Attachment 2.14-1

2011 WIND LIMIT STUDY

PREPARED FOR THE PUBLIC SERVICE COMPANY OF COLORADO 2011 ELECTRIC RESOURCE PLAN

OCTOBER 31, 2011

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

SECTION 1 STUDY OBJECTIVE

Through analysis of the Public Service Company of Colorado electric system reliability/performance requirements and generation supply characteristics, determine whether a maximum level of installed wind generation resources can be identified at which point reliable system operation would be jeopardized. In addition, estimate the level of wind energy that will likely need to be curtailed as a result of physical and economic limitations on the remainder of the Company's electric system at increasing levels of wind generation.

SECTION 2 SUMMARY

<u>Introduction</u>

Public Service Company of Colorado ("Public Service" or the "Company") began its investigation of a possible maximum level of wind generation for its system by scoping the systems operations issues that wind generation resources cause as the result of the resource's variability and uncertainty. The intermittent or variable nature of wind generation coupled with the difficulties inherent in trying to forecast wind generation (uncertainty) pose significant challenges to operators who work to maintain the continuous balance between generation and load as well as planners who must anticipate future changes to the electric or fuel supply systems that will be needed to ensure reliable operation of the system going forward. Over the last three years (2009-2011) personnel from the Company's Commercial Operations, Transmission Operation, Transmission Planning and Resource Planning departments with the assistance of industry experts investigated a number of wind integration related issues (including cost) and their effects on operation of the Public Service electric supply system. The Company completed two studies that have recently been filed with the Commission in Docket No. 11M-710E, the Coal Plant Cycling Cost Study and the 2GW/3GW Wind Integration Cost Study. Given that these completed studies addressed many of the cost issues associated with integrating wind on to our system, Public Service narrowed the scope for this investigation of a maximum level of wind generation to three areas;

1. flexible generation resources
2. flexibility of the gas supply system
3. curtailment of wind energy

<u>Study Results</u>

For the three investigated areas, Public Service did not identify through a discrete MW level of wind generation on the Company's system at which point reliable operation would become jeopardized. Instead, our efforts have shown that the challenges associated with the variable and uncertain nature of wind generation exist more as a continuum in that they increase with increasing levels of wind generation. This study effort also resulted in a heightened expectation that Public Service will be faced with some degree of increased challenges as a result of the Company's current commitments for over 2,100 MW of wind generation operating on its system by the end of 2012. The degree to which these challenges present themselves as well as the best practices for managing them will not be known until such time that our system operators have gained actual experience operating the system with this level of wind generation.

SECTION 3 POWER SYSTEM OPERATION BASICS

This section is intended to provide the reader with a basic understanding of power system operations, the various reliability standards to which operators must comply and how each of these are impacted by wind generation on the power supply system.

Reliable electric power system operation requires that a Balancing Authority ("BA") continuously balance power system generation and net load in accordance with established operating criteria e.g., maintaining system voltage and frequency within acceptable limits. Public Service is the NERC registered BA for its electric power system and for the following utilities : Platter River Power Authority, Black Hills Colorado Electric, Arkansas River Power Authority, Municipal Power Agency of Nebraska, and Tri-State Generation and Transmission Association ("Tri-State"). This aggregation of systems is the BA Area.

System Operators are tasked with the duty of maintaining the minute-to-minute operation of the power system by continuously matching the power system's generation level with its net load requirements while also ensuring that sufficient levels of generation are available to achieve balancing in future hours and to respond to contingency events such as the unexpected loss of generation supplies. Operators are trained and certified to perform these functions and rely on long standing business practices, procedures, control software and hardware to help manage the overall operation and continuous reliability of the bulk power system.[1]

Historically, the power system's net load (the remaining load not served by wind or other non-dispatchable resources) changed in a relatively easy-to-forecast pattern, e.g., increasing in the morning and decreasing in the evening. Increasing levels of variable and hard to forecast generation resources such as wind has altered the timeframe over which the load changes occur and have reduced the level of net load on the system. Large amounts of variable generation that are highly correlated, such as concentrated areas of wind generation resources, can introduce significant net load variability, requiring the output of the other generation resources on the system to either be increased or decreased in order to maintain the balance between generation and load. .

[1] NERC, "Special Report: Accommodating High Levels of Variable Generation," April 2009 http://www.nerc.com/files/Special%20Report%20-%20Accommodating%20High%20Levels%20of%20Variable%20Generation.pdf.

The following NERC reports provide information on these issues:

1. NERC – Special Report: Accommodating High Levels of Variable Generation – April 2009
2. NERC IVGTF Task 2.4 Report Operating Practices, Procedures, and Tools – March 2011[2]

System Balancing

Integrating wind generation on to the Public Service electric system can be described as involving three categories of activities; 1) short-term planning, 2) real-time operations, and 3) emergency actions.

Short-Term Planning

The short-term planning function manages the balancing of electric supply and net load by planning the operation, including maintenance outages, of generation resources over a time horizon from 1-day to 1-year out. The day-ahead portion of the short-term planning involves the use of generation unit-commitment and dispatch models that simulate operation of the power supply system from which schedules can be developed that outline which generation resources will be needed to meet the next days forecast of net load and maintain the required regulating and contingency reserves. In addition, these models are used to develop estimates of the next day's natural gas consumption due to electric operations. These gas burn estimates form the basis upon which the Company's gas buyers make their day-ahead nominations with gas suppliers. The difficulties associated with accurately forecasting the next days wind generation acts to increase in the level of error inherent within these day-ahead unit commitment and gas nomination plans.

Real-Time Operations

During real-time operations, the System Operator continually balances loads and generation, while maintaining the required regulating and contingency reserves. These activities involve committing or decommitting generating units, calling on demand response programs, and engaging in energy sale and purchase transactions all of which is guided by use of a computer based energy management system ("EMS").[3] To achieve and maintain balance, the EMS calculates the BAs Area Control Error ("ACE") which is determined by netting the actual power flow levels across the metered boundary of the BA less the scheduled flows with an adjustment for frequency and meter errors.[4] NERC standards govern several aspects of real-time operations including allowable levels of ACE.

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[2] NERC, "IVGTF Task 2.4 Report Operating Practices, Procedures, and Tools," March 2011 http://www.nerc.com/files/IVGTF2-4.pdf.

[3] In rare instances, a system disturbance can be of sufficient magnitude to require System Operators to interrupt or shed load.

[4] NERC Resource and Demand Balancing Standard BAL-001-0.1a, Real Power Balancing

In addition to balancing the power system within the hour, real-time operations requires planning to meet expected load in the next hour and through the remainder of the day. This often involves the need to make decisions to commit (turn on) or decommit (shut off) generating units. The variability of wind generation complicates these decisions given that it is difficult to accurately predict when increases or decreases in wind generation events (ramp-up events or drop off events) are likely to occur throughout the day. These complications include the need to consider physical restrictions of individual generators such as minimum online or offline times. For example if the operator makes a decision to shut off a generating unit in response to a wind ramp-up event and that unit requires that it be offline for 6 hours before being recommitted, that offline requirement and its potential repercussions on the ability of that same generator to help arrest a wind ramp-down event later that day ultimately need to be considered before making that decision. .

Emergency Actions

There are times when the balance between generation and load becomes sufficiently mismatched that operators employ Emergency Actions to return the power system to balance and alleviate or eliminate the potential for violating System Operating Limits or Interconnection Reliability Operating Limits.[5] Several options are available to the system operator for purposes of performing this rebalancing including starting quick start units, starting long-lead units, deploying contingency reserves, making emergency purchases, curtailing generation, and possibly shedding non-firm and firm obligation load.[6] Each BA is tasked with protecting the bulk electric system and not allowing problems on their systems placing a burden on other BAs and the rest of the interconnected system. NERC has developed specific reliability standards to guide operations in a manner to prevent burdening other BAs. The Federal Energy Regulatory Commission ("FERC") approved these standards and compliance is mandatory for Registered Entities such as Public Service.

Operating Standards

As discussed, earlier operating standards that ensure safe, stable and reliable operation of power systems require specific BA/System Operator actions be taken to maintain system reliability. Below is a brief discussion of a subset of these standards that are of concern to the three wind integration issues that define the scope of this study. Refer to Attachment A for more details on these standards.

Power System Standards that Govern Generation Resource Reserve

To help ensure reliable operation of the interconnected power system, BAs must maintain a contingency reserve comprised of available generation resources not

[5] NERC Emergency Operations Planning Standard EOP-001, Emergency Operations Planning and NERC Emergency Operations Planning Standard EOP-002, Capacity and Energy Emergencies

[6] NERC Emergency Operations Planning Standard EOP-003, Load Shedding Plans

committed to serving load. Public Service is a member of the Rocky Mountain Reserve Group (RMRG) which is a NERC registered reserve sharing group authorized to establish such contingency reserves for the group. The RMRG's establishes the appropriate level of contingency reserves based on the Most Significant Single Contingency which is defined for the group as loss of the 790 MW Comanche 3 unit.[7] The RMRG also establishes how this contingency reserve requirement is allocated across the member systems. Through this allocation process, Public Services is required to carry 381 MW of contingency reserve[8] at least half of which must be spinning reserves capable of responding to a system disturbance within ten minutes. The remaining contingency reserve can be met with either non-spinning, fast start generation resources, reducing scheduled power deliveries, or dropping load.

Additionally, a BA must maintain a regulating reserve that follows changes in the BA Area's firm obligation load by responding to an electronic signal from Public Service's Automatic Generation Control (AGC") system to increase or decrease the output of generation resources.[9] The required Regulating reserve level for Public Service varies in magnitude depending on the system load.

NERC and WECC are now considering the implementation of a frequency reserve standard which would require additional on-line unloaded generation capable of quickly responding to system frequency changes. Given that the level and timing of the frequency reserve standard is not certain, Public Service did not consider frequency reserve requirements in any wind integration limit analysis.

SECTION 4 WIND ON PUBLIC SERVICE'S SYSTEM

Public Service's Power System

Public Service is a summer peaking utility system that recorded a 2011 summer peak firm obligation load of over 6800 MW and has existing generation resources that total approximately 7,700 MW. During off-peak hours of the day the system load obligation can fall to around 2,700 MW. Currently there is over 1,200 MW[10] of wind generation operating on the system day in and day out. The Company has committed to adding another 900 MW of wind generation before the end of 2012 at which point it would have over 2,100 MW of wind generation potentially serving a 2,700 MW load.

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[7] Public Service's portion of the Comanche 3 unit is 511 MW.

[8] NERC Resource and Demand Balancing Standard BAL-002, Disturbance Control Performance; WECC Standard BAL-002-WECC-1, Contingency Reserves.

[9] WECC Standard BAL-STD-002-1 - Operating Reserves.

[10] In recent months test energy from an additional 500 MW of wind has been added to system; however, Company operators have little if any experience operating the system with 1,700 MW of wind on a continued basis.

Table 4-1 lists the current and planned Public Service wind generation resources that are within the Public Service BA Area. All resources, with the exception of 26.4 MW of the Ponnequin facility, are purchased resources.

Table 4-1 Public Service Wind Generation Resources (MW)

Existing Wind Resources	Size (MW)
Cedar Creek	300.5
Colorado Green	162.0
Logan	201.0
Northern Colorado	151.8
Northern Colorado II	22.5
Peetz Table	199.5
Ponnequin	31.7
Ridgecrest	29.7
Spring Canyon	60.0
Twin Buttes	75.0
Cedar Creek II (2011 In-Service)	250.5
CedarPoint (2011 In-Service)	252
Subtotal	**1,736.2**
Planned Wind Resources	**Size (MW)**
Limon (2012 In-Service)	201.0
Limon II (2012 In-Service)	201.0
Subtotal	**402.0**
Total	**2,138.2**

Variability of Wind Generation

In general, minute-to-minute changes in wind generation levels are less significant as it concerns system balancing issues. But, when a continued change (up or down) in wind generation level is sustained over a period of time, e.g., greater than ten minutes, such changes are classified as wind ramping events.

<u>Ramping Events</u>

Ramp- Up

Continued or sustained increases in wind generation levels are termed ramp-up events. Operators generally respond to wind ramp-up events by reducing the level of generation from one or more of its gas-fired units. If the ramp-up event is large enough such that reducing generation output at other units (but still keeping the units operating) is not sufficient to maintain system balance, the operator must consider whether to curtail wind energy production or shut down generating units. Wind ramp-up events pose less of a reliability concern due to the ability to either curtail wind generation automatically through the use of AGC or manually through operator action or to reduce the output of other generating units on the system

Ramp-Down

Similarly, continued decreases in wind generation levels are termed ramp-down events. Unlike wind ramp-up events, there are no wind farm control actions available to limit the magnitude, rate, or duration of ramp-down events (with the rare exception of a coincident wind curtailment that could be stopped to help counter a ramp-down event). Consequently, wind ramp-down events pose the greater reliability concern for System Operators who must respond to such events with an offsetting increase in generation from other resources. Public Service cannot use the spinning or regulating reserves to offset wind ramping events. Ensuring that other resources are available to provide this offsetting effect is addressed in the discussion of flexible resources below.

Uncertainty of Wind Generation

Public Service's day-ahead wind forecast during the year 2010 had a Mean Absolute Percentage Error ("MAPE") of 14.3%. This means that on average over the year, the day-ahead forecast of wind generation was 14.3% higher or lower each hour than the actual wind generation that occurred on the day for which the forecast was made. The MAPE for 2011 thru August is 13.5%. Public Service believes these MAPE figures represent good forecasting performance. Nonetheless, the uncertain nature of the wind resource creates the potential for situations throughout the year where errors in the day-ahead forecast greatly exceed these annual average error values. For example, in 2010 when the Company operated with approximately 1,200 MW of wind on its system, there were 80 hours in which the day-ahead forecast over predicted wind generation by greater than 500 MW. Of these 80 hours where day-ahead forecasts over predicted by more than 500 MW, 47 of these over forecasted hours occurred in consecutive blocks of 5 hours or more.

At this time, Public Service does not anticipate it will be able to achieve dramatic improvement in the day-ahead wind forecast. The Company does however expect that as the level of wind integration increases to over 2,100 MW by the end of 2012 that Public Service will experience larger hourly forecast error and possibly more sustained periods of error into the future.

SECTION 5 FLEXIBLE RESOURCE ANALYSIS

As discussed earlier, wind ramp-down events pose the greater reliability concern for System Operators who must respond to such events with an offsetting increase in generation from other resources or other means. For operators to be confident that a sufficient level of generation resources are available to provide this offsetting response, the Company had to first determine what constituted "sufficient" in the context of not only the magnitude in MW for the amount of generation to be kept available but also the responsiveness or flexibility or ability of that generation to be brought on-line in a timely manner. To address this question Public Service initiated a study of wind generation variability in which the magnitude and duration of actual wind ramping events on the Public Service system were analyzed. As a result of this study work a 30-minute Wind Reserve

Guideline was adopted in which system operators maintain enough standby generation capability that can be brought on-line within 30-minutes to cover 100% if the total wind energy being produced on the system in any particular hour up to 290 MW i.e., MW for MW coverage of the first 290 MW of wind energy. At wind energy generation levels above 290 MW, additional 30-minute capable standby generation is held based on the aggregate wind energy being produced from wind facilities located along the northern Colorado border within Energy Resource Zone 1 ("ERZ1"). Note that the 290 MW level to which MW for MW reserve coverage is provided will likely change as the additional wind generation currently planned for the system comes on-line.

Wind Generation Variability Study

Public Service gathered wind generation data for its system over a ten year period from 2001 to 2011. Combined with this data were projections of future wind generation from facilities under construction at the time.[11] This data was used to develop a Typical Wind Year Profile ("TWY profile") which was intended to represent the aggregate hourly generation from wind resources over the 8,760 hours of a year.

The Company used the TWY profile to determine the level of wind ramp-up and ramp-down events and the duration of those events. Two categories of wind ramp events were evaluated 1) wind ramp events of 300 MW or greater within a 30-minute timeframe and 2) wind ramp events of 100 MW or greater within a 30-minute timeframe during times when the level of wind energy from wind facilities were less than 250 MW within each ERZ[12] at the start of the ramp event.

<u>Large Wind Ramp-Downs</u>

The analysis identified a total of 33 of the larger 300 MW or greater wind ramp-down events using the TWY profile. The vast majority of these occurred in the area of greatest wind concentration, ERZ1, along the Northern Colorado border.[13] Of these 33 large wind ramp-down events 90% were driven by a fall off in wind generation from ERZ1.

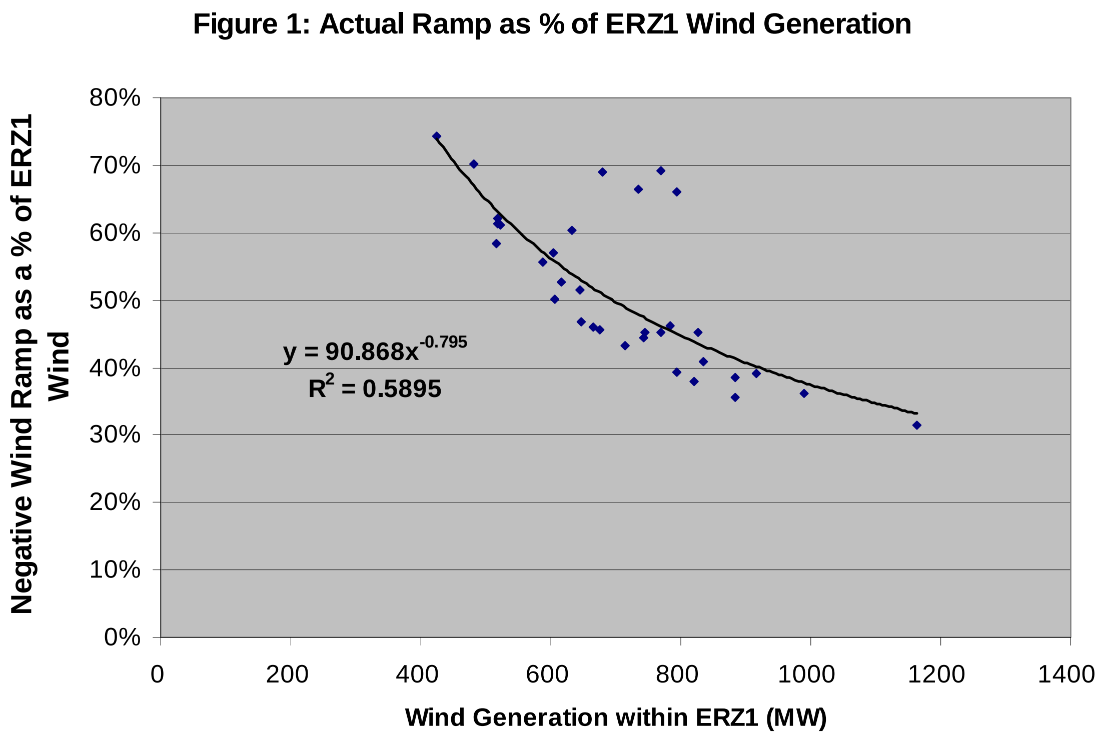
For each of the 33 large wind ramp-down events mentioned above, the aggregate wind energy being generated from ERZ1 at the start of the ramp-down event was calculated. The magnitude of the ramp-down event was then represented as a percentage of this aggregate ERZ1 wind generation level at the start of the ramp-down event. A plot of these calculated figures for the 33 large wind ramp-down events and a least square curve that expresses the data relationship is shown in Figure 1.

[11] The wind information did not include any production data for the Limon 1 or Limon II wind generation resources.

[12] There are five Energy Resource Zones in Colorado. Public Service currently has wind generation facilities within ERZs 1 and 3 with additional facilities planned within Zone 2.

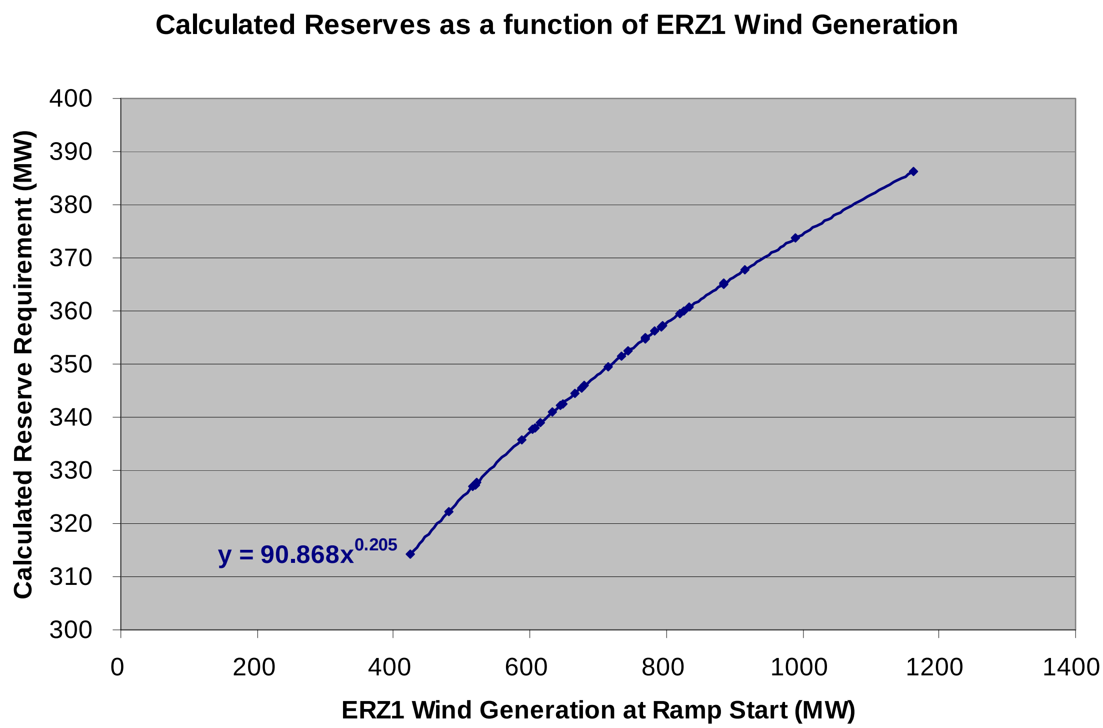
[13] The ERZ1 wind comprises approximately 81% of the installed wind generation resources on Public Service's system.

Figure 1



The analysis results of the 33 large wind ramp-down events were used to inform the development of the appropriate operating guidelines regarding the level of 30-minute reserve generation needed as a function of wind generation levels. Figure 2 depicts the information contained in Figure 1 represented as the level of 30-minute reserve generation recommended as a function of total wind generation within ERZ1.

Figure 2



In summary, Figure 2 indicates that operators will maintain roughly 315 MW of 30-minute reserve generation when the aggregate wind generation from ERZ1 wind facilities is roughly 425 MW with reserve levels increasing up to 392 MW when the aggregate wind generation from within ERZ1 is 1,247 MW.

<u>Moderate Wind Ramp-Downs</u>

While examination of the 33 large wind ramp-down events provided insight as to the appropriate level of reserves needed when ERZ 1 wind was generating above 425 MW, it was recognized that similar guidance was needed for times when ERZ1 wind was producing at lower levels. More specifically at lower ERZ1 levels of wind generation it would be possible that a loss of wind generation from either ERZ2 or ERZ3 would have a larger impact on the total ramp than the loss of wind generation in ERZ1. This prompted additional investigation to see if perhaps an ERZ other than ERZ1 was the "controlling" ERZ as it concerns potential to drive the required wind reserve at times when ERZ 1 wind generation was below roughly 400 MW. To address this issue the Company assessed wind ramp-down events greater than 100 MW in 30-minutes that were coincident with wind generation levels for ERZ 1, 2 and 3 each being less than 250 MW at the start of the wind ramp-down event. The Company calculated the total wind ramp-down magnitude as a percentage of the *highest* wind generation level from among the three ERZs at the start of the wind ramp. Table 5-1 contains the results of this comparison.

Table 5-1 Moderate Wind Ramp-Down Comparison

Negative Ramp Size (MW)	Count	Max (%)	Avg (%)	Count > 100%
200 < X < 250	3	107%	98%	2
180 < X < 200	10	137%	91%	2
160 < X < 180	25	139%	83%	3
140 < X < 160	45	100%	71%	1
120 < X < 140	119	140%	67%	7
100 < X < 120	180	127%	59%	4
Total	382	140%	66%	19

Table 5-1 shows that on average, the magnitude of moderate wind ramp-downs were less than 100% of the highest wind energy generation among the three regions across all of the ramp size categories examined. When looking at all ramp-down events greater than 100 MW in the data set, in only 19 out of 382 total (5% of the time) was the ramp-down event larger in size than the largest wind generation level among the three regions at the start of the ramp-down event.

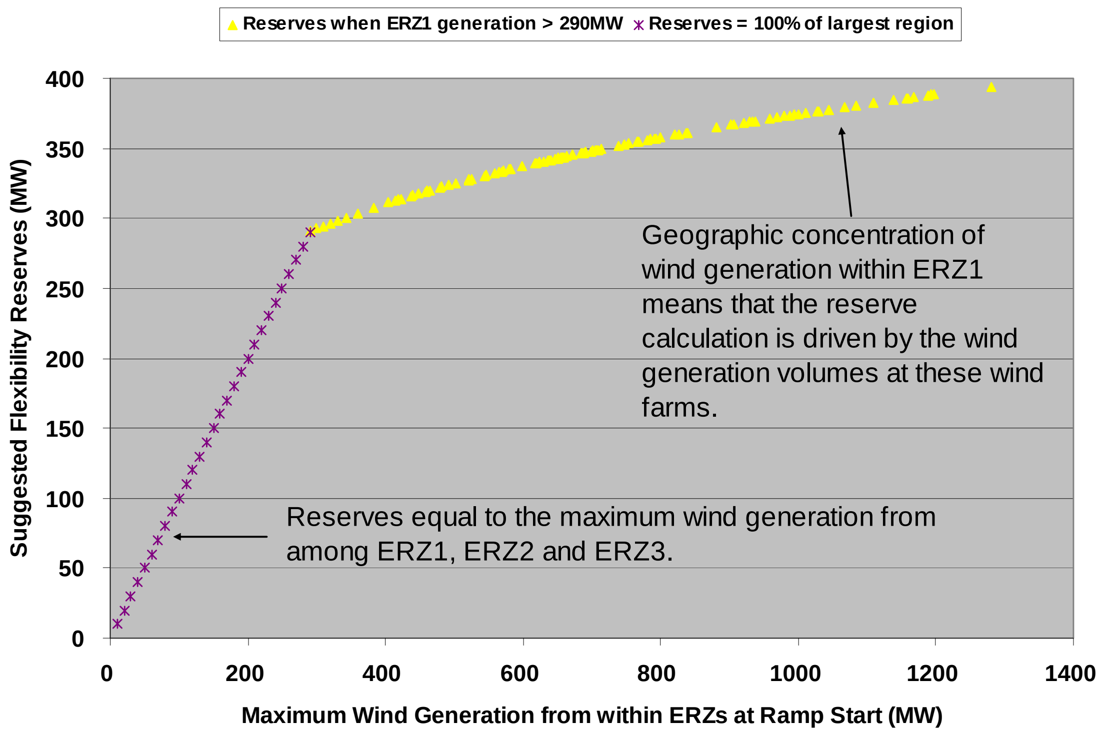
<u>Resulting Operating Guidelines</u>

The analysis results of both large and moderate wind ramp-down events indicated that the 30-Minute Wind Reserve Guideline for the level of wind studied (~ 1,200 MW) should require sufficient 30-minute reserve generation be maintained in amounts equal to 1) 100% of the highest wind energy generation levels from ERZ's 1, 2, or 3 up to 290 MW, and 2) additional 30-minute reserves would be held as a function of Northern Colorado wind energy generation above 290 MW.

Figure 3 shows a graphical depiction of the recommended level of 30-minute reserves for the level of wind studied as a function of wind energy generation levels.

Figure 3

Calculated Reserves as a function of Wind Generation



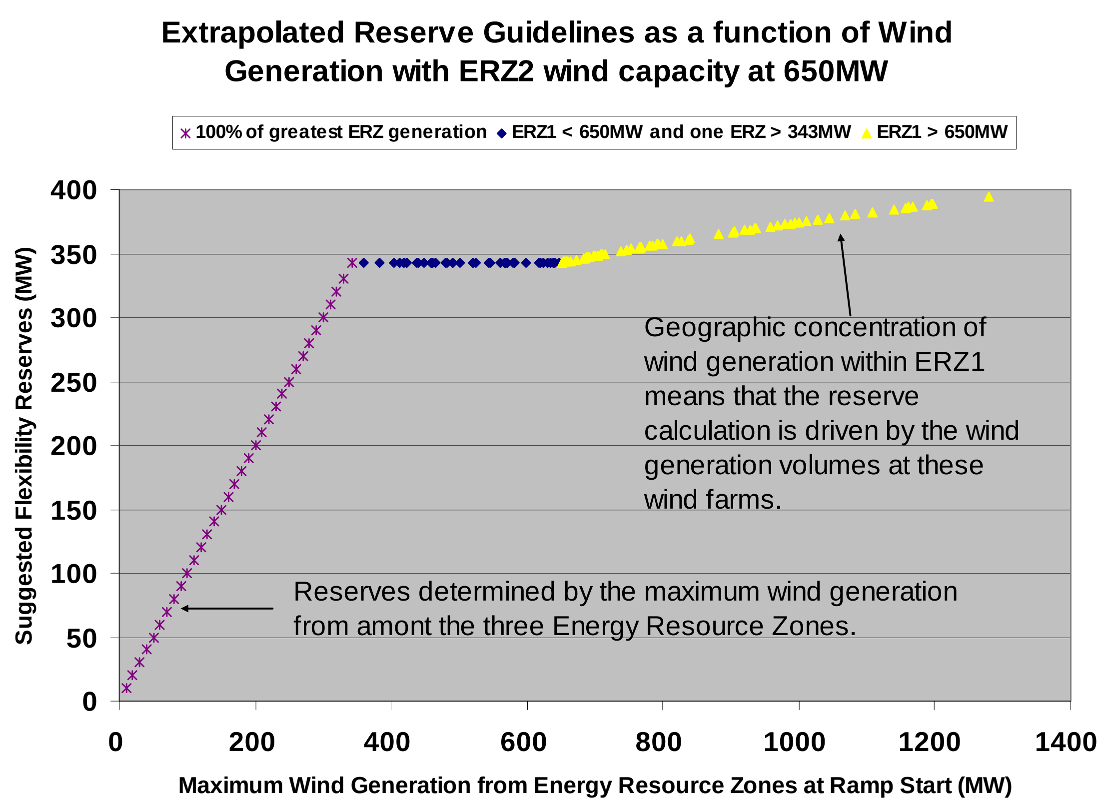
Application of Reserve Guideline to Future Wind Additions

The historic wind generation data that was used to establish the 30-minute Wind Reserve Guideline discussed above contained a maximum of approximately 1,200 MW of installed wind generation. By the end of 2012, the Company expects that over 2,100 MW of installed wind capacity will be operating on Public Service's system. This 2,100 MW includes the proposed additional 201 MW at Limon II in ERZ 2 which would bring the Limon area wind capacity to 654 MW.

The planned and proposed wind additions will not change the fact that the installed wind capacity in ERZ1 would still be close to twice as large as the installed capacity in ERZ2. The Company therefore expects that large wind ramp-down events will continue to be driven ERZ1. The yellow data points in Figure 3 above would be unchanged above 650 MW since ERZ1 would continue to be the only ERZ with greater than 650 MW of installed wind capacity. Likewise, the data in Table 1 would still apply for cases in which the wind generation from each of the three wind regions was relatively low. This left open the issue of how best to calculate reserves for cases in which the wind generation in ERZ2 is between 250 MW and 650 MW. While at this time Public Service has no actual wind ramp data for the planned Limon area to help inform a ERZ2 curve, the existing guidelines on the extremes (high wind extreme and low wind extreme) can be used to develop a conservative 30-Minute Wind Reserve Guideline for the moderate conditions for which we lack data.

At 654 MW of ERZ1 wind energy generation the calculated guideline is 343 MW of 30-minute capable reserves. As mentioned earlier, the lowest level of wind generation in ERZ1 at the beginning of a large, negative ramp (300 MW or more in 30 minutes) was 425 MW. The Company believes it is reasonable that the 1-for-1 reserve criteria at the low wind extreme could be extended from 290 MW up to 343 MW. The 343 MW reserve guideline would be recommended for cases in which both (1) ERZ1 wind generation is less than 650 MW and (2) the wind generation from ERZ1 or ERZ2 exceeds 343 MW. For cases in which the ERZ1 wind generation exceeds 650 MW, the 30-Minute Wind Reserve Guideline would be calculated as a function of ERZ1 wind generation. See Figure 4.

Figure 4



Flexible Generation Resources Balance

Having established the appropriateness of a 30-minute response time for the generation resources needed to address wind ramp-down events, the Company assessed the level of 30-minute capable resources that will exist on its system during the 7-year resource acquisition period ("RAP") of the upcoming 2011 Electric Resource Plan ("ERP"). The intent of this assessment was to determine whether sufficient 30-minute capable generation supplies will exist throughout the

RAP to cover the over 2,100 MW of wind generation that is expected by the end of 2012, or whether additional resources were needed. To the extent additional 30-minute capable generation were needed, such resources would be pursued in the 2011 ERP.

In assessing the level of 30-minute capable generation supplies available through the RAP, power supplies from PPA's were only counted as contributing to the pool of 30-minute resources during the years covered in their current PPA term. These resources were not included in the assessment for years after the PPA termination date. In addition, the level of 30-minute capable resources was reduced by 191 MW each year to reflect that spinning reserves are not considered as part of the 30-minute pool of resources available to manage wind ramp-downs.

The results of this assessment show that Public Service will have an excess of flexible generation resources needed to meet the 30-Minute Wind Reserve Guideline in every year of the RAP.

Table 5-2 Excess Flexible Generation Resources (MW)

	2012	2013	2014	2015	2016	2017	2018
Excess Flexible Generation	197	197	197	197	283	255	255

SECTION 6 FLEXIBILITY OF GAS SUPPLY

The second area of investigation that was identified as potentially impacting the maximum amount of wind that could be operated on the Public Service system deals with the ability of the natural gas storage and delivery system to supply fuel to gas-fired generation resources which shoulder the majority of the 30-minute wind reserve duty.

Discussion

Historically gas storage has provided natural gas as the swing fuel for the electric generation fleet. The fuel swing impacts due to wind generation variability and unpredictability continues to demonstrate how critical gas storage is to the reliable operation of the electric system. We know that additional operational gas storage capacity will allow the fuel flexibility needed for increased wind generation capability on the system, but gas storage comes at a significant cost. Public Service should explore the reliability, cost, emissions, and operational impacts of using our fuel oil capable generation as an additional option for increased ramp-up swing capability in conjunction with the existing natural gas storage. Oil use has a significant cost impact as oil is 3-5 times the cost of gas, and it also has an emissions impact that needs to be reviewed in the context of allowing more wind capability on the system. The reliability of the oil units is good in the current operational plan which minimizes oil use. We need to see if quickly switching to or starting units on oil to allow more ramp-up would impact the electric system's reliability.

Public Service currently has a process to ensure adequate reserve margins for both the Gas LDC and the Electric Generation fuel during cold weather. With additional wind energy resources, Public Service may study the wind forecasting relationships with gas purchasing to see if there is a process that could provide for additional ramp-up on high wind days but still protect the gas system from being significantly over supplied. There is a balance that must fit within the storage injection capability of the gas storage services we have under contract and the use of wind curtailment to force burn excess gas all while continuing to meet the swing need of the electric system both up and down.

Gas Delivery System Capabilities

Public Service estimates that the dedicated gas delivery system from the contract services using the CIG Totem Gas Storage facility can provide adequate gas to operate approximately 850 MW of generation resources. Similarly the contract services using the Young Gas Storage can provide adequate gas to operate approximately 100 MW of generation resources. If the Public Service Gas LDC is not having a critical gas day, it is estimated that the normal LDC gas transportation balancing services can provide gas to operate an additional 450 MW for a few hours. Combined this would allow for an electric total up ramp capability of about 1,400 MW using natural gas. This gas ramp-up capability must cover a change in wind generation, the failure of a significant coal resource, missed load forecast, as well as a change in generation efficiency of the gas fired generation on the system (the failure of a efficient gas fired combined cycle plant).

The Company operations group review of the electric system indicates that these estimated ramp-up rates should be sufficient to cover the Wind Forecast error for the currently planned portfolio of over 2,100 MW of wind generation capacity. There are several options that should be explored and better understood before connecting additional wind generation beyond this level including: the possible need for additional gas storage; use of an alternative swing fuels such as fuel oil; and developing a gas purchase strategy that will appropriately protect against large potential swings in wind generation.

SECTION 7 WIND CURTAILMENT ANALYSIS

The third area of investigation regarding the maximum amount of wind that could be operated on the Public Service system deals with the need to curtail wind energy due to limitations on the power supply system. While the issue of curtailing wind is not expected to jeopardize system reliability, increased curtailment of wind is expected to have cost implications. Given that Public Services wind generation is almost entirely purchased under what can be termed "take or pay" contracts, the Company must often pay the wind generator for the curtailed wind energy including any tax incentives for which the generator may qualify. This study effort did not attempt to quantify the issue of cost or at what point it would become limiting but rather focused on quantifying the potential amount of wind curtailment at installed levels of wind generation above 2,000 MW.[14]

In periods when load is low and wind energy production is high, system operators can encounter situations were they have essentially turned-down their dispatchable supply fleet to its lowest level of electric output at which it can continue in a safe and reliable operating mode. Shutting down some of these dispatchable generation resources may not be permitted due to contingency margin or other reliability concerns. In these situations, operators will consider curtailing the amount of wind energy production to maintain system balance.

Curtailing wind energy effectively raises the overall cost of wind energy, causes increased fuel burns at other generation resources and, depending on whether the wind is owned or purchased and specific contract terms, can trigger other costs including payments for the value of lost Production Tax Credits.[15] Other costs of curtailment include potential carbon mitigation costs, and Renewable Energy Credit opportunity costs. Wind curtailment costs clearly erode the economic value of new wind farms.

As the level of wind integration increases, it is possible and likely that the frequency of wind curtailment will increase. To assess the likely level of increased wind curtailments Public Service performed an analysis of its electric system operation to determine the potential level of wind energy production curtailment required to balance supply and net load (firm load obligation less energy production of variable generation resources) after economically dispatching the generation resource portfolio. Public Service used the Strategist representation of the Public Service system that it used in the 2011 Electric Resource Plan filing. The Strategist representation of the Public Service system includes all planned generation resources additions (including wind generation resources) and all planned generation resource retirements

As expected the level of curtailment increased as a percentage of the incremental wind energy production and as a percentage of the total system wind energy production. See Table 7-1 for the percentage of total wind energy curtailment as a portion of total wind energy production. See Table 7-2 for the

[14] Recall that the Company's load obligation can fall to around 2700 MW during off-peak periods.

[15] Public Service's wind energy purchase contracts generally specify curtailed wind must be compensated at the full purchase price and that the wind energy seller must be made whole for lost tax incentives. Exceptions include transmission emergencies and/or curtailments that result from wind farm issues outside the control of Public Service. In addition, two wind farm purchase agreements have curtailment allowances.

percentage of incremental wind energy curtailment as a portion of the incremental wind energy production.

Table 7-1 Wind Curtailment - % of Total

Level of Wind (MW)	2012	2013	2014	2015	2016	2017	2018
3,000	1%	6%	5%	4%	4%	4%	1%
3,200	1%	8%	7%	6%	5%	5%	2%
3,400	2%	10%	8%	7%	7%	6%	3%
3,600	2%	11%	10%	9%	8%	7%	4%
3,800	2%	12%	11%	10%	10%	8%	5%
4,000	2%	14%	12%	10%	10%	9%	6%

Table 7-2 Wind Curtailment - % of Incremental

Level of Wind (MW)	2012	2013	2014	2015	2016	2017	2018
3,000	5%	16%	13%	12%	11%	9%	4%
3,200	12%	28%	25%	23%	20%	17%	9%
3,400	19%	30%	27%	25%	24%	21%	14%
3,600	23%	36%	32%	29%	30%	26%	18%
3,800	32%	27%	29%	27%	28%	29%	19%
4,000	15%	35%	29%	22%	26%	26%	18%

There is no compliance standard or good utility practice that Public Service could use to assess the point at which wind curtailments might become unacceptable. The study results indicate that a significant amount, 5-35% of the incremental wind energy production, could be curtailed at high installed levels of wind.

ATTACHMENT 1: STANDARDS

NERC Standards - General

The NERC mission is to ensure the reliability of the North American Bulk Electric System ("BES").[16] To accomplish this mission, NERC developed various standards that utilities must meet. The NERC standards address long term planning, modeling, switching, communications, emergency operations, training and many other areas of operating an electric power system. A utility must comply with these standards. Failure to comply can result in significant fines.

The NERC Resource and Balancing standards, also known as BAL standards enhance stability to the BES by requiring each BA to balance its loads and resources in a specific manner and within specific guidelines. The two primary metrics are, maintaining the BA's ACE near zero and maintaining interconnection frequency within predefined boundaries. These two metrics seek to minimize a BA's burden on the BES.

The BAL standards which principally concern or govern Public Service's power system operations are:

- BAL-001 Real Power Balancing
- BAL-002 Disturbance Control Performance
- BAL-005 Automatic Generation Control
- BAL-006 Inadvertent Interchange
- BAL-007 Trial Real Power Balancing

Below is a summary description of the BAL standards.

BAL-001 requires that a BA maintain interconnection steady state frequency within defined limits by balancing real power demand and supply in real time. This standard defines the ACE equation and the control performance standards CPS1 and CPS2. CPS1 is a statistical measure of ACE variability and CPS2 is a statistical measure of ACE magnitude. The standard requires a BA to seek an ACE of zero and to achieve a CPS1 score of 100% and a CPS2 score of no less than 90%. Failure to achieve the minimum requirements can result in fines or carrying more reserves which can increase costs.

BAL-002 ensures the BA is able to utilize its contingency reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. This standard requires a BA to carry enough contingency reserves to cover its most sever single contingency and to be 100% compliant with responding to all reportable disturbances, i.e., return ACE back to pre-disturbance levels. Failure to comply with this standard would result in NERC requiring a BA to carry more contingency reserves or monetary penalties. The

[16] NERC, http://www.nerc.com

Western Electricity Coordinating Council ("WECC") established a regional standard that dictates the amount of reserves that should be held by Public Service.

BAL-005 provides guidance concerning the use of Automatic Generation Controls including metering requirements (on power plants and boundaries with other BAs). AGC typically is set in the Energy Management System to always return ACE to zero by sending signals to plants. Use of the AGC systems allows the BA to continuously balance loads and resources; and if there is a disturbance, the AGC system immediately seeks to rebalance with online resources.

BAL-006 establishes the process for monitoring a BA such that over the long term BA's do not excessively depend on other BAs in the interconnection for meeting their demand or interchange obligations. The standard acknowledges that inadvertent instances of non-compliance are inevitable, but requires that BAs monitor ACE performance and strive to consistently maintain imbalances near zero.

NERC and WECC are currently testing a proposed revision to BAL-001 with BAL-007 which recognizes that inadvertent interchange between BAs is an economic concern and reliable operations must focus on maintaining frequency. BAL-007 is less concerned with ACE being zero, but makes the measure a function of interconnect frequency, allowing those BA's helping frequency to not be penalized, while forcing BA's inhibiting return to 60 Hz to get their ACE under control within 30 minutes. BAL-007 is in a trial period and Public Service fully supports adoption of this standard over BAL-001.

The primary goal of the described standards (and many other NERC standards not described) is to protect the BES by taking measures up to and including the shedding of firm load. The failure to operate in such a manner can result in the overloading of system elements through power or frequency excursions which causes cascading damage to other connected elements.

Standards that Govern Power Flow between BAs

NERC Resource and Demand Balancing Standard BAL-006-2 — Inadvertent Interchange[17]

Purpose

This standard defines a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.

Requirements

[17] http://www.nerc.com/files/BAL-006-2.pdf

R1. Each Balancing Authority shall calculate and record hourly Inadvertent Interchange. (*Violation Risk Factor: Lower*)

R2. Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators. (*Violation Risk Factor: Lower*)

R3. Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities. (*Violation Risk Factor: Lower*)

R4. Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following: (*Violation Risk Factor: Lower*)

R4.1. Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to: (*Violation Risk Factor: Lower*)

R4.1.1. The hourly values of Net Interchange Schedule. (*Violation Risk Factor: Lower*)

R4.1.2. The hourly integrated megawatt-hour values of Net Actual Interchange. (*Violation Risk Factor: Lower*)

R4.2. Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month. (*Violation Risk Factor: Lower*)

R4.3. A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies). (*Violation Risk Factor: Lower*)

R5. Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. (*Violation Risk Factor: Lower*)

WECC Standard TOP-007-WECC-1 – System Operating Limits[18]

Purpose

[18] http://www.wecc.biz/Standards/Approved%20Standards/TOP-007-WECC-1.pdf

When actual flows on Major WECC Transfer Paths exceed System Operating Limits ("SOL"), their associated schedules and actual flows are not exceeded for longer than a specified time.

Requirements

R1. When the actual power flow exceeds an SOL for a Transmission path, the Transmission Operators shall take immediate action to reduce the actual power flow across the path such that at no time shall the power flow for the Transmission path exceed the SOL for more than 30 minutes. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2. The Transmission Operator shall not have the Net Scheduled Interchange for power flow over an interconnection or Transmission path above the path's SOL when the Transmission Operator implements its real-time schedules for the next hour. For paths internal to a Transmission Operator Area that are not scheduled, this requirement does not apply. *[Violation Risk Factor: Low] [Time Horizon: Real-time Operations]*

Standards that Govern Generation Resource Reserves

<u>NERC Resource and Demand Balancing Standard BAL-002-0 — Disturbance Control Performance[19]</u>

Purpose

The purpose of the Disturbance Control Standard ("DCS") is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.

Requirements

R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.

> R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.

R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:

> R2.1. The minimum reserve requirement for the group.
>
> R2.2. Its allocation among members.

[19] http://www.nerc.com/files/BAL-002-0.pdf

R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.

R2.4. The procedure for applying Contingency Reserve in practice.

R2.5. The limitations, if any, upon the amount of interruptible load that may be included.

R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.

R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.

R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period. or

R5.2. The Reserve Sharing Group reviews each member’s ACE in response to the activation of reserves. To be in compliance, a member’s ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.

R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.

R6.2. The default Contingency Reserve Restoration Period is 90 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by the NERC Operating Committee.

WECC Standard BAL-002-WECC-1 — Contingency Reserves[20]

Purpose

Contingency Reserve is required for the reliable operation of the interconnected power system. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment.

Requirements

R1. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain as a minimum Contingency Reserve that is the sum of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R1.1. The greater of the following:

R1.1.1. An amount of reserve equal to the loss of the most severe single contingency; or

R1.1.2. An amount of reserve equal to the sum of three percent of the load (generation minus station service minus Net Actual Interchange) and three percent of net generation (generation minus station service).

R1.2. If the Source Balancing Authority designates an Interchange Transaction(s) as part of its Non-Spinning Contingency Reserve, the Sink Balancing Authority shall carry an amount of additional Non-Spinning Contingency Reserve equal to the Interchange Transaction(s). This type of transaction cannot be designated as Spinning Reserves by the source BA. If the Source Balancing Authority does not designate the Interchange Transaction as part of its Contingency Reserve, the Sink Balancing Authority is not required to carry any additional Contingency Reserves under this Requirement.

R1.3. If the Sink Balancing Authority is designating an Interchange Transaction(s) as part of its Contingency Reserve either Spinning or Non-Spinning, the Source Balancing Authority shall increase its Contingency Reserves equal in amount and type, to the capacity transaction(s) where

[20] http://www.nerc.com/files/BAL-002-WECC-1.pdf

the Sink Balancing Authority is designating the transaction(s) as a resource to meet its Contingency Reserve requirements. These types of transactions could be designated as either spinning or non-spinning reserves. If designated as Spinning Reserves, all of the requirements of section R2.1 & R2.2 must be met.

R2. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R2.1. Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.
R2.2. Capable of fully responding within ten minutes.

R3. Each Reserve Sharing Group or Balancing Authority shall use the following acceptable types of reserve which must be fully deployable within 10 minutes of notification to meet R1: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R3.1. Spinning Reserve
R3.2. Interruptible Load;
R3.3. Interchange Transactions designated by the source Balancing Authority as non-spinning contingency reserve;
R3.4. Reserve held by other entities by agreement that is deliverable on Firm Transmission Service;
R3.5. An amount of off-line generation which can be synchronized and generating; or
R3.6. Load, other than Interruptible Load, once the Reliability Coordinator has declared a capacity or energy emergency.

<u>WECC Standard BAL-STD-002-1 - Operating Reserves[21]</u>

Purpose

Regional Reliability Standard to address the Operating Reserve requirements of the Western Interconnection

Requirements

WR1.

The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to:

• supply requirements for load variations.

[21] http://www.nerc.com/files/BAL-STD-002-0.pdf

• replace generating capacity and energy lost due to forced outages of generation or transmission equipment.
• meet on-demand obligations.
• replace energy lost due to curtailment of interruptible imports.

a. Minimum Operating Reserve. Each Balancing Authority shall maintain minimum Operating Reserve which is the sum of the following:

(i) Regulating reserve. Sufficient Spinning Reserve, immediately responsive to Automatic Generation Control (AGC) to provide sufficient regulating margin to allow the Balancing Authority to meet NERC's Control Performance Criteria (see BAL-001-0).

(ii) Contingency reserve. An amount of Spinning Reserve and Nonspinning Reserve (at least half of which must be Spinning Reserve), sufficient to meet the NERC Disturbance Control Standard BAL-002-0, equal to the greater of:

(a) The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency; or

(b) The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation.

(iii.) The combined unit ramp rate of each Balancing Authority's on-line, unloaded generating capacity must be capable of responding to the Spinning Reserve requirement of that Balancing Authority within ten minutes

Additional reserve for interruptible imports. An amount of reserve, which can be made effective within ten minutes, equal to interruptible imports.

(iv) Additional reserve for on-demand obligations. An amount of reserve, which can be made effective within ten minutes, equal to on-demand obligations to other entities or Balancing Authorities.

b. Acceptable types of Nonspinning Reserve. The Nonspinning Reserve obligations identified in subsections a(ii), a(iii), and a(iv), if any, can be met by use of the following:

(i) interruptible load;

(ii) interruptible exports;

(iii) on-demand rights from other entities or Balancing Authorities;

(iv) Spinning Reserve in excess of requirements in subsections a(i) and a(ii); or

(v) off-line generation which qualifies as Nonspinning Reserve.

c. Knowledge of Operating Reserve. Operating Reserves shall be calculated such that the amount available which can be fully activated in the next ten minutes will be known at all times.

d. Restoration of Operating Reserve. After the occurrence of any event necessitating the use of Operating Reserve, that reserve shall be restored as promptly as practicable. The time taken to restore reserves shall not exceed 60 minutes (Source: WECC Criterion)

ATTACHMENT 2: IMPROVEMENT OPPORTUNITIES

Frequency Response Improvement

Public Service did not perform any specific analysis of the impact of increasing levels of wind integration on Public Service's ability to regulate system frequency but has analyzed the issue and offers the following observations.

Large mass generators, such as those employed with conventional thermal generation resources, provide good frequency response and frequency response is superior on systems that have high levels of conventional thermal generation. Frequency response covers the following time frames:[22]

- Inertial response (up to a few seconds);
- Governor response (aka "Primary Response" – 1 to 10s of seconds);
- AGC response (re-dispatch) (aka "Secondary Response" – tens of seconds to tens of minutes).

The primary response to changes in system frequency has been declining in WECC and other areas of the nation for many years. Although the WECC declining governor response predates the growing level of wind integration, wind generation has contributed to the problem. Wind generation lowers the frequency nadir (point of lowest system frequency following a disturbance which typically occurs within the first 10 seconds of a large disturbance) by reducing the inertial response. This is particularly true at low levels of firm obligation load when system economics generally dictate that fewer thermal generation resources are operating. But in this situation the on-line thermal generation resources have greater headroom (thermal units have room to dispatch up due to lower loading caused by wind generation) which accelerates the recovery *following* the frequency nadir. Unfortunately, the frequency nadir represents the critical period for risk of under-frequency load shedding and cascading outages.

Concerning frequency response and wind, General Electric has developed a way to use a wind turbine's power electronics to extract stored inertial energy from the turbine during the first ten-to-fifteen seconds following a large frequency dip and return the inertial energy to the turbine over the next ~30 seconds. This technology has the potential to actually improve system performance (reduce frequency nadir) over a base case scenario with no installed wind capacity. Public Service will consider requiring this capability in future wind energy solicitations or all-source solicitations. Public Service will also consider retrofitting existing wind turbines with this capability.

[22] Nicholas Miller, Kara Clark, Miaolei Shao, GE: Impact of Frequency Responsive Wind Plant Controls on Grid Performance, (http://web.mit.edu/windenergy/windweek/Presentations, Jan 22, 2011).

Flexible Resource Improvement

There are a number of projects that could increase the availability of flexible generation resources or otherwise enhance the system capability to respond to the variability and uncertainty of wind. Below is a list of options the Company could examine to increase the amount or response of flexible generation resources

Cabin Creek

- Move black start away from Cabin Creek to another unit(s) freeing up black start water for peak shaving/pumping;
- Get WECC approval for Cabin Creek capacity to count toward spinning reserve;
- Build upper reservoir walls to increase amount of energy at Cabin Creek and upgrade generator for increased power and greater efficiency at Cabin Creek as part of FERC relicensing.

Coal Plants

- Enable LL3 (emergency minimum) operation for Pawnee, and Comanche Plant;
- Change EMS logic to accept piece-wise curve for ramp rates as a function of dispatchable range;
- Enable entire coal fleet to reliably operate on AGC.
- Change EMS to reflect dispatch range of AGC-control vs manual-control at coal plants;
- Install Ramp Controller on each unit that monitors boiler stability and adjusts allowable ramp rate accordingly (similar to Sherco design) ;
- Fix high and low control limit functionality at plant/EMS (Fix/add telemetry where possible.

Gas Plants/Supply

- Install LCI (start up controller) at FSV 5&6 and Blue Spruce 1&2 so both units can start-up simultaneously;
- Build firm natural gas to Plains End 1&2;
- Install GE FastStart technology at later model F-series machines (takes start from 30 minutes to 75% within 10 minutes);
- Adopt risk-adjusted gas buying strategy to hedge against large DA forecast error;
- Expand remote start capability

Wind Farms

Hold flex reserves on AGC-enabled wind farms (spin, reg-up and reg-down)