DOCKET NO. 46936

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR: A CERTIFICATE OF CONVENIENCE AND NECESSITY AUTHORIZING CONSTRUCTION AND OPERATION OF WIND GENERATION AND ASSOCIATED FACILITIES IN HALE COUNTY, TEXAS AND ROOSEVELT COUNTY, NEW MEXICO, AND RELATED RATEMAKING PRINCIPLES; AND APPROVAL OF A PURCHASED POWER AGREEMENT TO OBTAIN WIND GENERATED ENERGY	**§ § § § § § § § § § § § § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

DIRECT TESTIMONY
of
WILLIAM A. GRANT

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

(*Filename:* GrantTXDirect.doc; *Total Pages:* 30)

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
Bonita PPA	Bonita Wind Energy, LLC Power Purchase Agreement
Commission	Public Utility Commission of Texas
FERC	Federal Energy Regulatory Commission
GIA	Generator Interconnection Agreement
IM	Integrated Marketplace
Invenergy	Invenergy, LLC
MW	Megawatt
Network Upgrades	Facilities needed to physically and electrically connect the generation to the transmission system
RegDown	Regulation Down
RegUp	Regulation Up
SPP	Southwest Power Pool
SPS	Southwestern Public Service Company, a New Mexico corporation
SPS Wind Projects	Hale and Sagamore Wind Projects
Tariff	SPP Open Access Transmission Tariff
Xcel Energy	Xcel Energy Inc.

LIST OF ATTACHMENTS

<u>**Attachment**</u>	<u>**Description**</u>
WAG-1	Calculating Regulating Reserve Requirements SPP Integrated Marketplace (*non-native format*)

DIRECT TESTIMONY
OF
WILLIAM A. GRANT

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is William A. Grant. My business address is 600 South Tyler Street, Suite 2900, Amarillo, Texas 79101.

Q. On whose behalf are you testifying in this proceeding?

A. I am filing testimony on behalf of Southwestern Public Service Company, a New Mexico corporation ("SPS") and wholly-owned electric utility subsidiary of Xcel Energy Inc. ("Xcel Energy").

Q. By whom are you employed and in what position?

A. I am employed by SPS, as Regional Vice President of Regulatory and Strategic Planning.

Q. Please briefly outline your responsibilities as Regional Vice President of Regulatory and Strategic Planning.

A. My responsibilities include:

- determining the appropriate planning strategy for SPS, including working with generation and transmission planning and coordinating with the Southwest Power Pool, Inc. ("SPP") on regional policy and cost allocation issues affecting SPS;
- overseeing the activities of the SPS regulatory department to ensure that SPS meets the regulatory requirements of the Texas and New Mexico commissions as well as the Federal Energy Regulatory Commission ("FERC"); and
- overseeing the relationships with the state and federal commissions and managing the relationships and policy decisions with the SPP.

Q. Please describe your professional experience.

A. I have over 30 years of experience in both power plant and system operations at Xcel Energy or its predecessors. For seven years, I was Director, Power Operations for Xcel Energy Services Inc., in which I was responsible for the economic dispatch and analytical support for all of the Xcel Energy Operating Companies, including SPS. For seven years, I was Manager, Transmission Control Center and Wind Integration for SPS. In 2012, I was named Director, Strategic Planning for SPS. In 2017, I was named Regional Vice President of Regulatory and Strategic Planning.

Q. Have you testified before any regulatory authorities?

A. Yes. I testified before the Public Utility Commission of Texas ("Commission") in Docket No. 46042, which involved a request by SPS to construct a transmission facility.

I have also submitted pre-filed testimony to the Commission on behalf of SPS regarding the SPP in several proceedings. These include: Docket Nos. 45524, 43695, 42004 (SPS rate cases); Docket Nos. 46025 and 42004 (SPS fuel reconciliation cases); Docket No. 42042 (transmission cost recovery factor); Project No. 45633 (evaluation of whether Lubbock Power and Light should move part its load to the Electric Reliability Council of Texas); and Docket No. 46496 (SPP's back-billing for transmission projects placed in service between 2008 and 2016). I have also submitted pre-filed testimony to the New Mexico Public Regulation Commission and the FERC regarding the SPP. My testimony has covered, among other topics:

- SPP’s operations and planning, and how those activities affect SPS;
- SPP fees and charges;
- SPP regional cost allocation for transmission facilities; and
- SPS generation dispatch and outages.

II. ASSIGNMENT AND SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. What is your assignment in this proceeding?

A. In this proceeding, I discuss:

- the process to determine what type of transmission upgrades are needed to interconnect the Sagamore and Hale Wind Projects (collectively referred to herein as the "SPS Wind Projects") to the SPP transmission grid and what the current status is of those efforts;
- how the acquisition of the SPS Wind Projects is expected to impact the ancillary services SPS needs prospectively;
- how firm transmission service is not needed for the SPS Wind Projects, but SPS will submit requests for firm transmission service in the future and, if the costs are reasonable, acquire firm transmission service, which would qualify the SPS Wind Projects for capacity credit under the SPP's Open Access Transmission Tariff ("Tariff"); and
- SPS's responsibility under the Bonita Wind Energy Power Purchase Agreement ("Bonita PPA") for arranging for any transmission service for deliveries of energy beyond the point of delivery, as defined in the PPA.

Q. Please summarize the conclusions and recommendations in your testimony.

A. The developers of the SPS Wind Projects (NextEra Energy Resources, LLC for the Hale Wind Project and Invenergy, LLC ("Invenergy") for the Sagamore Wind Project) have already begun the process for determining the transmission upgrades needed to interconnect the Hale and Sagamore Wind Projects to the SPP transmission grid. The process for the Hale Wind Project is complete. For the Sagamore Wind Project, Invenergy has a Generator Interconnection Agreement ("GIA") request, which will be transferred to SPS upon closing of the transaction. The SPP is continuing to study the requested interconnection for the Sagamore Wind Project.

SPS expects the acquisition of the SPS Wind Projects will increase its ancillary service requirements. In particular, SPS expects Regulating Reserves to increase as a result of acquiring the SPS Wind Projects. The increase will be determined by the SPP through a formula that is described further in my testimony. However, the costs of procuring the Regulating Reserves is expected to be low because: (1) the average price per megawatt ("MW") is relatively low; and (2) SPS self-provides the vast majority of its required Regulating Reserves.

The estimated fuel cost savings resulting from the SPS Wind Projects and the Bonita PPA are not dependent on firm transmission service. However, SPS will request the SPP to determine what transmission upgrades are necessary to obtain firm transmission service. If the required upgrades for firm transmission service are a reasonable cost, then SPS may agree to pay for the upgrades and receive a capacity credit as allowed under the SPP Tariff.

Q. Is Attachment WAG-1 a true and correct copy of the document you have described in your testimony?

A. Yes.

III. INTERCONNECTION OF WIND FACILITIES TO THE SPP TRANSMISSION SYSTEM

Q. What topic do you discuss in this section of your testimony?

A. I discuss how the developers for the SPS Wind Projects have already started the process to determine what type of transmission upgrades are needed to interconnect the SPS Wind Projects to the SPP transmission grid and what the current status is of those efforts.

Q. SPS witness Riley Hill discusses Generation Tie lines from the wind facilities to the interconnection tie breaker on the transmission grid. Is this all that is needed for the wind facilities to be interconnected to the SPP transmission system footprint?

A. No. A connection is still needed from the interconnection tie breaker to the SPP transmission system. In addition, the SPP must: (1) analyze the impact to the system to inject power equal to the generator nameplate at the interconnection point; and (2) determine the need for any possible network upgrades.[1]

[1] "Network upgrades" are the upgrades in addition to the direct interconnection lines and substations needed to physically and electrically connect the wind generating facilities to the transmission system.

Q. How did the developers start the process for the SPP to evaluate the need for possible transmission upgrades?

A. The developers initiated the process by submitting a generator interconnection request to the SPP. In Order No. 2003, the FERC established standardized procedures and agreements for the interconnection of large generators.[2]

Q. How will the SPP determine what transmission upgrades are necessary?

A. The SPP will perform analyses that will specify and estimate the cost of network upgrades. The types of analyses performed are dictated by the type of interconnection queue a generator chooses.

The three interconnection study queues are:

(1) the feasibility study queue (Feasibility Queue), which results in an optional feasibility study completed within 90 days of the close of a cluster window;

(2) the preliminary interconnection system impact study queue (Preliminary Queue), which results in an optional system impact study completed within 180 days of the close of a cluster window; and

(3) the definitive interconnection system impact study queue (Definitive Queue), which is the first required stage within the interconnection process and results in a system impact study completed within 120 days of the close of a cluster window and an Interconnection Facilities Study completed in 90 days, thereafter.

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[2] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003) (Order No. 2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277, (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230, 128 S. Ct. 1468, 170 L. Ed. 2d 275 (2008)). *See also Midwest Indep. Transmission Sys. Operator, Inc.*, 124 FERC ¶ 61,183, at P 31 (2008), *order on reh'g*, 127 FERC ¶ 61,294 (2009); *Interconnection Queuing Practices*, 122 FERC ¶ 61,252 (2008).

Q. Is Invenergy in the Definitive Queue for the Sagamore Wind Project?

A. Yes. Invenergy is in the Definitive Queue. Invenergy will continue the process until it gets a GIA in place. At the closing of the transaction between SPS and Invenergy, the GIA will transfer to SPS.

Q. Does SPS know if there are any costs for network upgrades for interconnection of the Sagamore Wind Project?

A. Not currently; however, the purchase sale agreement with Invenergy allows SPS to terminate if the costs of the network upgrades exceed $44.4 million.

Q. Have any of the steps outlined above been undertaken for the Hale Wind Project?

A. Yes. NextEra already has a GIA in place. The cost of the network upgrades were $1.5 million and is a part of the purchase price to be paid by SPS. The interconnection is already physically built.

IV. ANCILLARY SERVICES RELATED TO THE WIND FACILITIES

Q. What topic do you discuss in this section of your testimony?

A. I provide background regarding ancillary services, why ancillary services are needed, the types of ancillary services that are available to SPS, and how the acquisition of the SPS Wind Projects and the Bonita PPA is expected to affect the ancillary services SPS needs prospectively.

Q. Please briefly describe ancillary services.

A. Ancillary services help balance the transmission system as it moves electricity from generating sources to ultimate consumers. Specifically, at any given point in time, the amount of electricity produced must correspond precisely to the amount of electricity being consumed to ensure secure operation of the electricity grid at a constant frequency. Unforeseen fluctuations between electricity being added to and withdrawn from the electrical grid must be balanced on short notice, which is generally accomplished through directing power plant operators to increase or reduce power plant output. All but one of the ancillary services involves generating units. The amount of resources needed to meet ancillary services requirements have always been spread over multiple units in the footprint rather than carried on just a few units to ensure adequate response to system imbalances.

Q. From whom does SPS procure ancillary services?

A. SPS procures ancillary services through the Ancillary Services Market, which is a component of the SPP Integrated Marketplace ("IM"). SPS also sells ancillary services through the SPP IM, as well.

Q. How does SPS procure ancillary services from the SPP?

A. SPS procures ancillary services under the following six ancillary service schedules:

- Schedule 1 – Scheduling, System Control and Dispatch Service
- Schedule 2 – Reactive Supply and Voltage Control from Generation or Other Sources Service
- Schedule 3 – Regulation and Frequency Response Service
- Schedule 4 – Energy Imbalance Service
- Schedule 5 – Operating Reserve – Spinning Reserve Service
- Schedule 6 – Operating Reserve – Supplemental Reserve Service

Q. How does the acquisition of wind generation affect the need for ancillary services?

A. Due to its variability, wind generation increases the requirement for Regulation and Frequency Response Services (Schedule 3).

A. Schedule 3 – Regulation and Frequency Response Service

Q. Please describe Schedule 3 – Regulation and Frequency Response Service.

A. Schedule 3, Regulation and Frequency Response Service, is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining normal operating frequency (i.e., 60 Hertz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. All load within the SPP balancing area purchases Schedule 3 service through the SPP IM.

Q. How will the change in the level of Regulation and Frequency Response Service (i.e., Schedule 3) be determined?

A. The SPP uses a formula to determine the levels of required Regulating Reserves. The formula is attached to my testimony as Attachment WAG-1.

Q. Please explain how the formula operates.

A. In essence, Regulating Reserves in the SPP IM are based on both the total market area load forecast and the total market area intermittent resource output forecast. The Regulation Up ("RegUp") and Regulation Down ("RegDown") MW value for each operating hour consist of the sum of four components. These components are: (1) a load magnitude component; (2) a load variability component; (3) an intermittent resource magnitude component; and (4) an intermittent resource variability component. All of these components are calculated each day, for each operating hour, on a rolling seven day-ahead basis for both RegUp and RegDown.

Q. Please describe the effect of intermittent resources, such as wind, on the formula.

A. As seen on Attachment WAG-1, both the RegUp and RegDown calculations have variables specifically for intermittent resources such as wind. An increase in the amount of wind on the system leads to an increase in both RegUp and RegDown requirements.

Q. Has the SPP evaluated the effect of wind integration on Reserve Regulation Service?

A. Yes. The SPP has regularly studied the impact, with the most recent study released on January 5, 2016. It can be viewed at:

https://www.spp.org/documents/34200/2016%20wind%20integration%20study%20(wis)%20final.pdf

Some key take-aways are presented under Section 1.3 "Major Findings." In particular, SPP performed a Ramping Analysis, which:

> examined the impact of wind on system ramping requirements and the ability of the system to meet the ramping needs. *By studying one year of data (March 2014-Feb 2015), it was shown that wind does have an impact on overall system ramping, albeit at a relatively small level*. Ramp lengths from 5 minutes up to 12 hours were all shown to increase due to wind, with longer intervals seeing a larger impact. While the largest ramps show a minor increase, the time periods during which large ramping occurs becomes less predictable, and the net load (load minus wind) has become slightly more variable due to the presence of wind. Studying the actual hourly dispatch of the system, SPP appears to have sufficient ramping capability for the near term. However, ramping issues should be monitored – the study here provides a useful base against which future changes can be measured. *As wind increases, the system may require new operational capabilities, either by developing new ancillary service products to manage within-hour ramping, or new situational awareness tools for inter-hour ramping*. It was also shown that the ability to dispatch variable energy resources can reduce the largest short term net load ramps, particularly in the case of over-generation issues. [emphasis added]

In addition, under Section 7.4, "Main Insights and Conclusions", the study found that the "hourly-averaged data showed that one hour load ramping was seen to increase by an amount equivalent to approximately 3% of installed wind capacity, when wind was netted from load." Thus, when the load profile is considered in comparison to the variability of the load profile and diversity of the wind resources, only 3% more Regulating Reserve would have to be provided by the market for an increase of wind generation. To illustrate this conclusion further, if you connected 100 MW of wind generation, then 3 MW of additional Regulating Reserve would be required.

Q. Is the ratio of 3 MW of additional Regulating Reserve per 100 MW of wind generation addressed in the January 5, 2016 study consistent with the SPP formula you addressed above?

A. Yes. The 3 MW per 100 MW of wind generation is a computation from the formula.

B. Cost Affect Due to Increases in Regulating Reserve Service

Q. How does the SPP charge for the Regulating Reserve requirement?

A. It is cleared by the load in the real time market.

Q. What are the components of charges that SPS pays?

A. The charges that are assessed are: (1) an energy component; and (2) a procurement component. The procurement component is a charge for an entity procuring the Regulation Reserve Service.

Q. Has SPS considered any component of the charges for Regulating Reserve as a part of its cost savings estimates presented by SPS witness Jonathan Adelman?

A. Yes. The energy component of the charges for Regulating Reserve is captured by the Promod IV modeling discussed by Mr. Adelman. The procurement component, however, was not included in the savings analysis because the charges will be insignificant.

Q. Why do you think the increase in costs for the procurement component of Regulating Reserve will be insignificant?

A. This cost increase will be insignificant for two reasons. First, the amount of additional Regulating Reserve to be purchased by SPS will be low. Second, SPS self-provides the majority of Regulating Reserve service that is required.

Q. Can you estimate the additional costs of the procurement component of Regulating Reserve associated with the new wind generation?

A. Yes. As noted above, the SPP has found that for every 100 MW of wind generation added, 3 MW of Regulating Reserve is required. In total, the wind acquisition will be 1,230 MW (478 MW for the Hale Wind Project, 522 MW for the Sagamore Wind Project, and 230 MW for the Bonita PPA). Applying the 100:3 ratio to 1,230 MW equals 36.90 MW. SPS's load ratio share is approximately 11%; therefore, 11% of 36.90 MW would be assigned to SPS or 4.06 MW of Regulating Reserve.

Q. How can you determine the costs for procuring the additional 4.06 MW of Regulating Reserve?

A. Using the actual settled regulation purchases from the SPP in 2016, SPS procured 560,105 MW of regulation at a cost of $3,152,765 or an average price of $5.63/MW. This price can be used to approximate the impacts of any additional Regulating Reserve service SPS may need to purchase as a result of the addition of the wind.

Q. What are the additional costs of procuring the 4.06 MW of Regulating Reserve?

A. Using $5.63/MW and 4.06 MW of additional reserves results in a maximum annual cost of approximately $200,234 (4.06 MW x $5.63/MW x 8,760 hours/year).

Q. What is the SPS retail customers' share of the $200,234?

A. It is approximately 65% or $130,152 annually (combined for SPS's Texas and New Mexico retail jurisdictions). However, as I will explain, the net dollar effect is even less than this amount.

Q. Does SPS self-supply Regulating Reserve?

A. Effectively, yes. SPS sells Regulating Reserve into the SPP IM from its generators and separately purchases Regulating Reserves from the SPP IM for its load. SPS supplies approximately 97% of the Regulating Reserve ancillary services it requires to serve its load.

Q. How does self-supply affect the charges SPS will pay for the Regulating Reserve?

A. Since SPS assets sell Regulating Reserves to the SPP IM while SPS load simultaneously purchases regulation, this situation results in no additional costs from SPP to SPS for 97% of the required volumes. Thus, on a net basis, the costs to SPS would be approximately 3% of the annual $200,234 for the increase in Regulating Reserve Service, or approximately $6,000. As I mentioned earlier, approximately 65% of this net dollar amount would be assigned to SPS's two retail jurisdictions combined, or approximately $3,900 annually.

Also, since SPS is supplying the incremental regulation, any deployed regulation further benefits SPS customers by selling deployed energy during RegUp events to the SPP or the repurchase of lower-priced energy during RegDown deployment events. Additionally SPP's make whole payment market mechanisms assure no losses should circumstances result in a negative economic outcome.

V. TRANSMISSION SERVICE FOR THE SPS WIND PROJECTS AND THE BONITA PPA

Q. What topic do you discuss in this section of your testimony?

A. I discuss how firm transmission service is not needed for the SPS Wind Projects and Bonita PPA, but SPS will submit requests for firm transmission service in the future. If the network upgrades necessary for firm transmission service fall within a reasonable range of costs, then SPS may agree to pay for the upgrades, after which the SPS Wind Projects and Bonita PPA would qualify for capacity credit under the SPP Tariff for a portion of their nameplate capacity.

Q. Is firm transmission service required for SPS to integrate the SPS Wind Projects or Bonita PPA?

A. No.

Q. Even though firm transmission service is not required for either the SPS Wind Projects or the Bonita PPA, has SPS submitted requests for firm transmission service?

A. No, not at this time.

Q. Will SPS request firm transmission service for either the SPS Wind Projects or the Bonita PPA?

A. Yes, for both the SPS Wind Projects and the Bonita PPA.

Q. Why would SPS request firm transmission service if it is not necessary?

A. Acquiring firm transmission service could allow the SPS Wind Projects and Bonita PPA to qualify for capacity credit. In particular, under SPP Criteria 12.1.5.3(g), if SPS obtains firm transmission service, then it could receive approximately 185 MW of capacity credit (15% of the nameplate capacity) towards SPS's planning reserve margin. Additionally, firm transmission service provides transmission congestion rights.

Q. Because SPS has not requested firm transmissions service, does it know what the transmission cost impacts might be to secure firm network transmission service for the SPS Wind Projects?

A. No, not at this time.

Q. Please describe the process by which SPS will request the SPP to study firm transmission service for the SPS Wind Projects and the Bonita PPA.

A. SPS will submit Transmission Service Requests to be entered into SPP's Aggregate Study process. SPP will perform transmission service studies to identify what network upgrades, if any, are necessary for the SPS Wind Projects and Bonita PPA to receive firm transmission service. SPS will receive preliminary results from the transmission service study no later than three months after the initial requests are submitted. Under the current Aggregate Study process, the final results will be known within six months of study commencement. SPS expects one of the following two end results and resulting actions: (1) if the transmission upgrades are significant, then SPS likely will not accept firm transmission service; (2) if the transmission upgrades are minimal, i.e., cost less than the benefits received from the firm service, then SPS would move forward with firm transmission service. The benefits to be evaluated would be the value of the capacity credit and an evaluation of the amount and potential value of the transmission congestion rights.

Q. If SPS does not obtain firm transmission service, will that substantially affect the avoided energy savings SPS estimates for the SPS Wind Projects?

A. No. The benefits described by Mr. Adelman are not dependent on receiving firm transmission service.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

AFFIDAVIT

STATE OF TEXAS)
)
COUNTY OF POTTER)

WILLIAM A. GRANT, first being sworn on his oath, states:

I am the witness identified in the preceding testimony. I have read the testimony and the accompanying attachment and am familiar with their contents. Based upon my personal knowledge, the facts stated in the testimony are true. In addition, in my judgment and based upon my professional experience, the opinions and conclusions stated in the testimony are true, valid, and accurate.

DONNA M. ANDERSON
Notary Public, State of Texas
Notary ID #853163-5
My Commission Expires 06-17-2020

William A. Grant
WILLIAM A. GRANT

Subscribed and sworn to before me this 17 day of March, 2017 by WILLIAM A. GRANT.

Donna M Anderson
Notary Public, State of Texas
My Commission Expires: 6/17/2020

CERTIFICATE OF SERVICE

I certify that on March 21, 2017, this instrument was filed with the Public Utility Commission of Texas, and a true and correct copy of it was served by hand delivery on the Staff of the Public Utility Commission of Texas and the Office of Public Utility Counsel, and by hand delivery, next business day courier delivery, or first class mail on each party of record in SPS's most recent base rate case, Docket No. 45524.

SPP Southwest Power Pool

HELPING OUR MEMBERS WORK TOGETHER
TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE

Calculating Regulating Reserve Requirements
SPP Integrated Marketplace

SPP Operations

2/7/2017

Overview

Regulating Reserves in the SPP Integrated Marketplace are based on both the total market area load forecast and the total market area intermittent resource output forecast. Load forecast data is provided by SPP's Mid-term Load Forecast "MTLF", a component of SPP's GE EMS system. Intermittent resource forecast data, abbreviated to "IRF" below, is provided by Energy & Meteo.

The Regulation Up (RegUp) and Regulation Down (RegDown) MW value for each operating hour consist of the sum of four components. These components are a load magnitude component, a load variability component, an intermittent resource magnitude component, and an intermittent resource variability component. Magnitude components are simply just carrying a percentage of forecasted values as regulation. Variability components are intended to increase the amount of regulation carried in a given hour due to certain forecasted conditions. The variability components cannot be negative and, therefore, will not reduce the amount or regulation requirement derived from the magnitude components. All components are calculated each day for each operating hour on a rolling seven day ahead basis for both Regulation Up and Regulation Down.

Example Data

	Load Forecast (MTLF)	Intermittent Resource Forecast (IRF)
Hour Ending 7	28975	3824
Hour Ending 8	32542	3161

Load Magnitude Coefficient (RegUp and RegDown)	0.005
Load Variability Coefficient (RegUp and RegDown)	0.02
Intermittent Magnitude Coefficient (RegUp and RegDown)	0.01
Intermittent Variability Coefficient (RegUp and RegDown)	0.03

The data above is intended for example purposes only and does not represent production environment conditions.

Load Magnitude Component – Regulation Up and Regulation Down

The load magnitude component will be calculated using the most recent MTLF data for the hour being calculated multiplied by the Load Magnitude Coefficient. RegUp and RegDown calculations can use different coefficients if needed. The load magnitude components of RegUp and RegDown are what many Balancing Authorities would consider to be the "standard" method of calculating a regulation reserve requirement.

$$Hour\ Ending\ X\ RegUp\ Load\ Magnitude\ Component = (Hour\ Ending\ X\ MTLF) * (RegUp\ Load\ Magnitude\ Coefficient)$$

Example 1

$$Hour\ Ending\ 7\ RegUp\ Load\ Mag.Comp. = (28975\ MW) * (.005) = 144.875\ MW$$

$$Hour\ Ending\ X\ RegDown\ Load\ Magnitude\ Component = (Hour\ Ending\ X\ MTLF) * (RegDown\ Load\ Magnitude\ Coefficient)$$

Example 2

$$Hour\ Ending\ 7\ REG\ Down\ Load\ Comp = (28975\ MW) * (.005) = 144.875\ MW$$

Load Variability Component – Regulation Up and Regulation Down

A load variability component is used in both RegUp and RegDown calculations. These components are intended to increase the total amount of RegUp or RegDown when a large change is occurring in the load forecast from one hour to the next. For RegUp, this variability component is only valid when the load forecast is increasing from the current hour to the next hour. For RegDown, the load forecast must be decreasing for the variability component to be valid. When a component is invalid due to these rules, a value of zero is used.

$$Hour\ Ending\ X\ RegUp\ Load\ Varability\ Component = [(Hour\ Ending\ X + 1\ MTLF) - (Hour\ Ending\ X\ MTLF)] * (RegUp\ Load\ Var. Coefficient)$$

$$(Hour\ Ending\ X + 1\ MTLF) - (Hour\ Ending\ X\ MTLF)\ must\ be > 0\ for\ the\ RegUp\ Load\ Varability\ Component\ to\ be\ valid$$

Example 3

$$Hour\ Ending\ 7\ RegUp\ Load\ Var. Comp. = (32542 - 28975) * 0.02 = 71.34\ MW$$

$$Hour\ Ending\ X\ RegDown\ Load\ Varability\ Component = [(Hour\ Ending\ X + 1\ MTLF) - (Hour\ Ending\ X\ MTLF)] * (RegUp\ Load\ Var. Coefficient) * (-1)$$

$$(Hour\ Ending\ X + 1\ MTLF) - (Hour\ Ending\ X\ MTLF)\ must\ be < 0\ for\ the\ RegDown\ Load\ Varability\ Component\ to\ be\ valid$$

Example 4

$$Hour\ Ending\ 7\ RegDown\ Load\ Var.Comp. = (32542 - 28975) * 0.02 * -1 = 0$$

Since the load forecast is increasing from Hour Ending 7 to Hour Ending 8, the Load Variability Component for RegDown is not valid for Hour Ending 7.

<u>Intermittent Resource Magnitude Component – Regulation Up and Regulation Down</u>

The Intermittent Resource Magnitude Component will be calculated using the most recent IRF multiplied by the Intermittent Resource Magnitude Coefficient. RegUp and RegDown calculations can use different coefficients if needed.

$$Hour\ Ending\ X\ RegUp\ Intermittent\ Resource\ Magnitude\ Component = (Hour\ Ending\ X\ IRF) * (RegUp\ Intermittent\ Resource\ Magnitude\ Coefficient)$$

Example 5

$$Hour\ Ending\ 7\ RegUp\ Int.Resource\ Mag.Comp. = (3824\ MW) * (.01) = 38.24\ MW$$

$$Hour\ Ending\ X\ RegDown\ Intermittent\ Resource\ Magnitude\ Component = (Hour\ Ending\ X\ IRF) * (RegDown\ Intermittent\ Resource\ Magnitude\ Coefficient)$$

Example 6

$$Hour\ Ending\ 7\ RegDown\ Int.Resource\ Mag.Comp. = (3824\ MW) * (.01) = 38.24\ MW$$

<u>Intermittent Resource Variability Component – Regulation Up and Regulation Down</u>

An intermittent resource variability component is used in both RegUp and RegDown calculations. These components are intended to increase the total amount of RegUp or RegDown when a large change is forecasted to occur in the intermittent resource output from one hour to the next. For RegUp, this variability component is only valid when the intermittent resource forecast is decreasing from the current hour to the next hour. For RegDown, the intermittent resource forecast must be increasing for the variability component to be valid. When a component is invalid due to these rules, a value of zero is used.

$$Hour\ Ending\ X\ RegUp\ Intermittent\ Resource\ Varability\ Component = [(Hour\ Ending\ X+1\ IRF)-(Hour\ Ending\ X\ IRF)] * (RegUp\ Load\ Var.Coefficient) * (-1)$$

$$(Hour\ Ending\ X+1\ IRF)-(Hour\ Ending\ X\ IRF)\ must\ be < 0\ for\ the\ RegUp\ Intermittent\ Resource\ Varability\ Component\ to\ be\ valid$$

Example 7

$$Hour\ Ending\ 7\ RegUp\ I.R.Var.Comp. = (3161-3824) * 0.03 * (-1) = 19.89\ MW$$

$$Hour\ Ending\ X\ RegDown\ Intermittent\ Resource\ Varability\ Component = [(Hour\ Ending\ X+1\ IRF)-(Hour\ Ending\ X\ IRF)] * (RegUp\ Intermittent\ Resource\ Var.Coefficient)$$

$$(Hour\ Ending\ X+1\ IRF)-(Hour\ Ending\ X\ IRF)\ must\ be > 0\ for\ the\ RegDown\ Load\ Varability\ Component\ to\ be\ valid$$

Example 8

$$Hour\ Ending\ 7\ RegDown\ I.R.Var.Comp. = (3161-3824) * 0.03 = 0$$

Since the intermittent resource forecast is decreasing from Hour Ending 7 to Hour Ending 8, the Intermittent Resource Variability Component for RegDown is not valid for Hour Ending 7.

Summing the Four Components – Regulation Up and Regulation Down

The sum of the four components for RegUp and RegDown will give the hourly MW requirement for each. Values are rounded to the nearest whole MW.

Example 9

$$Hour\ Ending\ 7\ RegUp\ Requirement = 145 + 71 + 38 + 20 = 274\ MW$$

Example 10

$$Hour\ Ending\ 7\ RegDown\ Requirement = 145 + 0 + 38 + 0 = 183\ MW$$