Attachment 2.13-1

Final Report:

Public Service Company of Colorado 2 GW and 3 GW Wind Integration Cost Study

Prepared by

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TECHNICAL REVIEW COMMITTEE

The following individuals comprised a technical review committee (TRC) for this project. The TRC was kept apprised of the approach, methodology, and assumptions for the analysis described in this report, and provided valuable comments, suggestions, and guidance at several junctures from project commencement to conclusion.

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John Nielsen	Western Resource Advocates
Charlie Smith	Utility Wind Integration Group
Bob Zavadil	EnerNex Corporation

PROJECT TEAM

Xcel Energy Services Inc. on behalf of Public Service Company of Colorado (Public Service or the Company) retained EnerNex Corporation of Knoxville, Tennessee for this project to assist the Company in determining the wind integration costs for the Public Service system.

EnerNex Corporation is an electric power engineering and consulting firm specializing in the development and application of new electric power technologies. EnerNex provides engineering services, consulting, and software development and customization for energy producers, distributors, users, and research organizations. EnerNex has substantial expertise with a broad range of technical issues related to wind generation, from turbine electrical design to control area operations and generation scheduling.

EXECUTIVE SUMMARY

Background

This wind integration cost study, the 2GW/3GW Study, is the third such analysis of wind integration costs performed by Public Service Company of Colorado. This particular study addresses the 2 GW and 3 GW levels of nameplate wind capacity on the Company's electric system. The prior studies examined wind penetration levels of 10%, 15%, and 20% (nameplate wind capacity divided by peak load). The focus of this 2GW/3GW study is to determine the costs of integrating 2,000 MW and 3,000 MW (nominal values) of wind energy into the Public Service electric system. The wind integration costs quantified in this study are associated with the uncertain and variable nature of wind generation. These costs are often referred to as "hidden costs." When Public Service evaluates new power supply options for its system, the total incremental integration cost determined using this study will be added to the bid or build price of wind resources to ensure that all costs associated with wind generation are represented and that wind is compared on an equivalent basis with other generation technologies.

The wind integration costs for the 2,000 MW nominal wind penetration level were determined in this study using an installed nameplate wind capacity of 1,939 MW. The wind integration costs for the 3,000 MW nominal wind penetration level were determined in this study using an installed nameplate wind capacity of 2,999 MW.

At the outset of the modeling phase of this 2GW/3GW Study, Public Service chose to reanalyze the 20% wind penetration level on its system that was previously studied in 2008. The reason for this "recasting" of the 20% study results was that sufficient changes and updates (different study year, thermal resource additions, retirements and performance characteristics) were made to the modeling inputs for this 2GW/3GW study compared to those used in the prior 20% study. By recasting the 20% study results with these updated assumptions, the resulting total incremental wind integration cost associated with moving from the 20% level (~1,400 MW) of wind up to the 2 GW level of wind will be based on a consistent set of assumptions and analyses. Table 1 contains the wind capacity levels used for the "original" 20% Study and the 2GW/3GW Study.

Table 1: Nameplate Wind Capacity Levels for the Public Service Wind Integration Cost Studies[1]

Wind Integration Cost Study	Nameplate Wind Capacity (MW)
Original 20%	1,440
20% with the 2GW/3GW Study inputs	1,414
2GW	1,939
3GW	2,999

[1] The nameplate wind capacity values chosen as capacity levels for modeling were determined by aggregating nameplate levels of installed wind (installed by year end 2012) to achieve aggregate levels that approximate the nominal levels of 20% (1,440 historically) and 2,000 MW and aggregating nameplate levels of installed wind and potential wind to achieve a level that approximated the nominal 3,000 MW level.

Wind Integration Costs Quantified in this 2GW/3GW Study

This study analyzed and quantified the average wind integration costs associated with three aspects of power supply system operations:

1. Regulation,
2. System operations,
3. Gas storage.

The study did not quantify wind integration costs associated with curtailment of wind generation,[2] electricity trading inefficiencies introduced by wind uncertainty, or increased operating and maintenance costs at existing thermal units that may be called upon to ramp output levels over a broader range more often and with shorter notice. The costs of curtailment of wind generation and increased operating and maintenance costs at existing coal plants were evaluated by Public Service in a separate study, the *Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment* study, which was completed in parallel with the 2GW/3GW Study. Like total incremental wind integration costs, incremental wind curtailment and cycling costs will be added to the bid or build price of wind resources when evaluating wind against other power supply options.

Summary and Conclusions

The 2GW/3GW Study results for the regulation component of wind integration costs are shown in Table 2. This cost arises from the intra-hour variability of wind resources that requires additional fast-responding regulation capacity be available.

Table 2: Average Regulation Wind Integration Cost

Wind Penetration Level	20%	2 GW	3 GW
Average Regulation Wind Integration Costs ($/MWh)	0.10	0.14	0.21

The 2GW/3GW Study results for the system operations component of wind integration costs are shown in Table 3. This cost arises from less than optimal operation of the electric system as the result of the uncertain nature of wind energy production. The results were determined with a base gas price of $5.06/MMBtu and with the On/Off Peak Proxy.

Table 3: Average System Operations Wind Integration Cost ($5.06/MMBtu gas price)

Wind Penetration Level	20%	2 GW	3 GW Scenario 2[3]
Average System Operations Wind Integration Cost ($/MWh)	2.39	3.40	3.71

[2] As explained below, the calculation of average gas storage wind integration cost included the price of a limited amount of wind energy curtailment that was used to preclude the purchase of additional natural gas storage injection demand.

[3] The "Scenario 2" designation refers to geographic diversity sensitivities performed in the 2GW/3GW Study.

The 2GW/3GW Study results for the gas storage component of wind integration costs are shown in Table 4. The gas storage component of wind integration costs stems from inaccuracies in the amount of gas nominated each day for electric energy production caused by the uncertain nature of forecasting the wind. The average gas storage wind integration cost was determined by Public Service's gas planning business units based on estimates of how gas nomination inaccuracies due to wind generation result in the need to either inject or withdraw gas from storage.

Table 4: Average Gas Storage Wind Integration Cost ($5.06/MMBtu gas price)

Wind Penetration Level	2 GW	3 GW Scenario 2
Average Gas Storage Wind Integration Cost ($/MWH)	0.14	0.17

The costs in Tables 2, 3 and 4 were calculated by estimating the total annual integration costs for a given level of wind on the Public Service system and dividing by the total system annual wind energy. The resulting $/MWh value, therefore, represents the *average* wind integration cost for the entire amount of wind energy on the system. When Public Service uses wind integration costs for purposes of evaluating future power supply options, the Company will use the total *incremental* wind integration cost (the sum of the incremental wind integration cost for the three components divided by the incremental wind energy production).[4]

[4] As determined by calculations using the On/Off Peak Proxy approach discussed later in this report.

INTRODUCTION

Public Service is an electric operating company with a large and growing wind energy resource. The Company first integrated wind energy into its resource mix in 1997 and has since continued in the development of wind resource operating protocols and performance of studies to estimate the cost impacts of increasing levels of wind generation. This wind integration cost study is the third performed by Public Service and addresses the 2 gigawatt (GW) and 3 GW levels of nameplate wind capacity operating on the Company's electric system. Public Service uses the total incremental wind integration cost when assessing the overall cost of wind resources during resource planning/selection processes. In addition to determining wind integration costs, this study continues the Company's approach of investigating the value of other aspects of wind resource integration, e.g., geographic diversity, that can help reduce integration costs and inform future resource selection and investment decisions as discussed at greater depth in this study.

Public Service previously analyzed wind integration costs in 2008 when it completed its study of the wind integration costs for the 20% penetration level of wind resources (the "20% Study" - and in 2006 when it analyzed the wind integration costs for the 10 and 15% levels of wind penetration. Table 5 provides the results of Public Service's prior wind integration cost studies at a natural gas cost of \$5.06/MMBtu.[5]

Table 5: Prior Integration Cost Study Results (\$5.06/MMBtu gas)[6]

Wind Penetration	Average Regulation and System Operations Wind Integration Cost (\$/MWh)	Average Gas Storage Wind Integration Cost (\$/MWh)
10%	\$2.25	\$1.26
15%	\$3.32	\$1.45
20%	\$3.95	\$1.18

For this study the Company chose to deviate from the past approach of analyzing wind integration costs at different wind penetration percentages and to instead perform this study for two discrete levels of nominal nameplate wind capacity, 2GW and 3 GW. The reason for this

[5] The average system operations wind integration cost is dependent of the cost of energy for the fossil-fueled resources in an electric operating company's generating resource portfolio as those resources constitute the majority of the resource portfolio and the less-than-optimal operation of fossil-fueled resources (as the consequence of wind generation uncertainty) produces average system operations wind integration cost. Please note that while the prior studies were done for a 2007 test year and this study uses a 2018 test year, the results of the studies are comparable as it concerns dollar value as gas costs, a major driver for the average system operations wind integration cost, are normalized. The operations and maintenance expense component of average system operations cost, which would be modeled for a different study year and expressed in a different nominal dollar, is a smaller component of the determined average system operations wind integration cost and Public Service does not believe that discounting the costs to an equivalent year's dollars is necessary as it would not be material.

[6] Zavadil, Bob, King, Jack, "Wind Integration Study for Public Service of Colorado Addendum detailed Analysis of 20% Wind Penetration," December 1, 2008, Page 7.

change is that growth in the Company's peak load, the denominator in a wind penetration percentage calculation, means that reported percentage levels, which were ostensibly comparable, were in fact not comparable from study to study. Therefore, Public Service chose to begin performing, and naming these studies, using installed nameplate wind capacity.

For this study a nominal level of 2 GW and 3 GW was selected and the study is referred to as the "2GW/3GW Study." The wind integration cost for the nominal 2,000 megawatt (MW) level was determined in this study using an installed nameplate wind capacity of 1,939 MW which closely represents the amount of wind Public Service expects to be operating on its system by the end of 2012. The wind integration cost for the nominal 3,000 MW level was determined in this study using an installed nameplate wind capacity of 2,999 MW. Differences between the nominal 2 GW and 3 GW levels and the 1,939 MW and 2,999 MW levels reflected in the study are rooted in the sizes of the existing and under construction wind facilities on the Public Service system.

In addition to analyzing 2GW and 3GW of wind, Public Service chose to recalculate the wind integration costs for the 20% penetration level of wind that was previously studied in 2008. The reason for this recalculation was that sufficient changes and updates (different study year, thermal resource additions, retirements and performance characteristics) were made to the modeling inputs for this 2GW/3GW Study compared to those used in the prior 20% Study. By recasting the 20% results with these updated assumptions, the Company believes the resulting total incremental wind integration costs associated with moving from the 20% level (~1,400 MW) of wind up to the 2 GW level of wind will be more accurate because the 20% and the 2 GW wind integration costs will have been derived from a common set of assumptions and the same computer model representation of the Public Service System. Table 6 contains the wind capacity levels used for the "original" 20% Study and the 2GW/3GW Study.

Table 6: Nameplate Wind Capacity Levels - Public Service Wind Integration Cost Studies

Wind Integration Cost Study	Nameplate Wind Capacity (MW)
Original 20%	1,440
20% with the 2GW/3GW Study inputs	1,414
2 GW	1,939
3 GW	2,999

2GW/3GW Study Objectives

The focus of this study is to determine the costs of integrating wind energy into the Public Service system. The integration costs quantified in this study are associated with the uncertain and variable nature of wind generation. When Public Service performs resource planning and selection processes, total incremental wind integration costs are added to the bid price of wind resources to ensure that all costs associated with wind generation proposals are represented such that wind can be equitably compared with other generating technologies.

The Couger unit commitment and dispatch model was used in this study to determine wind integration costs at three levels, 1,414 MW, 1,939 MW and 2,999 MW, of nameplate wind generation capacity on the Public Service system. The wind facilities that comprise the 1,414 MW and 1,939 MW levels of nameplate wind capacity are currently constructed or are under construction at known locations and have known points of interconnection to the Public Service electric transmission system and are referred to as the Base Case.

Four alternative scenarios were analyzed for the 1,060 MW of wind facility additions that would grow the total Public Service wind resource from approximately 2 GW to approximately 3 GW. The four scenarios grew the nameplate wind on the system by 1,060 MW through differing patterns of addition. The first scenario (No Diversity Scenario) added 1,060 MW of nameplate wind capacity in the northeast corner of Colorado, an area of Colorado that contains the majority of the Company's existing wind resources. The second scenario (Diversity in Addition Scenario) added 1,060 MW of nameplate wind capacity in equal amounts to four likely areas for wind resource development in the state, Energy Resource Zones (ERZ) 1,2,3 and 5. The third scenario (Diversity in Result Scenario) added 265 MW of nameplate wind capacity in ERZs 2 and 5 and 530 MW of nameplate wind capacity in ERZ 3. The fourth scenario (Wyoming Scenario) added 1,060 MW of nameplate wind capacity in southeast Wyoming. See Appendix A.

A number of sensitivity cases were also constructed and run through the Couger model to understand the effects of different assumptions on the costs of integrating wind resources.

Wind Integration Costs Quantified in this Study

The 2GW/3GW Study analyzed and quantified the wind integration costs associated with three aspects of the electric power supply operations:

1. Regulation,
2. System operations,
3. Gas storage.

The study did not quantify integration costs associated with curtailment of wind generation,[7] electricity trading inefficiencies introduced by wind uncertainty, or increased O&M costs at existing thermal units that may be called upon to ramp output levels over a broader range more often and with shorter notice. The costs of curtailment of wind generation and increased O&M costs at existing coal plants were evaluated by Public Service in a separate study, the *Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment* study, which was completed in parallel with the 2GW/3GW Study. Like total incremental wind integration costs, incremental wind curtailment and cycling costs will be added to the bid or build price of wind resources when evaluating wind against other power supply options.

Calculating the Average Regulation Wind Integration Cost

Regulation wind integration cost arises from the intra-hour variability of intermittent generating resources that require additional fast-responding regulation capacity be available. This component of wind integration costs was calculated by Public Service's Commercial Operations business unit which examined historical time-series load data to quantify the range of regulation capability that would be required to compensate for the fast variations in net system load. The evaluation process involved performing a statistical analysis of a system Net Load profile (Obligation Load less wind generation) and an Obligation Load profile and then using that

[7] As explained below, the calculation of average gas storage wind integration cost included the price of a limited amount of wind energy curtailment that was used to preclude the purchase of additional natural gas storage injection demand.

analysis to determine the amount of required regulation capacity for the specific levels of wind. This regulation capacity was then assigned a cost using Public Service's Open Access Transmission Tariff (OATT) Schedule 3 – Regulation and Frequency Response Service filed on May 13, 2011. This tariff specifies a cost of Network Integration Delivery of $6.740/kW-month, or $80.88/kw-year. Once the cost is determined, the average regulation wind integration cost was determined for the 20%, 2 GW and 3 GW levels by dividing by the calculated annual system wind energy production for each scenario.

Calculating the Average System Operations Wind Integration Cost

System operations wind integration cost arises from less than optimal operation of the electric system as the result of the uncertain nature of wind energy production. Specifically, day-ahead commitment of generation resources using load and wind forecasts and the subsequent dispatch of those committed units is often less than optimal given the uncertainty of the wind resource. Public Service engaged EnerNex Corporation for the 2GW/3GW Study to perform computer modeling to determine average system operations wind integration costs using Ventyx's Couger model.

Couger is a unit commitment and dispatch model that can both produce an optimal day-ahead generating unit commitment plan, and also dispatch the committed generating units of that plan in a least-cost manner to serve load for the electric system being represented.[8] The 2GW/3GW Study methodology involved developing individual commitment and economic dispatch plans within the Couger model for every hour of the study year, which was the year 2018.

Similar to the Company's previous wind integration studies, the modeling protocol used in this study to quantify system operations wind integration costs consisted of a five step process. The first four steps involve performing four separate Couger modeling runs of the Public Service electric supply system under specific configurations in order to establish four separate operating costs for serving system load. The fifth step takes the arithmetic difference in total system costs between the fourth and the second modeling runs and uses this difference to represent the system operations wind integration cost. The specifics of this process are as follows. The Couger model is first run in "optimization mode" using a forecast of the next day's load to create a day-ahead generating unit commitment plan. A separate commitment plan is developed for each hour of the 2018 study year. This generating unit commitment plan is then used in "simulation" mode to serve the actual day's load and produce a system operating cost for each hour of the study year. These first two steps of the modeling process are performed with the system wind generation represented by an hourly wind energy shape termed a "proxy" (two proxy types were used – the Flat Block Proxy which distributes the wind energy such that for each day of the study year the daily wind generation is distributed evenly over each hour of that 24 hour period and the On/Off Peak Proxy which distributes the daily wind energy over two flat blocks, an on-peak block and an off-peak block).

Two additional model runs are then performed, Steps 3 and 4, to produce a system operating cost with the wind energy proxy replaced by, first, the day-ahead hourly forecast of wind energy (Step 3, which like Step 1 uses the day-ahead load forecast) and second by a representation of the actual hourly wind energy (Step 4, which like Step 2 uses the actual load). The average system

[8] The Couger model was at one time used by Xcel Energy Services. Inc's Commercial Operations group for the purpose of establishing day-ahead commitment plans to be used in the operation of the Public Service electric supply system.

operations wind integration cost is determined in Step 5 by subtracting the system production cost produced by Step 2 from the system production cost produced in Step 4 and dividing the result by the total MWh of modeled actual annual wind energy production. Since the system production costs for Step 2 and Step 4 were both produced with the actual load, subtracting Step 2 results from Step 4 removes any costs associated with load forecasting error leaving only the estimated cost associated with integrating wind onto the system. The five steps or modeling runs are described again below.

Step 1 - Reference case optimization: Unit commitment of Public Service system generation to meet Public Service's *day-ahead forecast of system load* using a *proxy* shape for the wind energy production.

Step 2 - Reference case simulation: Economic dispatch of unit commitment from Step 1 to meet Public Service's *actual load* and the same *proxy* shape for wind energy production.

Step 3 - Actual case optimization: Develop a new unit commitment of Public Service system generation fleet to meet Public Service's *day-ahead forecast of system load* and using a *day-ahead forecast for the wind energy production*.

Step 4 - Actual case simulation: Economic dispatch of the unit commitment from Step 3 to meet Public Service's *actual load* and *actual wind energy production*.

Step 5 – System operations wind integration cost is difference between Steps 4 and 2. The average system operations wind integration cost is the system operations wind integration cost divided by the modeled actual annual wind energy production.

The 2GW/3GW Study using the Couger model and with the above described protocol simulated the economic commitment and dispatch of the Public Service electric supply system at nominal 20% (1.4 GW), 2 GW and 3 GW levels of installed wind generation. As will be explained in greater detail, the 2GW/3GW Study also simulated commitment and dispatch of the Company's electric supply system under different assumptions for key system parameters, i.e., sensitivities.

Calculating the Average Gas Storage Wind Integration Costs

The gas storage component of wind integration cost stems from inaccuracies in the amount of natural gas nominated each day for electric energy production as a result of the uncertainty of wind energy production. This component of wind integration costs was calculated by Public Service's Gas Planning business unit based on gas consumption projections from the Couger-modeling of Steps 3 and 4 discussed above.

To determine the average gas storage wind integration cost, Public Service had EnerNex extract from the base case model runs both the largest over and under nominations of natural gas volumes for a gas day[9] and the total *annual* amounts of over and under-nomination of natural gas for a gas day. Over-nomination results when electric system generation resources require less gas (Step 4 in modeling process) than predicted the day before (Step 3 in modeling process).[10] Under-nomination results when electric system generation resources require more gas (Step 4) than was estimated the prior day (Step 3). The over and under nominations for the largest gas day

[9] A gas day is defined as the 24 hour period beginning at 8:00 AM MST.

[10] The Run 4 minus Run 3 gas burn figure was adjusted to remove load related gas nomination error. The load related gas error was determined by subtracting the Run 1 gas burn from the Run 2 gas burn.

represent the largest required levels of gas extraction and injection flexibility on Public Service's gas storage fields in order to accommodate wind energy on the system. The largest gas day over and under nominations set the demand charge for injection and withdrawal from storage facilities. The total yearly amounts of over and under-nomination determine the commodity charge for the injected or withdrawn gas volumes into/from gas storage facilities. These demand and commodity charges were totaled (with a less consequential "losses" charge set by total annual amounts) for both over and under nomination costs and the most controlling of those cost totals, i.e., the value that requires the greatest storage system demand, and which is most costly, was used to determine the average gas storage wind integration cost.

Study Data and Assumptions

Clean Air-Clean Jobs

Contemporaneous with the initiation of the 2GW/3GW Study in 2010 the Colorado Legislature enacted the Colorado Clean Air-Clean Jobs Act (CACJA or the Act). The CACJA required Public Service to evaluate various options for reducing NOx emissions from electric generating facilities prior to the end of 2017. While the level of emissions reductions in the CACJA were specified, the Act allowed Public Service flexibility to determine how best to achieve those reductions. The Company could retrofit coal-fired power plants with new emission controls, replace coal-fired power plants with natural gas generation (by retirement and new build or by fuel-switching) or consider other clean energy resources.

Ultimately, the Company proposed and the Colorado Public Utilities Commission (CPUC) approved (with modifications) a course of action that included installation of emission controls on some coal units, coal plant retirements and replacement with natural gas generation and coal plant fuel switching to natural gas. The CPUC final order was issued on February 3, 2011. While development and verification of Couger model input files for this 2GW/3GW study were completed in advance of this February 3 final order, the Couger model's representation of the Public Service generation fleet was consistent with that approved by the CPUC in CACJA with the exception of the representation of Cherokee 4. In this study, Cherokee 4 was modeled to burn coal during the study year of 2018 but will likely burn gas in 2018 per the CPUC final CACJA order. The Company does not believe this discrepancy in the representation of Cherokee 4 effects the validity of the study approach or results.

The Calendar year 2018 was chosen as the "study year" for modeling the Public Service electric system because that was the year by which CACJA related actions to the Company generation fleet would be completed.

Modeling and Calculation Specifics

The chronological simulation algorithm employed by the Couger model to determine production costs requires extended sets of hourly load data including day-ahead forecasts of hourly load, which were used for forward scheduling and unit commitment in addition to nomination of natural gas for both owned and tolled gas-fired generation. The load data used was from recent historical years so that the daily patterns represent future Public Service system loads as closely as possible.

It is also important for the wind resource generation data to be comparable to the load data, i.e., drawn from same historical year so that correlations between hourly wind and hourly load due to meteorology are properly retained within the analysis. Public Service chose to use historical system load data from three years, 2004, 2005, and 2006, since these match the years for which wind energy generation data was developed for the Western Wind Resources Dataset (WWRD) that was selected as the source for the day-ahead forecasted wind energy generation patterns as well as the actual wind energy generation patterns involved with the five step process described earlier. The 2004, 2005, and 2006 WWRD data sets, and the hourly load patterns, were scaled so that the wind generation level matched the level of wind integration and the peak hour loads matched that projected for the year 2018.

The *Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment* study results were not incorporated into the dispatch costs of coal units within the Couger production cost modeling.

The study year, Calendar year 2018, was represented in the Couger model input files with:

- Projected peak load of 7,035 MW;
- Projected energy requirements of 37,655 GWh;
- Nameplate wind capacity levels of 1,414 MW, 1,939 MW, and 2,999 MW. Note that the price or cost of wind energy is not a factor in this study methodology. It is assumed that the wind energy generated is a "must take" resource, and that the Public Service will manage its other dispatchable generating units in a manner to accommodate wind energy production when balancing overall system load and generation. The added costs associated with using these other generating units in a sub-optimal manner to accommodate wind energy production (higher production costs due to less-than optimal commitment and dispatch operations, etc.) are what constitute the system operations component of wind integration cost;
- A generation supply portfolio that reflected the planned coal unit retirements and gas-fired replacement generation associated with the CACJA with the exception that Cherokee Unit 4 ran on coal in the Couger model; whereas, Cherokee 4 is expected to be operating on gas in 2018;
- Projected solar capacity of 395 MW AC of solar electric power, including customer-sited solar facilities. Solar insolation data was used to construct an hourly energy production pattern for the solar electric generation resources on the Public Service system. The data was used to adjust (reduce) total system load;[11]
- Updates to various existing power purchase and sale contracts as appropriate to reflect 2018;
- Planned maintenance and forced outage history for generating units;
- Gas Prices for base case runs and for sensitivity runs were chosen to be consistent with those used in the Company's prior wind integration cost studies. The average base case

[11] While it was not addressed in the 2GW/3GW Study, it is possible that the variability of the energy produced by the solar resources may have had the result of slightly increasing the wind integration costs produced by this study compared to an analysis where solar generation was not reflected in the study. Future wind integration cost studies should investigate whether this is in fact the case.

gas price was \$5.06/MMBtu and the sensitivities were performed at average gas prices of \$7.83/MMBtu and \$9.83/MMBtu;[12]

- Hourly wind energy production profiles, both day-ahead forecasts and actual day wind energy generation, were derived from the WWRD. Wind sites from the WWRD for the 20%, 2GW and 3GW study cases were selected based on the proximity of the WWRD sites to 1) existing wind facilities on the Public Service system; 2) planned wind facilities on the system; and 3) potential future sites for wind facility additions. The National Renewable Energy Laboratory (NREL) members of the study's Technical Review Committee counseled that the WWRD day-ahead forecasts for the CO East area had a 15-20% positive forecast error bias (over-forecasting)[13] and recommended that as part of this study, EnerNex take the average of this bias and subtract it out of each of the hourly day-ahead wind forecasts. In accordance with this NREL recommendation, EnerNex created an adjusted WWRD wind production forecast for the selected wind sites used in the study. The resulting adjusted WWRD forecasted wind energy production profiles trend to the original forecast profile while maintaining the annual forecast energy production in appropriate proximity to the actual energy production. EnerNex performed the following steps to produce the adjusted WWRD wind data:

    1) Calculated the monthly forecast and actual wind energy production;
    2) Determined the ratio of monthly forecast and actual wind energy production;
    3) Calculated the hourly mean absolute error (MAE) for the forecasted wind energy production;
    4) Created a histogram of hourly MAE in increments of 10% ;
    5) For each hour of forecast wind
        a. applied the respective monthly ratio
        b. trimmed the result with the error adjustment based on the MAE of the forecast.

    The capacity factors of the selected WWRD sites were low compared to the historical wind production Public Service has observed at the sites. The Technical Review Committee believes that an improved source for wind generation data, if available, would be beneficial for use in future wind integration cost studies.

- In situations when the committed generation capacity (Steps 1 and 3) was insufficient in dispatch (Steps 2 and 4) to serve customer loads (a.k.a., unserved energy), it was necessary to post-process each computer model run and manually add the costs associated with starting gas turbines into the previously calculated production costs as well as increasing the gas consumption and unit hourly loading for gas units. Unit starts were determined by analyzing how many 190 MW gas turbines were required to meet the unserved energy need. The parameters for calculating the added costs to eliminate unserved energy are as follows:

[12] As explained below, gas price sensitivities in addition to those listed here were performed to further explore proxy performance and to produce additional gas price curves.

[13] GE Energy, "Western Wind And Solar Integration Study," May 2010, Section 5.6, Page 88.

1) Number of gas turbine starts;
2) Hours of operation;
3) MWh generated;
4) Cost parameters as described below for CT.

- For purposes of this study, when building the Couger model representation of the year 2018 Public Service electric system, approximately 2,000 MW of additional generic gas-fired generating capacity (summer rating) was added to meet the Company's planning reserves. This 2,000 MW of generation capacity was comprised of the following thermal generating resources;

  1) Combustion Turbines - Six (6) Generic Combustion Turbines before 2018
     a. Ratings - Summer = 169.9 MW (each); Winter = 189.4 MW (each)
     b. Full Load Heat Rate = 9,723 MMBtu /MWh
     c. Variable O&M = $8.36/MWh
     d. Min Run Time = 0 hours
     e. Ramp Rate = 15 MW/Minute
     f. Start-Up Costs = $7,414/turbine start

  2) Combined Cycle – Two (2) Generic Combined Cycle plants before 2018
     a. Ratings - Summer = 501 MW (each); Winter = 547.8 MW (each)
     b. Heat Rate = 6,849 MMBtu /MWh
     c. Variable O&M = $2.90/MWh
     d. Min Run Time = 1 hour
     e. Ramp Rate = 11 MW/minute
     f. Start-Up Costs = $13,668/facility start

Couger Model Input and Operation Review

After configuring the Couger model to properly represent the Public Service electric system for year 2018, EnerNex ran the model and produced a variety of output information pertaining to how the model simulated economic dispatch of the generation fleet to meet system load. These output results were compared to the output results produced by the Company's PROSYM production cost model that is used for our internal business planning and budget projections. This comparison showed the Couger model results to be in good agreement with PROSYM thereby providing confidence that the Couger model was properly configured for use in performing the 2GW/3GW Study.

Scope of Work

A total of 12 base case Couger model runs and 65 Couger model sensitivity case runs were performed for this study. Base case runs were done with Public Service year 2018 hourly system load represented in a manner consistent with three historical years, 2004, 2005 and 2006 (to allow maintaining correlation to the WWRD study years of 2004, 2005 and 2006). Several additional sensitivity runs were performed to validate or further explore aspects of the 2G/3G Study.

Additionally, four alternative base case scenarios were produced with geographically diverse locations for the 1,000 MW of wind facilities needed to grow the Public Service system wind resource from 2 GW to 3 GW. All four of these scenarios added wind facilities in strong wind regions on the eastern plains of either Colorado or Wyoming. These regions are reasonably close to the Colorado Front Range load center. The four alternative scenarios were developed to achieve 1) no geographic diversity by siting the expansion facilities in close proximity to the largest existing base of wind generation in Colorado's northeast corner; 2) geographic diversity in addition by siting the expansion facilities in equal capacity increments over several strong wind regions in Colorado's eastern plains where wind facilities currently exist; 3) geographic diversity in result by siting the expansion facilities in underrepresented strong wind regions in Colorado's eastern plains; and 4) a Wyoming scenario by siting the expansion facilities solely in Wyoming. See Appendix A for maps of the 2 GW wind resource locations and the locations of the facilities added to achieve 3 GW of wind resource penetration.

Please see Table 7 for a complete listing of the base case and planned sensitivity runs.

Table 7: Number of Couger Base Case and Sensitivity Model Runs

	Wind Scenario Name	Base Case			Gas Price			Storage	Proxy Shape	CO_2	Forecast Methods	Quick Start	Demand Response
Load Year		2004	2005	2006	2004	2005	2006	2004	2004	2004	2004	2004	2004
Wind Level													
New 20%	Installed MW	1	1	1	8				1				
2 GW	Installed Plus Planned MW	1	1	1	8			2	1	1	2	2	1
3 GW													
Scenario 1	No Diversity	1			1				1				
Scenario 2	Diversity in Addition	1	1	1	8	2	2	2	1	1	2	2	1
Scenario 3	Diversity in Result	1			1				1				
Scenario 4	Wyoming	1			1				1				
Total Model Runs = 65		6	3	3	27	2	2	4	6	2	4	4	2

A description of the sensitivities that were performed follows:

- **Gas Price**
  In addition to the base case runs made at a base gas price of $5.06/MMbtu, four gas price sensitivity cases were performed, $3.24, $7.83, $9.83 and $12.00/MMBtu. A complete set of gas price sensitivities was performed for both the Flat Block and On/Off Peak Proxy approaches to modeling for the 20%, 2GW and 3GW (Scenarios 2) levels of wind integration. The gas price sensitivities were not performed for all of the six base case runs. The 3GW Scenarios 1, 3 and 4 had runs at only the base case gas price of $5.06.

- **Storage**
  Two storage sensitivity cases were performed for the 2 GW and the 3 GW (Scenario 2) levels of wind. 1) the "Upgrade Cabin Creek" sensitivity modeled a 36 MW/115 MWh upgrade of the Company's existing Cabin Creek pumped storage facility and 2) the "Additional Storage Resource" sensitivity which considered the addition of a second pumped storage facility similar in size to the existing 324 MW Cabin Creek facility.
- **Wind Energy Proxy**
  An "On/Off Peak Proxy" sensitivity examined the impacts of substituting an On/Off Peak Proxy (with a two hour ramp between on and off peak) for the Flat Block Proxy that used a four hour ramp between days.
- **Day Ahead Wind Forecast Methods**
  Two sensitivity cases were performed on the day-ahead forecast of both the 2 GW and the 3 GW (Scenario 2) levels of wind. The objective of these sensitivities was to establish the outer bounds of integration costs as a function of the day-ahead wind forecast. The first set of sensitivity cases, the "No Forecast" sensitivity, (one 2 GW and one 3 GW (Scenario 2)) were performed by replacing the "day-ahead forecast" of wind production data in the Actual Case Optimization run (Step 3) with a wind production level of zero MWh for the day i.e., likely the most you could ever miss on your wind generation forecast. The second set of sensitivity cases, the "Perfect Forecast" sensitivity, (one 2 GW and one 3 GW (Scenario 2)) were performed by replacing the "day-ahead forecast" of wind production data in the Actual Case Optimization run (Step 3) with the "actual" wind production data i.e., the least you could ever miss your wind generation forecast.
- **Quick Start Resources**
  Two Quick Start Resource sensitivity cases were performed for both the 2 GW and the 3 GW (Scenario 2) levels of wind. The first set of sensitivity cases, the "No Additional Quick Start Resources" sensitivity, (one 2 GW and one 3 GW (Scenario 2)) were performed by removing six Quick Start CT resources. The second set of sensitivity cases, the "Two Additional Quick Start Resources" sensitivity, (one 2 GW and one 3 GW (Scenario 2)) were performed by adding two Quick Start CT resources.
- **Carbon**
  One sensitivity case, the "CO_2" sensitivity, was performed for both the 2 GW and the 3 GW (Scenario 2) levels of wind using a CO_2 cost of $20/ton. The CO_2 cost was accounted for by adding a cost to the wind integration cost in a post-processing calculation.
- **Demand Response**
  One sensitivity case, the "No Demand Response" sensitivity, was performed for both the 2 GW and the 3 GW (Scenario 2) levels of wind. In the base case runs the level of unserved energy from the Couger model run results was reduced by 6,000 MWh at no cost to reflect use of the Company's demand response resources. In the "No Demand Response" sensitivity this 6,000 MWh adjustment was not performed. In both the base case runs and the sensitivity, the remaining unserved energy was then addressed through the start of a requisite number of CTs as discussed earlier.

STUDY RESULTS

Base Case Results

The base case 2GW/3GW Study results are shown in Table 8. The results were determined with a base gas price of $5.06/MMBtu and with the On/Off Peak Proxy.[14]

Table 8: Average System Operations Wind Integration Costs ($5.06/MMBtu gas price)

Wind Penetration Level	20%	2 GW	3 GW Scenario 1	3 GW Scenario 2	3 GW Scenario 3	3 GW Scenario 4
Average System Operations Wind Integration Cost ($/MWh)	2.39	3.40	4.02	3.71	3.37	3.82

The "actual" annual wind energy production modeled in the base case is shown in Table 9.

Table 9: Modeled Annual Actual Wind Energy Production

Wind Penetration Level	Wind Energy Production (MWh)
20%	3,305,791
2 GW	4,378,115
3 GW	6,925,855

Geographic Diversity Influence on Average System Operations Integration Cost

At the base gas price of $5.06/MMBtu, the degree of geographic diversity in the wind facilities added to grow the wind penetration level from 2 GW to 3 GW produced changes in average system operations integration cost in the range of 4-16%. The Company believes that reductions in average system operations integration cost with increased geographic diversity makes intuitive sense. 3 GW (Scenario 2) was chosen as the "base case" for 3 GW sensitivity runs because the Company believes this 3 GW scenario represents a plausible outcome for future wind resource additions – future resources being added in more than one ERZ.

Average Regulation Wind Integration Costs

The 2GW/3GW Study results for the regulation component of wind integration costs are shown in Table 10. The results are not gas price dependent.

[14] All 2GW/3GW Study results, other than those for gas price sensitivities, were created with the Couger model using an average annual gas cost of $5.06/MMBtu.

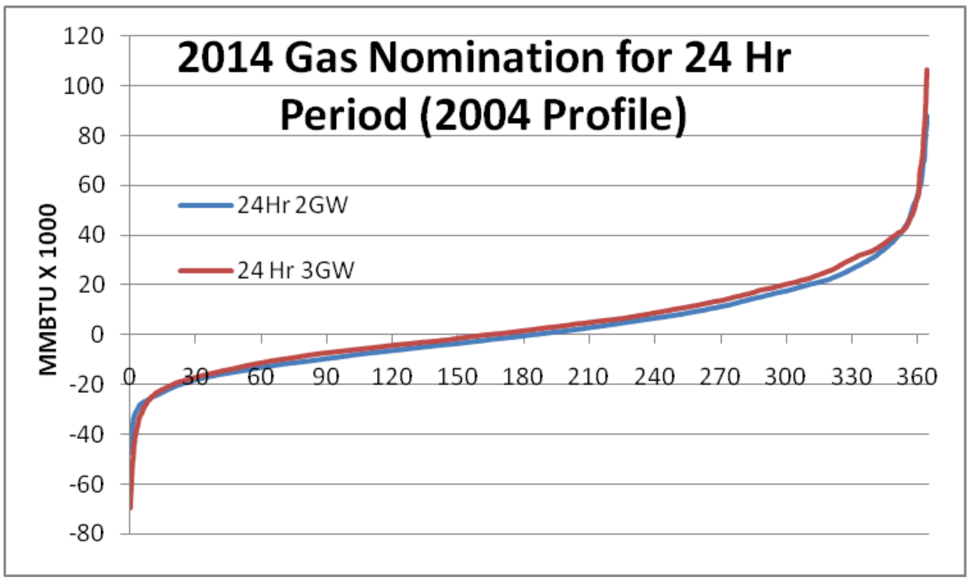
Table 10: Average Regulation Wind Integration Cost

Wind Penetration Level	20%	2 GW	3 GW
Average Regulation Wind Integration Costs ($/MWh)	0.10	0.14	0.21

Average Gas Storage Wind Integration Costs

In reviewing the Couger model runs, Public Service observed that the gas day over nomination demand charge was being set or determined by only a few "outlier" days over the entire 2018 study year that exceeded the 60,000 Decatherm/day gas injection capability used to represent the remaining capacity of the Company's existing storage facilities. Figure 1 shows over and under nomination for 365 days of 24 hour gas days ordered from lowest under nomination to greatest over nomination and illustrates the occurrence of outliers.

Figure 1: 24 Hour Gas Nomination for 2014 using 2004 Wind and Load Profile



Public Service determined that curtailment of wind resources to allow the excess gas to be burned rather than purchasing additional injection demand would be the most cost-effective approach to managing these outlier days. Therefore, Public Service chose a curtailment approach to handle the "outlier" gas day over nominations to minimize the average gas storage wind integration cost. The cost to curtail wind on these outlier days is included in the average gas storage wind integration costs which were determined with a base gas price of $5.06/MMBtu and with the On/Off Peak Proxy and which are shown in Table 11 below.

Table 11: Average Gas Storage Wind Integration Cost ($5.06/MMBtu gas price)

Wind Penetration Level	2 GW	3 GW Scenario 2
Gas Storage Wind Integration Cost ($/MWH)	0.14	0.17

Total Average Wind Integration Costs

The total average wind integration costs is the sum of the three components of wind integration cost and the values for the 2GW and 3GW levels of wind are summarized in Table 12

Table 12: Total Average Wind Integration Cost ($5.06/MMBtu gas price)

Wind Penetration Level	2 GW	3 GW Scenario 2
Average Regulation Wind Integration Cost ($/MWh)	0.14	0.21
Average System Operations Wind Integration Cost ($/MWH)	3.40	3.71
Average Gas Storage Wind Integration Cost ($/MWH)	0.14	0.17
Total Average Wind Integration Cost ($/MWH)	**3.68**	**4.09**

As explained in the "Application of Results" section below, Public Service will use the total *incremental* not *average* wind integration costs in its resource planning and selection processes. Therefore, **Table 12 is provided for illustrative purposes only**.

GAS PRICE SENSITIVITY

The price of natural gas is a key factor in the calculation of average system operations wind integration cost estimates since much of the wind uncertainty is accommodated by starting, operating, and stopping gas-fired generating units. Table 13 below shows the range of gas prices analyzed in this 2GW/3GW Study. A total of 31 gas price sensitivities were run, eight for the 2004/20% base case run, eight for the 2004/2 GW base case run, and one for each scenario of the 2004/3 GW base case runs with the exception of 3 GW Scenario 2 which had eight (as well as 2 each for 2005 and 2006). Each of the four sensitivities was run for the Flat Block Proxy and for the On/Off Peak Proxy.

Table 13: Gas Prices for Base Cases and for Sensitivities ($/MMBtu)

	AVG	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Base	**5.06**	6.02	5.82	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	5.11	5.40
Sensitivity 1	**7.83**	8.18	8.26	8.16	7.45	7.48	7.56	7.68	7.72	7.48	7.52	8.09	8.32
Sensitivity 2	**9.83**	10.27	10.37	10.25	9.35	9.39	9.49	9.65	9.69	9.39	9.44	10.16	10.45
Sensitivity 3	**3.24**	3.85	3.73	3.07	3.07	3.07	3.07	3.07	3.07	3.07	3.07	3.27	3.46
Sensitivity 4	**12.00**	14.28	13.80	11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	12.12	12.81

The average system operations wind integration costs determined for the base case and gas price sensitivities using the On/Off Peak Proxy are presented in Table 14 below. Average system operations wind integration costs are given in $/MWh and gas costs are given in $/MMBtu.

Table 14: Average System Operations Wind Integration Cost/Gas Price Matrix

Gas Price Sensitivity Cases	Average Gas Price ($/MMBtu)	Average System Operations Wind Integration Costs ($/MWh)					
		20%	2 GW	3 GW Scenario 1	3 GW Scenario 2	3 GW Scenario 3	3 GW Scenario 4
Sensitivity 3	3.24	2.19	2.70	N/A	2.87	N/A	N/A
Base	5.06	2.39	3.40	N/A	3.71	N/A	N/A
Sensitivity 1	7.83	3.35	4.68	N/A	5.87	N/A	N/A
Sensitivity 2	9.83	5.11	5.57	N/A	7.50	N/A	N/A
Sensitivity 4	12.00	5.85	6.54	N/A	9.60	N/A	N/A

STORAGE SENSITIVITY

The base case runs were performed with Public Service's 324 MW Cabin Creek pumped storage facility as the sole "energy storage" resource on the system. The "Upgrade Cabin Creek" sensitivity involved increasing the efficiency and generation capacity of the existing Cabin Creek facility and the "Additional Storage Resource" sensitivity included the addition of a second 324 MW pumped storage plant.

For the "Upgrade Cabin Creek" sensitivity, the following improvements were made to the model representation of the Cabin Creek facility 1) the upper storage pond holding capacity and its spill capacity was increased by 115 MWh per cycle (1,400 to 1,515 MWh); 2) the nameplate capacity rating of the unit was increased 36.6 MW (324 MW to 360 MW).; and 3) the pumping efficiency of the facility was increased 7% (from 0.62 to 0.66).

The "Additional Storage Resource" sensitivity added a second, two unit pumped storage resource with the same 324 MW capability and efficiency as the exiting Cabin Creek facility.

The purpose of these sensitivities is to examine the effect additional storage capability might have on reducing average system operations wind integration cost. The results of the sensitivities using the Flat Block Proxy are provided in Table 15 below.

Table 15: Average System Operations Wind Integration Cost - Storage Sensitivities ($5.06/MMBtu gas price)

Storage Sensitivity Cases	Average System Operations Wind Integration Cost ($/MWh)	
	2 GW	3 GW Scenario 2
Base Case	4.11	5.44
Upgrade Cabin Creek Sensitivity	3.87	5.11
Additional Storage Resource Sensitivity	3.63	4.32

The storage sensitivity results indicate that average system operations wind integration cost can be reduced by making improvements to the Cabin Creek facility or by the addition of a second pumped storage facility. The reduction in average system operations wind integration cost for the upgrade sensitivity is $0.24/MWh for the 2 GW scenario and $0.33/MWh for the 3 GW (Scenario 2) scenario. The reduction in average system operations wind integration cost for the storage facility addition sensitivity is $0.48/MWh for the 2 GW scenario and $1.12/MWh for the 3 GW (Scenario 2) scenario. Both the upgrade and additional storage resource sensitivity cases were built upon the base case.

The average system operations wind integration cost reductions achieved by the addition of a second 324 MW storage facility appeared disproportionately low when compared to the reduction achieved by increasing the efficiency and MW capability of the existing pumped storage facility. This result prompted further review of the results of the storage sensitivities.

In addition to verifying that the Couger model was functioning properly, including the dispatch of the storage resources, when it produced the sensitivity results provided above, Public Service and EnerNex investigated the effects of storage resources on reserve capacity, unserved energy, start up costs etc. and also performed an additional sensitivity. The additional sensitivity was identical to the "Additional Storage Resource" sensitivity except that the additional storage resource was also modeled with improved pumping efficiency (7% improvement). This sensitivity produced average system operations wind integration costs of $3.47 for 2 GW and $4.13 for 3 GW Scenario 2.

In deciding when to generate with the pumped storage resource, Couger first examines the hours within the week when the pumped storage resource can displace a high cost resource. Couger then considers whether the water used to provide this generation can be pumped to the upper reservoir with an available thermal generating resource that is sufficiently low in cost to make the combined pumping and generation cycle economic. As background assumption, wind energy was modeled in Couger as a must take energy resource thereby acting to reduce the load on the system that is eventually served by dispatchable resources. As a result, all of the energy used to pump water back to the upper reservoir is from dispatchable resources.

Tables 16 and 17 show the generation and pumping parameters for the storage sensitivity cases. For the 2 GW level of wind penetration, the "Upgrade Cabin Creek" sensitivity shows a 9.2% increase in pumped storage generation and the "Additional Storage Resource" sensitivity shows a 75.5% increase in pumped storage generation over the Base Case. For the 3 GW (Scenario 2) level of wind penetration, pumped storage generation also increased when compared to the Base Case – 16.1% and 68.6% for the two sensitivities. Corresponding increases in pumped storage pumping were also seen in the sensitivities. The additional pumped storage efficiency or capability (upgrade or second unit) provided an increase in pumped storage utilization that is generally proportional to the modifications made to the storage resource.

Table 16: Pumped Storage Generation Comparison

	2 GW				3 GW (Scenario 2)			
Storage Sensitivity Cases	Pumped Storage Generation (MWh)	Delta to Base (MWh)	% Delta to Base (MWh)	Average System Lambda	Pumped Storage Generation (MWh)	Delta to Base (MWh) (1)	% Delta to Base (MWh)	Average System Lambda
Base Case	256,513			54.38	281,379	24,866		60.57
Upgrade Cabin Creek Sensitivity	280,178	23,665	9.2%	53.72	326,770	45,391	16.1%	58.74
Additional Storage Resource Sensitivity	450,149	193,636	75.5%	53.70	474,328	192,949	68.6%	60.20

Table 17: Pumped Storage Pumping Comparison

Storage Sensitivity Cases	2 GW				3 GW (Scenario 2)			
	Pumped Storage Pumping (MWh)	Delta to Base (MWh)	% Delta to Base (MWh)	Average System Lambda	Pumped Storage Pumping (MWh)	Delta to Base (MWh) (1)	Delta to Base (MWh) (1)	Average System Lambda
Base Case	(413,833)			29.00	(454,012)			32.03
Upgrade Cabin Creek Sensitivity	(434,768)	(20,935)	5.1%	29.10	(492,641)	(38,629)	8.5%	32.66
Additional Storage Resource Sensitivity	(726,202)	(312,370)	75.5%	32.28	(765,383)	(311,371)	68.6%	34.65

Notes:

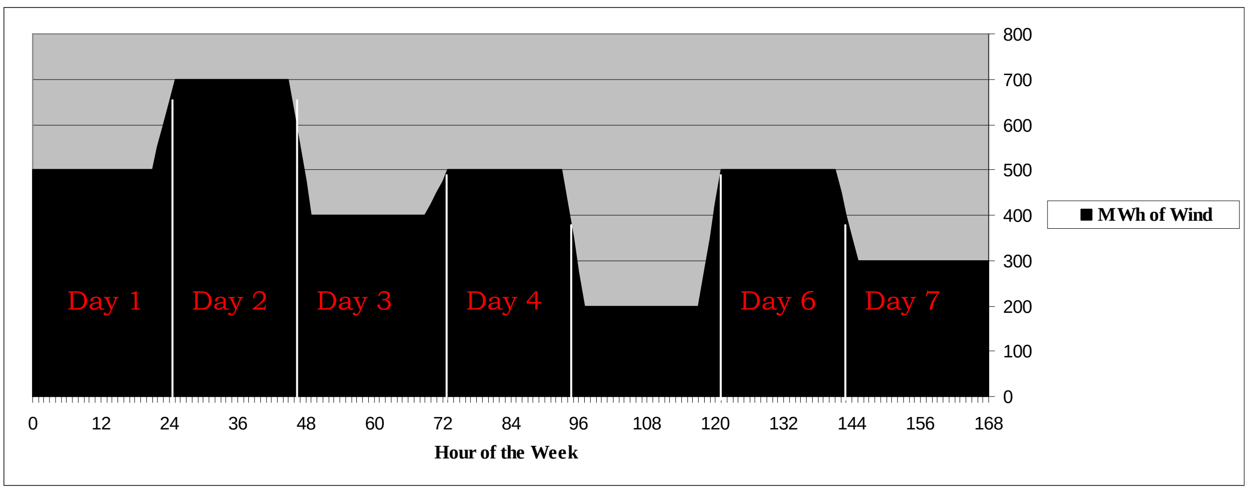
1) The "Delta to Base" figures for 3 GW (Scenario 2) Base Case are a comparison to the 2 GW Base Case figures.

The average system lambdas (the average cost of the marginal unit of energy) for each of the case results show the pumping costs for the "Additional Storage Resource" sensitivities were notably higher. This higher cost to pump the water appears to diminish the cost effectiveness of the additional storage resource with regards to reducing the average system operations integration cost of wind on the Public Service system.

WIND ENERGY PROXY SENSITIVITY

Both the Reference Case Optimization run (Step 1) and the Reference Case Simulation run (Step 2) employed an hourly wind energy pattern or proxy as a substitute for actual hourly wind energy production patterns. Public Service employed a "flat block proxy" that, for each day of the study year, distributed the actual wind energy production from WWRD for a 24 hour period evenly over each hour of that 24 hour period. In addition, the block energy proxy step change from one day's block to the next day's block was smoothed by calculating a four-hour ramp between blocks (a day's last two hours and the following day's first two hours had wind energy production values that incremented up or down between block proxy values). See Figure 2 for an illustration of a Flat Block Proxy with a four hour ramp between daily proxy energy blocks.

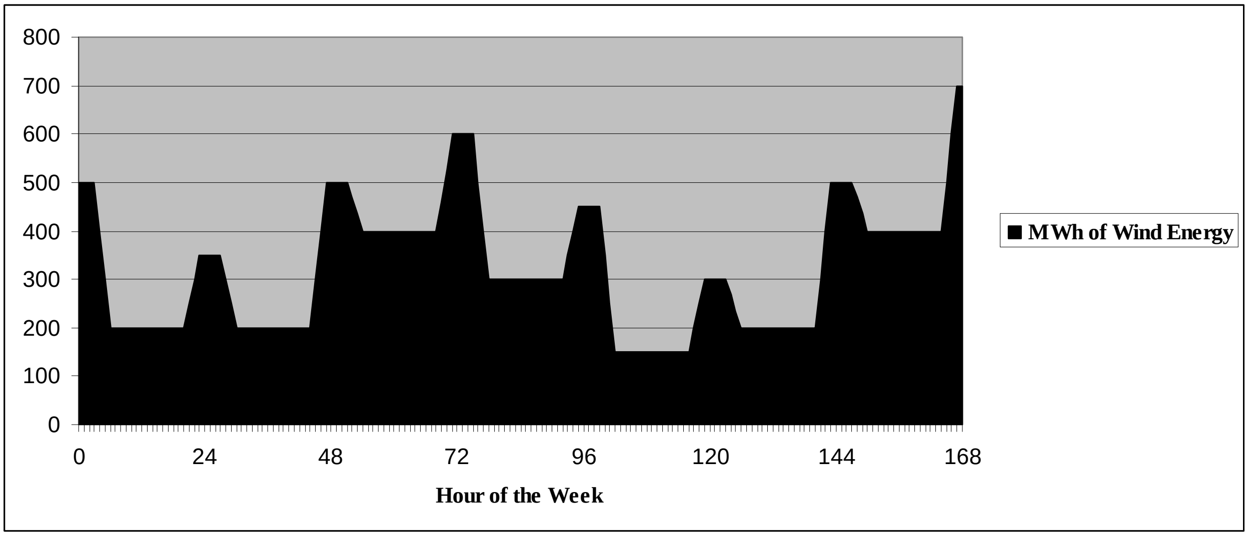
Figure 2: Example "Flat Block Proxy" with Four Hour Ramp Between Blocks



For the "On/Off Peak Proxy" proxy shape sensitivity an On/Off Peak wind energy proxy with a two hour ramp between on-peak and off-peak energy proxy blocks was used for both the 2 GW and the 3 GW (Scenario 2) levels of wind penetration. The On/Off Peak Proxy distributes the wind energy production from WWRD into two blocks within each 24 hour day to more closely match the diurnal on-peak and off-peak periods of the day. See Figure 3 for an illustration of an On/Off peak Proxy with a two hour ramp between the on-peak and the off-peak proxy energy blocks.[15]

[15] The illustration uses a large or exaggerated difference between peak and off-peak energy levels.

Figure 3: Example On/Off Peak Proxy with Two Hour Ramp Between Blocks



The purpose of the proxy sensitivity is to determine the effect that wind proxy shapes/approaches utilized in the Steps 1 and 2 model runs have on the average system operations wind integration costs that result from the methodology applied in this study. Proxy shape does not affect the average regulation wind integration cost and would have a de minimus affect on the average gas storage wind integration cost. The result of the sensitivity is provided in Table 18 below.

Table 18: Average System Operations Wind Integration Cost – Proxy Shape Sensitivity ($5.06/MMBtu gas price)

Proxy Shape Sensitivity Cases	Average System Operations Wind Integration Cost ($/MWh)	
	2 GW	3 GW Scenario 2
Base Case – Flat Block Proxy	4.11	5.44
On\Off Peak Proxy Sensitivity	3.40	3.71

The proxy shape sensitivity results indicate that average system operations wind integration costs produced in this study are lowered when the Step 1 and 2 model runs are performed using an On/Off Peak Proxy. The Company believes that the results of this sensitivity create a decision point as to the appropriate average system operations wind integration cost to select for purposes of calculating the incremental wind integration costs to be used in comparing the cost of wind resources with other power supply alternatives. The decision, "Is it most appropriate to use the "Flat Block Proxy" or "On/Off Peak Proxy" results?"

Recall that the wind energy proxy is used in Steps 1 and 2 of the modeling protocol in order that Step 4 total system costs minus Step 2 total system costs removes the load uncertainty factor from the determination of average system operations wind integration cost. It is, therefore, integral and important to the modeling protocol to employ a wind energy proxy. At issue is the nature or shape of the proxy and the effect the proxy has on Step 2 costs.

To put the issue succinctly, when a flat block proxy is used, some wind energy is moved to the daytime period where wind is generally displacing more costly resources. The result is that Step 2 system costs determined with the proxy are "artificially" lowered. In the modeling protocol Step 2 costs are subtracted from Step 4 costs; therefore, any reduction in Step 2 costs results in a higher wind integration cost. This issue was explored in the paper, "Calculating Wind Integration Costs: Separating Wind Energy Value from Integration Costs Impacts."[16] Block proxies of any sort also have the attendant issue of ramping events between the blocks which can cause cost increases as changing generation levels up or down causes operating inefficiencies.

Alternatives to the Flat Block and the On/Off Peak proxies include block proxies that use shorter time periods, e.g., six hours, and moving or rolling average proxies. The smaller time period block proxies more closely match the proxy energy levels to those actually encountered during wind generator operation mitigating the problem caused by larger time period block proxies. The rolling average proxies mitigate both the adverse effects of ramping and the time shifting of wind production produced by block proxies.

The historical context is that many wind integration cost studies and Public Service's past wind integration cost studies used a Flat Block Proxy. Public Service recognizes the validity of arguments for using a different proxy than the Flat Block Proxy but was concerned that sufficient research with empirical data has not been conducted that demonstrates the superiority of the On/Off Peak Proxy, other time period block proxies, or the rolling average proxies as it concerns more valid results for average system operations wind integration cost.

Public Service believes that the question of what proxy wind shape produces the most accurate prediction of actual average system operations wind integration cost can be informed by assessing how well each proxy approach aligns with average system operations wind integration cost estimates developed from actual historical operation data for the Public Service system. The process for developing average system operations wind integration cost estimates from actual historical operational data is referred to herein as "back casting."

Pubic Service's back casts of historical average system operations wind integration costs are developed in a manner similar to that used to estimate future average system operations wind integration cost within the Couger model, i.e., the back cast compares 1) the system operating costs of a unit commitment developed from a wind energy forecast to 2) the system operating costs of a commitment developed using actual wind energy production. Specifically, a day-ahead wind forecast is used to commit resources and then those resources are dispatched against the wind generation that actually occurred on the system. Finally, a third step is performed using the actual wind generation for both the commit and dispatch decisions. The total amount of wind energy is the same between the second and third runs. The system operating cost difference between the second and third steps is representative of the actual average system operations wind integration cost of wind for the historical period analyzed.

The key distinction between the Couger modeling and the back cast modeling is that the back cast uses *actual* hourly forecasts of load and wind energy production, an *actual* day-ahead commitment and *actual* loads and wind energy production to estimate the average system operations wind integration cost. The back cast determines only the integration costs associated

[16] Milligan, Michael, Kirby, Brendan, "Calculating Wind Integration Costs: Separating Wind Energy Value from Integration Costs Impacts," National Renewable Energy Laboratory, July 2009.

with the electric system operations component of wind integration costs that the Couger model determines and is, therefore, comparable to the values contained in Table 8 of this report.

Public Service's back cast analysis of the average system operations wind integration cost for 2010 (a period that reflects the results of Public Service's most recent efforts to improve wind forecasting) determined that the average system operations wind integration cost averaged $3.22/MWh at an average gas price of $4.01/MMBtu. The level of wind generation installed on the Public Service system throughout the time period of the back cast was 1,233 MW name plate; therefore, the 20% penetration level results from this study are most comparable to those of the 2010 back cast. With a comparable level of mean absolute forecast error, and at the $4.01/MMBtu gas price, the average system operations wind integration cost for the 20% wind penetration Flat Block Proxy is $2.89/MWh and the "like" figure for the On/Off Peak Proxy is $2.27/MWh. Please see Appendix B.

The Company believes that the 2010 back casting results validate the wind integration cost results produced in this 2GW/3GW study using either the adjusted Flat Block Proxy and the On/Off Peak Proxy approaches. The Flat Block Proxy result (with the appropriate adjustments) more closely approximates the average system operations wind integration cost developed through the 2010 historical back casting but not in a way that indicates that the Flat Block Proxy produces a more valid result or that the On/Off Peak Proxy produces a less valid result. Because the On/Off Peak Proxy more accurately distributes the wind energy to the appropriate time period and energy cost category, Public Service intends to use the On/Off Peak Proxy results when assessing the overall cost of wind resources during future resource planning/selection processes.

WIND FORECAST METHODS SENSITIVITY

The base case studies were performed using WWRD wind production data for both the day-ahead "forecast" of wind generation in the Actual Case Optimization run (Step 3) and the "actual" production figure used for wind generation in the Actual Case Simulation run (Step 4).

The "No Forecast" sensitivity was performed by replacing the day-ahead "forecast" wind generation in the Actual Case Optimization run (Step 3) with a wind generation level of zero MWh for the day. The "Perfect Forecast" sensitivity was performed by replacing the day-ahead "forecast" wind generation in the Actual Case Optimization run (Step 3) with the "actual" wind generation for the day. The purpose of these sensitivities is to establish the bounds of the day-ahead wind forecast's effect on the average system operations wind integration cost. The results of the sensitivities using the Flat Block Proxy are provided in Table 19 below.

Table 19: Average System Operations Wind Integration Cost – Forecast Methods Sensitivities ($5.06/MMBtu gas price)

Forecast Methods Sensitivity Cases	Average System Operations Wind Integration Cost ($/MWh)	
	2 GW	3 GW Scenario 2
Base Case	4.11	5.44
No Forecast Sensitivity	10.24	14.69
Perfect Forecast Sensitivity	1.48	3.33

The 2G/3G Study results provide a level of validation to the modeling approach employed in this study in that the value of an accurate day-ahead wind forecast is shown by the large increase in the average system operations wind integration cost when no forecast of wind generation is available or used, the "No Forecast" sensitivity. In addition, the "Perfect Forecast" sensitivity demonstrates a marked decrease in the average system operations wind integration cost when the same value of wind production is used to perform both the commitment and dispatch of the system. As noted above, the results of the No Forecast and Perfect Forecast sensitivities "bound" the 2G/3G Study results between $1.48/MWh and $10.24/MWh for the 2 GW level of wind integration.

QUICK START RESOURCES SENSITIVITY

The base case studies were performed with each thermal resource receiving a designation as to whether it is a Quick Start resource or not. For purposes of this study quick start units are those capable of being off-line and counting towards the 10-minute spinning reserve requirement because of their ability to start, synchronize, and come to full load in 10 minutes. The Public Service power supply system is expected to have approximately 194 MW of quick start resources in 2018 (not counting any of the six generic CT resources included in the Couger model for purposes of meeting future load requirements).

The "No Additional Quick Start Resources" sensitivity was performed by changing the designation of the six quick start CT resources added to the model to non-quick start such that they would need to be on line to count against the 10-minute reserve requirement. The "Two Additional Quick Start Resources" sensitivity was performed by changing the designation of four of the six quick start CT resources to non-quick start. The purpose of these sensitivities is to examine the value provided by quick start facilities in lowering average system operations wind integration cost. The results of the sensitivities using the Flat Block Proxy are provided in Table 20 below.

Table 20: Average System Operations Wind Integration Cost – Quick Start Resources Sensitivities ($5.06/MMBtu gas price)

Quick Start Resources Sensitivity Cases	Average System Operations Wind Integration Cost ($/MWh)	
	2 GW	3 GW Scenario 2
Base Case	4.11	5.44
No Additional Quick Start Resources Sensitivity	4.13	5.44
Two Additional Quick Start Resources Sensitivity	4.13	5.46

The quick start resources sensitivities results indicate that for purposes of minimizing average system operations wind integration cost, sufficient quick start resource are expected to exist on the Public Service system by 2018 (not counting any of the six generic CT's added to the system) and that adding more quick start resources will have little incremental impact on reducing these costs. Note that the Couger model, being an *hourly* unit commitment and dispatch model, is not capable of fully quantifying the total value that quick start and flexible resources can bring to the system. The Couger model allows an offline quick start unit to meet a portion of the system operating reserve requirement. The results of these sensitivity runs indicate that the amount of quick start units that will exist on the Public Service system in 2018 (not counting any of the generic CTs added) will be sufficient to minimize wind integration costs at both the 2GW and 3GW levels and that additional quick start capability is expected to provide little if any value in reducing integration costs.

CARBON SENSITIVITY

The base case studies were performed with no cost included for CO_2 emissions from fossil fuel plants. One sensitivity case, the "CO_2" sensitivity, was performed by adding a CO_2 cost of $20/ton to the prior-determined average system operations wind integration cost.

The purpose of the "CO_2" sensitivity was to produce a wind integration cost value for application in situations where wind generation is being compared with other generation technologies and a cost is being assigned to CO_2 emissions. Since the majority of total incremental wind integration cost results from sub-optimal thermal unit commitment and dispatch, the expectation going into this sensitivity was that these sub-optimal outcomes would result in increased CO_2 emissions and subsequently a higher integration cost. The result of the sensitivity using the Flat Block Proxy is provided in Table 21 below.

Table 21: Average System Operations Wind Integration Cost – CO_2 Sensitivity ($5.06/MMBtu gas price)

CO_2 Sensitivity Cases	Average System Operations Wind Integration Cost ($/MWh)	
	2 GW	3 GW Scenario 2
Base Case	4.11	5.44
CO_2 Sensitivity	3.81	4.85

Unexpectedly, the assignment of costs to CO_2 emissions produced lower integration costs. This result is misleading. In reviewing this outcome, EnerNex and Public Service concluded that the methodology employed to examine the impacts of CO_2 does not produce a reliable result. The reason for this stems from the use of the wind energy proxy resource in Steps 1 and 2. The wind energy proxy 1) averages or "smooths" the forecasted daily wind energy production either over a single period, the Flat Block proxy, or over two periods, the On/Off Peak Proxy; and 2) allows Public Service to isolate the cost of load forecast error and ensure these load forecast related costs don't get included in the wind integration cost. Recall that wind energy acts to reduce system load in the model and that the average system operations wind integration cost is the result of the total production cost of Run 4 minus the total production cost of Run 2 (divided by the modeled actual annual wind energy produced).

Use of the flat block proxy shifts wind generation to daytime hours when lower CO_2 emitting gas units are on the margin. This effect reduces the level of CO_2 emissions that wind avoids in Runs 1 and 2 relative to the level of CO_2 wind avoids in Runs 3 and 4. Run 2 ends up with more CO_2 per level of wind than does Run 4. When a cost is applied to CO_2, more cost is applied to Run 2 versus Run 4, thus reducing the overall cost delta between the runs subsequently reducing the wind integration cost result.

DEMAND RESPONSE SENSITIVITY

In the base case studies it was assumed that 6,000 MWh of Public Service's demand response program, Interruptible Service Option Credit, would be used for purposes of helping reduce the average system operations wind integration cost.[17] In these base case studies the level of unserved energy within the Couger model was reduced by 6,000 MWh. The remaining unserved energy was then assigned a $/MWh cost representative of the operating costs of a CT. In the "No Demand Response" sensitivity, no downward adjustments were made to the unserved energy within the Couger model runs.

The purpose of "No Demand Response" sensitivity is to examine the effect of demand response resources on the average system operations wind integration cost. The result of the sensitivity using the Flat Block Proxy is provided in Table 22 below.

Table 22: Average System Operations Wind Integration Cost – No Demand Response Sensitivity ($5.06/MMBtu gas price)

Demand Response Sensitivity Cases	Average System Operations Wind Integration Cost ($/MWh)	
	2 GW	3 GW Scenario 2
Base Case	4.11	5.44
No Demand Response Sensitivity	4.21	5.51

The procedure for performing this sensitivity predetermines the result of an increase in the average system operations wind integration cost. The sensitivity serves to define the amount of change in the average system operations wind integration cost for a given amount of demand response resource. Within the 2GW/3GW study model, a 6,000 MWh resource can change the average system operations wind integration cost by $0.10 for a 2 GW wind penetration level and $0.07 for a 3 GW wind penetration level.

[17] There is approximately 17,200 MWh of possible demand response energy provided by the Interruptible Service Option Credit tariff in 2018 (215 MW multiplied by 80 hours average availability). Commercial Operations estimated that approximately 6,000 MWh of this amount would be used for purposes of reducing wind integration costs in 2018.

APPLICATION OF THE STUDY RESULTS

At the base case gas price of $5.06/MMBtu and with the On/Off Peak Proxy, the 2GW/3GW Study determined that the average system operations wind integration cost was $3.40 at the 2 GW level of penetration and $3.71 at the 3 GW level of wind. The integration cost to be included for any additional or incremental wind generation above 2 GW is not, however, equivalent to either the $3.40 or $3.71 values stated above. A total *incremental* wind integration cost must be determined for additional wind by taking the difference between the total average integration costs (electric and gas) determined for the 2 GW wind penetration level and any new level of wind penetration and dividing that figure by the incremental actual annual wind energy produced. Below is an illustration of the calculation for adding a 200 MW wind facility to a 2,000 MW level of installed wind generation.

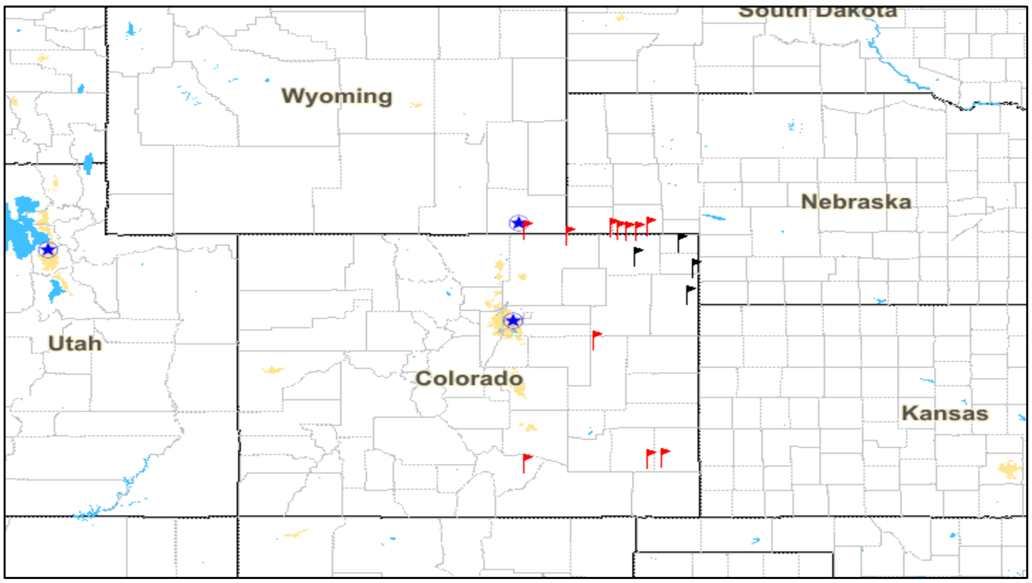
Table 23: Example Total Incremental Wind Integration Cost Calculation

Step	Value and (Calculation)	Result
	2,000 MW Calculation	
a	Total Actual Annual Wind Energy Assumption (MWh)	6,000,000
b	Average Regulation Wind Integration Cost ($/MWh)	0.14
c	Regulation Wind Integration Cost ($) **(a*b)**	840,000
d	Average System Operations Wind Integration Cost ($/MWh)	3.40
e	System Operations Wind Integration Cost ($) **(a*d)**	20,400,000
f	Average Gas Storage Wind Integration Cost ($/MWh)	0.14
g	Gas Storage Wind Integration Cost ($) **(a*f)**	840,000
h	Total Wind Integration Cost ($) **(c+e+g)**	22,080,000
	2,200 MW Calculation	
i	Capacity addition between 2,000 and 3,000 MW	1000
j	Capacity Factor of Added Wind Assumption	0.5
k	Amount of Added Wind Capacity Assumption (MW)	200
l	Hours in a Year	8,760
m	Total Actual Annual Wind Energy (MWh) **(a+(j*k*l))**	6,876,000
n	Average Regulation Wind Integration Cost at 3,000 MW ($/MWh)	0.21
o	Average Regulation Wind Integration Cost ($/MWh) **(b+((k/i)*(n-b)))**	0.15
p	Regulation Wind Integration Cost ($/MWh) **(m*o)**	1,058,904
q	Average System Operations Wind Integration Cost at 3,000 MW ($/MWh)	3.71
r	Average System Operations Wind Integration Cost ($/MWh) **(d+((k/i)*(q-d)))**	3.46
s	System Operations Wind Integration Cost ($) **(m*r)**	23,804,712
t	Average Gas Storage Wind Integration Cost at 3,000 MW ($/MWh)	0.17
u	Average Gas Storage Wind Integration Cost ($/MWh) **(f+((k/i)*(t-f)))**	0.15
v	Gas Storage Wind Integration Cost MW ($) **(m*u)**	1,003,896
w	Total Wind Integration Cost ($) **(p+s+v)**	25,867,512
	Total Incremental Wind Integration Cost Calculation	
x	Total Incremental Wind Integration Cost ($/MWh) **((w-h)/(m-a))**	4.32

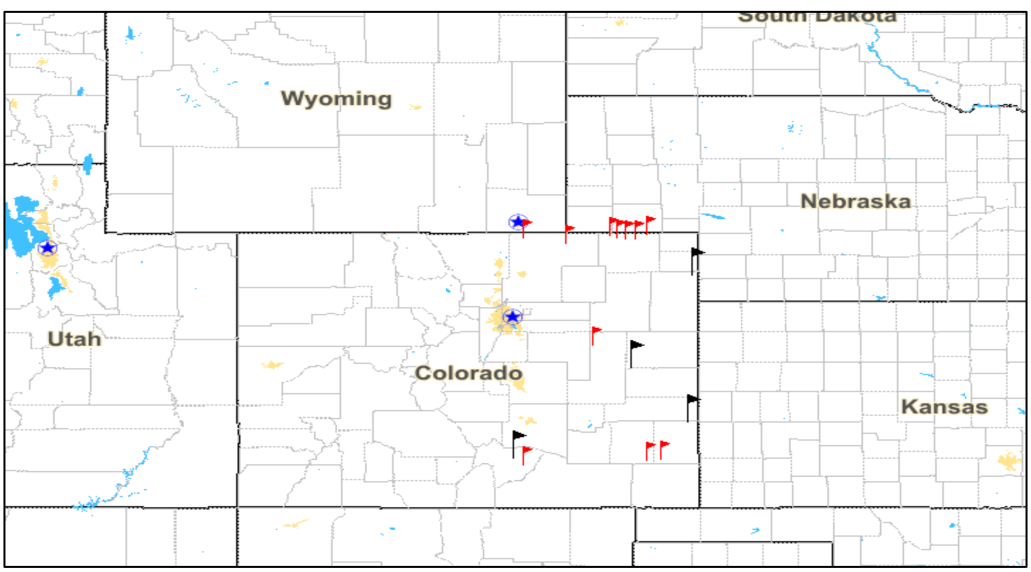
APPENDIX A – LOCATION OF WIND FACILITIES

Red flags indicate location of 2 GW wind facilities. Black flags indicate location of the wind facilities added (1,060 MW) to reach 3 GW of wind generation resources.

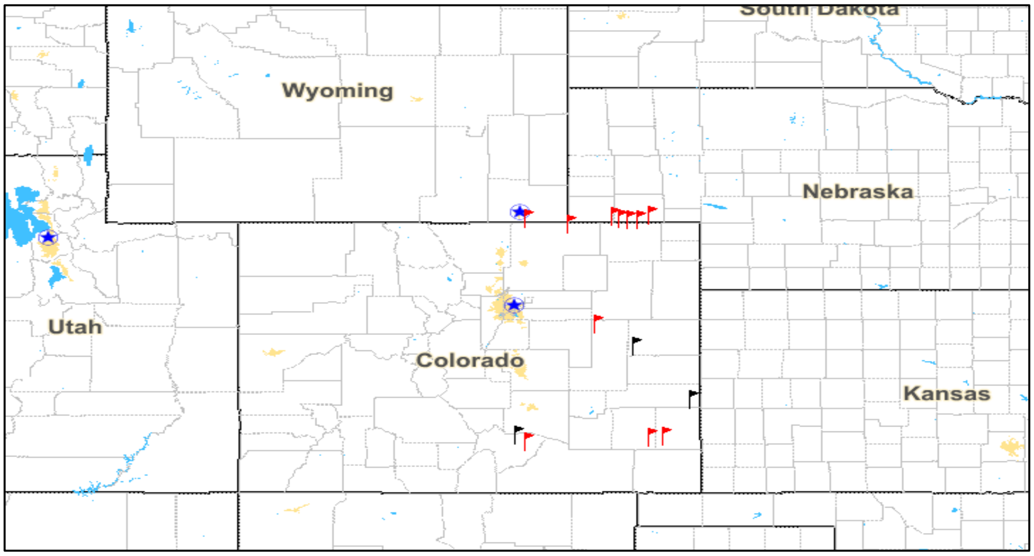
3 GW Scenario 1 Wind Site Locations



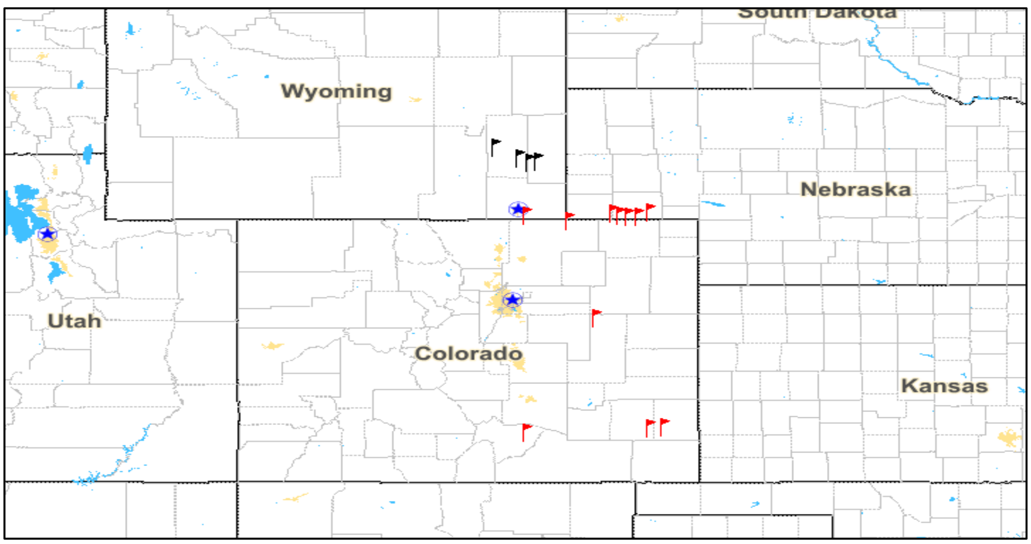
3 GW Scenario 2 Wind Site Locations



3 GW Scenario 3 Wind Site Locations [18]



3 GW Scenario 4 Wind Site Locations



[18] 3 GW Scenario 3 has 530 MW added at one site in Southeast Colorado and, therefore, has only three black flags to identify facility location.

APPENDIX B – WIND INTEGRATION COSTS: FLAT BLOCK AND ON / OFF PEAK PROXY VS BACK CAST STUDY

Comparison of Average System Operations Wind Integration Costs Determined with a Flat Block Proxy and an On/Off Peak Proxy to Average System Operations Wind Integration Costs Determined by a Back Cast Study

Public Service monthly performs a back cast study of average system operations wind integration costs The study is done for installed wind capacity that ranged from 1,130 MW in 2009 to 1,234 MW in 2010 and, therefore, is closest in installed capacity to the 20% Study Results

		Average System Operations Wind Integration Costs			**Slope of Gas Cost Curve 1**	**Slope of Gas Cost Curve 2**
		2009	**2010**			
Backcast Average Gas Price ($/MMBtu)		3 33	4 01			
Backcast GW		1 13	1 23			
Backcast Average System Operations Wind Integration Cost ($/MWh)		3 00	3 22			
Backcast Mean Absolute Error of Forecast to Actual Wind (%)		19 55%	14 18%			
Backcast Mean Absolute Error of Forecast to Actual Wind of 1 4 GW study (%)		13 80%	13 80%			
MAE of Forecast to Actual Wind Generation Adjustment		41 65%	2 78%			
		2 12	3 13			
Avg Annual Gas Price ($/mmBtu)	**3.24**	**5.06**	**7 83**	**9.83**		
20% (~1 4 GW) Flat Block Proxy Average System Operations Wind Integration Cost ($/MWh)	2 70	3 15	4 50	5 24	0 25	0 48
2 GW Flat Block Proxy Average System Operations Wind Integration Cost ($/MWh)	3 29	4 11	5 96	7 37	0 45	0 67
3 GW Flat Block Proxy Average System Operations Wind Integration Cost ($/MWh)	3 77	5 44	7 84	10 02	0 92	0 87
20% (~1 4 GW) On/Off Peak Proxy Average System Operations Wind Integration Cost ($/MWh)	2 19	2 39	3 35	4 51	0 11	0 35
2 GW On/Off Peak Proxy Average System Operations Wind Integration Cost ($/MWh)	2 70	3 40	4 68	6 54	0 38	0 46
3 GW On/Off Peak Proxy Average System Operations Wind Integration Cost ($/MWh)	2 87	3 71	5 87	6 86	0 46	0 78
Adjustment to Back Cast Gas Price		**Flat Block**				
		$3 33	**$4.01**			
MAE and Gas Price Adjusted 20% Average System Operations Wind Integration Costs ($/MWh)	1 4 GW	2 72	2 89			
MAE and Gas Price Adjusted 2 GW Average System Operations Wind Integration Costs ($/MWh)	2 GW	3 33	3 64			
MAE and Gas Price Adjusted 3 GW Average System Operations Wind Integration Costs ($/MWh)	3 GW	3 85	4 48			
		On/Off Peak				
MAE and Gas Price Adjusted 20% Average System Operations Wind Integration Costs ($/MWh)	1 4 GW	2 20	2 27			
MAE and Gas Price Adjusted 2 GW Average System Operations Wind Integration Costs ($/MWh)	2 GW	2 73	3 00			
MAE and Gas Price Adjusted 3 GW Average System Operations Wind Integration Costs ($/MWh)	3 GW	2 91	3 22			