts payable, payables to the municipality, customer deposits, taxes accrued, interest accrued and miscellaneous current and accrued liabilities.

Table 4. Current Ratio

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	119	1.41	1.81	2.52	4.60
1. Customer Size Class					
2,000 to 5,000 Customers	4	b	a	b	a
5,000 to 10,000 Customers	25	2.66	1.98	2.52	4.14
10,000 to 20,000 Customers	29	1.77	1.64	2.40	4.05
20,000 to 50,000 Customers	36	2.88	1.95	2.85	4.28
50,000 to 100,000 Customers	11	0.54	1.42	3.42	5.51
More than 100,000 Customers	14	1.65	1.50	2.14	3.67
2. Region					
Northeast	6	0.86	a	2.23	a
Southeast	29	1.38	1.47	2.15	3.08
North Central/Plains	36	3.28	1.76	2.55	8.17
Southwest	14	2.76	2.49	3.54	3.92
West	34	1.06	1.92	3.09	4.72

a Quartiles are not calculated for fewer than 9 responses

b Means and Medians are not calculated for fewer than 5 responses

5a. Times Interest Earned

Definition: The ratio of net electric utility income, plus interest paid on long-term debt, to interest on long-term debt. This ratio measures the ability of a utility to cover interest charges and is indicative of the safety margin to lenders. Utilities that do not report any long-term debt are excluded from this ratio.

This ratio may be influenced by a utility's financial policies.

Table 5A. Times Interest Earned

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	113	2.00	1.57	3.40	7.34
1. Customer Size Class					
2,000 to 5,000 Customers	4	b	a	b	a
5,000 to 10,000 Customers	24	2.89	1.61	4.17	8.31
10,000 to 20,000 Customers	27	2.10	2.26	4.08	10.82
20,000 to 50,000 Customers	32	2.55	2.28	3.46	7.54
50,000 to 100,000 Customers	11	2.56	1.37	4.27	8.93
More than 100,000 Customers	15	1.58	1.34	1.54	1.71
2. Region					
Northeast	4	b	a	b	a
Southeast	31	1.60	1.62	4.02	9.87
North Central/Plains	32	2.57	1.66	3.54	7.72
Southwest	15	1.85	1.53	3.93	9.29
West	31	1.78	1.44	2.60	4.04

a Quartiles are not calculated for fewer than 9 responses
b Means and Medians are not calculated for fewer than 5 responses

5b. Debt Service Coverage

Definition: The ratio of net revenues available for debt service to total long-term debt service for the year. This ratio measures the utility's ability to meet its annual long-term debt obligation.

Net revenues available for debt service equal net electric utility operating income (operating revenues minus operating expenses) plus net electric utility non-operating income, plus depreciation. Debt service includes principle and interest payments on long-term debt.

This ratio may be influenced by a utility's financial policies.

Table 5b. Debt Service Coverage

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	109	1.47	1.77	3.15	7.09
1. Customer Size Class					
2,000 to 5,000 Customers	4	b	a	b	a
5,000 to 10,000 Customers	21	3.75	1.07	2.89	13.24
10,000 to 20,000 Customers	28	2.42	2.37	4.31	7.32
20,000 to 50,000 Customers	31	5.02	1.82	2.77	7.46
50,000 to 100,000 Customers	11	2.76	1.85	4.26	6.58
More than 100,000 Customers	14	1.09	1.26	1.66	2.99
2. Region					
Northeast	5	4.05	a	6.98	a
Southeast	27	2.03	1.51	2.62	5.17
North Central/Plains	32	2.04	1.60	2.36	6.36
Southwest	16	0.36	1.67	2.88	14.52
West	29	4.35	2.47	4.28	6.99

a Quartiles are not calculated for fewer than 9 responses

b Means and Medians are not calculated for fewer than 5 responses

Appendix F-5

6. Net Income per Revenue Dollar

Definition: The ratio of net electric utility income to total electric operating revenues. This ratio measures the amount of income remaining, after accounting for operation and maintenance expenses, depreciation, taxes and tax equivalents, for every dollar received from sales of electricity.

The ratio may be influenced by the type and availability of power supply options and by the amount of taxes and tax equivalents that a utility transfers to the municipality or other governmental body. Financial policies and the amount of debt may also affect this ratio (e.g., how a utility finances capital investments).

Table 6. Net Income Per Revenue Dollar

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	133	$0.053	$0.023	$0.048	$0.071
1. Customer Size Class					
2,000 to 5,000 Customers	5	$0.076	a	$0.049	a
5,000 to 10,000 Customers	29	0.033	$0.020	0.039	$0.065
10,000 to 20,000 Customers	35	0.071	0.034	0.049	0.074
20,000 to 50,000 Customers	39	0.039	0.029	0.048	0.067
50,000 to 100,000 Customers	11	0.082	0.020	0.054	0.102
More than 100,000 Customers	14	0.048	0.023	0.046	0.061
2. Region					
Northeast	6	0.054	a	0.049	a
Southeast	35	0.044	0.021	0.043	0.055
North Central/Plains	41	0.054	0.012	0.046	0.065
Southwest	16	0.058	0.032	0.056	0.106
West	35	0.062	0.031	0.058	0.110

a Quartiles are not calculated for fewer than 9 responses

7. Uncollectible Accounts per Revenue Dollar

Definition: The ratio of total uncollectible accounts to total electric utility operating revenues. This ratio measures the portion of each revenue dollar that will not be collected by the utility.

This ratio will be influenced by the financial and customer service policies of the utility.

Table 7. Uncollectible Accounts per Revenue Dollar

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	132	$0.0041	$0.0009	$0.0019	$0.0037
1. Customer Size Class					
2,000 to 5,000 Customers	5	$0.0021	a	$0.0015	a
5,000 to 10,000 Customers	29	0.0031	$0.0002	0.0009	$0.0020
10,000 to 20,000 Customers	33	0.0022	0.0009	0.0023	0.0037
20,000 to 50,000 Customers	40	0.0047	0.0012	0.0019	0.0037
50,000 to 100,000 Customers	11	0.0029	0.0015	0.0023	0.0034
More than 100,000 Customers	14	0.0045	0.0019	0.0036	0.0063
2. Region					
Northeast	6	0.0029	a	0.0024	a
Southeast	35	0.0036	0.0013	0.0019	0.0043
North Central/Plains	39	0.0018	0.0005	0.0011	0.0021
Southwest	16	0.0042	0.0017	0.0033	0.0046
West	36	0.0058	0.0012	0.0020	0.0037

a Quartiles are not calculated for fewer than 9 responses

8. Retail Customers per Non-power-generation Employee

Definition: The ratio of the average number of retail customers from all classes to the total number of full-time, part-time and contract employees not involved in the generation of power. This ratio measures the average number of customers served by each non-generation employee.

The ratio may be influenced by the mix of customers and by population density. It will be influenced by the extent that employees shared with other (non-electric) departments are not properly prorated, or that employees involved in resale transactions are included. Part-time employees are assumed to work half-time (i.e., two part-time employees are counted as one full-time employee). To the extent that this assumption is violated, the ratio will be biased. Contract employees include only those individuals performing regular utility work on an on-going basis.

Table 8. Retail Customers per Non-power-generation Employee

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	132	274	250	332	417
1. Customer Size Class					
2,000 to 5,000 Customers	4	b	a	b	a
5,000 to 10,000 Customers	29	307	240	334	392
10,000 to 20,000 Customers	33	320	259	381	479
20,000 to 50,000 Customers	40	329	274	348	461
50,000 to 100,000 Customers	11	282	240	291	397
More than 100,000 Customers	15	254	255	273	331
2. Region					
Northeast	6	326	a	365	a
Southeast	32	242	241	289	371
North Central/Plains	40	323	254	363	493
Southwest	17	244	215	289	352
West	37	301	268	334	453

a Quartiles are not calculated for fewer than 9 responses
b Means and Medians are not calculated for fewer than 5 responses

9. Total Operation and Maintenance Expense per Kilowatt-hour Sold

Definition: The ratio of total electric utility operation and maintenance expenses, including the cost of generated and purchased power, to total kilowatt-hour sales to ultimate and resale customers. This ratio measures average total operation and maintenance expenses associated with each kilowatt-hour of electricity sold, either for resale or to ultimate customers.

Included in operation and maintenance costs are the expenses associated with power supply (generation and purchased power), transmission, distribution, customer accounting, customer services, sales, and administrative and general functions of the electric utility. Because power supply expenses typically comprise the largest component of total operation and maintenance expenses, this ratio may be influenced by the proportion of power generated by a utility and the availability of alternative power supplies. Kilowatt-hours of electricity produced but not sold, i.e., energy furnished without charge, energy used internally and energy losses are not included in the denominator.

Table 9. Total O&M Expense per KWH sold

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	136	$0.060	$0.055	$0.072	$0.088
1. Customer Size Class					
2,000 to 5,000 Customers	5	$0.060	a	$0.059	a
5,000 to 10,000 Customers	29	0.071	$0.062	0.078	$0.088
10,000 to 20,000 Customers	35	0.071	0.064	0.077	0.087
20,000 to 50,000 Customers	41	0.066	0.055	0.074	0.091
50,000 to 100,000 Customers	11	0.066	0.056	0.061	0.097
More than 100,000 Customers	15	0.056	0.047	0.056	0.078
2. Region					
Northeast	6	0.093	a	0.117	a
Southeast	35	0.067	0.076	0.087	0.089
North Central/Plains	40	0.064	0.058	0.074	0.083
Southwest	17	0.062	0.054	0.066	0.076
West	38	0.052	0.045	0.057	0.068
3. Generation					
No generation	63	0.072	0.062	0.078	0.088
more than 0 but less than 10%	34	0.067	0.061	0.077	0.094
10 to 50%	19	0.048	0.043	0.057	0.077
50 to 100%	20	0.057	0.048	0.055	0.069

a Quartiles are not calculated for fewer than 9 responses

10. Total Operation and Maintenance Expense (Excluding Power Supply Expense) per Retail Customer

Definition: The ratio of total electric utility operation and maintenance expenses, excluding all costs of power supply, to the total number of ultimate customers.

Operation and maintenance expenses include the costs of transmission, distribution, customer accounting, customer services, sales and administrative and general expenses. The costs of power supply (generation and purchased power) are excluded from the ratio. This ratio may be affected by population density and the mix of customers between various classes (residential, commercial, industrial or other). Also, the extent that a utility services a large number of resale customers will influence the ratio.

Table 10. Total O&M Expense (Excluding Power Supply Expense) per Retail Customer

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	132	$482	$330	$407	$547
1. Customer Size Class					
2,000 to 5,000 Customers	4	b	a	b	a
5,000 to 10,000 Customers	28	$447.00	$330.00	$432.00	$517.00
10,000 to 20,000 Customers	33	401	296	362	488
20,000 to 50,000 Customers	41	446	332	412	522
50,000 to 100,000 Customers	11	441	319	402	498
More than 100,000 Customers	15	511	399	476	694
2. Region					
Northeast	6	650	a	627	a
Southeast	35	413	309	347	414
North Central/Plains	37	427	327	412	543
Southwest	17	601	386	418	610
West	37	500	340	480	617

a Quartiles are not calculated for fewer than 9 responses

b Means and Medians are not calculated for fewer than 5 responses

11. Total Power Supply Expense per Kilowatt-hour Sold

Definition: The ratio of the total costs of power supply to total sales to both ultimate and resale customers. This ratio measures all power supply costs, including generation and purchased power, associated with the sale of each kilowatt-hour of electricity.

The ratio includes operation and maintenance costs arising from all generation types, including steam, nuclear, hydraulic and other types of generation. Operation and maintenance expenses include the costs of fuel, labor, supervision, engineering, materials and supplies, and also include the costs of purchased power. The ratio may be influenced by the geographic location of the utility, the availability of alternative power supplies, the degree to which the utility can generate its own power, and access to transmission. The ratio does not include kilowatt-hours produced but not sold, i.e., energy used internally, energy furnished without charge, or energy losses.

Table 11. Total Power Supply Expense per KWH Sold

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	136	$0.047	$0.043	$0.058	$0.073
1. Customer Size Class					
2,000 to 5,000 Customers	5	$0.044	a	$0.044	a
5,000 to 10,000 Customers	29	0.058	$0.051	0.066	$0.076
10,000 to 20,000 Customers	35	0.057	0.050	0.062	0.072
20,000 to 50,000 Customers	41	0.052	0.034	0.057	0.073
50,000 to 100,000 Customers	11	0.052	0.042	0.050	0.079
More than 100,000 Customers	15	0.044	0.036	0.044	0.060
2. Region					
Northeast	6	0.066	0.045	0.075	0.079
Southeast	35	0.057	0.064	0.074	0.079
North Central/Plains	40	0.050	0.049	0.060	0.069
Southwest	17	0.046	0.041	0.053	.059.
West	38	0.037	0.029	0.043	0.055
3. Generation					
No generation	63	0.059	0.050	0.067	0.075
more than 0 but less than 10%	34	0.052	0.050	0.059	0.076
10 to 50%	19	0.032	0.029	0.047	0.062
50 to 100%	20	0.046	0.039	0.043	0.051

a Quartiles are not calculated for fewer than 9 responses

12. Purchased Power Cost per Kilowatt-hour

Definition: The ratio of the cost of purchased power to the amount of kilowatt-hours purchased. This ratio measures the purchased power component of power supply costs.

Purchased power includes purchases from investor-owned utilities, municipalities, cooperatives or other public authorities for subsequent distribution and sale to ultimate customers. It does not include power exchanges. Adjustments to the cost data were made in a small number of cases to eliminate power exchanges. The cost reflects the amount billed, including adjustments and other charges.

The ratio may be influenced by the geographic location of the utility, availability of alternative power supplies, access to transmission, and the type of purchase agreement, such as firm power, economy power or surplus sales.

Table 12. Purchased Power Cost per KWH

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	135	$0.050	$0.040	$0.056	$0.069
1. Customer Size Class					
2,000 to 5,000 Customers	5	$0.046	a	$0.044	a
5,000 to 10,000 Customers	29	0.054	$0.048	0.060	$0.071
10,000 to 20,000 Customers	35	0.059	0.048	0.060	0.073
20,000 to 50,000 Customers	40	0.049	0.032	0.053	0.069
50,000 to 100,000 Customers	11	0.055	0.042	0.048	0.080
More than 100,000 Customers	15	0.045	0.036	0.046	0.057
2. Region					
Northeast	5	0.042	a	0.035	a
Southeast	35	0.063	0.059	0.071	0.077
North Central/Plains	40	0.053	0.048	0.053	0.067
Southwest	17	0.054	0.045	0.056	0.060
West	38	0.037	0.028	0.037	0.048
3. Generation					
No generation	62	0.057	0.048	0.062	0.073
more than 0 but less than 10%	34	0.048	0.046	0.058	0.071
10 to 50%	19	0.037	0.029	0.040	0.055
50 to 100%	20	0.047	0.038	0.047	0.056

a Quartiles are not calculated for fewer than 9 responses

13. Retail Customers per Meter Reader

Definition: The ratio of retail customers to the number of meter readers employed by the utility. This measures the average number of retail customers served by each meter reader.

The number of meter readers includes the total number of full-time meter readers plus half of all part-time meter readers. It is assumed that all part-time employees work half-time (i.e., one full-time employee is equivalent to two part-time employees). Population density, frequency of meter readings, and the technology or methods used to read meters will influence the ratio.

Table 13. Retail Customers per Meter Reader

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	124	6,701	4,252	6,203	9,783
1. Customer Size Class					
2,000 to 5,000 Customers	3	b	a	b	a
5,000 to 10,000 Customers	27	5,282	4,106	5,338	8,111
10,000 to 20,000 Customers	32	4,607	3,552	4,844	7,171
20,000 to 50,000 Customers	38	5,692	5,353	6,650	10,600
50,000 to 100,000 Customers	10	6,567	4,494	9,325	10,583
More than 100,000 Customers	14	7,959	7,557	9,564	11,036
2. Region					
Northeast	6	5,851	a	5,880	a
Southeast	33	6,888	4,209	5,963	9,032
North Central/Plains	34	6,243	3,984	6,176	8,919
Southwest	16	4,717	3,398	4,526	5,691
West	35	8,157	5,262	8,978	10,958

a Quartiles are not calculated for fewer than 9 responses
b Means and Medians are not calculated for fewer than 5 responses

14. Distribution Operation and Maintenance Expenses per Retail Customer

Definition: The ratio of total distribution operation and maintenance expenses to the total number of retail customers. This ratio measures the average distribution expense associated with delivering power to each retail customer.

Distribution costs include expenses associated with labor, supervision, engineering, materials and supplies used in the operation and maintenance of the distribution system. Population density and the mix of customer classes served by the utility will influence the ratio.

Those utilities that do not allocate expenses to all three categories of (1) distribution expense (2) customer accounting, customer service, and sales expense and (3) administrative and general expense are excluded from ratios 14 through 17 (Distribution Operation and Maintenance Expenses per Retail Customer; Distribution Operation and Maintenance Expenses per Circuit Mile; Customer Accounting, Customer Service and Sales Expenses per Retail Customer; and Administrative and General Expenses per Retail Customer).

Table 14. Distribution O&M Expenses per Retail Customer

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	127	$138	$120	$143	$186
1. Customer Size Class					
2,000 to 5,000 Customers	5	$300	a	$301	a
5,000 to 10,000 Customers	26	167	$123	143	$203
10,000 to 20,000 Customers	32	159	123	148	178
20,000 to 50,000 Customers	39	156	108	144	183
50,000 to 100,000 Customers	10	167	132	148	169
More than 100,000 Customers	15	123	99	124	140
2. Region					
Northeast	6	174	a	178	a
Southeast	35	123	118	131	149
North Central/Plains	36	145	118	141	196
Southwest	16	145	117	156	225
West	34	144	125	159	187

a Quartiles are not calculated for fewer than 9 responses

15. Distribution Operation and Maintenance Expenses per Circuit Mile

Definition: The ratio of total distribution operation and maintenance expenses to the total number of circuit miles of distribution line. This measures the total distribution costs associated with each circuit mile of distribution line used to deliver power to customers.

Distribution costs include expenses associated with labor, supervision, engineering, materials and supplies used in the operation and maintenance of the distribution system. The ratio will be affected by population density, the mix of customer classes served by the utility, the dispersion of customers within the utility's service territory, and the proportion of underground and overhead distribution lines.

Those utilities that do not allocate expenses to all three categories of (1) distribution expense (2) customer accounting, customer service, and sales expense and (3) administrative and general expense are excluded from ratios 14 through 17 (Distribution Operation and Maintenance Expenses per Retail Customer; Distribution Operation and Maintenance Expenses per Circuit Mile; Customer Accounting, Customer Service and Sales Expenses per Retail Customer; and Administrative and General Expenses per Retail Customer).

Table 15. Distribution O&M Expenses per Circuit Mile

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	127	$5,855	$13	$5,852	$11,736
1. Customer Size Class					
2,000 to 5,000 Customers	5	$7,267	a	$12,883	a
5,000 to 10,000 Customers	26	4,286	$4,330	6,297	$11,166
10,000 to 20,000 Customers	32	5,677	3,792	5,548	11,335
20,000 to 50,000 Customers	39	4,437	3,889	4,812	12,112
50,000 to 100,000 Customers	10	8,391	6,678	9,426	12,910
More than 100,000 Customers	15	6,346	5,313	7,422	10,306
2. Region					
Northeast	6	13,041	a	12,471	a
Southeast	35	5,997	4,036	5,162	9,499
North Central/Plains	36	5,322	3,579	5,826	11,337
Southwest	16	5,589	3,889	7,023	11,407
West	34	5,821	4,270	6,088	13,494

a Quartiles are not calculated for fewer than 9 responses

16. Customer Accounting, Customer Service and Sales Expenses per Retail Customer

Definition: The ratio of total customer accounting, service, and sales expenses to the total number of retail customers. This ratio measures the average expenses incurred by the utility in handling each customer's account. This includes the costs of obtaining and servicing all retail customers. Uncollectible accounts and meter reading expenses are included in this ratio.

The ratio includes the costs of labor, materials and other expenses associated with advertising, billing, collections, records, handling inquiries and complaints. It also includes the costs of promoting and providing customer service programs such as energy services or conservation programs. The ratio will be influenced by the degree to which the utility provides various energy services and other types of customer programs, and also by the mix of customer classes it serves.

Those utilities that do not allocate expenses to all three categories of (1) distribution expense (2) customer accounting, customer service, and sales expense and (3) administrative and general expense are excluded from ratios 14 through 17 (Distribution Operation and Maintenance Expenses per Retail Customer; Distribution Operation and Maintenance Expenses per Circuit Mile; Customer Accounting, Customer Service and Sales Expenses per Retail Customer; and Administrative and General Expenses per Retail Customer).

Table 16. Customer Accounting, Customer Service and Sales Expense per Retail Customer

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	127	$105	$42	$59	$89
1. Customer Size Class					
2,000 to 5,000 Customers	5	$86	a	$121	a
5,000 to 10,000 Customers	26	59	$34	56	$77
10,000 to 20,000 Customers	32	61	40	55	77
20,000 to 50,000 Customers	39	66	41	55	85
50,000 to 100,000 Customers	10	85	53	79	114
More than 100,000 Customers	15	127	70	85	129
2. Region					
Northeast	6	79	a	56	a
Southeast	35	76	43	55	74
North Central/Plains	36	55	32	47	70
Southwest	16	116	44	64	97
West	34	133	58	88	129

a Quartiles are not calculated for fewer than 9 responses

17. Administrative and General Expenses per Retail Customer

Definition: The ratio of total electric utility administrative and general expenses to the total number of retail customers. This ratio measures the average administrative and general expenses incurred by the utility on behalf of each retail customer.

Administrative and general expenses are those electric operation and maintenance expenses not allocatable to the costs of power production (generation and power purchases), transmission, distribution, or customer accounting, service and sales. Items which may be included are compensation of officers and executives, office supplies, professional fees, property insurance and claims, pensions and benefits, and other expenses not provided for elsewhere.

Those utilities that do not allocate expenses to all three categories of (1) distribution expense (2) customer accounting, customer service, and sales expense and (3) administrative and general expense are excluded from ratios 14 through 17 (Distribution Operation and Maintenance Expenses per Retail Customer; Distribution Operation and Maintenance Expenses per Circuit Mile; Customer Accounting, Customer Service and Sales Expenses per Retail Customer; and Administrative and General Expenses per Retail Customer).

The amount and type of the utility's generation may affect the ratio.

Table 17. Administrative and General Expenses per Retail Customer

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	127	$163	$104	$150	$219
1. Customer Size Class					
2,000 to 5,000 Customers	5	$245	a	$280	a
5,000 to 10,000 Customers	26	177	$119	152	$203
10,000 to 20,000 Customers	32	187	88	150	248
20,000 to 50,000 Customers	39	181	108	148	198
50,000 to 100,000 Customers	10	167	99	141	175
More than 100,000 Customers	15	153	127	149	217
2. Region					
Northeast	6	213	a	210	a
Southeast	35	173	89	126	157
North Central/Plains	36	201	113	157	280
Southwest	16	230	105	135	178
West	34	126	119	161	220
3. Generation					
No generation	60	167	92	149	205
more than 0 but less than 10%	29	132	100	127	170
10 to 50%	18	209	151	209	298
50 to 100%	20	153	124	154	277

a Quartiles are not calculated for fewer than 9 responses

18. Labor Expense per Worker-hour

Definition: The ratio of total annual earnings of full-time, part-time and contract labor employees to the total number of hours worked during the year by these employees. This ratio measures the actual cost of labor to the utility.

Total annual earnings include all payroll compensation received by full-time, part-time or contract employees, including straight-time pay, overtime pay, and payment for time not worked such as sick pay, vacation pay, holiday pay, or other payments. Fringe benefits, such as health care premiums paid by the employer, are excluded. Hours worked includes total productive hours spent at work, including both straight time and overtime hours worked. Hours paid but not worked, such as on holidays or other paid leave time, are not included. This is not the same as a wage rate, which is simply the earnings per hour. A wage rate generally includes hours not worked (such as vacation or sick pay), which this ratio does not.

Table 18. Labor Expense per Worker Hour

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	125	$37.10	$28.67	$33.04	$39.84
1. Customer Size Class					
2,000 to 5,000 Customers	5	$36.22	a	$34.68	a
5,000 to 10,000 Customers	30	30.82	$27.20	30.54	$34.77
10,000 to 20,000 Customers	28	35.07	29.40	33.27	39.59
20,000 to 50,000 Customers	38	33.65	28.47	32.32	40.21
50,000 to 100,000 Customers	11	39.01	33.85	36.34	43.96
More than 100,000 Customers	13	38.30	32.86	40.84	43.55
2. Region					
Northeast	6	44.10	a	41.11	a
Southeast	33	32.28	25.45	28.57	31.88
North Central/Plains	37	35.14	29.97	33.06	37.33
Southwest	16	39.71	28.38	29.79	35.99
West	33	43.91	36.34	42.14	46.58
3. Generation					
No generation	58	35.15	27.20	32.83	38.20
more than 0 but less than 10%	29	33.93	28.44	31.15	35.17
10 to 50%	19	44.65	38.08	40.60	42.90
50 to 100%	19	35.98	30.30	33.04	41.45

a Quartiles are not calculated for fewer than 9 responses

19. OSHA Incidence Rate (per 100 employees)

Definition: The ratio of lost workday cases during the year to the total worker-hours of exposure, per 100 employees. This ratio measures the proportion of employees subject to on-the-job injuries and illnesses over the course of the year.

Worker-hours of exposure are calculated by adding the total full-time and part-time annual hours worked. Contract workers' hours are included in the calculation only if the utility supervises the workers' day-to-day activities.

Lost workday cases are those which involve days away from work or days of restricted work activity because of non-fatal occupational illness or injury. Restricted work activity occurs when 1) an employee is assigned to another job on a temporary basis; 2) an employee works at a permanent job less than full time; or 3) the employee works at a permanent job but cannot perform all normal duties. This ratio will be influenced by management practices and policies, and by the proportion of employees involved in hazardous occupations.

Table 19. OSHA Incidence Rate

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	125	2.8	0.0	2.6	4.7
1. Customer Size Class					
2,000 to 5,000 Customers	5	1.0	a	0.0	a
5,000 to 10,000 Customers	29	3.5	0.0	0.0	5.6
10,000 to 20,000 Customers	28	2.7	0.0	3.4	5.3
20,000 to 50,000 Customers	38	2.2	0.9	3.0	4.7
50,000 to 100,000 Customers	11	2.8	2.4	2.9	3.3
More than 100,000 Customers	14	2.8	0.6	0.9	4.0
2. Region					
Northeast	6	4.3	a	3.6	a
Southeast	30	3.8	0.0	1.8	4.5
North Central/Plains	38	1.1	0.0	0.9	3.9
Southwest	17	1.9	0.6	2.6	4.5
West	34	2.5	1.2	3.2	5.3
3. Generation					
No generation	58	6.6	0.0	3.0	4.9
more than 0 but less than 10%	27	4.2	0.0	3.0	4.5
10 to 50%	20	2.8	0.0	1.7	4.9
50 to 100%	20	0.8	0.3	1.1	3.3

a Quartiles are not calculated for fewer than 9 responses

20. Energy Loss Percentage

Definition: The ratio of total energy losses to total sources of energy. This ratio measures how much energy is lost in the utility's electrical system, and is an indicator of the efficiency of the electrical system. It represents the percentage of electrical energy that is bought or generated by the utility, but is not available to be sold to customers (or for the utility's own use).

Losses include both physical losses that occur in the distribution system and metering and billing losses. Generation, purchases, net exchanges and net wheeling are all included in total sources of energy.

Table 20. Energy Loss Percentage

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	124	3.11%	2.01%	3.22%	4.36%
1. Customer Size Class					
2,000 to 5,000 Customers	4	b	a	b	a
5,000 to 10,000 Customers	28	2.92%	1.67%	3.32%	4.04%
10,000 to 20,000 Customers	31	2.99	2.23	2.74	4.01
20,000 to 50,000 Customers	37	3.74	2.22	3.62	5.27
50,000 to 100,000 Customers	10	2.77	1.30	2.16	4.27
More than 100,000 Customers	14	3.02	2.77	3.24	3.72
2. Region					
Northeast	6	2.90	a	3.45	a
Southeast	29	2.39	1.69	2.53	4.09
North Central/Plains	37	2.89	1.76	2.76	3.90
Southwest	16	3.86	3.16	4.33	5.48
West	36	1.86	2.21	3.44	4.41
3. Generation					
No generation	55	2.84	1.80	2.94	4.42
more than 0 but less than 10%	32	3.54	2.44	3.94	4.57
10 to 50%	18	3.08	1.75	2.68	3.32
50 to 100%	19	3.11	2.54	3.35	3.82

a Quartiles are not calculated for fewer than 9 responses
b Means and Medians are not calculated for fewer than 5 responses

Appendix F-5

21. System Load Factor

Definition: The ratio of the system average load, total sales plus losses (MWh) divided by 8760 (hours), to system peak demand (typically a summer or winter peak measured during a particular hour at all delivery points and generator busses on a totalized basis).

System load factor is descriptive of the total system load characteristics. It tells system planners how much the overall system load varies diurnally and seasonally. It is a very broad indicator. It also provides financial planners with information about how to spread fixed costs across energy sales. This will give financial planners and rate designers information to support greater unbundling of fixed and variable costs--a goal of competitive rate design.

Table 21. System Load Factor

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	125	59.1%	51.2%	55.3%	61.1%
1. Customer Size Class					
2,000 to 5,000 Customers	4	b	a	b	a
5,000 to 10,000 Customers	28	59.1%	52.3%	54.2%	58.9%
10,000 to 20,000 Customers	31	56.8	50.7	53.8	61.3
20,000 to 50,000 Customers	40	58.2	49.0	53.4	61.0
50,000 to 100,000 Customers	10	60.5	50.7	56.6	64.1
More than 100,000 Customers	12	59.4	56.8	58.6	64.9
2. Region					
Northeast	6	49.4	47.7	49.5	52.1
Southeast	34	56.1	50.5	52.9	56.9
North Central/Plains	35	59.7	53.6	57.4	64.1
Southwest	15	58.6	46.7	56.9	61.0
West	35	63.2	52.9	57.9	73.8

a Quartiles are not calculated for fewer than 9 responses

b Means and Medians are not calculated for fewer than 5 responses

APPENDIX A: APPA Performance Indicators Survey, 2011

(Note: The 2011 survey was conducted on-line)

PART I. EMPLOYMENT, HOURS AND EARNINGS -- CALENDAR YEAR ENDING IN 2011

A. Electric Utility Employees	**a. Full-Time**	**b. Part-Time**
1. Total Average No. of Employees	____________	____________
2. Total Annual Hours Worked	____________	____________
3. Total Annual Earnings	____________	____________

B. Contract Labor	**Employees Supervised By the Utility**	**Employees Supervised by the Supervising Company**
1. Total Average No. of Employees	____________________	____________________
2. Total Annual Hours Worked	____________________	____________________
3. Total Annual Earnings	____________________	____________________

C. Number of Employees, Selected Electric Utility Departments	**a. Full-time**	**b. Part-time**	**c. Contract**
1. No. of Power Production Employees (Include all employees involved in operation and maintenance of power generating facilities.)	__________	_________	_________
2. No. of Meter Readers (If responsible for meters other than electric, prorate employees allocated to electric only.)	____________	_________	_________

PART II. SELECTED ELECTRIC UTILITY STATISTICS -- CALENDAR YEAR ENDING IN 2011

A. Distribution Lines (up to 69 kV)

Total Distribution Line Circuit Miles _________
(Circuit miles include the total length in miles of separate circuits regardless of the number of conductors used per circuit.)

B. Total Electric Utility Uncollectible Accounts (FERC 904) $___________

C. Total Electric Utility Debt Service Payments on Long-Term Debt $_____________

D. Safety (Please note: If you have no data for these categories, please write N/A. Only write 0 if you have no lost workdays or workday cases)

1. Total No. of Lost Workday Cases During 2011 ________________
2. Total No. of Lost Workdays During 2011 ________________

Part III. Financial Data

Special Instructions: In order to help you more accurately complete this section, we have included these checks to perform to ensure that accurate numbers are given.

- Line 2 must be greater than line 5
- Line 12 must be equal to or greater than line 11
- Lines 12 through 16 must be equal to line 17
- Remember that lines 12-17 include both operations AND maintenance
- Neither line 14, line 15, nor line 16 can be zero
- Report **full** dollar amounts, rounding to the nearest dollars.

Balance Sheet **Report full numbers (NOT in 000's)**

Asset Side
1. Total Current and Accrued Assets ______________________

2. Total Assets and Other Debits ______________________

Liability Side
3. Long-Term Debt: Bonds ______________________

4. Long-Term Debt: Total Long-Term Debt ______________________

5. Total Current and Accrued Liabilities ______________________

Selected Income Statement Items

6. Electric Operating Revenue (Must include only revenue from sales to ultimate consumers and sales for resale) ______________________

7. Depreciation Expenses ______________________

8. Electric Income (Electric operating income and other Electric income ______________________

9. Interest payment on Long-Term Debt paid during fiscal year (Include the amount of interest on outstanding long-term debt issued or assumed by the utility) ______________________

10. Net Income (Electric Income Minus Deductions) ______________________

Appendix F-5

Operation and Maintenance Expenses

11. Purchased Power Expenses ______________________

12. Total Production Expenses (including purchased power) ______________________

13. Transmission Expenses ______________________

14. Distribution Expenses ______________________

15. Customer Accounts Expenses; Customer Service and Information Expenses; and Sales Expenses ______________________

16. Administrative and General Expenses ______________________

17. Total Electric Operation and Maintenance Expenses (Sum of lines 12-16) ______________________

Part IV. EIA Form 861 Data. CALENDAR YEAR ending in 2011
Information in parenthesis refers to Form 861 survey.
A blank copy of the Form 861 can be found on the EIA's website at
http://www.eia.doe.gov/cneaf/electricity/forms/eia861/eia861.pdf

For lines 1 – 5, report in Megawatt hours (MWHs)

1. Net Generation
(Schedule 2, part B, line 1) ______________________
2. Purchases from Electricity Suppliers
(Schedule 2, part B, line 2) ______________________
3. Total sources of electricity
(Schedule 2, part B, line 10) ______________________
4. Sales to ultimate customers
(Schedule 2, part B, line 11) ______________________
5. Sales for Resale
(Schedule 2, part B, line 12) ______________________
6. Total Energy losses (**Report as positive number)**
(Schedule 2, part B, line 15) ______________________

	Revenue (Report in 000s)	**Sales (Report in MWHs)**
8. Residential (Schedule 4, part A, column a)	______________________	______________________
9. Commercial (Schedule 4, part A, column b)	______________________	______________________
10. Industrial (Schedule 4, part A, column c)	______________________	______________________
11. Total (Schedule 4, part A, column e)	______________________	______________________

12. Total number of customers
(Schedule A, part A, column e) ______________________

13. Highest Hourly Electrical Peak (Schedule 2, Part A)
Winter (MW)______ Summer (MW) ________

APPENDIX B

DATA SOURCES AND COMPUTATIONAL PROCEDURES

The financial and operating ratios in this report are calculated using data from the **APPA Performance Indicators Survey, 2011.** The **APPA Survey** includes data on employees, hours worked, earnings, distribution lines, reliability, lost workdays, uncollectible accounts. It also includes financial data formerly reported on Form EIA-412, including balance sheet, income statement and operation and maintenance expense information, as well as data on revenues, kilowatt-hour sales and customers as reported on the U.S. Department of Energy, Energy Information Administration (EIA) Form EIA-861

The list below contains data sources and computational procedures for each of the ratios in the report. Definitions are found within the body of the report. All data are for 2011.

1. Revenue per kWh (Dollars)

a. All Retail Customers

$$\frac{\text{APPA Survey, part IV, line 10, Total Revenue}}{\text{APPA Survey, part IV, line 10, Total Megawatthours}}$$

b. Residential Customers

$$\frac{\text{APPA Survey, part IV, line 7, Residential Revenue}}{\text{APPA Survey, part IV, line 7, Residential Megawatthours}}$$

c. Commercial Customers

$$\frac{\text{APPA Survey, part IV, line 8, Commercial Revenue}}{\text{APPA Survey, part IV, line 8, Commercial Megawatthours}}$$

d. Industrial Customers

$$\frac{\text{APPA Survey, part IV, line 9, Industrial Revenue}}{\text{APPA Survey, part IV, line 9, Industrial Megawatthours}}$$

2. Debt to Total Assets - (Long Term Debt + Current and Accrued Liabilities to Total Assets)

$$\frac{\text{(APPA Survey, part III, line 4) + (APPA Survey, part III, line 5)}}{\text{APPA Survey, part III, line 2}}$$

3. Operating Ratio - (Total Electric O&M Expense to Total Electric Revenue)

$$\frac{\text{APPA Survey, part III, line 17}}{\text{APPA Survey, part III, line 6}}$$

4. Current Ratio - (Current & Accrued Assets to Current & Accrued Liabilities)

APPA Survey, part III, line 1
APPA Survey, part III, line 5

5a. Times Interest Earned - (Net Electric Utility Income + Interest on Long Term Debt to Interest on Long Term Debt)

(APPA Survey, part III, line 10) + (APPA Survey, part III, line 9)
APPA Survey, part III, line 9

5b. Debt Service Coverage - (Electric Utility Income + Depreciation to Total Electric Utility Debt Service Payments on Long-term Debt)

(APPA Survey, part III, line 8) + (APPA Survey, part III, line 7)
APPA Survey, Part II, Section C

6. Net Income per Revenue Dollar

APPA Survey, part III, line 10
APPA Survey, part III, line 6

7. Uncollectible accounts per Revenue Dollar

APPA Survey, Part II, Section B, Uncollectible Accounts
APPA Survey, part III, line 6

8. Retail Customers per Non-power-generation Employee

APPA Survey, Part IV, line 11, Total number of customers
Employees – Power Production Employees (APPA Survey, Part I)

Employees = Full Time + Part Time/2 + all contract employees (supervised by utility and supervised by contractor)

9. Total O & M Expense per kWh Sold

APPA Survey, part III, line 17
(APPA Survey, part IV, line 4 + line 5) *1000

10. Total O & M Expense (Excluding Power Supply Expense) per Retail Customer

(APPA Survey, part III, line 17) - (APPA Survey, part III, line 12)
APPA Survey, Part IV, line 11, Total number of customers

11. Total Power Supply Expense per kWh Sold

$$\frac{\text{APPA Survey, part III, line 12}}{\text{(APPA Survey, part IV, line 4 + line 5) *1000}}$$

12. Purchased Power Cost per kWh

$$\frac{\text{APPA Survey, part III, line 11}}{\text{(APPA Survey, part IV, line 2, Purchases from Electricity Suppliers) / 1000}}$$

13. Retail Customers per Meter Reader

$$\frac{\text{APPA Survey, Part IV, line 11, Total number of customers}}{\text{Meter Readers (from APPA Survey, Part I, Section C)}}$$

(Number of Meter Readers = Full Time + Part Time/2 + Contract)

14. Distribution O & M Expenses per Retail Customer

$$\frac{\text{APPA Survey, part III, line 14}}{\text{APPA Survey, Part IV, line 11, Total number of customers}}$$

15. Distribution O & M Expenses per Circuit Mile

$$\frac{\text{APPA Survey, part III, line 14}}{\text{APPA Survey, Part II, Section A, Total Distribution Line Circuit Miles}}$$

16. Customer Accounting, Customer Service and Sales Expense per Retail Customer

$$\frac{\text{APPA Survey, part III, line 15}}{\text{APPA Survey, Part IV, line 11, Total number of customers}}$$

17. Administrative and General Expenses per Retail Customer

$$\frac{\text{APPA Survey, part III, line 16}}{\text{APPA Survey, Part IV, line 11, Total number of customers}}$$

18. Labor Expense per Worker-hour

$$\frac{\text{Total Labor Expense (APPA Survey, Part I)}}{\text{Total Hours Worked (APPA Survey, Part I)}}$$

Labor Expense = Full-Time Earnings + Part-time Earnings + Contractor Earnings
Hours Worked = Full-Time Hours + Part-Time Hours + Contractor Hours
(supervised by utility and supervised by contractor)

19. **OSHA Incidence Rate** (per 100 employees)

$$\frac{\text{(APPA Survey, Part II, Section D, Total Number of Lost Workday Cases) * 200,000}}{\text{Number of Hours Worked (APPA Survey, Part I)}}$$

Hours Worked = Full Time Hours + Part Time Hours + Contract Hours (Supervised by utility only).

20. **Energy Loss Percentage -** Total Energy Losses to Total Sources of Energy

$$\frac{\text{APPA Survey, part IV, line 6, Total Energy Losses}}{\text{APPA Survey, part IV, line 3, Total Sources of Energy}}$$

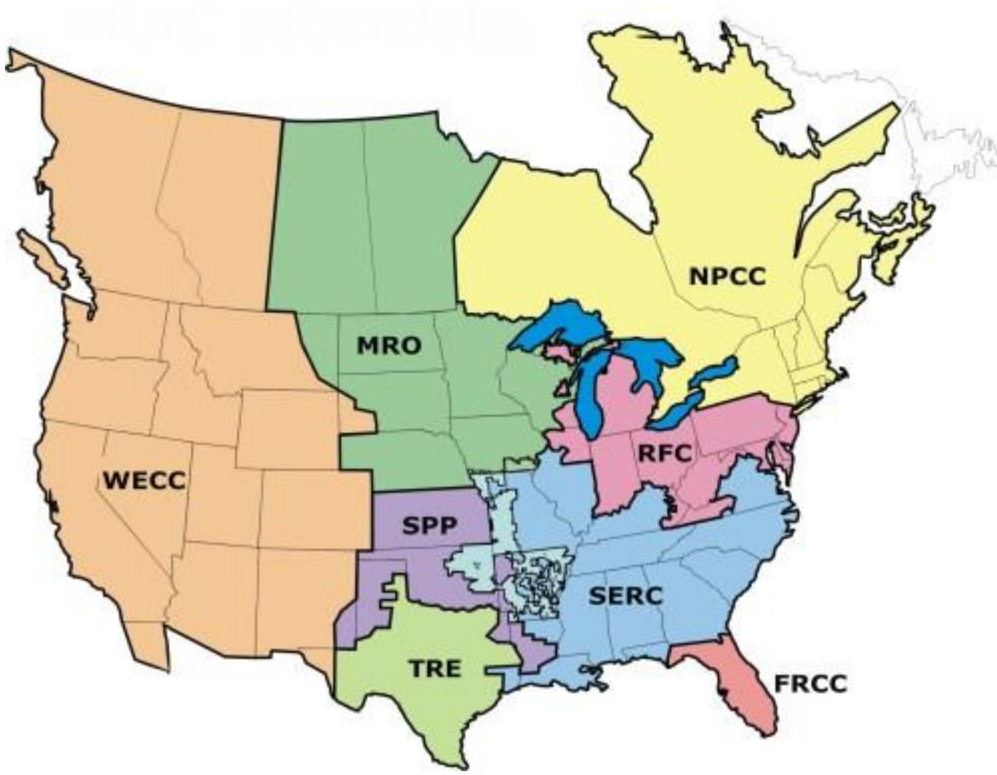
To express as a percent, multiply the result by 100.

21. **System Load Factor -** ((Total Sales + Total Energy Losses) / 8760 hrs./yr.) / Highest Hourly Peak Demand

$$\frac{\text{(APPA Survey, part IV, line 4 + line 5 + line 6/ 8760)}}{\text{APPA Survey, part IV, line 12, Highest Hourly Electrical Peak}}$$

To express as a percent, multiply the result by 100.

APPENDIX C – REGIONAL DEFINITIONS



The regions used for this report correspond to regions of the North American Electric Reliability Council (NERC) as specified below.

"Region"	Corresponding NERC Region(s)
Northeast	NPCC - Northeast Power Coordinating Council
Southeast	SERC - Southeastern Electric Reliability Council FRCC – Florida Reliability Coordinating Council
North Central/ Plains*	MRO – Midwest Reliability Organization RFC – Reliability First Corporation
Southwest	SPP – Southwest Power Pool TRE – Texas Reliability Entity
West	WECC - Western Electricity Coordinating Council ASCC - Alaska Systems Coordinating Council

*: MAIN, ECAR, and MAAC joined to become the "Reliability First" NERC region, effective January 2006. However, the Energy Information Administration continues to identify utilities by their former NERC regions. APPA uses the former regions in establishing regional breakdowns to be consistent with prior reports.

APPENDIX D

UTILITIES INCLUDED IN THE 2011 REPORT

ALABAMA
Decatur Utilities
Foley Board of Utilities

ARIZONA
Electrical District No. 2 Pinal County
Navajo Tribal Utility Authority
Salt River Project

ARKANSAS
Conway Corporation
Hope, City of
Jonesboro, City of
North Little Rock, City of
Paragould Light & Water Commission

CALIFORNIA
Alameda, City of
Anaheim, City of
Glendale, City of
Lodi, City of
Pasadena, City of
Redding, City of
Riverside, City of
Turlock Irrigation District

COLORADO
Fort Collins, City of
Longmont, City of
Loveland, City of

FLORIDA
JEA
Key West, City of
Kissimmee Utility Authority
Orlando Utilities Commission
Tallahassee, City of
Vero Beach, City of

GEORGIA
Crisp County Power Commission

IDAHO
Idaho Falls, City of

ILLINOIS
St. Charles, City of

INDIANA
Lebanon, City of

IOWA
Ames, City of
Atlantic Municipal Utilities
Cedar Falls, City of
Muscatine Power & Water
Spencer, City of
Waverly Municipal Electric Utility

KANSAS
Kansas City, City of
McPherson, City of

KENTUCKY
Murray, City of

MASSACHUSETTS
North Attleborough, Town of
Reading, Town of
Taunton, Town of
Westfield, Town of

MICHIGAN
Bay City, City of
Coldwater Board of Public Utilities
Grand Haven, City of
Holland, City of
Marquette, City of

MINNESOTA
Austin, City of
Brainerd Public Utilities
East Grand Forks, City of
Fairmont Public Utilities Commission
Grand Rapids Public Utilities Commission
Marshall, City of
Moorhead, City of
New Ulm Public Utilities Commission
Owatonna, City of
Shakopee Public Utilities Commission
Willmar Municipal Utilities Commission
Worthington, City of

MISSOURI
Poplar Bluff, City of
Rolla, City of
Springfield, City of

NEBRASKA
Hastings, City of
Grand Island, City of
Lincoln Electric System

NEBRASKA *continued*
Loup River Public Power District
Northeast Nebraska Public Power District

NEW MEXICO
Farmington, City of
Los Alamos County

NEW YORK
Massena, Town of
Plattsburgh, City of

NORTH CAROLINA
Fayetteville Public Works Commission
New River Light & Power Commission
Rocky Mount, City of
Shelby, City of

OHIO
Jackson, City of
Orrville, City of
Piqua, City of

OKLAHOMA
Stillwater Utilities Authority

OREGON
Canby Utility Board
Central Lincoln People's Utility District
Emerald People's Utility District
Eugene, City of
Northern Wasco Count People's Utility District
Springfield, City of
Tillamook People's Utility District

SOUTH CAROLINA
Easley Combined Utility System
South Carolina Public Service Authority

SOUTH DAKOTA
Watertown Municipal Utilities

TENNESSEE
Athens Utility Board
Chattanooga, City of
Columbia Power System
Cookeville, City of
Erwin, Town of
Fayetteville, City of
Humboldt, City of
Jackson Energy Authority
McMinnville Electric System
Memphis, City of
Pulaski, City of
Sevier County Electric System
Tullahoma Board of Public Utilities
Weakley County Municipal Electric System

TEXAS
Austin Energy
Bryan, City of
Denton, City of
Floresville, City of
Garland, City of
Georgetown, City of
Kerrville Public Utility Board
New Braunsfels, City of
Weatherford Municipal Utility Systems

UTAH
Logan, City of
Murray, City of
Provo City Corporation
Springville, City of
St. George, City of

VIRGINIA
Bristol Virginia Utilities
Danville, City of
Manassas, City of
Martinsville, City of

WASHINGTON
Centralia, City of
Ellensburg, City of
PUD No 1 of Benton County
PUD No 1 of Clallam County
PUD No 1 of Clark County
PUD No 1 of Lewis County
PUD No 1 of Okanogan County
PUD No 1 of Snohomish County
Seattle, City of
Tacoma, City of

WISCONSIN
Kaukauna, City of
Manitowoc Public Utilities
Marshfield, City of
Menasha, City of
Wisconsin Rapids W W & L Comm

Reliability Recommendations Outline

1. Prior to Day 1
    a. Staff on-board and familiarizing themselves with the system
    b. Create Standards
        i. Construction and Operation
            1. Allowable equipment overloads
            2. Substation load capacities and backup plans
        ii. Safety
            1. Personnel safety policies
            2. Safe operating methods and procedures
            3. Training and certification requirements
            4. Hazard analysis and mitigation processes
        iii. Design Criteria
            1. Reliability Design Standards
            2. Code Compliance – typically adopt the latest NESC
            3. Equipment Structural Loading Criteria
            4. Minimum Clearances
            5. Weather Cases
        iv. Map/GIS/Operational symbols, designations, accuracy
            1. Equipment numbering
            2. Customer/meter numbering/service location - address
    c. Analyze Electrical System
        i. Create electrical system analysis model, starting from existing map and GIS data and updating as field data comes in
        ii. Assign loads to each transformer connection
        iii. Perform analysis for existing/peak conditions
            1. Voltage drop
            2. Load balance
            3. Losses
            4. Sectionalizing/Coordination
    d. Create Outage Reporting/Detection System
        i. Dispatch Center (control center)
        ii. Integrate with GIS for outage analysis
        iii. Outage Tickets - Outage Reporting Database
    e. System Assessment
        i. Establish prioritization system and categories for equipment repair and replacement
        ii. Verify maps and model against existing equipment
        iii. Review outage history information
        iv. Infrared scans
        v. Assign repair and replacement value to each piece of equipment
        vi. Assign priorities for line clearance to ground issues
        vii. Assign priorities for vegetation management
        viii. Assign priorities for joint use management
    f. Create first Two-Year Construction Work Plan
        i. Load growth projections
        ii. System Upgrades/ Economic Conductor Analysis

      iii. Prioritized repair and replacement
      iv. Removal of unused equipment
      v. Implementation of meter replacements
      vi. Sectionalizing/Coordination modifications
      vii. Feeder configuration modifications
   g. System Inventory and General Equipment
      i. Obtain necessary material and equipment to be utilized for O&M and construction activities, unless this will be out-sourced to a contractor or another party initially.
      ii. Obtain general equipment, including trucks, vehicles, tools, equipment that will be required for O&M and construction activities, unless this will be out-sourced initially.
   h. Computer system for billing, customer records, accounting, and plant records
      i. After evaluation of available options, obtain hardware and software required for handling all activities including billing, customer records, accounting, and plant records.
      ii. Complete necessary training for staff members to utilize these platforms.
      iii. Develop a software and data conversion plan to bring all of these records over from their current source to the hardware/software platforms to be utilized by the City.

2. Day 1
   a. High priority tasks related to reliability improvement
      i. Sectionalizing/Coordination
      ii. Potential Hazard Items
      iii. Vegetation management
      iv. Integrate substation and feeder communications with control center for sectionalizing and outage management/reporting
      v. Feeder configurations
         1. Load allocation
         2. Redundancy for critical loads
         3. Balancing substation loads

3. First Two Years of Operation
   a. Implement Two-Year Construction Work Plan
   b. Establish pole-testing program
      i. Review existing records if available
      ii. Establish a program that covers 10% of all poles per year (100% testing completed in 10 years recommended due to age of poles and unknown conditions)
         1. Start with oldest areas
         2. Add any areas that were noted in the initial System Assessment
         3. Exclude areas tested within the past ten years
   c. Establish underground system inspection program
      i. Review existing records if available
         1. Prioritize areas that have experienced frequent failures
      ii. Establish an initial program that covers 33% of all equipment per year (100% inspection completed in 3 years)

1. Pad-mount transformers
2. Sectionalizing cabinets and switches
3. Vaults

d. Establish substation inspection program
    i. Review existing records if available
    ii. Initiate monthly substation inspections and reporting process
    iii. Initiate annual substation transformer oil testing program
    iv. Initiate substation relay testing program and reporting process

e. Establish breaker/recloser testing program
    i. Review existing records if available
    ii. Initiate periodic testing and repair work
    iii. Create inventory of spare equipment

f. Establish power quality standards and monitor
    i. Annual voltage recording program
    ii. Record baseline system harmonic levels

4. First Five Years of Operation
    a. Establish program for conversion of overhead to underground where most useful
    b. Determine areas for more major projects such as:
        i. Feeder rebuilds and reconductors
        ii. Transformer replacement
        iii. Conversion from single phase to three phase feeders
        iv. Sectionalizing equipment

ATTACHMENT G

Municipalization Charter Requirement Metrics

Approved by City Council on Nov. 15, 2012

Charter Requirement	Metric	Comments
Rates do not exceed rates charged by Xcel at time of acquisition	Average cost per kilowatt hour (kWh) of electricity by class as provided by Xcel (residential, commercial and industrial) compared to Xcel's average cost per kWh at time of acquisition	The average cost is calculated using the utility's annual revenue requirement divided by the most recent annual kWh projections provided by Xcel, The revenue requirement includes all elements that are currently included in rate-payer costs, such as operations & maintenance, incentives, fuel costs, purchased power, and capital costs (debt service). Due to the inability of city staff to obtain key rate calculation inputs, such as kWh (energy) and kW (demand) by rate class and tariff, rate comparisons by rate schedule cannot be calculated. These inputs, along with the methodology Xcel uses to allocate costs and calculate rates currently are unavailable. The breakdown of total revenues and kWh between residential, commercial and industrial are currently the only level of detail available at this time. *Note:* If cost allocation by rate class data is available from Xcel, the city would try to model at that level.
Rates produce revenues sufficient to pay for the new utility's operating expenses and debt payments plus an amount equal to 25% of debt payments	Debt service coverage ratio (DSCR) will be measured by dividing net annual operating income by the total annual debt service, using a standard rating agency methodology.	DSCR is measurement of a utility's ability to generate enough revenue to cover the cost of its debt payments. It is calculated by dividing the net operating income by the total debt service. The Charter requires that the new utility have a DSCR of 1.25, meaning that it generates 25% more revenue than required to cover its debt payment. This is a standard metric used by all rating agencies who evaluate municipal utility bonds. Staff will work with the city's financial advisor to develop a calculation of DSCR that will meet the rating agency requirements.

ATTACHMENT G

Municipalization Charter Requirement Metrics

Approved by City Council on Nov. 15, 2012

Charter Requirement	Metric	Comments
Reliability comparable to Xcel	1. Maintain comparable electric equipment, facilities and services as those of Xcel at time of acquisition, which will be designed to achieve the same System Average Interruption Duration Index (SAIDI) of 85 and a System Average Interruption Frequency Index (SAIFI) of .85, which is slightly better than the Xcel four year average for the Boulder region. 2. Maintain an adequate reserve margin of 15%); and 3. Meet applicable North American Electric Reliability Corporation (NERC) compliance requirements	1. "Comparable electric equipment" means the purchased or installed electric utility equipment and configuration provides the same level of reliability (redundancy and system protection) as the equipment currently owned and operated by Xcel for the area identified for municipalization. 2. "Comparable services and facilities" includes providing experienced and professional management of the local utility grid, including ongoing investment in maintenance and system improvement, and a strong customer-service ethic and partnerships to respond to emergencies, daily maintenance and long-term grid investment. 3. The SAIDI and SAIFI metrics are based on Xcel's four year average for the Boulder region. This includes more than the city of Boulder and discrete metrics for the city are not available. Without understanding the condition of the system and its performance, the selection of an average seemed to be a reasonable measure. 4. A reserve margin or "reserve capacity" is an amount of electricity capacity above the anticipated load. 15% is the accepted industry practice. 5. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards for electric utilities.

ATTACHMENT G

Municipalization Charter Requirement Metrics

Approved by City Council on Nov. 15, 2012

Charter Requirement	Metric	Comments
A plan to reduce greenhouse gas (GHG) emissions and increase renewable energy	A short-term plan (5 years) demonstrating that emissions will be reduced, as calculated based on metric tons equivalent, and that renewables will be increased proportionally beyond the levels that would have been otherwise achieved by staying with Xcel at the time of acquisition. A long-term plan (20 years) will demonstrate that the city's carbon intensity[1] from electricity in its portfolio will be less than Xcel's, and renewables (as a proportion of the resource mix) will be greater than Xcel's.	The specific metrics for showing measurable reductions will minimally include metric tons of carbon dioxide equivalent ($mtCO_2e$), which is used to convert all GHGs, such as CO_2 and CH_4, into a single measure. The plan will address emissions of other pollutants associated with generating electricity. The reductions will include, for both the city and Xcel the impacts of energy efficiency and demand response programs. Given that reductions are to be made over time, the comparison to Xcel must use the same load growth assumptions Xcel is using to define its future resource requirements and portfolio before energy efficiency or demand response adjustments.

[1] Carbon intensity is the ratio of emissions per unit of output, which in this case is the carbon dioxide equivalent released per MWh of energy produced. Emission intensities are used to derive estimates of air pollutant or greenhouse gas emissions based on the amount of fuel combusted.

ATTACHMENT H

Decision Analysis Framework and Process

GOALS OF DECISION ANALYSIS

No one can predict the future, but we can use good data to make realistic assumptions about aspects of it. Assisted by Greg Hamm of Stratelytics, LLC, staff applied a decision analysis framework to the Energy Future modeling. Decision analysis is the practice of addressing decision-making in a quantitative and probabilistic manner. The process incorporates the ability to add new information and expand and re-run models over time as additional information becomes available.

MODELING IN AN UNCERTAIN FUTURE

The financial, reliability, resource modeling, and decision analysis working groups, in addition to city staff and consultants, identified a list of “unknowns,” or uncertainties, which could have an impact on what path Boulder might take to achieve its Energy Future goals. In this case, uncertainties are things that Boulder has no—or very limited—control over. Altogether these groups provided expertise in electric utility management, distribution and transmission system management and reliability, resources and new power technology, finances, customer relations, environmental issues, and legal regulatory issues. The groups were encouraged to think about all the Energy Future goals when listing uncertainties that might have significant impacts.

Uncertainties are important to model because they expose both risks and opportunities. An uncertainty description requires: a precise definition, a description of the relevant time frame, a statement of likelihood, and quantification of its dependence on other variables in the model (dependence is a generalization of correlation). Some of the uncertainties the groups identified were long-term, such as game-changing energy management technologies. Some of them were short-term, such as startup costs associated with acquiring the local electric grid. These uncertainties were organized based on which Energy Future goal(s) they might create an impact on—this helped identify where research was needed outside the models. Not every uncertainty was modeled at this time. It was unclear how to quantify the impacts of some uncertainties, such as the possibility of significant regulatory change in Colorado. Some of these uncertainties currently are considered qualitatively rather than quantitatively.

IDENTIFYING KEY UNCERTAINTIES

A list of over 50 uncertainties was generated with working group, city staff, and consultant input. These are listed in Table 1 along with an identification of their relevant time frame and which goals they affect. First, city staff and consultants consolidated the list by eliminating redundant uncertainties and rolling more specific uncertainties up into broader categories. For example, ongoing legal costs were rolled up into O&M. Second, city staff and consultants screened the list based on impact on finances and GHG emissions, measures predicted by the quantitative model. This was based both on specific expertise of the team and on experience working with the 2011 financial model. This screening and consolidation reduced the list to 16 uncertainties. The list was circulated to working groups for additional comment. As data was refined by staff and the working groups and new information became available from engineering and legal consultants, some of the 16 uncertainties were removed or replaced with others, leading to a final list of 13. As examples:

- It was determined that prices for innovative renewable technologies were not cheap enough for them to be consistently used in resource modeling, so that uncertainty was removed.
- Staff realized that logistics costs related to startup of a local electric utility were uncertain and might be significant, so that uncertainty was added.

The broader list of unknowns is being evaluated by staff for additional qualitative review in future phases. Many of the unknowns raised by the working groups, while not modelable at this time, could help to provide more context to the question of which path—staying with Xcel Energy in the status quo, forming a new partnership, or forming a local electric utility—could best achieve the Boulder community's Energy Future goals. Correspondingly, Table 1 preliminarily classifies the unknowns based on which goal or goals they might impact.

Key to Energy Future Goals for Table 1
Goal Area 1: Ensure a stable, safe and reliable energy supply
Goal Area 2: Ensure competitive rates, balancing short- and long-term interests
Goal Area 3: Significantly reduce carbon emissions to improve environmental quality
Goal Area 4: Provide Boulder energy customers with a greater say about their energy supply
Goal Area 5: Promote local economic vitality
Goal Area 6: Promote social and environmental justice

ATTACHMENT H

TABLE 1: FULL LIST OF UNCERTAINTIES

	Timing		Energy Future Goal Impacted					
Uncertainty	**Short Term**	**Long Term**	**1**	**2**	**3**	**4**	**5**	**6**
Actual availability of IPPs to supply gas fired backup power, and cost	✓	✓	✓	✓	✓			
Actual availability of transmission capacity for wind power, and cost	✓		✓	✓	✓			
Actual availability of wind generation from existing or new wind farms, and cost	✓	✓	✓	✓	✓			
Black swan events and errors related to quantifying risk	✓	✓	✓	✓				
Capacity reserve requirements	✓	✓	✓					
Cost and timing for WAPA transmission	✓	✓	✓	✓	✓			
Costs of emergency mediation and responses to floods, fires, storms, other disasters	✓	✓	✓					✓
Costs of responding to lawsuits	✓	✓	✓	✓				
Frequency and magnitude of extreme events (climate)		✓	✓	✓	✓			
Fuel delivery interruptions forcing unplanned wholesale purchases without load balancing requirements	✓	✓	✓	✓				
Future capital investments in operations & maintenance		✓	✓				✓	✓
Level of reserve margins	✓	✓	✓					
Market wholesale cost fluctuations for energy purchases	✓	✓	✓	✓				
New regulatory requirements by FERC, NERC, WECC, Colorado, CPUC, FEMA, ERCOT	✓	✓	✓	✓	✓	✓	✓	
Renewable reserve requirements	✓	✓	✓	✓	✓			
Scheduling costs	✓	✓	✓	✓				
20-year time horizon may be incompatible with long-term leasing or contracting	✓	✓	✓	✓	✓			
Acquisition costs	✓	✓	✓	✓				
Competitive vs. non-competitive sale of bonds	✓			✓				
Cost of capital	✓	✓		✓				
Credit rating (investment grade vs. junk bond)	✓	✓		✓				
Effect of gas and coal price trajectories on Xcel vs. municipal utility	✓	✓	✓	✓	✓		✓	
Future capital investments in built generation	✓	✓	✓	✓	✓	✓	✓	
Human resources needs	✓	✓	✓	✓		✓	✓	✓
Interest rates	✓	✓		✓	✓			
Length of bonds	✓	✓		✓				
Potential for a CCA bill leading to stranded coal plants or other costs on Xcel system		✓		✓	✓	✓	✓	
Potential for existing coal plants to be stranded due to carbon tax or other GHG legislation, and resultant costs		✓		✓	✓			

Separation costs	✓	✓		✓				
Startup costs	✓		✓	✓				
Stranded costs	✓	✓		✓				
Timing of bond sales	✓	✓		✓				
Wage and price inflation	✓	✓		✓			✓	✓
Carbon tax	✓	✓		✓				
Cost and availability of coal	✓	✓		✓	✓			
Cost and availability of natural gas	✓	✓		✓	✓			
Cost and availability of water	✓	✓		✓	✓			
Cost and potential for hydroelectric expansion	✓	✓		✓	✓			
Cost and potential for large-scale renewable resources		✓		✓	✓			
Curtailment amount and costs	✓	✓	✓	✓				
Effect of rapid decrease in cost of solar and/or wind and/or storage	✓	✓		✓	✓			
Federal regulation on existing GHG emissions sources	✓	✓	✓	✓	✓			
Impacts from life-cycle analysis		✓			✓	✓		✓
Incentives for renewable energy – PTC, ITC, RECs	✓	✓		✓	✓	✓	✓	
Cost and potential for demand response	✓	✓	✓	✓	✓	✓	✓	
Cost and potential for distributed generation	✓	✓	✓	✓	✓	✓	✓	
Cost and potential for electric vehicles	✓	✓		✓	✓	✓	✓	
Cost and potential for energy efficiency	✓	✓		✓	✓	✓	✓	
Governance structure	✓	✓	✓	✓	✓	✓	✓	✓
Load growth	✓	✓	✓		✓			
Potential to "exchange" solar power between cities resulting in reduced intermittency		✓			✓	✓	✓	
Significant state legislation on energy choice (CCA, retail)		✓	✓	✓	✓	✓	✓	✓
Technological changes (process efficiency, monitoring devices)		✓	✓	✓			✓	
Local jobs benefits	✓	✓				✓	✓	✓
Major customer load losses through behind-the-meter changes or relocation	✓	✓		✓				
Revolving loan fund for innovation	✓	✓				✓	✓	✓
Impact of fracking concerns	✓	✓		✓	✓		✓	
Public health concerns	✓	✓		✓	✓		✓	✓

UNCERTAINTY DATA COLLECTION

Data collection occurred in stages. The Resource Modeling Working Group assembled a subgroup that vetted and updated a series of assumptions that were used in 2011 resource modeling, and the Financial Working Group vetted the assumptions that were used in the 2011 financial model. HOMER Energy staff provided significant input on the resource assumptions, with staff guidance and working group approval on final numbers. Similarly, the financial modeling consultant and financial advisor developed many financial inputs, supplemented by staff research and working group approval. The data was collected based on the principles that it should be realistic and locally relevant. It came from a range of sources, including Colorado Public Utilities Commission documents, NREL resources, indicative pricing, industry research, and local expertise.

For the uncertainties, the data that was collected included high and low values in addition to a median value. The goal was to find data that fit a 10-50-90 percent range—a median and 1.5 standard deviations in each direction. The 10 percent value means that there is a 10 percent chance that the actual result will be that or lower; the 90 percent value means that there is a 90 percent chance that the actual result will be that or lower. This can translate to modeling values that may look exceptionally high or low to someone who is in the field but not familiar with probabilistic analysis. This process helps identify whether a particular uncertainty has a narrow range or a wide one, and so can expose the likelihood of certain adverse outcomes. This process is important because the range of outputs discussed in the results is based on the likelihoods of the underlying data points.

Because data collection is resource intensive, it is best done in stages with the effort committed at each stage appropriate to the intended use at that stage. Data was collected in a manner judged to be appropriate to identifying the most important uncertainties and to drawing broad conclusions about the relative costs and benefits of the status quo and various municipalization strategies. As the strategies are refined an effort to refine the uncertainty distribution of the key variables by examining additional resources should be undertaken.

Importantly, while legal costs related to municipalization—stranded costs and acquisition costs—are uncertain, they have not been modeled probabilistically. The results presented in the memo include risk profiles based on the modeling of publicly available estimates from the city and Xcel Energy for informational purposes.

ANALYZING THE UNCERTAINTIES

This was a two-step process:

1. Sensitivity Analysis – This involves modeling a median value for a particular uncertainty and then testing alternately high and low values to determine whether they cause shifts in the overall outputs. If an uncertainty was not sensitive, it was not modeled as an uncertainty going forward. For example, the market cost of solar photovoltaics did not significantly impact the resource mix or cost of either a local electric utility or Xcel Energy, so it was treated as a fixed cost after this step.

2. Uncertainty Analysis – This involves modeling high, median, and low values of different uncertainties in combination with each other. A high gas price might be modeled with a low carbon price and a median interest rate. This begins to show the range of risks associated with the different options that were modeled.

RESULTS OF THE SENSITIVITY ANALYSIS

Staff and Stratelytics narrowed the full list of uncertainties to 13 for sensitivity (see Table 2). The sensitivity analysis involved varying each uncertainty as alternately high and low while keeping all others constant. Sensitivities were tested on the Xcel Baseline, Low Cost, and Lowest GHGs, Reduced Use options for the following outputs: 20-year net present value revenue requirements (NPVRR), 20-year average rates, and carbon intensity in year 2037.

The acquisition costs and stranded costs, while uncertain, were not treated as uncertainties that were fitted to a range of likelihood. Ranges were chosen to model the worst-case scenario for both types of legal costs—the worst-case numbers were provided by Xcel Energy—then lesser amounts. The $150 million for acquisition costs is the worst-case scenario for acquisition provided by a consultant to Xcel in 2011. The $255 million for stranded costs was Xcel's estimate of the worst-case scenario for stranded costs if the city left its system in 2017. Xcel provided the estimate in June 2011 in response to the city's request pursuant to the procedure of FERC Rule 888. Because the city believes that both acquisition and stranded costs will be less, acquisition costs were tested at $150 million and then thirds ($100 million and a best-case of $50 million). Stranded costs were tested at $255 million and at 50 percent, as well as a best-case of $0 because the city does not believe it is causing any stranded costs to Xcel by leaving Xcel's system.

The decision analysis software DPL organized this process and produced outputs called "tornado diagrams" which compared the impact of these uncertainties against each other as they affected outputs like revenue requirements, rates, and carbon intensity. Figures 1 through 3 show sample tornado diagrams on the three options tested for the output of average rates over 20 years. The vertical line in each of the figures shows the output when each uncertainty is set at its median value from Table 2. Taking the example of stranded costs for Figure 2 (the "Low Cost" option), setting the stranded costs at the best-case value of zero reduces the average rate over 20 years. Setting them at the worst-case value of $255 million increases the average rate over 20 years.

Staff used these results to determine which uncertainties had the most impact on the model outputs. As can be seen in Figures 1 through 3, stranded costs, gas prices, interest rates, and wind prices tended to be the largest impacts across the municipalization options. For the Xcel Baseline option, wind prices and gas prices had large and similar impacts. Stranded costs, interest rates, and debt service coverage all had similar impacts, as is to be expected. Operations and maintenance costs, somewhat surprisingly, demonstrated a higher sensitivity than acquisition costs—however, this makes sense because it is comparing ongoing annual investments with a one-year debt issue.

ATTACHMENT H

TABLE 2: UNCERTAINTIES TESTED FOR SENSITIVITY[1]

Uncertainty	Units	10% (Low)	Median	90% (High)	Applied to Muni	Applied to Xcel	Description	Sources for Range
Interest Rates	%	0.75x	6.5% (T) 5.5% (NT) 8.0% (B)	1.67x	✓	✓	Interest rates associated with Taxable (T), Non-taxable (NT), and Bridge (B) loans. See Att. E.	Based on conservative rates provided by PFM, compared by staff against ranges of interest rates by credit rating published by the Federal Reserve.
Startup Costs	thousands	0.833x	$19,475	1.333x	✓		Capital costs associated with transitioning control of the utility entity. See Att. E.	Based on thirds from highest original estimate of $32 million from the 2011 RBI Feasibility Study.
Operations & Maintenance	thousands	0.75x	$22,657	1.25x	✓		Annual investments to maintain local infrastructure. See Att. E.	Based on the range of error in cost estimates.
Logistics	thousands	0.75x	$4,934	1.25x	✓		One-time costs related to utility startup. See Att. E.	Based on the range of error in cost estimates.
Capital Improvement	thousands	0.75x	$1,500 annually + 5-year debt issuances	1.25x	✓		$1.5 million annually plus $65 million over 20 years to cover upgrades such as under-grounding and replacing aging infrastructure. See Att. E.	Based on the range of error in cost estimates; much wider range modeled than estimates from Exponential Engineering.
Debt Service Coverage Ratio (DSCR)	n/a	1.25	1.625	2.00	✓		Higher levels of coverage are connected to higher credit ratings. See Att. E.	PFM suggested 1.5-1.75 as a DSCR associated with an A- credit rating.
Natural Gas Cost	$/m^3	$0.113	$0.183	$0.252	✓	✓	2017 is listed here. See Att. E.	See Att. E.
Wind Cost (& transmission)	$/kWh	$0.031	$0.038	$0.073	✓	✓	2017 is listed here. See Att. E.	See Att. E.
Solar Cost	$/kWh	$0.133	$0.186	$0.228	✓		2017 is listed here. See Att. E.	See Att. E.
Carbon Tax	$/mt	$1.18	$5.88	$10.58	✓	✓	2017 is listed here. See Att. E.	See Att. E.
Wholesale Trade Margin	$/kWh	$0.002	$0.004	$0.006	✓		2017 is listed here. See Att. E.	See Att. E.

[1] The 10% represents a low value and the 90% represents a high value, as discussed above; some of these are depicted as multipliers on the nominal value.

ATTACHMENT H

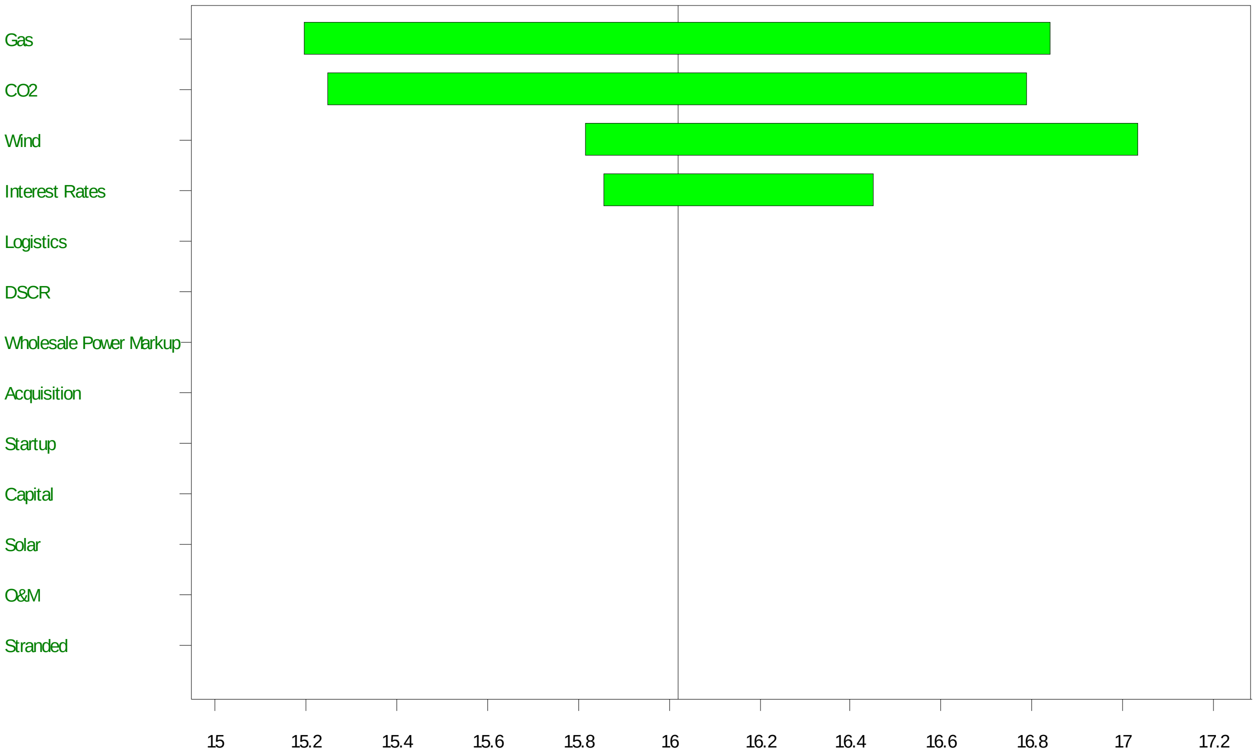


Figure 1: Tornado Diagram for Xcel Baseline Option – Average Rates over 20 Years (cents per kWh)

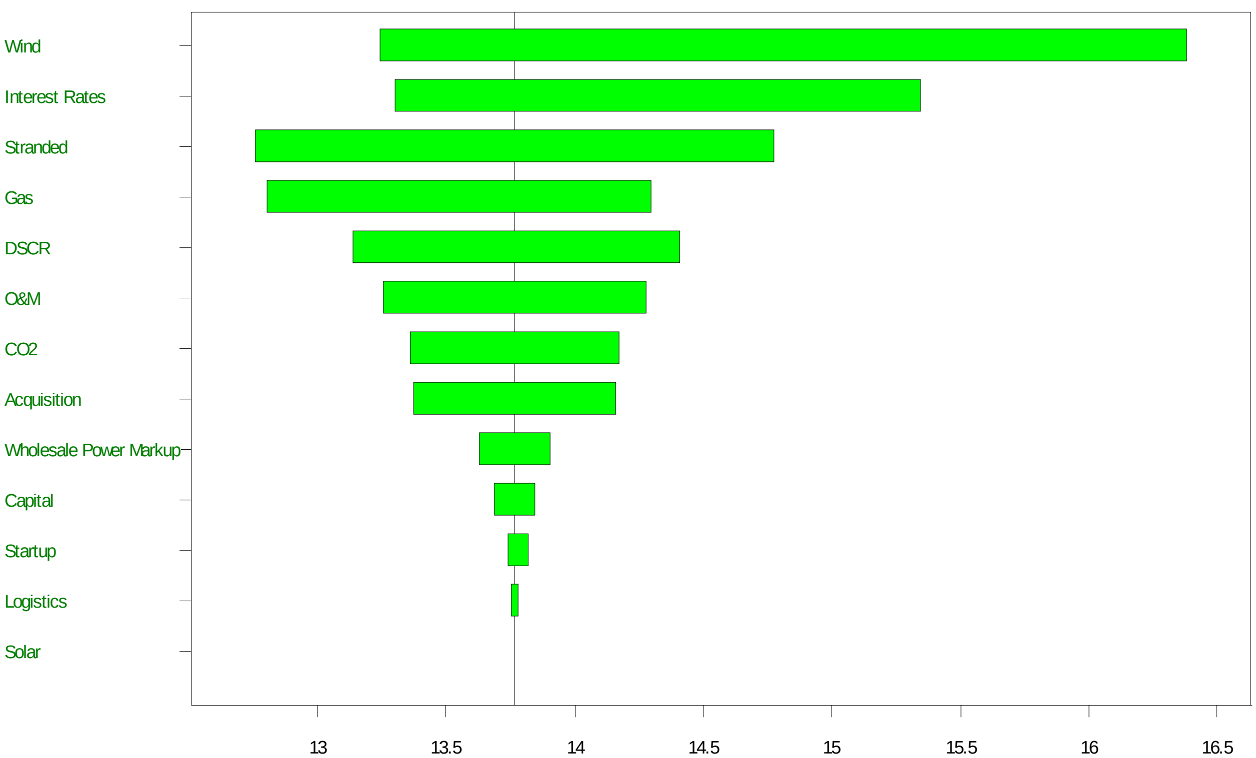


Figure 2: Tornado Diagram for Low Cost Option – Average Rates over 20 Years (cents per kWh)

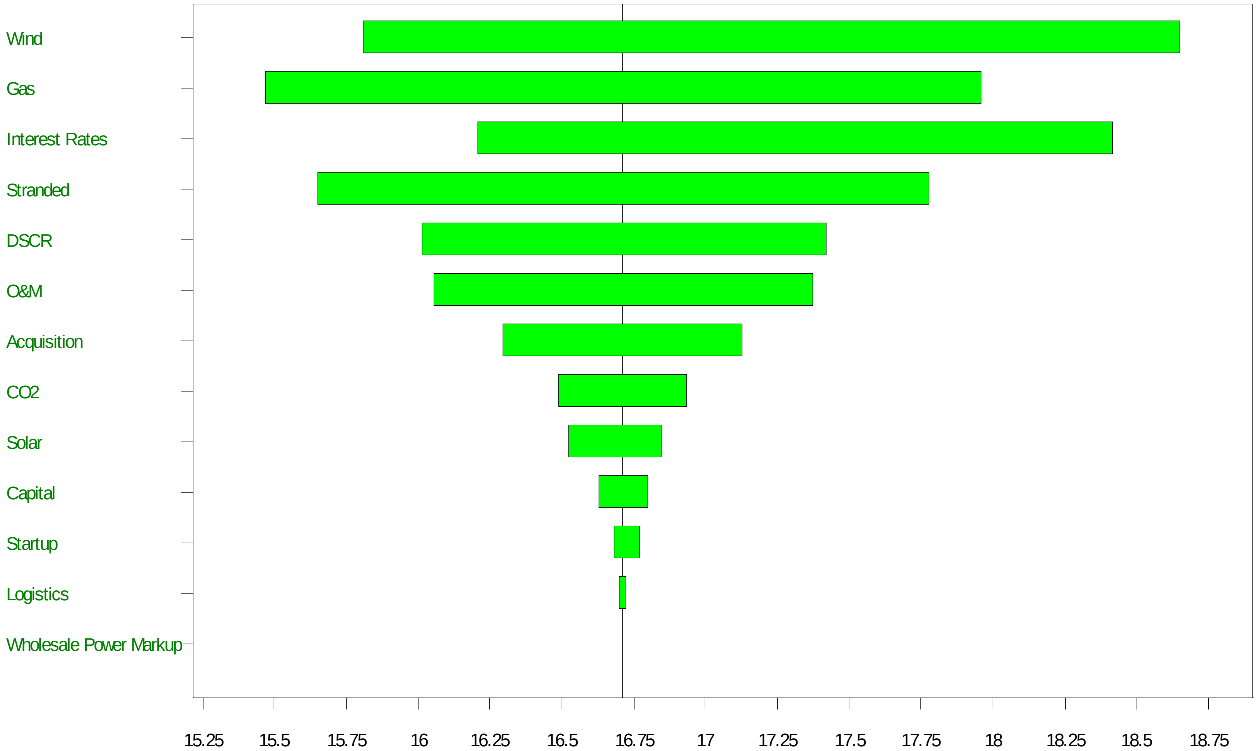


Figure 3: Tornado Diagram for Lowest GHGs, Reduce Use – Average Rates over 20 Years (cents per kWh)

UNCERTAINTY ANALYSIS

It is standard practice in decision analysis to reduce the number of uncertainties for full modeling to those that have significant impact, selecting only the most sensitive to treat probabilistically. This led to the elimination of solar prices, wholesale trade margin prices, logistics costs, startup costs, and capital costs, which were treated as fixed at their median value going forward. Additionally, acquisition and stranded costs were set prior to modeling. Therefore, the uncertainties that were modeled with high, median, and low values were interest rates, operations and maintenance, debt service coverage ratio, natural gas cost, wind cost, and carbon tax. Stranded and acquisition costs were shown as a combined best-case, middle, and worst-case costs. The results of this analysis are in the body of the memo.

ATTACHMENT I

Sample Residential Bill: Xcel Baseline vs. Phase Out possibilities

Xcel Baseline			
XCEL ENERGY			
		Average $/kWh Rate over 20 yrs=	*$ 0.2076*
Customer Name	JOE & JANE RESIDENT	*Average monthly bill over 20 yrs =*	*$ 131.20*
Date of Bill	**(YEAR 1) January 1, 2017**	**(YEAR 5) January 1, 2022**	**(YEAR 20) January 1, 2037**
Rate $/kWh	$ 0.1471	$ 0.1854	$ 0.3291
Monthly Usage	632 kWh	632 kWh	632 kWh
Total Bill:	**$92.97**	**$117.17**	**$207.99**
Total GHG emissions	**0.454** $mtCO_2$	**0.433** $mtCO_2$	**0.304** mtCO2
% Renewable Energy	**23.10%**	**22.60%**	**24.40%**
Assume 2.5% annual inflation			

Phased Out Purchase of Electricity from Xcel after Year 5			
CITY OF BOULDER - LIGHT + POWER UTILITY			
		Average $/kWh Rate over 20 yrs=	*$ 0.1940*
Customer Name	JOE & JANE RESIDENT	*Average monthly bill over 20 yrs =*	*$ 122.61*
Date of Bill	**(YEAR 1) January 1, 2017**	**(YEAR 5) January 1, 2022**	**(YEAR 20) January 1, 2037**
Rate $/kWh	$ 0.1432	$ 0.1855	$ 0.2491
Monthly Usage	632 kWh	632 kWh	632 kWh
Total Bill:	**$90.50**	**$117.24**	**$157.43**
Total GHG emissions	**0.432** $mtCO_2$	**0.136** $mtCO_2$	**0.132** mtCO2
% Renewable Energy	**24.50%**	**52.60%**	**54.10%**
ASSUME $150 million in Stranded and Acquisition costs; 2.5% annual inflation			

Phased Out Purchase of Electricity from Xcel after Year 5			
CITY OF BOULDER - LIGHT + POWER UTILITY			
		Average $/kWh Rate over 20 yrs=	*$ 0.2087*
Customer Name	JOE & JANE RESIDENT	*Average monthly bill over 20 yrs =*	*$ 131.90*
Date of Bill	**(YEAR 1) January 1, 2017**	**(YEAR 5) January 1, 2022**	**(YEAR 20) January 1, 2037**
Rate $/kWh	$ 0.1432	$ 0.2029	$ 0.2643
Monthly Usage	632 kWh	632 kWh	632 kWh
Total Bill:	**$90.50**	**$128.23**	**$167.04**
Total GHG emissions	**0.432** $mtCO_2$	**0.136** $mtCO_2$	**0.132** mtCO2
% Renewable Energy	**24.50%**	**52.60%**	**54.10%**
ASSUME $277.5 million in Stranded and Acquisition costs; 2.5% annual inflation			

Phased Out Purchase of Electricity from Xcel after Year 5			
CITY OF BOULDER - LIGHT + POWER UTILITY			
		Average $/kWh Rate over 20 yrs=	*$ 0.2235*
Customer Name	JOE & JANE RESIDENT	*Average monthly bill over 20 yrs =*	*$ 141.25*
Date of Bill	**(YEAR 1) January 1, 2017**	**(YEAR 5) January 1, 2022**	**(YEAR 20) January 1, 2037**
Rate $/kWh	$ 0.1432	$ 0.2203	$ 0.2794
Monthly Usage	632 kWh	632 kWh	632 kWh
Total Bill:	**$90.50**	**$139.23**	**$176.58**
Total GHG emissions	**0.432** $mtCO_2$	**0.136** $mtCO_2$	**0.132** mtCO2
% Renewable Energy	**24.50%**	**52.60%**	**54.10%**
ASSUME $405 million in Stranded and Acquisition costs; 2.5% annual inflation			

* 2017 rates do not vary by cost scenarios due to the capitalized debt in the first 18 months.
** Consumption is kept constant for illustration only. Actual utility modeling used variable consumption based on load models.

ATTACHMENT I

Sample Residential Bill: Xcel Baseline vs. Low cost, Lower GHGs possibilities

Xcel Baseline

XCEL ENERGY

Average $/kWh Rate over 20 yrs= $ 0.2076

Customer Name: JOE & JANE RESIDENT — *Average monthly bill over 20 yrs =* $ 131.20

Date of Bill	(YEAR 1) January 1, 2017	(YEAR 5) January 1, 2022	(YEAR 20) January 1, 2037
Rate $/kWh	$ 0.1471	$ 0.1854	$ 0.3291
Monthly Usage	632 kWh	632 kWh	632 kWh
Total Bill:	**$92.97**	**$117.17**	**$207.99**
Total GHG emissions	**0.454** $mtCO_2$	**0.433** $mtCO_2$	**0.304** $mtCO_2$
% Renewable Energy	**23.10%**	**22.60%**	**24.40%**

Assume 2.5% annual inflation

Low Cost Option

CITY OF BOULDER - LIGHT + POWER UTILITY

Average $/kWh Rate over 20 yrs= $ 0.1778

Customer Name: JOE & JANE RESIDENT — *Average monthly bill over 20 yrs =* $ 112.37

Date of Bill	(YEAR 1) January 1, 2017	(YEAR 5) January 1, 2022	(YEAR 20) January 1, 2037
Rate $/kWh	$ 0.1242	$ 0.1702	$ 0.2406
Monthly Usage	632 kWh	632 kWh	632 kWh
Total Bill:	**$78.49**	**$107.57**	**$152.06**
Total GHG emissions	**0.210** $mtCO_2$	**0.190** $mtCO_2$	**0.134** $mtCO_2$
% Renewable Energy	**57.50%**	**59.70%**	**60.50%**

ASSUME $150 million in Stranded and Acquisition costs

Low Cost Option

CITY OF BOULDER - LIGHT + POWER UTILITY

Average $/kWh Rate over 20 yrs= $ 0.1925

Customer Name: JOE & JANE RESIDENT — *Average monthly bill over 20 yrs =* $ 121.66

Date of Bill	(YEAR 1) January 1, 2017	(YEAR 5) January 1, 2022	(YEAR 20) January 1, 2037
Rate $/kWh	$ 0.1242	$ 0.1876	$ 0.2558
Monthly Usage	632 kWh	632 kWh	632 kWh
Total Bill:	**$78.49**	**$118.56**	**$161.67**
Total GHG emissions	**0.210** $mtCO_2$	**0.190** $mtCO_2$	**0.134** $mtCO_2$
% Renewable Energy	**57.50%**	**59.70%**	**60.50%**

ASSUME $277.5 million in Stranded and Acquisition costs; 2.5% annual inflation

Low Cost Option

CITY OF BOULDER - LIGHT + POWER UTILITY

Average $/kWh Rate over 20 yrs= $ 0.2072

Customer Name: JOE & JANE RESIDENT — *Average monthly bill over 20 yrs =* $ 130.95

Date of Bill	(YEAR 1) January 1, 2017	(YEAR 5) January 1, 2022	(YEAR 20) January 1, 2037
Rate $/kWh	$ 0.1242	$ 0.2050	$ 0.2710
Monthly Usage	632 kWh	632 kWh	632 kWh
Total Bill:	**$78.49**	**$129.56**	**$171.27**
Total GHG emissions	**0.210** $mtCO_2$	**0.190** $mtCO_2$	**0.134** $mtCO_2$
% Renewable Energy	**57.50%**	**59.70%**	**60.50%**

ASSUME $405 million in Stranded and Acquisition costs

* 2017 rates do not vary by cost scenarios due to the capitalized debt in the first 18 months.

** Consumption is kept constant for illustration only. Actual utility modeling used variable consumption based on load models.

ATTACHMENT I

Sample Residential Bill: <u>Xcel Baseline</u> vs. <u>Lowest cost, No Coal</u> possibilities

Xcel Baseline			
XCEL ENERGY			
		Average $/kWh Rate over 20 yrs=	*$ 0.2076*
Customer Name	JOE & JANE RESIDENT	*Average monthly bill over 20 yrs =*	*$ 131.20*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.1471	$ 0.1854	$ 0.3291
Monthly Usage	632 kWh	632 kWh	632 kWh
Total Bill:	**$92.97**	**$117.17**	**$207.99**
Total GHG emissions	**0.454** $mtCO_2$	**0.433** $mtCO_2$	**0.304** $mtCO_2$
% Renewable Energy	**23.10%**	**22.60%**	**24.40%**
Assume 2.5% annual inflation			

Low Cost - No Coal			
CITY OF BOULDER - LIGHT + POWER UTILITY			
		Average $/kWh Rate over 20 yrs=	*$ 0.1915*
Customer Name	JOE & JANE RESIDENT	*Average monthly bill over 20 yrs =*	*$ 121.03*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.1373	$ 0.1850	$ 0.2491
Monthly Usage	632 kWh	632 kWh	632 kWh
Total Bill:	**$86.77**	**$116.92**	**$157.43**
Total GHG emissions	**0.142** $mtCO_2$	**0.136** $mtCO_2$	**0.132** $mtCO_2$
% Renewable Energy	**50.40%**	**52.60%**	**54.10%**
ASSUME $150 million in Stranded and Acquisition costs			

Low Cost - No Coal			
CITY OF BOULDER - LIGHT + POWER UTILITY			
		Average $/kWh Rate over 20 yrs=	*$ 0.2063*
Customer Name	JOE & JANE RESIDENT	*Average monthly bill over 20 yrs =*	*$ 130.38*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.1373	$ 0.2024	$ 0.2643
Monthly Usage	632 kWh	632 kWh	632 kWh
Total Bill:	**$86.77**	**$127.92**	**$167.04**
Total GHG emissions	**0.142** $mtCO_2$	**0.136** $mtCO_2$	**0.132** $mtCO_2$
% Renewable Energy	**50.40%**	**52.60%**	**54.10%**
ASSUME $277.5 million in Stranded and Acquisition costs; 2.5% annual inflation			

Low Cost - No Coal			
CITY OF BOULDER - LIGHT + POWER UTILITY			
		Average $/kWh Rate over 20 yrs=	*$ 0.2210*
Customer Name	JOE & JANE RESIDENT	*Average monthly bill over 20 yrs =*	*$ 139.67*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.1373	$ 0.2198	$ 0.2795
Monthly Usage	632 kWh	632 kWh	632 kWh
Total Bill:	**$86.77**	**$138.91**	**$176.64**
Total GHG emissions	**0.142** $mtCO_2$	**0.136** $mtCO_2$	**0.132** $mtCO_2$
% Renewable Energy	**50.40%**	**52.60%**	**54.10%**
ASSUME $405 million in Stranded and Acquisition costs			

* 2017 rates do not vary by cost scenarios due to the capitalized debt in the first 18 months.

** Consumption is kept constant for illustration only. Actual utility modeling used variable consumption based on load models.

ATTACHMENT I

Sample Business Customer Bill:
Xcel Baseline vs. Phase Out possibilities

Xcel Baseline			
XCEL ENERGY			
Customer Name		*Average $/kWh Rate over 20 yrs=*	*$ 0.1390*
BOULDER BUSINESS [2ndary voltage] CUSTOMER		*Average monthly bill over 20 yrs =*	*$ 1,141.61*
Date of Bill	**(YEAR 1)** **January 1, 2017**	**(YEAR 5)** **January 1, 2022**	**(YEAR 20)** **January 1, 2037**
Rate $/kWh	$ 0.0991	$ 0.1250	$ 0.2217
Monthly Usage	8,213 kWh	8,213 kWh	8,213 kWh
Total Bill:	**$813.91**	**$1,026.63**	**$1,820.82**
Total GHG emissions	**5.906** $mtCO_2$	**5.628** $mtCO_2$	**3.953** mtCO2
% Renewable Energy	**23.10%**	**22.60%**	**24.40%**
Assume 2.5% annual inflation			

Phased Out Purchase of Electricity from Xcel after Year 5			
CITY OF BOULDER - LIGHT + POWER UTILITY			
Customer Name		*Average $/kWh Rate over 20 yrs=*	*$ 0.1307*
BOULDER BUSINESS [2ndary voltage] CUSTOMER		*Average monthly bill over 20 yrs =*	*$ 1,073.44*
Date of Bill	**(YEAR 1)** **January 1, 2017**	**(YEAR 5)** **January 1, 2022**	**(YEAR 20)** **January 1, 2037**
Rate $/kWh	$ 0.0966	$ 0.1254	$ 0.1685
Monthly Usage	8,213 kWh	8,213 kWh	8,213 kWh
Total Bill:	**$793.38**	**$1,029.91**	**$1,383.89**
Total GHG emissions	**5.620** $mtCO_2$	**1.773** $mtCO_2$	**1.717** mtCO2
% Renewable Energy	**24.50%**	**52.60%**	**54.10%**
ASSUME $150 million in Stranded and Acquisition costs; 2.5% annual inflation			

Phased Out Purchase of Electricity from Xcel after Year 5			
CITY OF BOULDER - LIGHT + POWER UTILITY			
Customer Name		*Average $/kWh Rate over 20 yrs=*	*$ 0.1406*
BOULDER BUSINESS [2ndary voltage] CUSTOMER		*Average monthly bill over 20 yrs =*	*$ 1,154.75*
Date of Bill	**(YEAR 1)** **January 1, 2017**	**(YEAR 5)** **January 1, 2022**	**(YEAR 20)** **January 1, 2037**
Rate $/kWh	$ 0.0966	$ 0.1371	$ 0.1788
Monthly Usage	8,213 kWh	8,213 kWh	8,213 kWh
Total Bill:	**$793.38**	**$1,126.00**	**$1,468.48**
Total GHG emissions	**5.620** $mtCO_2$	**1.773** $mtCO_2$	**1.717** mtCO2
% Renewable Energy	**24.50%**	**52.60%**	**54.10%**
ASSUME $277.5 million in Stranded and Acquisition costs; 2.5% annual inflation			

Phased Out Purchase of Electricity from Xcel after Year 5			
CITY OF BOULDER - LIGHT + POWER UTILITY			
Customer Name		*Average $/kWh Rate over 20 yrs=*	*$ 0.1505*
BOULDER BUSINESS [2ndary voltage] CUSTOMER		*Average monthly bill over 20 yrs =*	*$ 1,236.06*
Date of Bill	**(YEAR 1)** **January 1, 2017**	**(YEAR 5)** **January 1, 2022**	**(YEAR 20)** **January 1, 2037**
Rate $/kWh	$ 0.0966	$ 0.1489	$ 0.1890
Monthly Usage	8,213 kWh	8,213 kWh	8,213 kWh
Total Bill:	**$793.38**	**$1,222.92**	**$1,552.26**
Total GHG emissions	**5.620** $mtCO_2$	**1.773** $mtCO_2$	**1.717** mtCO2
% Renewable Energy	**24.50%**	**52.60%**	**54.10%**
ASSUME $405 million in Stranded and Acquisition costs; 2.5% annual inflation			

* 2017 rates do not vary by cost scenarios due to the capitalized debt in the first 18 months.
** Consumption is kept constant for illustration only. Actual utility modeling used variable consumption based on load models.

ATTACHMENT I

Sample Business Customer Bill:
Xcel Baseline vs. Low cost, Lower GHGs possibilities

OPTION A: Status Quo with Xcel Energy			
XCEL ENERGY			
Customer Name		*Average $/kWh Rate over 20 yrs=*	*$ 0.1390*
BOULDER BUSINESS [2ndary voltage] CUSTOMER		*Average monthly bill over 20 yrs =*	*$ 1,141.61*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.0991	$ 0.1250	$ 0.2217
Monthly Usage	8,213 kWh	8,213 kWh	8,213 kWh
Total Bill:	**$813.91**	**$1,026.63**	**$1,820.82**
Total GHG emissions	**5.906** $mtCO_2$	**5.628** $mtCO_2$	**3.953** $mtCO_2$
% Renewable Energy	**23.10%**	**22.60%**	**24.40%**
Assume 2.5% annual inflation			

Low Cost Option			
CITY OF BOULDER - LIGHT + POWER UTILITY			
Customer Name		*Average $/kWh Rate over 20 yrs=*	*$ 0.1196*
BOULDER BUSINESS [2ndary voltage] CUSTOMER		*Average monthly bill over 20 yrs =*	*$ 982.27*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.0837	$ 0.1149	$ 0.1628
Monthly Usage	8,213 kWh	8,213 kWh	8,213 kWh
Total Bill:	**$687.43**	**$943.67**	**$1,337.08**
Total GHG emissions	**2.724** $mtCO_2$	**2.463** $mtCO_2$	**1.746** $mtCO_2$
% Renewable Energy	**57.50%**	**59.70%**	**60.50%**
ASSUME $150 million in Stranded and Acquisition costs			

Low Cost Option			
CITY OF BOULDER - LIGHT + POWER UTILITY			
Customer Name		*Average $/kWh Rate over 20 yrs=*	*$ 0.1295*
BOULDER BUSINESS [2ndary voltage] CUSTOMER		*Average monthly bill over 20 yrs =*	*$ 1,063.58*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.0837	$ 0.1267	$ 0.1731
Monthly Usage	8,213 kWh	8,213 kWh	8,213 kWh
Total Bill:	**$687.43**	**$1,040.59**	**$1,421.67**
Total GHG emissions	**2.724** $mtCO_2$	**2.463** $mtCO_2$	**1.746** $mtCO_2$
% Renewable Energy	**57.50%**	**59.70%**	**60.50%**
ASSUME $277.5 million in Stranded and Acquisition costs; 2.5% annual inflation			

Low Cost Option			
CITY OF BOULDER - LIGHT + POWER UTILITY			
Customer Name		*Average $/kWh Rate over 20 yrs=*	*0.1395*
BOULDER BUSINESS [2ndary voltage] CUSTOMER		*Average monthly bill over 20 yrs =*	*$ 1,145.71*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.0837	$ 0.1385	$ 0.1833
Monthly Usage	8,213 kWh	8,213 kWh	8,213 kWh
Total Bill:	**$687.43**	**$1,137.50**	**$1,505.44**
Total GHG emissions	**2.724** $mtCO_2$	**2.463** $mtCO_2$	**1.746** $mtCO_2$
% Renewable Energy	**57.50%**	**59.70%**	**60.50%**
ASSUME $405 million in Stranded and Acquisition costs			

* 2017 rates do not vary by cost scenarios due to the capitalized debt in the first 18 months.
** Consumption is kept constant for illustration only. Actual utility modeling used variable consumption based on load models.

ATTACHMENT I

Sample Business Customer Bill:
Xcel Baseline vs. Low cost, No Coal possibilities

OPTION A: Status Quo with Xcel Energy

XCEL ENERGY

Customer Name — *Average $/kWh Rate over 20 yrs= $ 0.1390*
BOULDER BUSINESS [2ndary voltage] CUSTOMER — *Average monthly bill over 20 yrs = $ 1,141.61*

	(YEAR 1)	(YEAR 5)	(YEAR 20)
Date of Bill	January 1, 2017	January 1, 2022	January 1, 2037
Rate $/kWh	$ 0.0991	$ 0.1250	$ 0.2217
Monthly Usage	8,213 kWh	8,213 kWh	8,213 kWh
Total Bill:	**$813.91**	**$1,026.63**	**$1,820.82**
Total GHG emissions	**5.906** $mtCO_2$	**5.628** $mtCO_2$	**3.953** $mtCO_2$
% Renewable Energy	**23.10%**	**22.60%**	**24.40%**

Assume 2.5% annual inflation

Low Cost - No Coal

CITY OF BOULDER - LIGHT + POWER UTILITY

Customer Name — *Average $/kWh Rate over 20 yrs= $ 0.1290*
BOULDER BUSINESS [2ndary voltage] CUSTOMER — *Average monthly bill over 20 yrs = $ 1,059.48*

	(YEAR 1)	(YEAR 5)	(YEAR 20)
Date of Bill	January 1, 2017	January 1, 2022	January 1, 2037
Rate $/kWh	$ 0.0927	$ 0.1250	$ 0.1685
Monthly Usage	8,213 kWh	8,213 kWh	8,213 kWh
Total Bill:	**$761.35**	**$1,026.63**	**$1,383.89**
Total GHG emissions	**1.845** $mtCO_2$	**1.773** $mtCO_2$	**1.717** $mtCO_2$
% Renewable Energy	**50.40%**	**52.60%**	**54.10%**

ASSUME $150 million in Stranded and Acquisition costs

Low Cost - No Coal

CITY OF BOULDER - LIGHT + POWER UTILITY

Customer Name — *Average $/kWh Rate over 20 yrs= $ 0.1389*
BOULDER BUSINESS [2ndary voltage] CUSTOMER — *Average monthly bill over 20 yrs = $ 1,140.79*

	(YEAR 1)	(YEAR 5)	(YEAR 20)
Date of Bill	January 1, 2017	January 1, 2022	January 1, 2037
Rate $/kWh	$ 0.0927	$ 0.1368	$ 0.1788
Monthly Usage	8,213 kWh	8,213 kWh	8,213 kWh
Total Bill:	**$761.35**	**$1,123.54**	**$1,468.48**
Total GHG emissions	**1.845** $mtCO_2$	**1.773** $mtCO_2$	**1.717** $mtCO_2$
% Renewable Energy	**50.40%**	**52.60%**	**54.10%**

ASSUME $277.5 million in Stranded and Acquisition costs; 2.5% annual inflation

Low Cost - No Coal

CITY OF BOULDER - LIGHT + POWER UTILITY

Customer Name — *Average $/kWh Rate over 20 yrs= $ 0.1489*
BOULDER BUSINESS [2ndary voltage] CUSTOMER — *Average monthly bill over 20 yrs = $ 1,222.92*

	(YEAR 1)	(YEAR 5)	(YEAR 20)
Date of Bill	January 1, 2017	January 1, 2022	January 1, 2037
Rate $/kWh	$ 0.0927	$ 0.1486	$ 0.1890
Monthly Usage	8,213 kWh	8,213 kWh	8,213 kWh
Total Bill:	**$761.35**	**$1,220.45**	**$1,552.26**
Total GHG emissions	**1.845** $mtCO_2$	**1.773** $mtCO_2$	**1.717** $mtCO_2$
% Renewable Energy	**50.40%**	**52.60%**	**54.10%**

ASSUME $405 million in Stranded and Acquisition costs

* 2017 rates do not vary by cost scenarios due to the capitalized debt in the first 18 months.
** Consumption is kept constant for illustration only. Actual utility modeling used variable consumption based on load models.

ATTACHMENT I

Sample Industrial Customer Bill: Xcel Baseline vs. Phase Out possibilities

OPTION A: Status Quo with Xcel Energy

XCEL ENERGY

Customer Name			*Avg. $/kWh Rate over 20 yrs= $ 0.1898*
BOULDER INDUSTRIAL [Xmission Voltage] CUSTOMER			*Avg. monthly bill over 20 yrs = $ 8,161*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.1363	$ 0.1718	$ 0.3049
Monthly Usage	43,000 kWh	43,000 kWh	43,000 kWh
Total Bill:	**$5,860.90**	**$7,387.40**	**$13,110.70**
Total GHG emissions	**30.923** $mtCO_2$	**29.466** $mtCO_2$	**20.695** mtCO2
% Renewable Energy	**23.10%**	**22.60%**	**24.40%**

Assume 2.5% annual inflation

Phased Out Purchase of Electricity from Xcel after Year 5

CITY OF BOULDER - LIGHT + POWER UTILITY

Customer Name			*Avg. $/kWh Rate over 20 yrs= $ 0.1788*
BOULDER INDUSTRIAL [Xmission Voltage] CUSTOMER			*Avg. monthly bill over 20 yrs = $ 7,688*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.1328	$ 0.1724	$ 0.2317
Monthly Usage	43,000 kWh	43,000 kWh	43,000 kWh
Total Bill:	**$5,710.40**	**$7,413.20**	**$9,963.10**
Total GHG emissions	**29.422** $mtCO_2$	**9.284** $mtCO_2$	**8.990** mtCO2
% Renewable Energy	**24.50%**	**52.60%**	**54.10%**

ASSUME $150 million in Stranded and Acquisition costs; 2.5% annual inflation

Phased Out Purchase of Electricity from Xcel after Year 5

CITY OF BOULDER - LIGHT + POWER UTILITY

Customer Name			*Avg. $/kWh Rate over 20 yrs= $ 0.1924*
BOULDER INDUSTRIAL [Xmission Voltage] CUSTOMER			*Avg. monthly bill over 20 yrs = $ 8,273*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.1328	$ 0.1885	$ 0.2458
Monthly Usage	43,000 kWh	43,000 kWh	43,000 kWh
Total Bill:	**$5,710.40**	**$8,105.50**	**$10,569.40**
Total GHG emissions	**29.422** $mtCO_2$	**9.284** $mtCO_2$	**8.990** mtCO2
% Renewable Energy	**24.50%**	**52.60%**	**54.10%**

ASSUME $277.5 million in Stranded and Acquisition costs; 2.5% annual inflation

Phased Out Purchase of Electricity from Xcel after Year 5

CITY OF BOULDER - LIGHT + POWER UTILITY

Customer Name			*Avg. $/kWh Rate over 20 yrs= $ 0.2060*
BOULDER INDUSTRIAL [Xmission Voltage] CUSTOMER			*Avg. monthly bill over 20 yrs = $ 8,858*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.1328	$ 0.2047	$ 0.2599
Monthly Usage	43,000 kWh	43,000 kWh	43,000 kWh
Total Bill:	**$5,710.40**	**$8,802.10**	**$11,175.70**
Total GHG emissions	**29.422** $mtCO_2$	**9.284** $mtCO_2$	**8.990** mtCO2
% Renewable Energy	**24.50%**	**52.60%**	**54.10%**

ASSUME $405 million in Stranded and Acquisition costs; 2.5% annual inflation

* 2017 rates do not vary by cost scenarios due to the capitalized debt in the first 18 months.
** Consumption is kept constant for illustration only. Actual utility modeling used variable consumption based on load models.

ATTACHMENT I

Sample Industrial Customer Bill:
Xcel Baseline vs. Low Cost, Lower GHGs possibilities

OPTION A: Status Quo with Xcel Energy

XCEL ENERGY

Customer Name — *Avg. $/kWh Rate over 20 yrs= $ 0.1898*
BOULDER INDUSTRIAL [Xmission Voltage] CUSTOMER — *Avg. monthly bill over 20 yrs = $ 8,161*

	(YEAR 1)	(YEAR 5)	(YEAR 20)
Date of Bill	January 1, 2017	January 1, 2022	January 1, 2037
Rate $/kWh	$ 0.1363	$ 0.1718	$ 0.3049
Monthly Usage	43,000 kWh	43,000 kWh	43,000 kWh
Total Bill:	**$5,860.90**	**$7,387.40**	**$13,110.70**
Total GHG emissions	**30.923** $mtCO_2$	**29.466** $mtCO_2$	**20.695** $mtCO_2$
% Renewable Energy	**23.10%**	**22.60%**	**24.40%**

Assume 2.5% annual inflation

Low Cost Option

CITY OF BOULDER - LIGHT + POWER UTILITY

Customer Name — *Avg. $/kWh Rate over 20 yrs= $ 0.1634*
BOULDER INDUSTRIAL [Xmission Voltage] CUSTOMER — *Avg. monthly bill over 20 yrs = $ 7,026*

	(YEAR 1)	(YEAR 5)	(YEAR 20)
Date of Bill	January 1, 2017	January 1, 2022	January 1, 2037
Rate $/kWh	$ 0.1150	$ 0.1579	$ 0.2239
Monthly Usage	43,000 kWh	43,000 kWh	43,000 kWh
Total Bill:	**$4,945.00**	**$6,789.70**	**$9,627.70**
Total GHG emissions	**14.259** $mtCO_2$	**12.895** $mtCO_2$	**9.144** $mtCO_2$
% Renewable Energy	**57.50%**	**59.70%**	**60.50%**

ASSUME $150 million in Stranded and Acquisition costs

Low Cost Option

CITY OF BOULDER - LIGHT + POWER UTILITY

Customer Name — *Avg. $/kWh Rate over 20 yrs= $ 0.1770*
BOULDER INDUSTRIAL [Xmission Voltage] CUSTOMER — *Avg. monthly bill over 20 yrs = $ 7,611*

	(YEAR 1)	(YEAR 5)	(YEAR 20)
Date of Bill	January 1, 2017	January 1, 2022	January 1, 2037
Rate $/kWh	$ 0.1150	$ 0.1741	$ 0.2380
Monthly Usage	43,000 kWh	43,000 kWh	43,000 kWh
Total Bill:	**$4,945.00**	**$7,486.30**	**$10,234.00**
Total GHG emissions	**14.259** $mtCO_2$	**12.895** $mtCO_2$	**9.144** $mtCO_2$
% Renewable Energy	**57.50%**	**59.70%**	**60.50%**

ASSUME $277.5 million in Stranded and Acquisition costs; 2.5% annual inflation

Low Cost Option

CITY OF BOULDER - LIGHT + POWER UTILITY

Customer Name — *Avg. $/kWh Rate over 20 yrs= $ 0.1906*
BOULDER INDUSTRIAL [Xmission Voltage] CUSTOMER — *Avg. monthly bill over 20 yrs = $ 8,196*

	(YEAR 1)	(YEAR 5)	(YEAR 20)
Date of Bill	January 1, 2017	January 1, 2022	January 1, 2037
Rate $/kWh	$ 0.1151	$ 0.1903	$ 0.2521
Monthly Usage	43,000 kWh	43,000 kWh	43,000 kWh
Total Bill:	**$4,949.30**	**$8,182.90**	**$10,840.30**
Total GHG emissions	**14.259** $mtCO_2$	**12.895** $mtCO_2$	**9.144** $mtCO_2$
% Renewable Energy	**57.50%**	**59.70%**	**60.50%**

ASSUME $405 million in Stranded and Acquisition costs

* 2017 rates do not vary by cost scenarios due to the capitalized debt in the first 18 months.
** Consumption is kept constant for illustration only. Actual utility modeling used variable consumption based on load models.

ATTACHMENT I

Sample Industrial Customer Bill: Xcel Baseline vs. Lowest cost / No Coal possibilities

OPTION A: Status Quo with Xcel Energy

XCEL ENERGY

Customer Name			*Avg. $/kWh Rate over 20 yrs= $ 0.1898*
BOULDER INDUSTRIAL [Xmission Voltage] CUSTOMER			*Avg. monthly bill over 20 yrs = $ 8,161*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.1363	$ 0.1718	$ 0.3049
Monthly Usage	43,000 kWh	43,000 kWh	43,000 kWh
Total Bill:	**$5,860.90**	**$7,387.40**	**$13,110.70**
Total GHG emissions	**30.923** $mtCO_2$	**29.466** $mtCO_2$	**20.695** $mtCO_2$
% Renewable Energy	**23.10%**	**22.60%**	**24.40%**

Assume 2.5% annual inflation

Low Cost - No Coal

CITY OF BOULDER - LIGHT + POWER UTILITY

Customer Name			*Avg. $/kWh Rate over 20 yrs= $ 0.1765*
BOULDER INDUSTRIAL [Xmission Voltage] CUSTOMER			*Avg. monthly bill over 20 yrs = $ 7,590*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.1274	$ 0.1719	$ 0.2317
Monthly Usage	43,000 kWh	43,000 kWh	43,000 kWh
Total Bill:	**$5,478.20**	**$7,391.70**	**$9,963.10**
Total GHG emissions	**9.660** $mtCO_2$	**9.284** $mtCO_2$	**8.990** $mtCO_2$
% Renewable Energy	**50.40%**	**52.60%**	**54.10%**

ASSUME $150 million in Stranded and Acquisition costs

Low Cost - No Coal

CITY OF BOULDER - LIGHT + POWER UTILITY

Customer Name			*Avg. $/kWh Rate over 20 yrs= $ 0.1900*
BOULDER INDUSTRIAL [Xmission Voltage] CUSTOMER			*Avg. monthly bill over 20 yrs = $ 8,170*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.1274	$ 0.1881	$ 0.2459
Monthly Usage	43,000 kWh	43,000 kWh	43,000 kWh
Total Bill:	**$5,478.20**	**$8,088.30**	**$10,573.70**
Total GHG emissions	**9.660** $mtCO_2$	**9.284** $mtCO_2$	**8.990** $mtCO_2$
% Renewable Energy	**50.40%**	**52.60%**	**54.10%**

ASSUME $277.5 million in Stranded and Acquisition costs; 2.5% annual inflation

Low Cost - No Coal

CITY OF BOULDER - LIGHT + POWER UTILITY

Customer Name			*Avg. $/kWh Rate over 20 yrs= $ 0.2036*
BOULDER INDUSTRIAL [Xmission Voltage] CUSTOMER			*Avg. monthly bill over 20 yrs = $ 8,755*
	(YEAR 1)	**(YEAR 5)**	**(YEAR 20)**
Date of Bill	**January 1, 2017**	**January 1, 2022**	**January 1, 2037**
Rate $/kWh	$ 0.1274	$ 0.2043	$ 0.2600
Monthly Usage	43,000 kWh	43,000 kWh	43,000 kWh
Total Bill:	**$5,478.20**	**$8,784.90**	**$11,180.00**
Total GHG emissions	**9.660** $mtCO_2$	**9.284** $mtCO_2$	**8.990** $mtCO_2$
% Renewable Energy	**50.40%**	**52.60%**	**54.10%**

ASSUME $405 million in Stranded and Acquisition costs

* 2017 rates do not vary by cost scenarios due to the capitalized debt in the first 18 months.

** Consumption is kept constant for illustration only. Actual utility modeling used variable consumption based on load models.

ATTACHMENT J

The attached correspondence between the city staff and Xcel Energy discusses ways in which the organizations can begin to work together in exploring opportunities. The consensus is a working group, made up of both city and Xcel staff, including community participants, would be a good start to evaluating what a partnership would entail. Work on this effort, to include defining a process, selecting community participants, and engaging a facilitator will begin after the February 26 work session.

ATTACHMENT J

CITY OF BOULDER
Energy Strategy and Electric Utility Development

1720 14th Street, Suite 101 • P.O. Box 791, Boulder, Colorado 80306-0791
phone 303-441-3274 • fax 303-441-2174 • www.BoulderEnergyFuture.com

David L. Eves
President and CEO
Public Service Company of Colorado
1800 Larimer Street, Suite 1100
Denver, CO 80202

February 15, 2013

Re: Exploring Opportunities for Reaching Boulder's Energy Future Goals

Dear David:

I am writing to follow up on our meeting on January 24, 2013. I appreciate Xcel Energy's willingness to work with Boulder to explore some very exciting options for our future relationship. I understand that Jane Brautigam offered you the opportunity to present this proposal to the City Council at our February 26, 2013 study session. I also understand that you may not be able to commit to appear before the City Council. I do not feel comfortable presenting Xcel Energy's proposal to the City Council. City staff cannot agree to this proposal without an opportunity for the City Council to discuss it in a public meeting. Without some presentation from Xcel Energy, I do not see a way to proceed along this course. I would appreciate your letting me know by February 20, 2013, whether you or someone from your staff will be available to present to Council on February 26.

In any case, I wanted to suggest an alternative to your proposal. In your letter dated December 26, 2012, you proposed organizing a group of citizens to discuss and evaluate the proposals in the December 6, 2012 memorandum on potential alternatives to municipalization. I responded on January 11, 2013, by requesting that Xcel Energy narrow the scope of the inquiry by identifying which options would be feasible from your prospective.

Our recent experience with citizen working groups has been very positive. Even if we cannot agree to participate in your survey approach, there may be much to be gained from your December 26 proposal. I suggest that we jointly select a working group to explore alternatives to municipalization. To incentivize Xcel Energy to participate, we would agree not to file a condemnation action while the working group is meeting, provided that the group agrees to complete its work before July 1, 2013. The members of the group would be selected jointly by the city and Xcel Energy either by agreement or with each of us selecting half of the participants. A limited number of city staff and Xcel Energy employees would also be invited to participate. The group would need to have clear goals and an aggressive timetable. As I see it, the purpose of the group would be to evaluate the proposals in the December 6 memorandum and propose realistic options for a future partnership between Xcel Energy and the city that would meet the City Council's adopted energy goals.

Even if Xcel Energy decides not to participate, the discussion at the February 26 Study Session may very well inform ways in which we could work together. If you agree, I suggest that we look at creating the work group after the February 26 study session.

I appreciate your willingness to work with the city on this important effort. I look forward to hearing from you as soon as possible. Please make your best effort to respond by close of business on February 20, 2013.

Sincerely,

Heather Bailey
Executive Director
Energy Strategy and Electric Utility Development

Cc: Jane Brautigam, City Manager
Tom Carr, City Attorney

ATTACHMENT J

Xcel Energy®

RESPONSIBLE BY NATURE™

David L. Eves
President and CEO
Public Service Company of Colorado

1800 Larimer Street, Suite 1100
Denver, CO 80202

Heather Bailey
Executive Director
Energy Strategy and Electric Utility Development
City of Boulder
1720 14th Street, Suite 101
P.O. Box 791
Boulder, CO 80306-0791

February 20, 2013

Re: Exploring Opportunities for Reaching Boulder's Energy Future Goals

Dear Heather:

Thank you for your letter on February 15. As you know, Xcel Energy desires to continue to serve Boulder and as a national leader on many of the issues Boulder is concerned about, we are willing to work with Boulder on means to achieve the city's energy goals of increasing the use of renewables and reducing carbon emissions from power generation while remaining a customer.

As you know, Xcel Energy has one of the strongest platforms upon which to build. We are the nation's number one provider of wind energy, we are among the top five in solar production and we have recently worked with the City of Boulder to introduce an innovative Solar*Rewards Community program to Colorado.

In 2011, we provided our Boulder customers with over $1.8 million in rebates for making energy efficiency improvements to their homes and businesses and we provided our Boulder customers $6.145 million in incentives to install solar generation. Our Boulder customers also are great supporters of our WindSource program, a program that provides additional funding for renewable resources on our electric system.

We are in the process of retiring our older coal plants – including Valmont - and replacing them with new efficient combined cycle gas generation. We are on the way to cutting our carbon footprint by 30% from 2005 levels by 2020. And we have accomplished all this while still providing reliable electric service at rates that are 11% below the national average.

As we have discussed on several occasions, I continue to believe that Boulder can achieve its energy goals earlier, and with less risk and cost, by staying with

Xcel Energy as Boulder's electric utility. Working together we can tap Boulder's and others innovative ideas and provide the opportunity to communities and customers throughout our service area. Moreover, separating Boulder from our system will create significant economic disadvantages and potential reliability issues, while not resulting in any overall decrease in carbon emissions statewide.

Consequently, I believe Boulder can do better by working with us to achieve Boulder's goals. To that end, I welcome your suggestion that we jointly select a citizens' working group as soon as possible to explore alternatives to municipalization. We agree with your recommendation that the city and Xcel Energy each select half of the group's participants and that the group also include city staff and Xcel Energy employees. We also recommend that we hire a jointly-approved facilitator, at Xcel Energy's expense, to conduct the group meetings. While I cannot guarantee that the working group would conclude its work by July 1, 2013, I will commit to devote Xcel Energy resources to work toward that end.

However, I continue to be concerned that the city has not yet articulated clear energy goals; instead all we have seen are threshold "metrics" that provide a baseline but not much change from our current service. As we discussed at our meeting on January 24, Xcel Energy believes that we need to have a much better understanding of the amount of renewable energy our Boulder customers desire and on what timetable. We need to know how much our Boulder customers are willing to pay for additional renewable energy and/or for additional carbon reduction. How quickly and at what cost are they willing to pay for alternative energy sources? How important is it that the new generation be local generation – as opposed to potentially cheaper generation located in the premiere wind and solar regions of Colorado? In order to design new products and services, we need to have a better understanding of these targets.

To that end I informed you on January 24 that Xcel Energy intends to ask our Boulder customers these very important questions through professional polling and other methods. I continue to invite the city to participate in the preparation of this poll. Alternatively, the citizen working group could provide us input on this very important research.

Once we have a better understanding of our customers' specific preferences and goals, Xcel Energy intends to work with the city and the citizen working group to develop new products and services that could achieve the goals of the City and Boulder citizenry. This should also help our understanding of options that could be offered statewide.

All product offerings, by necessity, would be optional for cities and/or individual customers to purchase, and we would work with Boulder and our other cities and customers to offer products that each will find attractive. Of course, all products and services that we offer would require approval by the Colorado Public Utilities Commission – and all must be designed to meet requirements of state law.

Further, we see the purpose of the working group as broader than evaluating the proposals in the city's December 6 memorandum. Based on the findings of the market research, we anticipate the citizen working group could contribute additional concepts and new product ideas designed to address the city's environmental goals and those identified from our customers.

While we appreciate your offer to not file a condemnation action until after July 1, and we also agree that it would be better for both the city and Xcel Energy to avoid unnecessary litigation expense if we can instead find common ground through this working group process, Xcel Energy will not ask the city to make any commitments to delay any activities in furtherance of forming a municipal utility, as a condition of moving forward with this constructive joint effort.

Likewise, Xcel Energy will not commit to delay or stand down on any actions that we believe are appropriate to defend against the prospect of condemnation and continued pursuit by the city of its municipalization plans. I don't want the city to be surprised that Xcel Energy would take such actions to defend our interests and those of our Colorado customers, while at the same time we are working together on this constructive joint effort.

I sincerely look forward to hearing from you and to participating together in forming the citizen working group.

Very truly yours,

David Eves
President and CEO
Public Service Company of Colorado
an Xcel Energy company

cc:
Jane Brautigam, City Manager
Tom Carr, City Attorney

ATTACHMENT K

ARTICLE XIII. LIGHT AND POWER UTILITY

Sec. 178. Creation, purpose and intent.

(a) The city council, at such time as it deems appropriate, subject to the conditions herein, is authorized to establish, by ordinance, a public utility under the authority in the state constitution and the city charter to create light plants, power plants, and any other public utilities or works or ways local in use and extent for the provision of electric power. The city council shall establish a light and power utility only if it can demonstrate, with verification by a third-party independent expert, that the utility can acquire the electrical distribution system in Boulder and charge rates that do not exceed those rates charged by Xcel Energy at the time of acquisition and that such rates will produce revenues sufficient to pay for operating expenses and debt payments, plus an amount equal to twenty-five percent (25%) of the debt payments, and with reliability comparable to Xcel Energy and a plan for reduced greenhouse gas emissions and other pollutants and increased renewable energy; and

(b) The governing body of the electric utility enterprise shall be the city council. The council may, by ordinance, delegate responsibility to the electric utilities board or the city manager as appropriate.

(c) The people of Boulder seek electric power supplied in a reliable, fiscally sound, and environmentally responsible manner. Therefore, the utility will be operated according to the following guiding principles.

(1) Reliable Energy: Community safety, convenience, and prosperity all depend on the reliable delivery of electric power. The utility will deliver reliable electric power. The utility’s foremost responsibilities will be to provide electric power that is high quality and dependable, support economic vitality, prevent service outages, and respond promptly to any service outage.

(2) Fiscal Responsibility: The cost of electric power is a significant portion of business and household budgets. The utility will operate in a fiscally responsible manner, always being mindful that every expenditure will be reflected in customers’ rates and will affect household budgets and business profitability. The utility will, while always honoring its obligations to bondholders, strive to maintain rate parity with any investor-owned utility whose service area would include the City of Boulder.

(3) Clean Energy: Climate change and diminishing fossil fuel supplies, combined with the high cost of those fuels, are significant factors leading to the creation of the utility. The utility will strive to reduce reliance on fossil fuels, focus on sustainable alternatives, and seek new opportunities for producing clean energy.

(4) Ratepayer Equity: The utility will direct its efforts to promote ratepayer equity in all aspects of its operations. Rates charged by the utility will be designed to create a fair and equitable distribution among all users of the costs, replacement, maintenance, expansion, operations of facilities, energy, and energy conservation programs for the safe and efficient delivery of electric power to city residents and other customers. The utility will consider the effects of its programs, policies, and rates in the development of programs for low-income customers.

(5) Environmental Stewardship: Preserving and protecting our natural environment goes well beyond producing clean energy. The utility will be a good environmental steward by working to reduce the environmental impact of its operations, including working to reduce the demand for electricity. Energy and power that is produced in an environmentally responsible manner requires that the city balance environmental factors as an integral component of planning, design, construction, and operational decisions.

(6) Enterprise: The city will deliver electric power services by means of an enterprise, as that term is defined by Colorado law. The city further declares its intent that the city's electric utility enterprise be operated and maintained so as to exclude its activities from the application of Article X, Section 20 of the Colorado Constitution. (Added by Ord. No. 7804 (2011), § 2, adopted by electorate on November 1, 2011.)

Section 179. Definitions.

Unless the context specifically indicates otherwise, the following words and phrases shall have the following meanings as used in this article:

(a) "Electric Utility Activity" includes, but is not limited to, the provision of electric power to customers within its service area.

(b) "Electric Utility Enterprise" means the electric utility business now or hereafter owned by the city, which business receives under ten percent (10%) of its annual revenues in grants from all Colorado state and local governments combined and which is authorized to issue its own revenue bonds pursuant to this article or other applicable law.

(c) "Electric Utility Facilities" means all real and personal property utilized by the city in connection with the generation, transmission, provision distribution and conservation of energy, electricity, light and power for the city, now or hereafter owned or operated by the city.

(d) "Grant" means any direct cash subsidy or other direct contribution of money from the state or any local government in Colorado which is not required to be repaid. "Grant" does not include:

(1) any indirect benefit conferred upon the electric utility enterprise from the state or any local government in Colorado;

(2) any revenues resulting from rates, fees, assessments, or other charges imposed by the electric utility enterprise for the provision of goods or services by such enterprise; or

(3) any federal funds, regardless of whether such federal funds pass through the state or any local government in Colorado prior to receipt by the electric utility enterprise. (Added by Ord. No. 7804 (2011), § 2, adopted by electorate on November 1, 2011.)

Section 180. Powers of the electric utility enterprise.

In addition to any of the powers it may have by virtue of any of the applicable provisions of state law, this Charter, and the Code, the electric utility enterprise shall have the power under this article:

(a) to acquire by gift, purchase, lease, or exercise of the right of eminent domain, to construct, to reconstruct, to improve, to better and to extend electric utility facilities, wholly within or wholly without or partially within and partially without the territorial boundaries of the city, and to acquire in the name of the city by gift, purchase, or the exercise of the right of eminent domain lands, easements, and rights in land in connection therewith;

(b) to operate and maintain electric utility facilities for its or the city’s own use and for the use of public and private consumers and users within and without the territorial boundaries of the city;

(c) to accept federal funds under any federal law in force to aid in financing the cost of engineering, architectural, environmental, or economic investigations or studies, surveys, designs, plans, working drawings, specifications, procedures, or other action preliminary to the construction, operation or remediation of electric utility facilities;

(d) to accept federal funds under any federal law in force for the construction, operation or remediation of electric utility facilities;

(e) to prescribe, revise, and collect in advance or otherwise, from any consumer served by a electric utility activity, rates, fees, and charges or any combination thereof for the services furnished by, or the direct or indirect connection with, the electric utility facilities; and in anticipation of the collection of revenues of such electric utility facilities, to issue revenue bonds to finance in whole or in part the cost of acquisition, construction, reconstruction, improvement, betterment, or extension of the electric utility facilities; and to issue temporary bonds until permanent bonds and any coupons appertaining thereto have been printed and exchanged for the temporary bonds;

(f) to pledge to the punctual payment of said bonds and interest thereon all or any part of the revenues of the electric utility facilities;

(g) to make all contracts, execute all instruments, and do all things necessary or convenient in the exercise of the powers granted in this section or elsewhere in state law, the Charter, or the Code, or in the performance of its covenants or duties, or in order to secure the payment of its bonds if no encumbrance, mortgage, or other pledge of property, excluding any pledged revenues, of the electric utility enterprise or city is recreated thereby, and if no property, other than money, of the electric utility enterprise or city is liable to be forfeited or taken in payment of said bonds, and if no debt on the credit of the electric utility enterprise or city is thereby incurred in any manner for any purpose;

(h) to issue refunding bonds pursuant to this article or other applicable law to refund, pay, or discharge all or any part of its outstanding revenue bonds issued under this article or under any other law, including any interest thereon in arrears or about to become due, or for the purpose of reducing interest costs, effecting a change in any particular year or years in the principal and interest payable thereon or effecting other economies, or modifying or eliminating restrictive contractual limitations appertaining to the issuance of additional bonds or to any electric utility facilities; and

(i) to begin operations of the municipal utility at such time as the city council may by ordinance provide. (Added by Ord. No. 7804 (2011), § 2, adopted by electorate on November 1, 2011.)

Section 181. Revenue bonds.

(a) In accordance with and through the provisions of this section, the electric utility enterprise, through its governing body, is authorized to issue bonds or other obligations payable solely from the revenues derived or to be derived from the functions, services, benefits or facilities of such enterprise or from any other available funds of such enterprise. Such bonds or other obligations shall be authorized by ordinance, adopted by the governing body of the electric utility enterprise in the same manner as other ordinances of the city. Such bonds or other obligations may be issued without voter approval, notwithstanding the provisions of Section 2(d) of the charter, provided that, during the fiscal year of the city preceding the year in which the bonds or other obligations are authorized, the electric utility enterprise received under ten percent (10%) of its annual revenue in grants or, during the current fiscal year of the city, it is reasonably anticipated that such enterprise will receive under ten percent (10%) of its revenue in grants.

(b) The terms, conditions, and details of said bonds, or other obligations, and the procedures related thereto shall be set forth in the ordinance authorizing said bonds or other obligations and said bonds, or other obligations may be sold in accordance with the provisions of the charter. Each bond, note, or other obligation issued under this section shall recite in substance that said bond, note, or other obligation, including the interest thereon, is payable from the revenues and other available funds of the electric utility enterprise pledged for the payment thereof. Notwithstanding any other provision of law to the contrary, such bonds, or other obligations may be issued to mature at such times as are authorized by the charter, shall bear interest at such rates, and shall be sold at or above the principal amount thereof, all as shall be determined by the governing body of the electric utility enterprise. Notwithstanding anything in this section to the contrary, in the case of short-term notes or other obligations maturing not later than one year after the date of issuance thereof, the governing body of the electric utility enterprise may authorize enterprise officials to fix principal amounts, maturity dates, interest rates, and purchase prices of any particular issue of such short-term notes or obligations, subject to such limitations as to maximum term, maximum principal amount outstanding, and maximum net effective interest rates as the governing body of the electric utility enterprise shall prescribe. Refunding bonds of the electric utility enterprise shall be issued as provided in Part 1 of Article 56 of Title 11, C.R.S. The powers provided in this section to issue bonds, or other obligations are in addition and supplemental to, and not in substitution for, the powers conferred by any other law, and the powers provided in this section shall not modify, limit, or affect the powers conferred by any other law either directly or indirectly. Bonds, notes, or other obligations may be issued pursuant to this section without regard to the provisions of any other law. Insofar as the provisions of this section are inconsistent with the provisions of any other law, the provisions of this section shall control with regard to any bonds lawfully issued pursuant to this section.

(c) Any pledge of revenue or other funds of the electric utility enterprise shall be subject to any limitation on future pledges thereof contained in any ordinance of the governing body of the electric utility enterprise or of the city authorizing the issuance of any outstanding bonds or other obligations of the electric utility enterprise or the city payable from the same source or sources. Bonds or other obligations, separately issued by the city and the electric utility enterprise, but secured by the same revenues or other funds shall be treated as having the same obligor and as being payable in whole or in part from the same source or sources. (Added by Ord. No. 7804 (2011), § 2, adopted by electorate on November 1, 2011.)

Sec. 182. Utility service standards.

(a) Customer Benefit: The utility shall conduct its business and affairs for the benefit of its customers and the city.

(b) Cost Effective Service: The utility will provide the electric power requirements of the customers within the service areas in a reliable, cost-effective, and environmentally responsible manner.

(c) Energy, Energy Efficiency and Renewable Energy: The utility will engage in business activities related to the provision of electric power services, which may include but are not limited to investment in conventional electric generation, generation using renewable resources, energy efficiency measures, demand side management, and associated communication systems.

(d) Rates: The council will by ordinance fix, establish, maintain, and provide for the collection of such rates, classes of rates, fees, or charges for electric service and other utility services furnished by the city. The council will consider the following factors when setting utility rates:

ATTACHMENT K

(1) The utility will produce revenues at least sufficient to pay the cost of operation and maintenance of said utilities in good repair and working order; to pay the principal of and interest on all bonds of the city payable from the revenues of the utility;

(2) The utility will provide and maintain an adequate fund for replacement of depreciated or obsolescent property, and for the extension, improvement, enlargement, and betterment of the utility; to pay the interest on, and the principal of, any bonds issued by the city to extend or improve the utilities;

(3) The utility will consider electricity rates of surrounding and similarly situated communities and use best efforts to set competitive utility rates; and

(4) The council will fix rates for which electric service will be furnished for all purposes, and rates shall be as low as good service will permit, consistent with the guiding principles set forth in section 178 (c)(1) – (6).

(e) Budget and Appropriations: The council, by ordinance, will approve the budget and appropriations as required by Charter Art. VI.

(f) Accounting Standards: All revenues and expenditures of the city's electric system will be considered revenues and expenditures of the utility and shall be audited and accounted for in a manner that is consistent with charter § 127.

(g) No Free Service: No free energy or power shall be given to any person, firm, corporation, or institution whatsoever.

(h) Payments in Lieu of Taxes and for Services Rendered – City: The utility may only transfer funds for another governmental purpose within the city if:

(1) a service is provided to the utility by another department within the city; or

(2) in lieu of tax or franchise fee payments that a similarly situated private utility would have been required to pay taxes to the city. The maximum payment in lieu of taxes shall be limited by an estimated amount of property, sales or use tax, and a payment in lieu of a franchise fee not to exceed four percent of annual revenues.

(i) Payments in Lieu of Taxes and for Services Rendered – Other Governmental Entities: The utility shall annually transfer funds to the Boulder Valley School District in an amount the city council determines will approximate property taxes that a private utility would have paid to the School District on property owned by the electric utility enterprise. The utility may transfer funds to other governmental entities in lieu of property taxes that would have been paid if a similarly situated private utility would have been required to pay property taxes to the other governmental entity or for up to the value of a service rendered.

(j) Preferences Prohibited: The utility shall not make or grant any preference or advantage to any corporation or person or subject any corporation or person to any prejudice or disadvantage as to rates, charges, service, or facilities, or in any other respect.

(k) Advantages Prohibited: The utility shall not establish or maintain any unreasonable differences or undue preferences as to rates, charges, service, facilities, or any respect as between any class of services. The utility may create a fund to provide assistance to low-income customers for energy efficiency or generation improvements or utility bill payments. When considering whether to approve such a fund, and give a preference or advantage to low-income utility customers, the utility shall take into account the potential impact of and cost-shifting to, utility customers other than the low-income utility customers. (Added by Ord. No. 7804 (2011), § 2, adopted by electorate on November 1, 2011.)

Sec. 183. Creation of an electric utilities department and general powers.

(a) Electric Utilities Department: There shall be an electric utilities department, which shall be responsible for all planning, generation, transmission, and distribution of energy, electricity and power for the city, and such other responsibilities as the city council or city manager may assign.

(b) General Powers:

The electric utilities department shall have the authority to:

(1) Generate and deliver energy and exercise all the powers of the city including those granted by the Constitution and by the law of the state of Colorado and by the charter in regard to purchasing, condemning and purchasing, acquiring, constructing, leasing, extending and adding to, maintaining, conducting, and operating an electric utilities system for all uses and purposes, and everything necessary, pertaining or incidental thereto, including authority to dispose of real or personal property not useful for or required in the electric utilities operation.

(2) Purchase, generate, transmit, distribute, and sell electric energy.

(3) Make and execute contracts, take and give instruments of conveyance, and do all other things necessary or incidental to the powers granted in this charter.

(4) Carry out the operations, supervision, and regulation of the utility related to the lawful operation of the utility as directed by the city council.

(5) Make recommendations to the electric utilities board or the city council on matters required by the city charter.

(6) Enter into contracts and agreements with any public or private corporation or any individual, both inside and outside the boundaries of the city and state:

(A) for the joint use of property belonging either to the city or to the other contracting party or jointly to both parties; and

(B) for the joint acquisition of real and personal property, rights and franchises, and the joint financing, construction, and operation of plants, buildings, transmission lines, and other facilities. (Added by Ord. No. 7804 (2011), § 2, adopted by electorate on November 1, 2011.)

Sec. 184. Functions of the electric utilities director.

Under the direction, supervision, and control of the city manager, there shall be a director of the electric utilities department who shall be qualified by special training and experience in the field of electric utilities and municipal engineering. The director shall be the regular technical and policy advisor of the electric utilities board and shall have administrative direction of the electric utilities department. The director may be designated as the secretary of the electric utilities board and authorized to perform other necessary functions. (Added by Ord. No. 7804 (2011), § 2, adopted by electorate on November 1, 2011.)

Sec. 185. Creation of the electric utilities board.

(a) Board Created: There shall be an electric utilities board consisting of nine members not all of the same gender. The members of the board shall not hold any other office in the city, and shall serve without pay.

(b) Board Qualifications: Board members shall be selected from the registered electors of the city or from the owners or employees of a business or governmental entity that is a customer of the electric utility, provided, however, that a majority of the board shall be registered electors of the city. Board members shall be well known for their ability, probity, public spirit, and particular fitness to serve on the electric utilities board. At least three board members shall be owners or employees of a business or governmental entity that is a customer of the electric utility.

(c) Board Appointments: The city council shall appoint members of the board.

(d) Terms of Office: The term of each member shall be five years; provided, however, that in appointing the original members of the board, the city council and city manager shall continue the terms of the current members or shall stagger the initial terms so that at least one board member’s term expires in each year.

(e) Removal: The city council may remove any board member for cause.

(f) Vacancies: In the event that a board member’s term ends by resignation, vacation of seat or removal from service on the board, the board member shall be replaced by the city council.

(g) Creation of Electric Utilities Board: The electric utilities board shall be created at the time of the creation of the electric utility enterprise. Until such time as the board is created, the city council shall be responsible for fulfilling the responsibilities of the electric utilities board. (Added by Ord. No. 7804 (2011), § 2, adopted by electorate on November 1, 2011.)

Sec. 186. Organization and procedure of the board.

(a) Chair and Secretary: The board shall choose a chair and a secretary from among its members. The director of electric utilities may be designated as secretary by the board.

(b) Regular and Special Meetings: The board shall have regular meetings once a month. Special meetings may be called at any time by the city manager, the chair, or four members of the board upon the giving of at least 24 hours notice of said special meeting to the board members.

(c) Quorum: Five members of the board shall constitute a quorum. An affirmative vote of a majority of the members present shall be necessary to authorize any action by the board, except as otherwise expressly provided herein.

(d) Record of Meetings: The board shall keep minutes and records of its meetings, recommendations, and decisions.

(e) Rules of Order: Except as otherwise expressly provided herein, the board shall have power to make rules for the conduct of its business. (Added by Ord. No. 7804 (2011), § 2, adopted by electorate on November 1, 2011.)

Sec. 187. Functions of the board.

The electric utilities board shall not perform any administrative functions unless expressly provided in this charter. The duties and functions of the electric utilities board shall be:

(a) Advice. To advise the city council on policy matters pertaining to the municipal electric and utility systems, including without limitation such policies as the board determines are necessary or prudent to carry out its fiduciary duties and the requirement of the charter.

(b) Sounding Board. To act as a sounding board to the city council, city manager, and the electric utility director for the purpose of identifying the ratepayers' service delivery expectations.

(c) Rulemaking. To adopt rules and regulations with respect to any matter within its jurisdiction as it may be permitted by the council.

(d) Meeting Rules. To adopt bylaws governing its meeting and agenda procedures and other pertinent matters.

ATTACHMENT K

(e) Budget and Appropriations. To review and make recommendations to the city council on the city manager's proposed budget and appropriation as it relates to the utility.

(f) Revenue Bonds. To review and make recommendations to the city council concerning the issuance of revenue bonds or other obligations payable from revenues of the electric utilities enterprise.

(g) Other Recommendations. To review and make recommendations on any other matter relating to the electric utilities program, and may request and obtain from the electric utilities department and the city manager information relating thereto.

(h) Other Duties. To perform such other duties and functions and have such other powers as may be provided by ordinance. (Added by Ord. No. 7804 (2011), § 2, adopted by electorate on November 1, 2011.)