City of Boulder, Colorado

Review of Updated Model for New Electric Utility

PROVIDED BY:

PowerServices, Inc.

Power Services
Engineering & Management Services®

1616 East Millbrook Road, Suite 210
Raleigh, North Carolina 27609
Phone: (919) 256-5900

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CITY OF BOULDER, COLORADO

REPORT OF

SUPPLEMENTAL REVIEW OF UPDATED MODEL (JULY 2013)
FOR NEW ELECTRIC UTILITY

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1. Project Scope and Authorization

On August 14, 2013, PowerServices, Inc. submitted a report (Report) to the City of Boulder, Colorado containing the results of the Third Party Independent Review of Boulder's Municipalization Model (February 26, 2013 model or the "Base Model"). The Report contained several recommendations for model enhancements and refinements. Subsequent to the Third Party Independent Review, the City's Energy Future team (Boulder Staff) incorporated changes to the model inputs, including additional transmission infrastructure acquisition and updated quantitative assumptions (July 23, 2013 model, or the "Updated Model"). The Energy Future team presented this Updated Model and its results to the council at its July 23, 2013 meeting. PowerServices, Inc. attended this meeting. The City, after the August 21, 2013 meeting, requested that PowerServices review the Updated Model with the following objectives:

- Evaluate reasonableness of changes and identify any deficiencies in a manner consistent with the initial review.
- Identify those changes that satisfy PowerServices' recommendations contained in the Third Party Independent Review report.
- Identify recommendations in the Third Party Independent Review report that are not incorporated in the Updated Model.

2. Executive Summary

The updated components of the municipalization model were evaluated in a manner similar to the original review. Assumptions were tested, inputs were validated, and, where appropriate, quantitative and qualitative results were compared to report data, generally accepted industry standards or other municipalization efforts.

A summary in the following table shows PowerServices' key recommendations contained in the Third Party Independent Review of the Base Model as compared to the updates incorporated by Boulder Staff in the Updated Model. In some cases, the Updated Model included enhancements that satisfied the majority of recommendations, such as generation pricing and building a $0 carbon option. Other recommendations were partially satisfied and should continue to be refined with more sophisticated modeling if the city forms a municipal utility. These include updating the wind capacity factor, defining and estimating all components of transmission and wind integration costs, and developing a more flexible analysis tool that links the load, resource, and financial models for improved sensitivity evaluation.

Transmission ownership assumptions incorporated since the time of the initial review introduced a new set of operational and reliability issues. The budget and separation plan in the Updated Model were adequately adjusted for the addition of transmission components to be acquired. There are certain details related to "shared ownership" of a portion of the 115kV system which will be assessed during the acquisition phase. Transmission ownership also increases complexities surrounding O&M and NERC reliability requirements. The Updated Model includes budgets for capital improvements, ongoing maintenance, and NERC compliance with the anticipation that further adjustments will be incorporated as acquisition plans advance. Ultimately, PowerServices views transmission ownership as a separate component from operation of the distribution system. The plans for ownership, operation and reliability of local assets remain intact. System operations flexibility will be enhanced by the transmission acquisition plans.

Lastly, Boulder Staff included model revisions in addition to those that PowerServices' recommended in its initial Report. These components were found to be reasonable and enhanced the modeling process.

	PowerServices' Recommendations	**Boulder Model Revisions**	**Satisfies PowerServices' Recommendations?**
1	Refresh generation pricing •re-evaluate wind capacity factor	Update gas and wind pricing	Partial - Update capacity factor using actual operating data when seeking wind resources
2	Include proxies for renewable integration/transmission congestion costs	Included in revised wind price	Partial - Identify and estimate each component of transmission and wind integration costs when seeking wind resources
3	Exclude carbon cost	Add $0 and $20 carbon options	Yes
4	Consider financial and reliability impacts of transmission ownership	•Add 230kV transformers •Add 115kV circuit and transformers •Increase Capital Assumptions to cover Replacement costs •Increase O&M	Partial - Address O&M requirements for "shared ownership" of 115kV line during acquisition phase.
5	Test sensitivity to changes in load and load factor	Modeled loss of load by adjusting Energy Efficiency/Distributed Generation	Partial - Consider tying load, resource, and financial models if Utility is formed
6	Consider additional costs arising from litigation associated with separation		N/A
7		Modify Xcel Baseline	Additional Component; Acceptable
8		Add Energy Efficiency and PV incentives	Additional Component; Acceptable
9		Include option without capitalized interest	Additional Component; Acceptable
10		Cap Stranded & Acquisition Cost	Additional Component; Acceptable

3. Evaluation Components and Results

A. Generation Pricing

Wind

PowerServices originally reported that the Base Model included benefit of the Production Tax Credit (PTC), currently $23/MWh, in the median price. The median price was supported by various sources, including favorable wind pricing in areas outside the Colorado region, while assuming an aggressive decrease in costs driven by installation efficiencies and advanced technology.

PowerServices recommended re-evaluation of the wind pricing, recognizing that the PTC is set to expire in 2013 and that aggressive price declines were not supported by historical industry data. Current softness in wind markets may translate to lower pricing and benefit Boulder, but the median price in a more conservative model would not reflect a “snapshot” of favorable pricing. Subsequently, Boulder has updated the model wind pricing. The Base and Updated Model wind prices are as follows (median price emphasized):

FEBRUARY 26, 2013 ANALYSIS					
WIND PRICES IN $/MWh (2011 dollars)					
Category	2017	2022	2027	2032	2037
High Price	$73	$73	$73	$73	$73
Median Price	$38	$38	$38	$38	$38
Low Price	$31	$31	$31	$31	$31

JULY 23, 2013 ANALYSIS					
WIND PRICES IN $/MWh (2011 dollars)					
Category	2017	2022	2027	2032	2037
High Price	$67	$65	$64	$62	$60
Median Price	$50	$50	$49	$49	$49
Low Price	$31	$31	$31	$31	$30

The Updated Model benchmarked Xcel’s wind bid prices received in the 2013 all-source solicitation as the most recent proxy for regional wind pricing. The all-in price range of $34/MWh to $72/MWh provided in the report included PTC, integration costs and transmission costs[1]. To compare Boulder estimates with Xcel, the pricing in each case was adjusted to exclude a PTC, remove transmission and integration costs, and account for cost declines due to technology.

The results indicated that Boulder’s revised median price of $49-$50/MWh (in 2011 dollars) is within the range of the Xcel bid prices after adjustments were incorporated. This is a reasonable assumption for the median busbar price, and appropriately excludes a PTC. The full delivered cost of wind power should include transmission costs (network service and ancillaries) and wind integration costs (transmission system costs incurred to integrate

[1] Public Service Company of Colorado: 2013 All Source Solicitation 20-Day Report, May 30, 2013, page 8

intermittent generation resources), which Boulder states are accounted for separately in the Updated Model. Some of these costs are estimated by applying the Open Access Transmission Tariff (OATT) while remaining costs, including curtailment, are embedded in the HOMER model.

PowerServices recognizes that it is difficult to forecast wind delivery costs when generation resources have not been identified. It is equally difficult to determine if the combined OATT and HOMER estimates in the Updated Model adequately capture the full cost of wind supply. In moving forward, the complexities of forecasting and budgeting may be better addressed by separating each transmission and integration cost component. Most components may be estimated once resources have been identified and transmission studies completed. Additional incremental costs incurred as a result of day-to-day dispatch and energy delivery may be further defined as the portfolio is developed and discussions with the Balancing Authority commence. PowerServices does not advise further adjustments to wind pricing, but emphasizes the benefits of a more detailed model that will aid in evaluating bids and managing wind supply costs.

PowerServices also reiterates the need to prepare for congestion costs. Boulder's wind resource purchases are likely incremental additions to Xcel's grid at the time that Xcel is seeking over 500 MW of wind capacity. Colorado Public Utility Commission filings state that Xcel has "not attempted to assess and quantify the magnitude and cost of wind curtailment that could result because of transmission congestion and/or reliability concerns".[2] Boulder's wind purchases may be subject to similar congestion costs depending on the timing of PPA execution and subsequent energy delivery.

Additionally, PowerServices' initial report noted that the Base Model used a wind capacity factor of 42.3% that appeared high in comparison to actual operating results, such as that found in U.S Energy Information Administration data for Colorado units (roughly 34%). Comparatively, the Xcel ERP utilizes a 47.5% capacity factor, yet their own wind integration studies use factors ranging from 26-35% on a forward-looking basis.[3] The Updated Model did not revise the capacity factor and PowerServices continues to recommend adjustments in future resource models based on reliable operating data in comparison to production estimates provided during contract negotiations with wholesale providers.

In summary, Boulder's forecast appropriately excludes benefits of a PTC in the median wind price. PowerServices finds new model pricing consistent with available data, but continues to recommend that Boulder explicitly include all relevant components for wind integration in addition to OATT charges as power purchase activities advance. An example of these components is summarized by Colorado Public Utilities Commission Staff ("Staff") comments on PSCo's PTC Wind Evaluation Report. This report identified several factors that impact the ultimate price of wind, and Staff recommended separating bid prices into the following categories[2]:

[2] Staff Comments on PSCo 2013 PTC Wind Evaluation Report, June 11, 2013, page 9

[3] EIA data for Colorado units show capacity factor closer to 34%. Xcel ERP (VOL II pg 2-223) specifies wind capacity factor of 47.5% or uses 45% in LEC calculation (pg 2-307) which are based on modeled wind profiles with limited support. Xcel also states on pg. 2-13 that Colorado wind facilities generally have a capacity factor of 30-40%. Lastly, PSCo/Xcel wind integration study appears to use capacity factors in the 26-35% range as a basis for forward-looking costs of wind integration in 2018 and beyond.

- Injection Point Costs
- Generator Interconnection Costs
- Transmission Upgrade Costs
- Wheeling Charges
- Wind Integration Adder

Some of these will not be known until a portfolio is determined and system impact studies are performed. Absent actual operational data and costs, Boulder should continue to include proxies to account for uncertainties consistent with those applied by Xcel. Lastly, the wind capacity factor should be reviewed and compared against actual performance of units in the Colorado region.

<u>Gas</u>

The baseline natural gas prices and the standard deviation used for high and low values in the Updated Model were adjusted to be consistent with Xcel's most recent ERP filings. Overall pricing decreased, which is a reasonable assumption since increased shale production continues to lower domestic energy costs. PowerServices notes that gas prices are the major market-driven resource cost in the model and have more volatility than renewables that tend to fix pricing. Both long-range planning and short term operational models will require more frequent updates to account for market influences.

B. Carbon

The Base Model captured the potential for carbon legislation by assigning carbon costs to both the Boulder municipality and the Xcel baseline. PowerServices recognized that the desire to define carbon risk ultimately added an additional level of modeling uncertainty, since Boulder and Xcel would react differently to carbon costs. PowerServices recommended that the model include a scenario that removes carbon costs to decrease uncertainties and provide a higher level of confidence in the findings. Consistent with PowerServices' recommendation, the Updated Model excludes carbon costs as one of the modeling options. The Updated Model also includes a $20 carbon cost to align with Xcel's ERP assumptions (included both $0 and $20 carbon).

C. Transmission

The Base Model contemplated system acquisition and separation scenarios to align with various service area boundaries. PowerServices evaluated support data and found the budgets and engineering plans to be robust and complete. The Boulder municipalization plan also included options for additional transmission investment, and PowerServices emphasized that transmission ownership raised financial and reliability impacts beyond those considered in the Base Model.

The Updated Model is a result of incremental changes as far back as March 2013. It reflects Boulder's decision to acquire equipment from the high side of 115kV and 230kV transformers, and to acquire the 115kV transmission loop that ties six substations that serve Boulder, while integrating the hydro-electric facility into the transmission interconnection ownership. The changes required additional upfront capital, ongoing O&M, modified separation scenarios, and increased NERC requirements. Bond requirements increased to cover the majority of additional expenditures related to transmission infrastructure replacement and long term maintenance plans were refined to meet budgeted thresholds

115kV Transmission Loop

The changes to the separation plan were partially driven by acquisition of the 115kV transmission loop. The new configuration anticipates Boulder acquiring three substations that were previously planned as shared facilities. The separation estimate was adjusted by removing costs for redundant equipment that were previously required under partial substation ownership scenarios. Concurrently, there were budget increases to account for full substation ownership along with ongoing operations and maintenance of the transmission line. The updated Model plan results in an incremental increase in operational flexibility. A major compelling benefit associated with acquiring the 115kV transmission loop is the ability for the City to better direct its future operations and long term reliability through proposed significant transmission upgrades to the system.

Lastly, the 115kV loop includes a double-circuit section of line that Boulder anticipates acquiring and entering into “shared-ownership” arrangement with Xcel. Under this plan, Xcel will retain ownership of one of the two circuits. PowerServices notes that this configuration adds additional operational and maintenance complexities. These should be addressed during the acquisition phase in order to adjust long range plans as needed.

230kV

The plan was modified to include purchase of 230kV transformers, bays and circuit breakers at Gunbarrel, Niwot and Leggett, all of Boulder Canyon Hydro Sub, and 115kV bays at Eldorado and Valmont in order to receive high side service. The separation plan has been adequately adjusted, and this will result in greater operational flexibility and long term control for a Boulder utility system.

Reliability

Boulder Staff has emphasized the increased reliability that will be achieved through acquisition of the transmission loop and associated equipment. However, this purchase adds greater regulatory oversight, responsibilities, and exposure. PowerServices highlighted the need to plan for transmission ownership and separation in accordance with NERC standards. Depending on the final outcome of the proposed acquisition, Boulder may or may not be required to register as a Transmission Owner/Transmission Operator or Transmission Service Provider. The designation will depend on the impact to the Bulk Electric System (BES), however, it is almost a certainty that Boulder would register under one or more of the Distribution Entity requirements. Many NERC standards deal with the local utility complying with good industry practice, such as testing, design and training. The local utility should adopt its own standards that NERC would confirm are met through spot checks and audits, self-certifications and self-reports.

In summary, PowerServices recommends that Boulder plan for active leadership in reliability and compliance of the local distribution system and BES. At a minimum, a full time compliance officer and a documented compliance program would be needed. There are more than 120 NERC Reliability Standards and greater than 1,650 requirements of these Standards. Certain violations can result in significant fines until corrective action is taken. Boulder has anticipated and budgeted for some of the staffing requirements noted above. Once the actual assets are acquired, the City should re-assess the need for experienced external assistance or support of a Joint Registration Organization ("JRO"), and budget accordingly.

D. Load Sensitivity`

PowerServices recommended additional modeling refinement to include sensitivity to load decreases, particularly in the case of the loss of high load factor industrial/commercial customers. Boulder staff studied gradual decreases in load due to increased demand side management (DSM) and distributed generation (DG) and reported the following impacts[4]:

Load Scenario Sample Year: 2020	Average Cents/kWh	Average Monthly Residential* Bill Impact ($)	Average Monthly Commercial** Bill Impact ($)
Full Modeled Load	12.21	-	-
2% reduction	12.25	$0.28	$0.50
5% reduction	12.32	$0.72	$1.29
10% reduction	12.45	$1.53	$2.72

* Based on 632 kWh/month average usage
** Based on 1,123 kWh/month average usage

By adjusting revenues, Boulder Staff observed some shift in costs due to load loss, which they expect will occur gradually. Boulder Staff also concluded, without adjusting the actual load model, that reduced retail consumption would lower resource costs due to lower energy use and peak demand. This is only a proxy, and to understand full impacts of varying load, a useful tool for resource and financial planning, Boulder should incorporate functionality in the load model. This may not be achievable with the current modeling tools, but should be considered as municipalization efforts advance. A more sophisticated load and resource model, when tied to a financial tool, will allow Boulder to:

- Evaluate impacts of step changes in load, such as loss of commercial or industrial customers (2 Boulder customers account for 15% of energy use),
- Evaluate impacts on power supply costs under various load profiles (resource contracts may have limited flexibility to adjust to declining/shifting loads and Boulder may be obligated to take uneconomic power), and
- Incorporate retail rate strategies that allow recovery of fixed costs or system impact costs due to declining consumption and customer owned generation.

[4] 8/6/13 Council Presentation: Appendix B, packet page 61

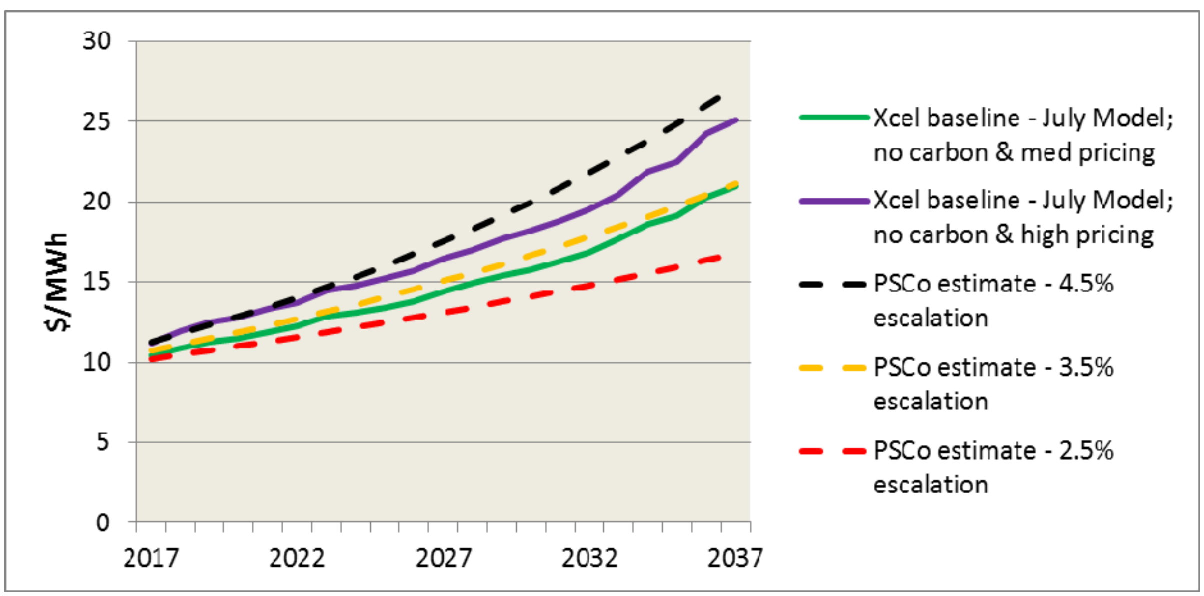
E. Xcel Baseline

The forecast of Xcel rates, or Xcel baseline, received several adjustments in the Updated Model including Xcel's estimated revenue requirement for the Boulder service territory, asset and expense allocations, resource prices, and DSM investments. The enhancements incorporated the most recent publically available data, but included several assumptions due to limited access of Xcel's rate studies and load information. The Updated Model ultimately lowered Xcel's rates.

To validate the Xcel baseline, PowerServices considered an estimate of the Public Service Company of Colorado's (PSCo) retail charges as a proxy for the "all-in" energy cost that Boulder customers might pay if they were to remain Xcel customers. PSCo's revenue per MWh sold was calculated using the most recent FERC Form 1 filings for 2012. The 10-year historical average change (from FERC Form 1) of 3.5% was applied to estimate future rates. PowerServices notes that this is not a prediction, but a tool to judge reasonableness of Boulder's "revenue requirement" methodology.

As part of its reasonableness test, PowerServices then compared Boulder's Xcel baseline to the PSCo estimate. Both the median and high priced generation scenarios were tested against PSCo rates using a low, average and high escalation rate. Carbon costs were excluded due to the uncertainty of applying this cost to a PSCo portfolio.

The results show that Boulder's estimate of Xcel rates with median generation pricing is at or below PSCo's forecasted rates that escalate at the historical average. It is reasonable to assume that Boulder's estimate may be slightly lower than the PSCo system forecast due to the high load factor in the Boulder region. The Xcel baseline with high generation costs initially tracks a PSCo forecast growing at 4.5%, but then follows a more moderate trajectory. This indicates that Boulder's forecast did not incorporate overly aggressive escalation in Xcel rates. PowerServices finds the model refinements and resulting impacts to the Xcel baseline to be reasonable and conservative.



F. Energy Efficiency and Solar Incentives (EE and DG)

The Updated Model increased annual funding for EE and solar incentives from $4.5M to $8M. The change was designed to align funding with the amount that Xcel currently provides in the Boulder region for incentive/rebate programs. Increasing the EE/DG budget is a reasonable refinement that has minimal model impacts.

G. Capitalized Interest

An enhanced feature of the updated model is an option to exclude capitalized interest. PowerServices initially reported that debt deferral is common practice for municipalities and provided Boulder with flexibility to increase cash flow, reduce initial retail rates, or seek lower GHG resources. While the refinement adds an additional way to "stress test" the model, PowerServices continues to support Boulder's original plans to capitalize interest.

H. Stranded and Acquisition Cost

Boulder focused on model options that limited stranded and acquisition costs to $214M. As with the first model, PowerServices will not evaluate or comment on stranded and acquisition costs.

4. Conclusion

After a review of key revisions to the Boulder municipalization model (Updated Model), PowerServices finds the changes to be reasonable and consistent with recommendations made in the initial Third Party Independent Evaluation. There were no major deficiencies identified, although some components, as identified above in this report, will benefit from ongoing refinements and enhancements. This is primarily due to the market-driven influence of inputs that require more frequent updates. The major component for continued evaluation is related to transmission ownership and ensuing NERC/FERC operational and reliability requirements. These requirements depend on the proposed acquisition, and may necessitate more resources or incur additional liabilities than previously identified.

In order to maintain a robust and comprehensive model that supports future municipalization activities, PowerServices recommends the following:

- Refinement of wind capacity factor assumptions, wind transmission and integration component costs, and continuous updates to generation pricing based on changing market conditions.

- Enhancing the modeling process to allow more efficient load sensitivity analysis, ultimately integrating the load, resource, and financial model.

- Incorporating a more comprehensive NERC operational and reliability strategy as the acquisition structure advances.

These actions will continue to drive improved risk assessment. This model has worked well with the decision process. If Boulder does municipalize, additional Engineering Software models will be needed to adequately support both near term and long range planning in a more seamless manner.

5. Signature and Seal Page

The foregoing report expresses my findings and opinions. I have reviewed the data provided for this project, and present herein the statement of my findings upon examination and analyses of the data and my engineering findings. I understand that data provided may be updated or modified, and I reserve the right to change or supplement the opinions and conclusions contained herein, as appropriate.

October 15, 2013

Gregory L. Booth, PE — Date

I hereby certify this document was prepared by me or under my direct supervision. I also certify I am a duly registered professional engineer under the laws of the State of Colorado, Registration No. 43948.

COLORADO LICENSED
GREGORY LEE BOOTH
43948
PROFESSIONAL ENGINEER

10/15/13

October 15, 2013

Gregory L. Booth, PE