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Colorado Public Utility Commission's Xcel Wind Decision

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COLORADO PUBLIC UTILITY COMMISSION'S XCEL WIND DECISION

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ABSTRACT

In early 2001 the Colorado Public Utility Commission ordered Xcel Energy to undertake good faith negotiations for a wind plant as part of the utility's integrated resource plan. This paper summarizes the key points of the PUC decision, which addressed the wind plant's projected impact on generation cost and ancillary services. The PUC concluded that the wind plant would cost less than new gas-fired generation under reasonable gas cost projections.

INTRODUCTION

In March 2001, the Colorado Public Utilities Commission (PUC) ordered Xcel Energy, a regulated Colorado utility company formerly known as Public Service Company of Colorado (PSCO), to engage in "good faith negotiations" for a wind power plant. Three important results emerge from the PUC's decision indicating that the wind power bid was cost effective:

- New wind generation on Xcel's system is predicted to cost less than new gas-fired generation, assuming that gas costs are more than $3.50 per million cubic feet (mcf)
- New wind power receives a fair capacity value, based on Xcel's method and data
- Ancillary services to back up new wind power are not a major cost.

The entire decision can be reviewed at: http://www.dora.state.co.us/puc/new.htm#dated

PUC Decision

"We find that adding Enron's Lamar wind energy bid to PSCo's preferred resource plan is in the public interest and comports with the IRP [integrated…resource…planning] rules. This determination is based solely on our finding that the acquisition of the Lamar facility will likely lower the cost of electricity for Colorado's ratepayers. After a careful analysis of the economics of the wind bid, we find that it is justified on purely economic grounds, without weighing other benefits of wind generation that could be considered under the IRP rules." (CPUC, Decision No. C01-295, page 34.)

COLORADO IRP RULES AND XCEL'S 1999 RESOURCE PLAN

The Colorado IRP rules require Xcel to file a plan every 3 years describing how it will meet future electric loads. The plan filed in November 1999 included draft Requests for Proposals (RFPs) seeking bids from power plant developers to supply generation resources. The 1999 RFPs sought proposals for a 3-year period 3 years in the future—in Xcel's case, 2003-2005. Xcel's plan included "segmented" bids—proposing separate RFPs for efficiency savings or "Demand-Side Management (DSM), for renewable energy, and for conventional supply-side resources.

The three bid segments and the resulting resource portfolio were concluded in three separate PUC hearings and decisions. First, the DSM segment was settled. The PUC accepted the DSM settlement to add 124 MW of DSM resources at an estimated cost of $74 million. Second, the renewable energy segment sought to supply the voluntary, tariffed Windsource green pricing program with four 6.25-MW wind plants for a total of 25 MW. After litigation of several issues—including waiting lists and contested demand estimates, uneconomic phasing of wind development, and the limited size of this segment—the PUC approved the renewable energy segment as proposed by Xcel. Xcel has awarded a contract for slightly more than 25 MW of new wind power for Windsource to enXco, a wind developer, to be installed near Peetz, Colorado.

The third segment of Xcel's bids was to acquire supply-side resources for the provision of power from conventional resources. This RFP offered 10-year contracts to conventional resources and 15-year contracts to wind power bidders. Xcel evaluated the bids by dividing them into various portfolios of resources, comparing the cost-effectiveness of the portfolios through computerized PROSCREEN modeling runs. Two of the portfolios included a bid by Enron Wind to supply the output of a 162-MW wind project to be constructed near Lamar, Colorado. Based on the results of the modeling, Xcel proposed that PUC approve an all-natural gas-fired portfolio of new generating plants. Xcel rejected the portfolios that included the Enron Wind bid.

THE XCEL APPLICATION

The PUC schuled hearings at the end of January 2001 to determine whether to approve Xcel's all-natural gas generation portfolio. Before the hearings, several parties intervened to take part in the PUC approval process, a courtroom-style litigation of contested issues. The Colorado Renewable Energy Society (CRES), the Land and Water Fund of the Rockies (LAW Fund), and the PUC staff all questioned the omission of the wind bid from Xcel's preferred portfolio. Parties asked and answered discovery questions and reviewed documents. On a schedule set by the PUC, parties (Xcel, CRES, LAW Fund, staff, and others) filed several rounds of written expert testimony with the PUC.

At the week-long hearings, all parties cross-examined the various experts on their written submissions. The PUC entered the testimonies, the transcript of cross-examination, and various exhibits into their record of the case. The Commissioners then discussed their decision based on this record in an open public meeting and issued their 54-page written order on March 18, 2001.

WIND CURRENTLY COST EFFECTIVE

The economic comparison of wind- and gas-fired generation options was at the heart of the Colorado PUC's decision. Two critical factors were at stake—how to estimate future prices for natural gas and how to model capacity and energy benefits of the wind bid for Xcel's energy supply system.

NATURAL GAS PRICE FORECASTS

The Commissioners had to decide whether they thought natural gas prices would be relatively low (about $3 per mcf and declining), as Xcel had testified, or higher ($4 per mcf and likely to rise), as CRES witness Steve Andrews had testified. The Commissioners agreed with CRES, finding that the higher range gas prices were more likely over the next two decades.

Xcel filed one non-confidential gas price forecast with their initial IRP plan and draft RFP in November 1999. This forecast projected that gas prices for the year 2000 would fall by 7.42% and then rise at about the level of assumed inflation in the economy for the rest of the 18-year forecasting period. This projection was intended to advise potential bidders, the Commission, and interested parties of how Xcel's gas prices would be treated when Xcel evaluated bids.

While bids were being submitted and evaluated, gas prices skyrocketed in 2000. From about $2.00 per mcf, prices increased by several hundred percent, and then floated back down to above $5.50 at the time of the PUC's hearings in early 2001. Between November 1999, when Xcel filed its first gas price forecast, and the PUC hearings in January 2001, Xcel claimed that their subsequent gas price forecasts were confidential. Their amended forecasts showed increased gas prices, at about $3.00 per mcf in year 2000, then declining in real terms over the next 18 years.

Looking back, the price of natural gas at the wellhead ranged between $1.50 and $2.50 per mcf from the late 1980s through 1999. Since 1996, the price briefly spiked above $3.00 per mcf four times, but never for more than 3 months and normally just prior to the heating season. The price in 2000 price started from a low of $2.10 in January, reached $4 by May and peaked in December at $10.10. Since late February 2001, the price has varied from $3.50 to $5.00 per mcf—more than double the rates prevailing in the 1990's. Futures markets in mid-2001 show that prices could well remain within this high new range over the next 3 years.

CRES testimony provided by Steve Andrews showed that primary determinants of future prices are more likely to be shifts in demand rather than surging supply. As for demand factors, the four key issues appeared to be as follows:

- The strength of the economy
- Severity of weather during the peak heating and cooling seasons
- Future load patterns for the astonishing number of new gas-fired electricity generators being added to the power producing "fleet"
- The amount of demand reduction achieved by fuel switching and efficiency investments.

Andrews testified that options for increasing supply are constrained by geologic challenges, such as increasing depletion rates and declining size of newly discovered gas pools. Subsequently, in April 25, 2001 testimony before a Congressional committee, the president of the Natural Gas Supply Association, Skip Horvath, testified that a depletion rate of 23 percent means "producers must find 23 percent more gas each year just to satisfy even a stagnant market." Additional problems are posed by physical system weaknesses; mainly a lack of sufficient experienced manpower and drilling equipment to substantially increase today's gas well completions compared to last year's increase in gas well completions.

During the course of this IRP planning process, Xcel Energy offered three different sets of price scenarios within the 6 months before the decision. With each change, the company increased its "high price" scenario, yet continued to project the fuel's inflation rate down in the 1.5% range. This did not inspire confidence, given the events of 2000.

PUC DECISION

Faced with the price volatility and the company's frequent shifts in price projections, the Colorado PUC ratified Andrew's views, choosing to assume that gas prices would be higher, rather than lower, over the term of the purchase power contracts at issue in the case.

PUC Decision and Order

"…(T)he Commission concludes that there is a substantial probability that future gas prices will be higher that the Company's base gas forecast. It is obviously difficult to predict natural gas prices. The Company itself adjusted its own forecast upwards twice in the last six months. We note that even the Company's most recent base forecast (confidential Exhibit 105) still begins several dollars lower than current natural gas prices. We also face the prospect that the unprecedented growth in natural-gas-fired electric generation nationwide will likely result in the natural gas market being driven by demand-side factors more than in the past. Based on the record here, we conclude that it is prudent to lean toward the higher range of the gas forecast to protect Colorado's ratepayers against the substantial possibility that natural gas prices will rise above PSCo's base case. We note that even if the Company's base forecast of natural gas prices turns out to be accurate the Lamar bid is still economic unless ancillary service costs are at the high end of the estimates. (CPUC, Decision No. C01-295, page 40-41.)

WIND BID ENERGY AND CAPACITY BENEFITS

The LAW Fund's witness John Nielsen submitted direct testimony stating that the initial Xcel portfolio analysis did not properly analyze capacity and energy benefits of the wind plant. Specifically, by examining only portfolios of groups of resources and not individual resources, Xcel never directly analyzed the cost-effectiveness of adding the Enron wind bid to the Xcel system. Nielsen pointed out that unrelated factors had rendered the two portfolios, including the wind bid, uneconomic. Nielsen recommended a new portfolio for consideration, "Preferred Portfolio + Wind," designed to isolate the economic benefits of adding the wind bid to the PSCo system. The "Preferred Portfolio + Wind" option did not seek to displace any of the bids in the preferred portfolio but rather sought to add the wind bid to that portfolio.

Because Xcel had initially declined the LAW Fund's request to use PROSCREEN to assess the cost-effectiveness of the "Preferred Portfolio + Wind" option, Nielsen's direct testimony included his own analysis of the cost-effectiveness of this portfolio. He developed a spreadsheet model that estimated the capacity and energy benefits that the Lamar wind facility would provide to the Xcel system. It was based on a present-value analysis that compared the energy costs of the Lamar wind plant against the plant's avoided capacity cost and the energy benefits. The analysis assumed that no ancillary service costs penalties were imposed on the wind plant.

Nielsen's present-value calculations were performed using the same 7.82% discount rate that Xcel used in its PROSCREEN analysis. He used the same data that Xcel used for the Lamar wind facility in its PROSCREEN modeling. He calculated the capacity cost savings of the wind plant with the method and data supplied by Xcel. Nielsen had requested from Xcel, but did not receive, marginal cost data for the Xcel system. As a surrogate, he used Xcel's projections of wholesale market prices in two adjacent energy markets (Four Corners and Southwest Power Pool).

WIND CAPACITY VALUE

As part of its evaluation of the Lamar wind plant, Xcel had conducted a reliability analysis to estimate an equivalent firm capacity value for the wind project. This analysis determined that the 162-MW wind farm would provide the equivalent reliability benefits of 49 MW of conventional generation. Xcel had proposed a wind capacity valuation method based on PROSCREEN modeling to settle a contested issue in their 1996 IRP. The parties accepted the Xcel method for purposes of issuing the 1999 RFPs and for subsequent bid evaluations. However, at the hearing, Xcel claimed their capacity valuation method was too generous to wind.

The LAW Fund and other parties essentially adopted Xcel's method for calculating the value of a portfolio's surplus capacity benefits attributable to the wind bid. To estimate dollar values of the avoided capacity savings, the LAW Fund used the same $7/kW/month capacity cost (escalating over time at PSCo's corporate escalation rate) that Xcel had used in its portfolio evaluation process.

The LAW Fund's analysis concluded that the wind bid would be a cost-effective addition to the preferred portfolio as measured on a capacity and energy basis under Xcel's base case, high-fuel price, and super-high fuel price forecasts. Other than looking at capacity and energy benefits, Nielsen did not attribute any additional costs or benefits to the "Preferred Portfolio + Wind" option for purposes of his analysis.

Xcel submitted rebuttal testimony challenging, among other things, Nielsen's analysis of the cost-effectiveness of the "Preferred Portfolio + Wind" option. This time around, Xcel used PROSCREEN to evaluate the "Preferred Portfolio + Wind" option. Unlike Nielsen's analysis, the PROSCREEN run used actual marginal cost data on the Xcel system to measure energy benefits, and it also attributed $41-46 million of additional ancillary services costs to the Lamar project (discussed below). Under these assumptions, the PROSCREEN run calculated that the "Preferred Portfolio + Wind" option would not be cost-effective.

However, if the additional ancillary services costs were excluded from the calculation and the "Preferred Portfolio + Wind" option were evaluated solely on a capacity and energy basis, it would be cost-effective under Xcel's own analysis. With ancillary service costs excluded, Xcel's analysis of the "Preferred Portfolio + Wind" option was estimated to result in a net present value of $8 million under the base case fuel price scenario and $45 million under the high case scenario. The LAW Fund sponsored Exhibit No. 102, setting forth these calculations, and the LAW Fund and Xcel stipulated to the results. Thus, the cost-effectiveness of "Preferred Portfolio + Wind" essentially depended upon which fuel price forecast should be relied upon and whether Xcel's estimate of ancillary service costs should be included in the bid evaluation.

The PUC staff position was presented by Saeed Barhaghi, who also questioned the modeling of the wind bid by Xcel, finding the bid to be cost effective based on his own modeling runs. Mr. Barhaghi also testified that the Enron wind bid was one of the lowest of all the bids submitted in the entire RFP.

The PUC's Decision and Order

". . .(T)he dispute as to the dollar value (1999 NPV) of the wind energy benefits to PSCo was essentially settled. In Exhibit 102 the energy benefits are calculated as a negative $28 million in the base gas price scenario and a positive $9 million in the high gas price scenario." Ibid, p. 41)

"Based on the limited evidence in this record, we accept PSCo's estimated capacity credit of 48 MWs as attributable to the Lamar project." (p. 42)

"Since the Commission is interested in determining whether the wind bid is justifiable on a strictly economic basis, we considered the $7 (per Kw/mo) price in our analysis. This results in our finding that the capacity benefit attributable to Lamar is approximately $36 million (1999 NPV) as calculated in Exhibit 102." (p. 42)

WIND FORECASTING AND OPERATIONAL COSTS

Xcel witnesses James Hill and Susan Goodrich testified that the wind bid, with its variable output characteristics, would add costs in addition to the costs of the wind energy. Hill estimated incremental system-wide ancillary service costs that would be incurred if the wind resource was added to the Xcel system, presenting an original and a revised analysis. The original estimate was $61 million in added ancillary service costs, while the revised analysis estimated $41 million in such costs, based on an average estimate of 56 MW of additional "spin/regulation" needed to cover wind variations and additional "wear and tear" costs on the Xcel system.

Goodrich's testimony assumed that the wind plant would be located in another utility service territory and would pay transmission fees to supply energy to PSCo. She then calculated the ancillary service costs that the wind plant would pay under FERC approved transmission tariffs. Her analysis suggested that ancillary service costs would total about $38 million, close to Hill's $41 million estimate.

The LAW Fund's witness, Jim Caldwell, testified that both the quantity and costs of future PSCo ancillary services allocated to the Lamar wind project had been grossly overestimated. He added that any remaining real costs could be significantly mitigated through relatively simple changes in operating procedures and cooperation between PSCo's control area operators and the operators of the Lamar wind facility. For Caldwell, allocation of a portion of system-wide ancillary service costs to a particular resource (whether a component of load or a component of generation) was nowhere close to being an exact science and, historically, has rarely been attempted in the industry.

Caldwell described the assumptions and approximations required when predicting future system-wide ancillary service costs as "truly daunting." In his opinion, to attempt to allocate a portion of those costs to a particular resource based on only a rough guess at both system-wide and individual resource characteristics is by nature arbitrary and necessarily colored by the bias of the observer. He concluded:

> ". . . industry experience with intermittent resources like wind on real utility systems has been relatively trouble free and predictions of large ancillary service costs to compensate for short-term variability in resource output have, in general, not proven to be true. For example, Pacific Gas & Electric Company for years operated an integrated utility system with as much as 10% of its generation resources being provided by wind without <u>any</u> increase in ancillary service costs."

The PUC staff witness, Barhaghi, also testified that Xcel's ancillary service cost estimates were too high. He based his own calculation of these costs on the spinning reserve levels required by the Western Systems Coordinating Council, a body that enforces reliability standards in the grid where Xcel operates. Staff and the LAW Fund estimated ancillary service costs in the range of $3 to $6 million over the 15-year wind plant contract.

The PUC's Decision and Order

1. Xcel's method is not required by any power pool or reliability council. (p. 36)
2. Xcel's method is not used by any other utility, not even by Xcel's sister operating companies in same holding company, so there is no industry or regulatory standard with which to evaluate the method. (p. 36-37)
3. Xcel's method did not adequately account for the ability of meteorological forecasting and persistence modeling to increase the predictability of the output of a wind plant, thereby reducing the need for regulation service. (p. 37)
4. Xcel's $17 million cost estimate for cycling costs (wear and tear) to provide regulation services is excessive. "PSCo's method assumed regulation and load following would be provided by existing coal-fired base load facilities, even though the Preferred Portfolio included thousands of megawatts of new, gas-fired plants that could provide these services at lower costs. (p. 37)
5. Xcel's analysis of ancillary service costs in FERC transmission tariffs and ancillary service charges was based on imbalance charges that are punitive, not cost based. (p. 37-38)
6. Xcel's witnesses agreed that "it has not been common industry practice to allocate system-wide ancillary service costs to a particular generator or a particular load in their a resource planning context or in actual operations." (p. 39)
7. "We agree that, as an intermittent resource, wind does impose incremental ancillary service costs on the system. However, we decline to adopt any particular method for determining such costs based on this record." (p. 39)
8. "We expect the Company to include an analysis of Ponnequin, Lamar, and its other wind resources in future cases where wind capacity and ancillary services are considered. Further, we expect such analysis to consider the combined effect of multiple wind farms operating together to better understand the reliability and system impacts of multiple wind sources in diverse location, and compared to conventional resources." (p. 42)
9. "We note Mr. Barhaghi's testimony that, in terms of levelized cost stated in $/MWh, the wind project was the lowest cost resource in the entire portfolio (except for one small 0.7 MW hydroelectric project). As Mr. Barhaghi pointed out, the Lamar bid appears non-competitive only when the Company attributes significant cycling and regulation costs to the project." (p. 38)

THE ROLE OF WIND FORECASTING

The ability of operators to accurately forecast the hourly output of a wind plant increases the economic viability of a wind power plant. One early study (Milligan et al) carried out a detailed simulation of two large electric utilities in a regulated electricity market. The simulations focused on the effect of accurate wind forecasts on unit-commitment, which involves scheduling the least-cost mix of generating units to meet the expected electrical load. Unit-commitment is the process of making sure that enough slow-start capacity will be online when needed and is subject to the required start-up times of the generating units that are involved.

In restructured electricity markets, an accurate wind forecast helps both the buyer and seller of wind energy. Deviations from the forecast can be handled by various contractual provisions. From the point of view of the seller of wind energy, better forecasts will minimize these contractual penalties and maximize the value of the wind energy. From the buyer's perspective, a record of accurate wind power forecasts improves the extent to which the wind plant can be relied upon to provide power.

The Milligan, Miller, and Chapman study estimated the economic value of an accurate wind forecast by simulating the unit commitment and economic dispatch decisions under various degrees of forecast accuracy. Not surprisingly, they found that an accurate forecast improves the ability of the GENCO to provide power at least-cost. The study also concluded that if a wind forecast is too low, the cost to the utility will be higher than if the forecast is too high. This effect is caused by the increasing marginal-cost curve, which predicts that as electricity output increases, the incremental cost of each additional GWh also increases. If the actual wind power exceeds the forecast level, then the utility would have needlessly kept unnecessary capacity online and increased costs.

A growing body of empirical evidence indicates that wind forecasting has significant value. According to L. Landberg of the Riso National Laboratory in Denmark, a principal researcher in this field, wind sites that can be accurately forecasted will forecast within 10% of their rated capacity. A "poorly" forecasted site can be within 20% of rated capacity. Assuming the Lamar site were difficult to forecast, according to Landberg's research, the forecast might be within 32 MW when predicting 24 to 48 hours ahead. This provides a "worse case" scenario. In some situations, the wind forecast is accurate up to 72 hours (3 days) in advance. A private company in the United States, True Wind Solutions, has significantly reduced the imbalance charges to a utility in California by applying their forecasting model to Southern California Edison's wind resource. True Wind has estimated the benefit-cost ratio of this forecasting at 30:1.

Figure 1 provides an example of 1-hour forecasts to show how wind power can be forecast. The figure is based on a regression forecast model that uses information about the previous 2 hours of wind power output to predict the following hour. In practice, the wind power forecast would be generated by a more sophisticated model and extend over 1-3 days in the future.

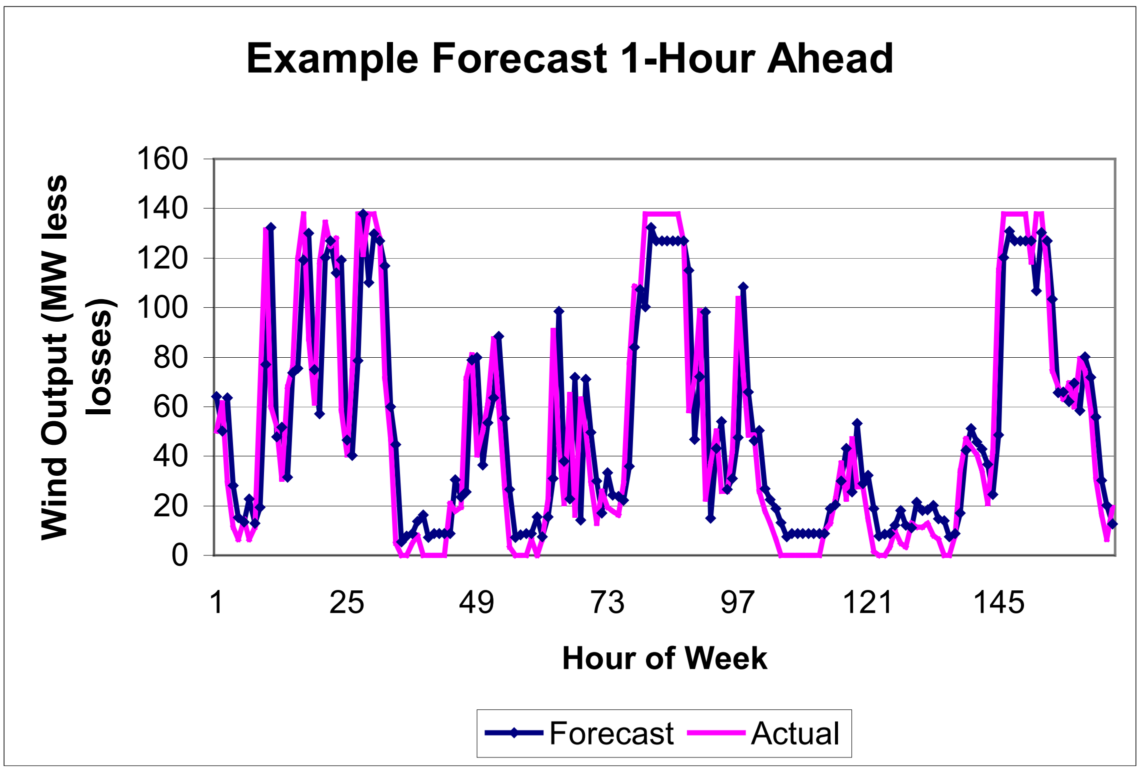

Figure 1. Example of Short-Term Wind Forecast

The ability to accurately forecast wind power is quite good today. Continued research promises to provide further improvements. Simple hourly forecasts can be based on the previous hour's output. To illustrate this process, several regression models were calculated using the Lamar data. Using a full year of hourly data, the mean absolute error for one of the models is 15.7 MW, with a mean absolute percentage error of 9.8%. The standard deviation of the absolute error is approximately 7.3 MW, which indicates that about 80% of the time we would expect the forecast to be within about 9.5 MW of the forecast. This translates into an error of approximately a 6% of the rated capacity of a 162-MW wind plant.

PUC Decision and Order

"We also agree with LAW Fund and other parties that PSCo's method does not adequately account for the ability of meteorological forecasting and persistence modeling to increase the predictability of the output of a wind plant, thereby reducing the need for regulation service." (p. 37)

OTHER ISSUES: WIND BENEFITS, CONFIDENTIALITY, DEMAND FORECAST, "WESTERN ENERGY CRISIS," PRESS COVERAGE

Advocates cited wind energy's economic development, environment, diversity, and risk management benefits as further support for the wind bid. The PUC found the wind bid to be cost effective without consideration of these benefits.

Xcel claimed confidentiality for all price, cost, bid, and contract details. Estimates in this paper are based on ranges discussed in public portions of the PUC's hearing record and decision.

During the IRP process, Xcel raised its demand forecasts, thereby adding to the need to acquire new generation resources. Wind was proposed as an extra hedge against forecasting risks. The PUC did not rely on this issue in their decision.

One Xcel witness testified that a "western energy crisis" provided the back-drop for his testimony. The PUC had heard from gas-heating customers angry about gas price increases. CRES argued that the wind bid was the only thing the PUC could do in the IRP process to relieve market pressure from gas generators to help gas-heating customers. Press coverage of the PUC's wind decision reflected these arguments.

CONCLUSION

Three important results emerge from the PUC's decision that the wind bid was cost effective:

A. New wind on Xcel's system was estimated to cost less than gas-fired generation, assuming that gas costs will be above $3.50.

B. New wind received a fair capacity value based on Xcel's method and data.

C. Ancillary services for new wind are not a major cost.

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