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.

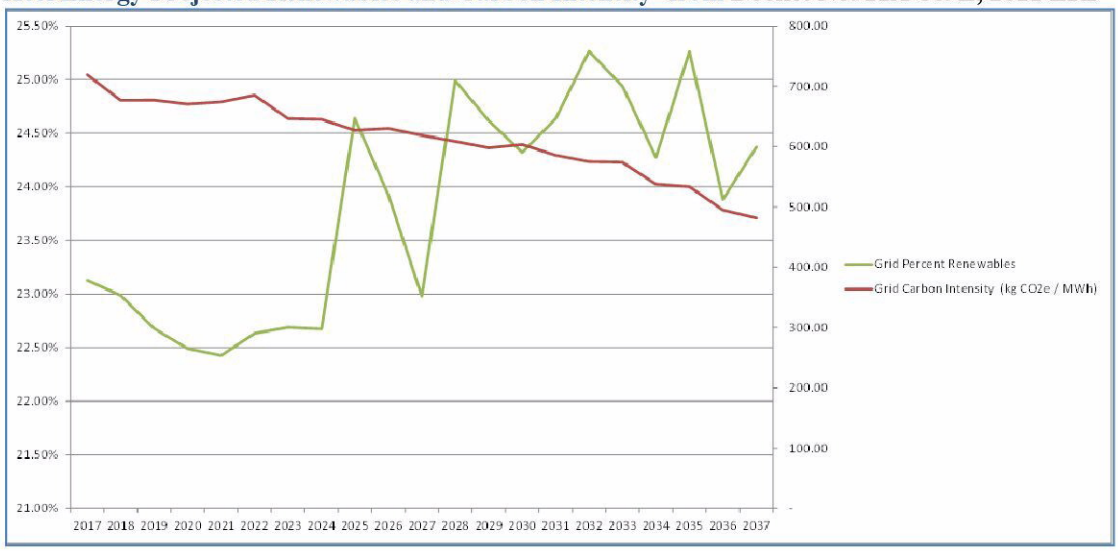
To ensure accuracy in measuring the differential between the Xcel Baseline and the municipalization options, the models used Xcel's own projections for inputs such as fuel costs, load growth, The assumptions related to the Xcel baseline were derived from recent and publicly available information such 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

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[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

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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. Operating & Maintenance Costs: 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. Start-up Costs: 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. Credit Rates: 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*

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

			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

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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

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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

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

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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

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

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