1. **In the city staff's report on key findings related to municipalization charter metrics, the analysis of the rate parity metric raises questions. None of the options fully meet the rate metric, and even those projected to have some probability of meeting it only do so at lower levels of estimated stranded and acquisition costs. To better understand the sensitivity of the city's modeling of rate parity under the different options and stranded/acquisition cost scenarios the following information would be helpful.**

The metrics have been "met" based on a demonstration of feasibility appropriate for this phase of the process. Staff presented multiple options as illustrations of different portfolios and associated costs. The actual portfolio will be developed based on community priorities, and approved by a future Utility Board and City Council. The options also provide ways of identifying, predicting and managing risk. For example, if stranded and acquisition costs are high, council could choose to prioritize low-cost resources (like the Low Cost option), or contract for a short-term power purchase agreement with Xcel (like the Phase Out option) and still meet the metrics. If stranded and acquisition costs were low, council could pursue a cleaner energy portfolio (like the Low Cost, No Coal option) and still meet the metrics. In sum, the analysis indicates that there is a high to very high level of certainty that a local electric utility could have lower overall costs—and therefore, be able to charge comparable or lower rates—than Xcel Energy over 20 years, if it pursues a lower-cost resource plan.[1] At the same time, the results indicated that this could be done without sacrificing environmental and clean energy goals.

Given that predicting the future is impossible, the city analysis—guided by a decision analysis expert with over 20 years of experience in formalized decision-making at large and small utilities—applied likelihoods to wide ranges of prices on the highest-impact uncertainties in the model. City Council's direction to perform additional research leading up to August will result in data that can be used to further refine the analysis with regard to the metrics. Wide ranges of high-impact uncertainties, like natural gas prices and interest rates, were modeled for February and April. As the data being modeled is narrowed, the metrics will be re-checked, but the function of that is to narrow—not increase—the costs being tested, making it unlikely that the metrics would not be met in the future.

Subparts (a)-(d) will be answered together.

a. **The line graphs presented by city staff indicate that average rates projected by the city through 2037 exceed Xcel's rates for at least some period of time under the $277.5M and $405M stranded and acquisition cost scenarios. What are the specific rate differentials by option, in nominal cents per kWh per year, projected through 2037 under all three stranded and acquisition cost scenarios? Graphical representation of average rates isn't specific enough to truly understand rate differentials between the different options and stranded/acquisition cost scenarios.**

[1] Notably, the city has a larger strategy related to the issue of what, if any, stranded costs the city may owe if it chooses to municipalize, and staff will not discuss litigation strategies publicly to protect the city's interests. The city does not believe it has any stranded cost liability but the modeling staff chose to model up to $255 million in stranded costs to illustrate the impact on a local electric utility.

b. **What are the specific rates, in nominal cents per kWh per year, projected through 2037 for different classes of energy users, e.g. industrial, commercial, and residential? "Average" rates aren't particularly instructive. Boulder business and institutional users can't truly evaluate the options when projected industrial and commercial rates are blended with residential rates.**

c. **If specific rates projected by different classes of users haven't actually been modeled yet, please provide some analysis of the rate differential likely to be experienced by industrial and commercial users versus residential users. Are projected industrial and commercial rates likely to higher, lower or the same as Xcel's under the different options and different stranded and acquisition cost scenarios? How do projected industrial and commercial rates under the different options and scenarios compare to projected residential rates?**

d. **When will specific rates projected by different classes of users be modeled and made available to the community?**

Rates have not yet been developed for this phase of the analysis. Ratemaking is complex and requires significant stakeholder involvement, meaning that it would be inappropriate and premature to initiate it now without greater certainty as to whether municipalization will proceed to completion. Unfortunately, we have periodically referred to these as rates rather than costs in materials, but we have been working to be more consistent in clarifying that these are based on anticipated costs and energy needs. What was shown in the Feb. 26 memo is not necessarily the same as the end rate a customer might pay, either under the municipalization or Xcel options.

What has been calculated so far is the average cost per kWh required to operate the local electric utility over 20 years for different options and with different levels of debt associated with stranded and acquisition costs. This has been compared to a forecast developed for Xcel's costs and resource needs over 20 years to determine whether the rate parity metric can be met. Total costs (and not just cost per kWh) are also being compared for that metric.

The overall average cost per kWh has been broken out between residential, commercial, and industrial customers to a limited extent. The city used annual reports (provided by Xcel when the city was under franchise) to determine which proportion of the overall revenues paid by city customers to Xcel came from each of the residential, commercial, and industrial sectors.[2] These proportions of costs were divided by the anticipated energy consumption for each of those categories to determine an average cost per kWh for each category. Notably, this analysis suggests that there is some significant cross-subsidization across rate classes.

With this caveat, staff reviewed the average cost per kWh for the residential, commercial, and industrial classes for the years 2017, 2022, 2027, 2032, and 2037.[3] This was done with the most recent version of the financial model, which was used for Apr. 16 (the Xcel Baseline was refined to include more recent

[2] Xcel refers to customers in three rate classes: residential, commercial and industrial. However, within each of the sectors, Xcel has close to 30 rate schedules differentiated by customer class, energy or demand needs, net metering, street lights, and other distinctions. Staff has not been able to obtain detailed information from Xcel to determine how each of these individual rates are calculated.

[3] The cost per kWh for each of the 5 years is in real dollars, applying 2.5% inflation. The average cost per kWh over 20 years is in 2017 dollars.

PUC filings).[4] Table 1 below shows a comparison of costs under three municipalization options compared to Xcel. More information can be provided as the modeling is refined during Phase 2:

Option	Stranded and Acquisition Costs		
	$150 million	**$277.5 million**	**$405 million**
Phase Out	**<Xcel:** 20-year avg, 2017, 2022, 2027, 2032, 2037 **>Xcel:** n/a	n/a*	n/a*
Low Cost	**<Xcel:** 20-year avg, 2017, 2022, 2027, 2032, 2037 **>Xcel:** n/a	**<Xcel:** 20-year avg, 2017, 2022, 2027, 2032, 2037 **>Xcel:** n/a	**<Xcel:** 20-year avg, 2017, 2027, 2032, 2037 **>Xcel:** 2022
Low Cost, No Coal	**<Xcel:** 20-year avg, 2017, 2022, 2027, 2032, 2037 **>Xcel:** n/a	**<Xcel:** 20-year avg, 2017, 2027, 2032, 2037 **>Xcel:** 2022	**<Xcel:** 20-year avg, 2017, 2032, 2037 **>Xcel:** 2022, 2027

Table 1: Compares the costs (and costs per kWh) for 3 municipalization options to the Xcel Baseline, under 3 levels of stranded and acquisition costs

*Because the Phase-Out Option was developed as mitigation strategy to reduce or remove the risk of stranded costs, a higher stranded cost obligation was not modeled for this Option.

As discussed below, the process of stabilizing rates over time would address those points in time where costs were higher than Xcel's, and is certainly feasible there would still be long-term cost savings (see question 5 below).

Until such a time as the City receives information from Xcel regarding its detailed rate design, or when a local utility and governing board is established, specific rates and rate differentials cannot be determined. Rate design would be considered in Phases 3 and 4. Phase 3 would begin in August 2013 if City Council approves an ordinance authorizing condemnation. This would enable the city to begin good-faith negotiations with Xcel Energy about acquiring its electric distribution system. Rate policies could be developed during this period. It is likely that rates would not be completed and authorized until Phase 4 (implementation of the utility), which would begin once the acquisition price had been obtained.

2. **The City study calculates delivered average rates on a kWh basis. Presumably, the economic model calculates monthly total power supply capacity payments by multiplying the capacity rates per kW/mo discussed in Attachment D, page 62, by a peak hour demand.**

    a. **Does the City study assume the monthly capacity payment will be calculated on an assumed peak demand for each month of the year or on the highest peak demand experienced in a year?**

The peak demand payment is based on each month of the year. The consultants and working groups believe that this approach was reasonable. If there is information that another method is more appropriate, it could be incorporated into additional modeling.

[4] Because we are currently undergoing additional review on the Xcel Baseline option modeling, the full probabilistic model has not yet been run. This means that this assessment uses "snapshot" costs rather than costs that have been adjusted based on the likelihood of the underlying variables. The results are based on the median values for the six major uncertainties—wind prices, gas prices, interest rates, O&M costs, carbon prices, and debt service coverage ratio—consistent with the Feb. 26 and Apr. 16 memos.

b. What are the generation facilities represented by the three categories? Obviously, the 8,000 Btu/kWh case is for a combined cycle unit. Less obvious, but a reasonable inference, is that the 10,000 Btu/kWh is related to a straight combustion turbine. What kind of facility or mix of facilities is related to the 9,000 Btu/kWh case?

The three categories are based on a reasonable price for a power purchase agreement (PPA) provided by the Resource Modeling Working Group, and vetted with industry experts. Assumptions were then checked against reference pricing for verification. The exact mix of generators was not specified (this was not necessary at this phase, and will be included in any future resource planning). This was one of the benefits of using a PPA—the PPA provider is responsible for finalizing the mix that will meet the terms of the contract. It is expected that the 8,000 BTU/kWh case will be, primarily, a combined cycle (CC), whereas the 10,000 BTU/kWh will be heavy on combustion turbines (CT). The 9,000 BTU/kWh is expected to be a mix of these two. All will contain a CC and a CT to maximize the ability to ramp and meet load.

c. Are monthly capacity payments and assumed peak demand isolated in a revenue requirement calculation so that an analyst can examine the details? If so, can we acquire it?

No, the capacity payments have not been isolated. HOMER provided total monthly costs to the financial model on a per technology basis. The demand and energy forecasts that were developed as part of the city's load model have been released at www.BoulderEnergyFuture.com as part of the new "Modeling" page. Monthly capacity payments have not been extracted from the model, however staff will be releasing the results of specific HOMER resource optimization runs. These are 135 complex spreadsheets that will be released in the upcoming weeks.

d. Does the City calculate capacity payment responsibility among customer classes based on demand differences or does the City distribute the payments on a total system kWh basis?

Currently capacity payment responsibility is aggregated as part of overall costs. The city's modeling did not include a formal ratemaking process, as is noted above; it used overall costs for operation of the local electric utility and apportioned them by major customer class based on the portion of revenues currently generated from that class. The revenue breakdown by class was based on data from Xcel, which combines demand and energy charges into overall revenues from Boulder customers. The costs per customer class were divided by the kWh forecast to be consumed by that customer class to obtain cost per kWh.

3. Boulder's Xcel ratepayers are part of a large aggregation. When the City is contracting at the economic margin for power, it is reasonable to assume we will have to commit for discrete generation resources and that commitment will exist on a year round basis. How is the loss of aggregation attributes analyzed in the Study?

The loss of aggregation attributes is inherently included, among numerous other factors, by comparing the various municipalization options to the Xcel Baseline. However, a PPA does not necessarily represent a single, discrete generation source. For example, the reference pricing used in the modeling was for firmed sources of power. A firmed source requires that backup sources are in place to replace the largest potential unit loss of the PPA provider. This, in essence, disqualifies single generation source providers. In addition to being firmed, reserved capacity available to meet peak load was included in the PPAs.

The PPA numbers are indicative, confirmed with additional cost modeling using Xcel's assumptions from its 2011 Electric Resource Plan for generic resources and fuels, including profits. The city could not make firm commitments for generation at this time, given the fact that it has yet to be determined whether a utility will even be created. Full resource planning would occur in a subsequent phase of the process and would include substantial public input on resource options available at that time.

4. Do the graphs and discussion on rate parity were include commercial rates?

The graphs and discussion on rate parity include overall costs per kWh based on the total revenue requirement for a municipal utility, including all customer classes. However, as discussed above, the sector-specific costs presented are not formal rates; they are apportioned to major customer classes by portion of revenues currently generated from that class.

5. What is the probability that rate stabilization could produce rates that remain competitive with Xcel's for commercial payers over the 20 year period modeled? (rather than starting lower, going higher, and sinking lower again?)

The probability of rate stabilization producing rates that are competitive over 20 years is comparable to the probability of there being long-term cost savings over 20 years. Options where cost savings could accrue over 20 years provide an opportunity for the rates charged to customers to be stabilized at a level at or below the rates charged by Xcel and to use any overages to mitigate increases in future years. This decision would be made by the policymakers setting rates.

6. Have you assigned the annual amortized cost to Year 1? If that wasn't included in Year 1, then that artificially lowers the cost for Year 1 by deferring that cost into the subsequent years.

The annual amortized cost was not assigned to year 1. It is common practice for public power utilities that interest can be capitalized and payments deferred for 18 months. It does not mean these costs do not exist; in fact, by deferring principal and interest payments for 18 months those costs are being financed over the term of the debt and increase the overall cost over 20 years. Staff acknowledged this in the Feb. 26 study session memo. There are three ways that this can be addressed:

(1) Rates could be stabilized. This would mean identifying Xcel's rates for comparability and then setting the municipal utility's rates at a rate equal to or less than Xcel's, but also higher than the utility's starting costs for the first 18 months, so that the additional costs could be used to mitigate any increase once the debt payments are required. Where there are projected to be long-term cost savings, this process is feasible.

(2) The model could be redone without capitalized interest. The impact of this would be greater cost savings over time as capitalizing interest creates greater costs in the long run. Based on recommendation by council, staff will evaluate doing this analysis, although it is not standard debt issuance practice and would likely not be the way the debt for a local electric utility would be structured.

(3) In addition to looking at comparable rates, staff will look at long-term forecasted cost savings. This is already an analysis that is being performed. If the local electric utility is projected to have lower overall costs for operations and resources than Xcel Energy, this is an indicator that rates

for its customers could be lower as well. This is being considered a secondary metric to average cost per kWh.

7. Reliability and operational efficiency of the electric utility have an impact on a community's GDP and its ability to hit green targets. Are there opportunities for the City, Xcel, or another utility to drive up reliability and operational efficiency through service level requirements and best practices?

Yes, based on our evaluation of best practices and comparison to other public power utilities, as well as expert advice from engineers, there are opportunities to improve reliability both through operations and maintenance practices and capital investment. These have both been incorporated into the municipalization options, with information available in Attachment D of the Feb. 26 study session memo and from the modeling process page of the Energy Future website.

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.

These best management practices have been considered in the development of startup and on-going operation and maintenance plans and cost modeling, as well as other opportunities to increase reliability and operational efficiency including:

- Capital replacement of assets on a regular basis
- Undergrounding cables
- Vegetation management on a 3-5 year cycle
- Smart grid implementation and adaptation
- Implementation of transmission and distribution system GIS

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 operations and maintenance costs 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.

8. What are the requirements for and assumptions around cooperation from Xcel in the Phase Out and possibly the Lower Cost option(s) in the face of a contentious relationship?

Should the City of Boulder become a wholesale electricity customer, federal law requires Xcel, as a public utility with transmission facilities, to wheel power to Boulder based on the Open Access Transmission Tariff (OATT) in Federal Energy Regulatory Commission (FERC) Rule 888. The FERC requires public utilities to provide non-discriminatory transmission services to other utilities and wholesale customers to provide for a more robust wholesale power market—ideally, a market that leads to lower prices for customers because public utilities are prevented from charging competitors exorbitant fees to use transmission. This means that Xcel has to charge itself transmission fees comparable to what it would charge Boulder. This applies whether Boulder purchases power from Xcel or from a third party.

9. What are the implications of significant unanticipated legal or financial liabilities arise such as:

a. 1 or 2 large customers are able avoid being served by the municipal utility?

Colorado is a regulated utility state and retail choice is not permitted. Customers do not have the ability to choose which utility provides their service. Rather, the customer is served by the utility provider that is within its authorized electric service area. Once the city has established its service area, it should be able to model and financially plan for all of the customers in its electric service area.

b. Potential ratepayers in unincorporated County bring a lawsuit?

Staff have anticipated and analyzed all of the potential legal challenges that are believed to be feasible, and included the likely costs thereof in the modeling. However, to protect the interests of the city we will not be discussing litigation strategy issues publicly. If there are any causes of action by a party with standing that anyone is concerned we have not anticipated or analyzed, they should so advise us of those causes of action to include in our analysis.

c. The city's possible liability for Xcel's "costs" to fight the city?

The following response was provided to a council Hotline question and is available on p. 56 of the Apr. 16, 2013 council memo, in Attachment A:

> Because staff does not believe that the city will have to pay Xcel for its legal fees, there are no fees to estimate. The United States follows the American Rule with respect to attorney's fees. The American Rule requires that each party to a lawsuit bear its own legal expenses. There must be explicit statutory exception to such rule for a court to order one party to pay the attorneys fees of another. FERC has no such authority. The PUC has no jurisdiction over the city. The only statutory exception for attorney's fees in a condemnation action is if the verdict in a condemnation action is more than 130% of the last offer of the condemning agency. Even then, the condemning agency is only responsible for paying a reasonable amount of attorney's fees directly related to the attempt by the property owner to increase the amount of the condemnation award. The condemning entity is not responsible for any attorney's fees related to the property owners attempt to stop the condemnation, stop the action necessitating the taking of the property, or any other costs unrelated to increasing the amount of the condemnation award to the property owner. If the city decides to abandon the condemnation

> or files any action in bad faith, it may be responsible for attorney's fees. However, staff does not recommend that the city proceed with condemnation under either event.
>
> The assistant attorney general representing the PUC in Docket No. 12A-155E, Verified Application and Petition for Rule Waiver (the "Boulder Docket"), did state that she believed that neither Xcel nor other ratepayers should have to bear the costs of municipalization by the city. That statement assumed that the PUC will incur costs related to the city's municipalization efforts. However, there is no clear role for the PUC related to municipalization (other than the approval of a revised Xcel service territory). It also assumed ratepayers will incur costs if Xcel is required to spend money fighting the city on municipalization and that the PUC has jurisdiction over the city. None of those assumptions is accurate.

d. The city's possible liability for Xcel's "going concern" costs?

We believe all costs related to acquisition are adequately covered in the ceiling of $150 million provided by Xcel. The following response was provided to a council Hotline question and is available on p. 56 of the Apr. 16, 2013 council memo, in Attachment A:

> Colorado courts have consistently ruled that business losses are not compensable in a condemnation setting. The "going concern" argument is requesting compensation for the loss of business or customers. Compensation for loss of business only happens in limited circumstances defined by statute. Colorado statute specifically excludes the value of the franchise area as part of just compensation in this case. The statutes do grant the right of compensation of amounts for loss of business when a municipality that operates an electric utility annexes property of a cooperative electric association that has a certificate of public convenience and necessity for the same area. However, that statute specifically does not provide such compensation in any other utility acquisition. In fact, in a 1991 case before the Colorado Supreme Court, Paula Connelly, currently general counsel for Xcel, argued that an investor-owned utility would not be owed any compensation under the statute.

e. How would a scenario in which Xcel shifts its portfolio significantly due to price signals from a carbon tax or other factors play out in terms of the comparative viability of municipalization? Do the metrics work without an assumed carbon tax?

Yes, the rate parity metric—as expressed based on long-term cost savings compared to staying with Xcel Energy—can be met even without a carbon tax. To clarify, although often labeled "carbon tax," this is a shadow price for carbon based on metric tons of carbon dioxide equivalent, and could also represent increased costs due to greenhouse gas regulation by the EPA or serve as a proxy for potential increases to coal costs beyond Xcel Energy's current forecasts. Xcel's forecasts are detailed in Attachment A to the Apr. 16 council memo and expanded further in response to the Apr. 16 Hotline questions from Councilmember Wilson.

Prior to the Feb. 26 study session, the modeling was performed without the carbon price, leading to the following likelihoods of showing 20-year cost savings at three levels of combined stranded and acquisition costs:

	Phase Out	Low Cost	Low Cost, No Coal
$150 million	70-80%	>80%	70-80%
$277.5 million	N/A	70-80%	<50%
$405 million	N/A	<50%	<50%

The options have not been tested without the carbon price against the Xcel Baseline option that was updated for the Apr. 16 council memo. However, because the Low Cost option does contain some coal, it is less impacted than the Low Cost, No Coal option by removing the carbon tax—staff does not anticipate that this option would be less than 80% likely to produce cost savings. Fuller testing will be performed after an independent analysis of the Xcel Baseline is completed.

Additionally, it is difficult to predict the impact of the carbon price without a sense of how Xcel would react in practice. While it seems logical that Xcel would shift its dispatch priority if costs of a particular fuel source (such as coal) become greater than another option, it is unclear how Xcel would address the "stranding" of owned baseload generation resources (i.e., their existing coal units) in this case. For example, the PUC approved a depreciable lifespan for Comanche 3 of about 60 years, and removing it before then would represent a significant cost to Xcel and its ratepayers. In other words, while Xcel would undoubtedly adapt to changing market conditions, it is unlikely that it could do so more cost-effectively and quickly than a utility that has not invested in generation assets.

Finally, the following response was provided to Council Hotline questions sent on April 16, 2013:

Q: As was discussed in the paper, the city's assumptions present something of a worst case for Xcel by assuming that they would not change the generation mix if a carbon tax is initiated (or if coal prices jump much higher). Xcel currently runs more coal plants because coal as a fuel is about half the price of gas. If that changed, why wouldn't Xcel change the mix of units it dispatches, putting more gas fired plants on line more of the time?

A: Staff does not agree that the modeling represented a "worst-case" for Xcel Energy. The baseline was derived directly from Xcel's own projections in their most recent Electric Resource Plan (ERP). It is correct that the city's modeling does not incorporate the assumption that Xcel would change course in response to, i.e., a high carbon tax. This has been acknowledged both in the Feb. 26 study session packet and at multiple council meetings. Again, the current assumptions for Xcel's resources are based on a baseline forecast that it provided in its 2011 ERP docket. If Xcel were willing to provide data indicating how a carbon price or other factors might shift its resource acquisitions and contracts from now until 2040 that could be incorporated into the modeling. However, it is realistic to assume that Xcel will need to have a certain level of coal costs in their long-term model, given the significant investment they have in those assets (as discussed further in Attachment A to the Apr. 16 council memo).

During the city's modeling effort, the municipalization options were treated the same way as the Xcel Baseline option. This means that each municipalization option depicts a choice to, for example, prioritize cost or emissions reductions, and maintain that priority across the 20 years modeled. In reality, the local electric utility—like Xcel—would adjust its resource mixes or other investments over time due to changing conditions. Staff is evaluating the usefulness of adding this functionality to the modeling at this stage of the process.

To the question of Xcel changing the mix or order of the energy it dispatches, staff is reluctant to speculate on how the company might react to changing market conditions. However, it is important to note that ratepayers, and not Xcel, are currently responsible for actual coal costs under the Electric Commodity Adjustment (ECA) pass-through rider—even when they differ from Xcel's projected coal costs. Without the element of risk associated with changes in fuel costs, there is little incentive to change the order of energy dispatch.

To illustrate this point, staff provided Xcel's 2007 and 2011 coal cost projections, along with actual Colorado coal costs, in the April 16 council memo (Attachment A, page 21). It is evident from Xcel's projections that coal costs are expected to rise. On April 16, Xcel released their updated ERP assumptions. Among other resource information, Xcel once again updated their projected coal costs. Figure 2 (from Attachment A) has been updated with Xcel's newest cost projections and is shown below. The city's modeling used Xcel's 2011 coal cost projection, as represented by the red line in Figure 1. Xcel's new projections, shown by the green line, are on average, 19 percent higher between 2017 and 2035.

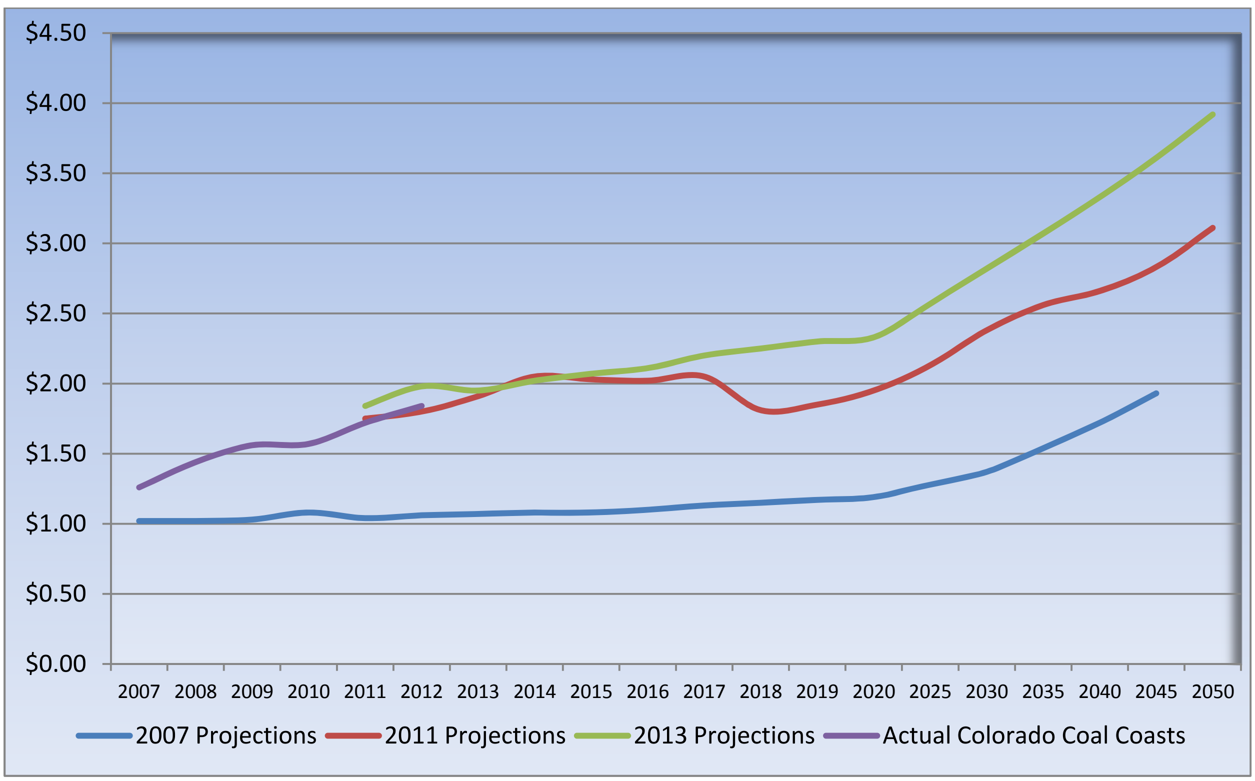

Figure 2: Xcel Energy's 2007, 2011, and 2013 Coal Price Projections Along With Actual Colorado Coal Costs Between 2007 and 2012

f. Could the price of wheeling wind go from $1M to $4M as suggested by Xcel to accommodate the real costs?

It is not clear what authority Xcel believes it may have to charge Boulder a higher cost for wheeling power. The costs associated with transmission and load balancing are set and published under the various schedules of the Open Access Transmission tariff (OATT), which is established through a regulatory process at the Federal Energy Regulatory Commission (FERC). Any change in rates would impact every other user of Xcel's transmission system, including Xcel. Specific costs associated with wheeling power are covered in Schedule 7 and 8 and Attachment H. The OATT Schedules include:

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)

g. How will a municipal utility with a high penetration of wind be able to handle the significant demands of realtime energy exchange with only 4 or 5 staff members? Is that covered by contracting for PPA's with firmed wind? If so, how?

This is covered both by contracting for firm wind through PPAs and through generalized scheduling costs, whether scheduling services would be provided internally or outsourced to experienced providers, in addition to being managed in the wider balancing authority. These costs have been included in the prices modeled in HOMER and the financial model.

h. What would be the City's exposure to curtailment costs with high wind penetration?

This would be negotiated as part of PPAs, and arrangements could be developed in which curtailment could be managed while providing the PPA manager with the ability to resell excess electricity. It is believed that curtailment costs would be less than Xcel's due to the difference in fuel mix and dispatch order between Xcel and a city-owned utility. This was also discussed briefly in Attachment A to the [Apr. 16 council memo](), on packet pages 42 and 52.

i. Is the price for wind assuming continued Production Tax Credits from the federal government?

The median and low prices for wind assume that the PTC is continued, as they are based on price trends that include the PTC. This is despite information by the International Energy Agency (IEA) and similar groups indicating that there could be declines in prices of 10-30% or more by 2030.[5] The high price assumes the PTC does not continue or technological advances do not decrease the price of wind.

[5] See, for example, a recent IEA report: http://www.ieawind.org/index_page_postings/WP2_task26.pdf.

j. How would a doubling of natural gas prices due to increasing fracking regulations (or bans) impact Boulder's ability to shift off of coal?

It is difficult to say precisely because HOMER resource software "optimizes" resources to different parameters. For example, if cost was the priority, and the only variable that was changed was natural gas prices, it might deliver a resource package with slightly larger amounts of wind, or it might mix wind, natural gas, and coal to reduce costs. Natural gas is a high-impact variable, as indicated by the results of the sensitivity analysis, described in Attachment H to the Feb. 26 study session memo.

Changing a single variable would have the greatest impact for those options where the resource mix that HOMER selected has the greatest proportion of natural gas. These percentage breakdowns were laid out in Attachment A of the Apr. 16 council memo, on p. 26 of the packet. Out of the municipalization options modeled, the Low Cost, No Coal option and the Phase Out option, at almost 50 percent natural gas, have the greatest risk associated with high natural gas prices. Because natural gas was one of the sensitivities incorporated into the city's model, a range of prices is included in the actual calculation to reflect that potential risk.

k. Boulder Weekly has suggested condemnation liabilities for the Valmont Plant could be at least $100M in toxic clean-up EPA. How would the City evaluate this significant financial risk?

If the city were planning to acquire any property with potential toxic clean-up issues, the city would retain the appropriate professionals to analyze the potential risks and costs associated with such an acquisition prior to making a recommendation to the city council.

10. If additional spending on legal costs of litigation is required beyond what voters approved in Measure 2A, how will those dollars be allocated, from which fund, and by whom?

The city would seek council approval and develop a plan at the time the issue arises.