CHAPTER 11
ANCILLARY SERVICES
LOSS OF LOAD PROBABLILITY

Introduction

Ancillary services are needed to correct for minutely and intra-hour changes in loads and generation. Loss of Load Probability ("LOLP") determines the amount of capacity that needs to be available to meet the desired or required reliability target.

Contingency Reserves

Contingency reserves must be maintained to ensure reliability under normal and abnormal conditions as part of WECC requirements.[1] For NorthWestern, this minimum amount is equal to the sum of 3% of hourly combined load and 3% of hourly combined generation. Of this minimum, at least 50% must be spinning reserves, which are on-line generators synchronized with the grid. The rest can be supplied by non-spinning reserves, which are off-line generators. Both types must be capable of responding within ten minutes and maintaining specified levels for at least sixty minutes. Table 11-1 shows the approximate minimum and maximum amount of reserves required during 2015.

Table 11-1 2015 Contingency Reserve Requirements

2015 Contingency Reserve Requirements		
	Min (MW)	Max (MW)
Spinning	14	35
Non-Spinning	13	34
Total Reserves	**27**	**69**

[1] Except within the first sixty minutes following an event requiring the activation of Contingency Reserves (WECC Standard BAL-002-WECC-2 – Contingency Reserve).

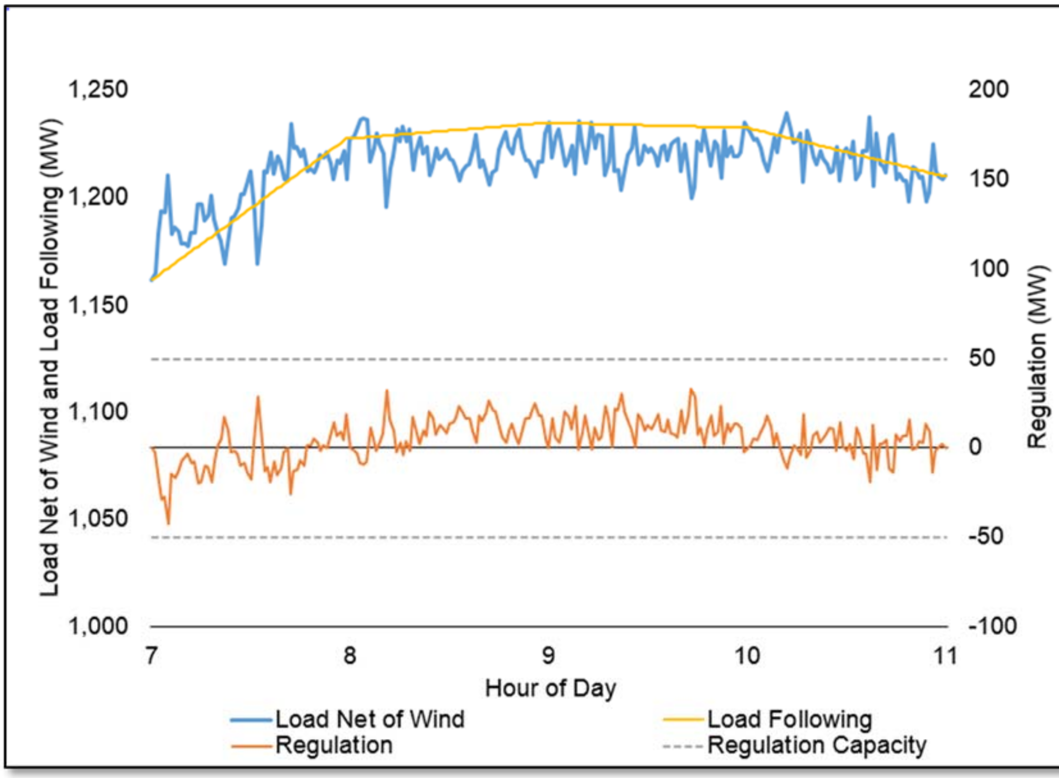
In 2015, spinning reserves were supplied by the Hydros, and a portion of Basin Creek's capacity was allocated for non-spinning reserves.

Ancillary Services

Historically, utilities were able to provide ancillary services from existing resources far in excess of their need. NorthWestern had no ability to self-provide ancillary services after purchasing the electric transmission and distribution system from Montana Power, but was able to purchase ancillary services from other regional utilities. However, as these utilities added intermittent renewable generation to their portfolios, they ended their sales of ancillary services to NorthWestern. Still lacking the resources necessary to provide its own ancillary services, NorthWestern constructed and placed DGGS into service in 2011 expressly for the provision of ancillary services. In 2015, NorthWestern acquired 442 MW of hydroelectric resources that have some ability to provide ancillary services.

Ancillary services provide fast and flexible response to keep the supply system in balance. There are two major components to ancillary services: 1) regulating reserves and 2) contingency reserves. Figure 11-1 illustrates the difference between regulation and load following services. The linear ramp between hours, designated by the yellow line, is primarily served using load following and base energy resources. Regulation, shown as the small deviations in load, is designated by the blue line, which varies around the yellow line. Regulation uses generators equipped with automatic generation control ("AGC") to quickly change output, on the order of megawatts per minute (MW/min), to correct for moment-to-moment fluctuations in customer loads and generation – particularly variations in generation of intermittent renewable resources. Regulation (right side scale) required is shown by the orange line and varies between positive and negative, netting to zero over the course of several hours.

Figure 11-1. Illustration of Regulation Compared to Load Following

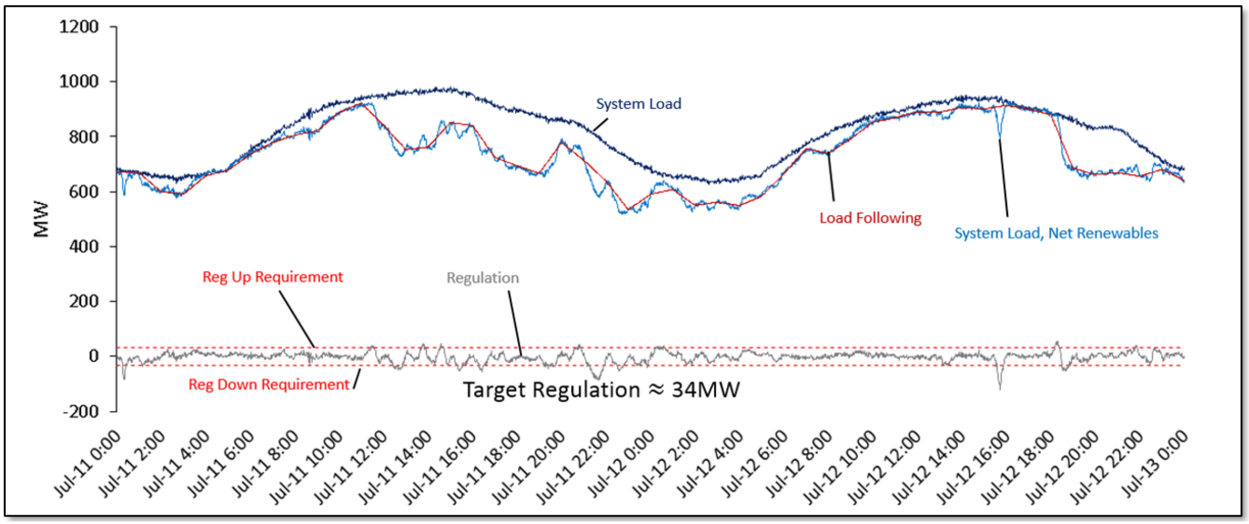


The 2015 Plan optimizes hydro and thermal resources to meet NorthWestern's regulation and load following needs. Thermal and hydro resources jointly share responsibility to meet load following and regulation requirements. Using minutely level dispatch that is co-optimized between thermal and hydro resources accurately portrays the operating patterns and resource cycles of the resources used to meet the minutely level fluctuations in net load. This analysis is performed using PowerSimm at a minutely level time step and analyzes regulation and flexibility needs and costs[2].

[2] This level of analysis is not possible with simplified spreadsheet models.

Figure 11-2 shows minutely load and intermittent renewable generation scaled to expected load and intermittent renewable generation for July 11th and 12th in 2022. System load is depicted by the relatively stable dark blue line at the top of Figure 11-2.

Figure 11-2 NorthWestern Load, Intermittent Renewable Generation, and Regulation Requirements



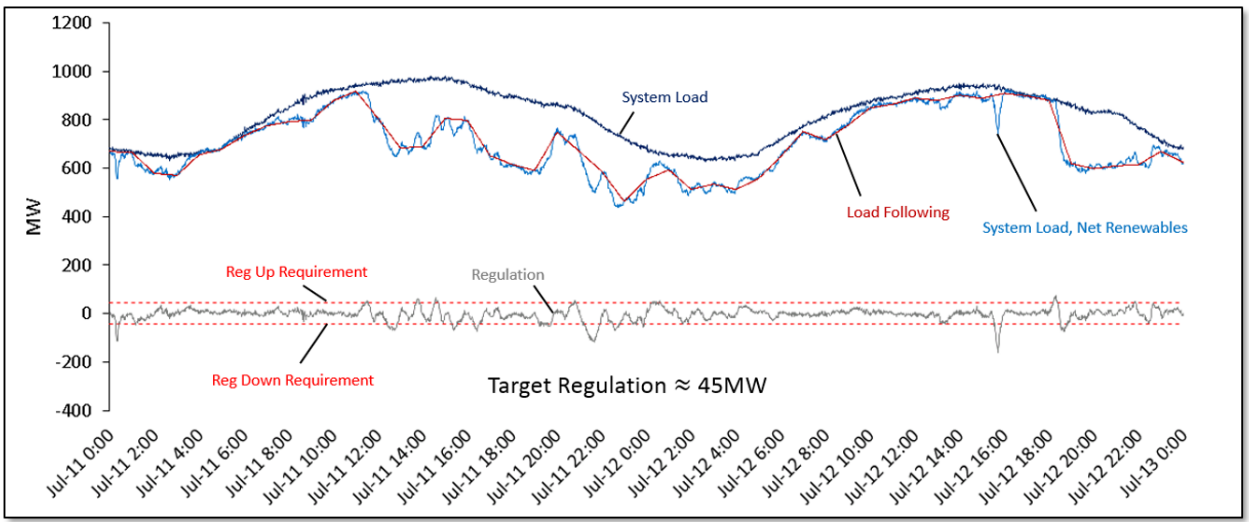
Load less intermittent renewable generation follows the light blue net load line, which moves above and below the red load following line. The difference between the red load following line and the light blue net load line represents the amount of system regulation, shown as the gray line, which is bounded by the 95th percentile confidence interval above and below.

Regulation Requirements for Wind and Solar PV

Running PowerSimm on a minutely time-step, the model is used to measure NorthWestern's ability to maintain acceptable CPS2 scores. The minutely level optimization in PowerSimm accounts for physical system limits, such as generation ramp rates needed to respond to system imbalances. The average monthly CPS2 score from

PowerSimm minutely dispatch for load and wind and solar PV for 2015 was 92[3]. The calculated regulation value required for NorthWestern is 34 MW in 2022, which consists of 12 MW of regulation required for load and 22 MW of regulation required for wind and solar PV. Figure 11-3 illustrates the impact of adding 100 MW of wind generation capacity on NorthWestern's minutely level operations.

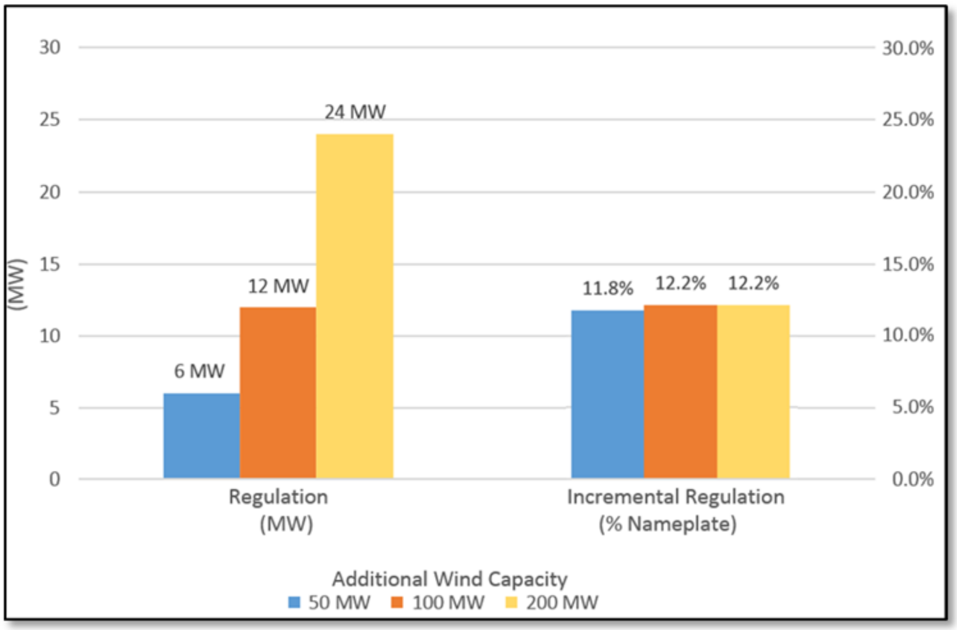
Figure 11-3 Impact of Adding 100 MW of Wind Generation on Regulation Requirements



NorthWestern's future incremental regulation requirements will be driven primarily by the amount of wind and, to a lesser extent, solar PV present on its system. The additional regulation needed to regulate an additional 50 MW, 100 MW and 200 MW of wind generation in 2022 is shown in Figure 11-4.

[3] 90 is the minimum score needed to satisfy CPS2.

Figure 11-4 Regulation Requirements for 2022 with Additional Wind Generation (Excludes Load Following Component)



NorthWestern's current resource portfolio contains relatively small amounts of solar PV. In order to gain a better understanding of solar PV resources, NorthWestern contracted with CPR and DNV-GL to provide solar irradiance data and an indicative design for solar PV facilities located in Montana. Production was modeled on a minutely basis using CPR solar data and DNV-GL's indicative design.

Figure 11-5 illustrates the impact of adding 100 MW of solar PV capacity on NorthWestern's minutely level operations. While solar PV generation does exhibit some erratic generation, the profile is generally smoother and better behaved than wind generation.

Figure 11-5 Impact of Adding 100 MW of Solar PV Generation on Regulation Requirements

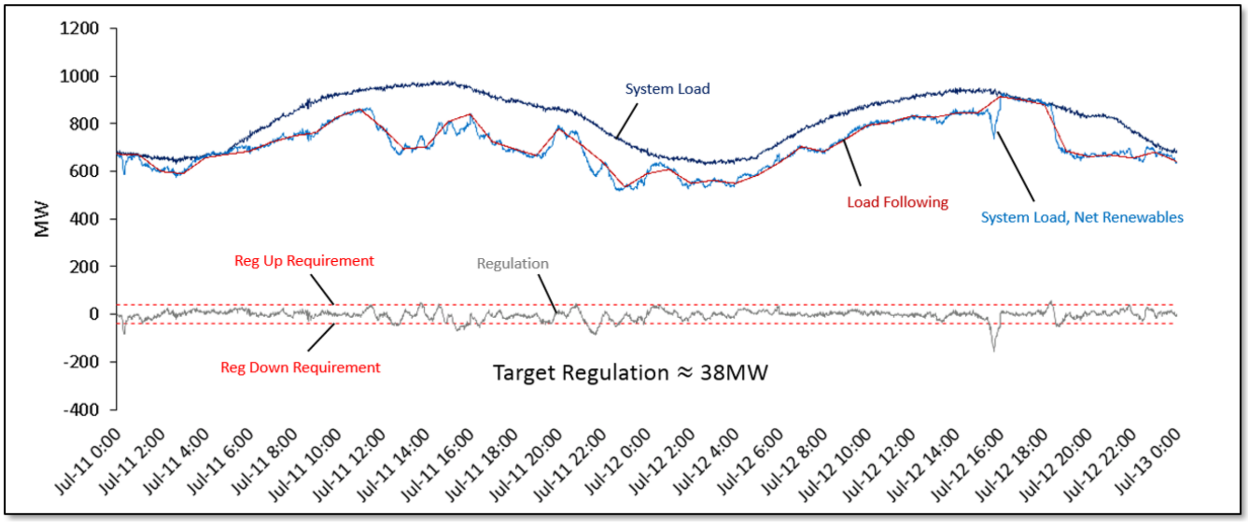


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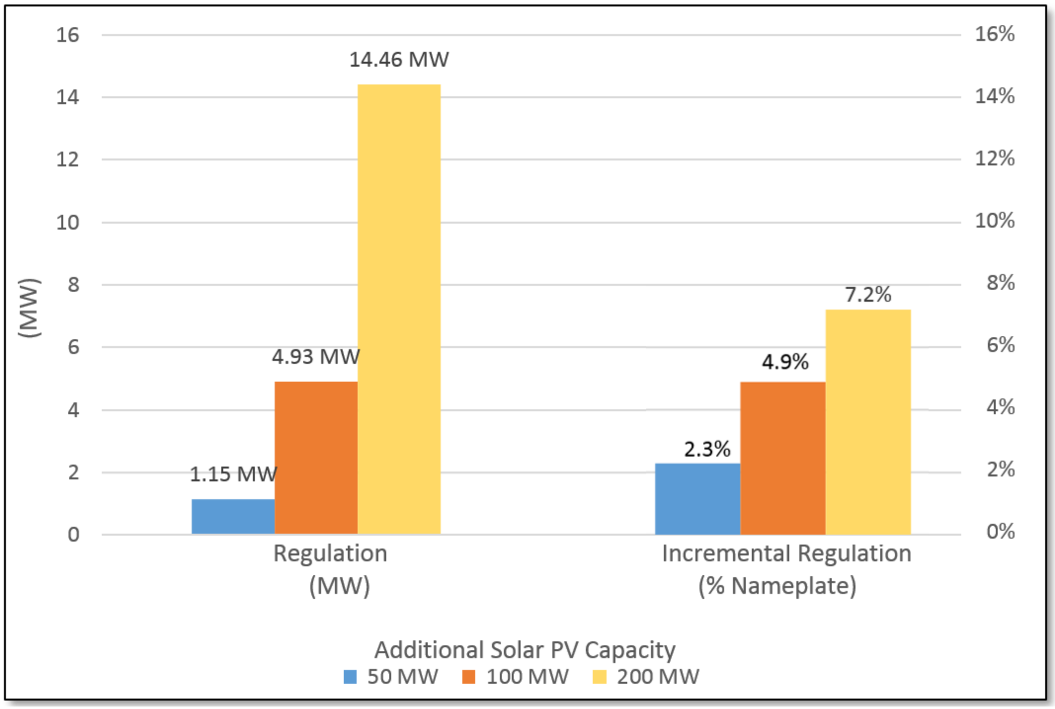
Figure 11-6 shows the small increases in regulation needed to accommodate the addition of 50, 100, and 200 MW of solar PV generation. The addition of 100 MW of solar PV generation in 2022 increases the regulation requirement by about 4 MW.

Figure 11-6 Regulation Requirements for 2022
With Additional Solar PV Generation
(Excludes Load Following Component)



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Flexibility Requirements for Wind and Solar PV

This section evaluates the level of flexible resources needed to balance loads and generation on NorthWestern's electric system. Figure 11-7 shows the hourly differential in load for NorthWestern over the two day period of July 11th and 12th, 2022. Total ramp (in red) is composed of the ramp needed for load, wind and solar. The figure illustrates that much of NorthWestern's current ramping need is caused by variations in wind generation.

Figure 11-7 One-hour Ramp Requirements with Current Resources

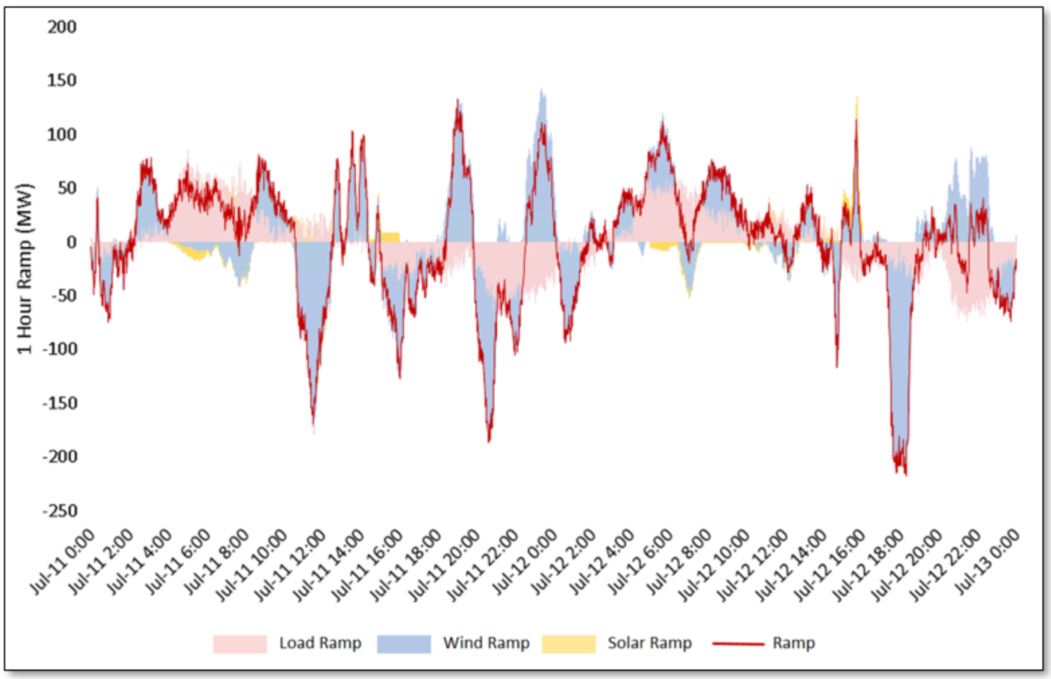

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Figure 11-8 shows the effect on ramp rates of adding 100 MW of wind generation for the same period. With the addition of 100 MW of wind, 1-hour ramp rates increase to 372 MW up and 376 MW down (increases of 85 MW up and 84 MW down). This analysis illustrates that additional intermittent wind generation cannot be added to NorthWestern's system without making sure that it has, or acquires, sufficient flexible generation.

Figure 11-8 One-hour Ramp Requirements with Additional 100 MW Wind

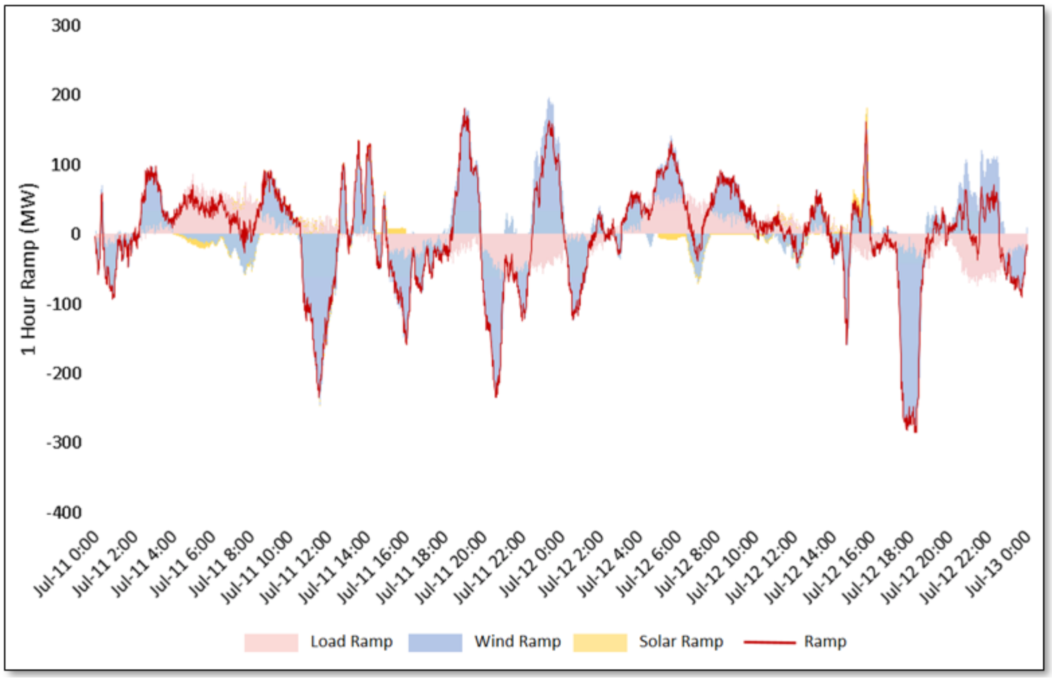

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Figure 11-9 shows effect on ramp rates of adding 100 MW of solar PV generation for the same period. With the addition of 100 MW Solar PV, 1-hour ramp rates increase by about 11 MW ramp up and no appreciable change in ramp down. While this analysis used the best data available, it used estimated solar production data and these results should be verified with actual solar PV production data to establish definitive conclusions.

Figure 11-9 One-hour Ramp Requirements with Additional 100 MW Solar

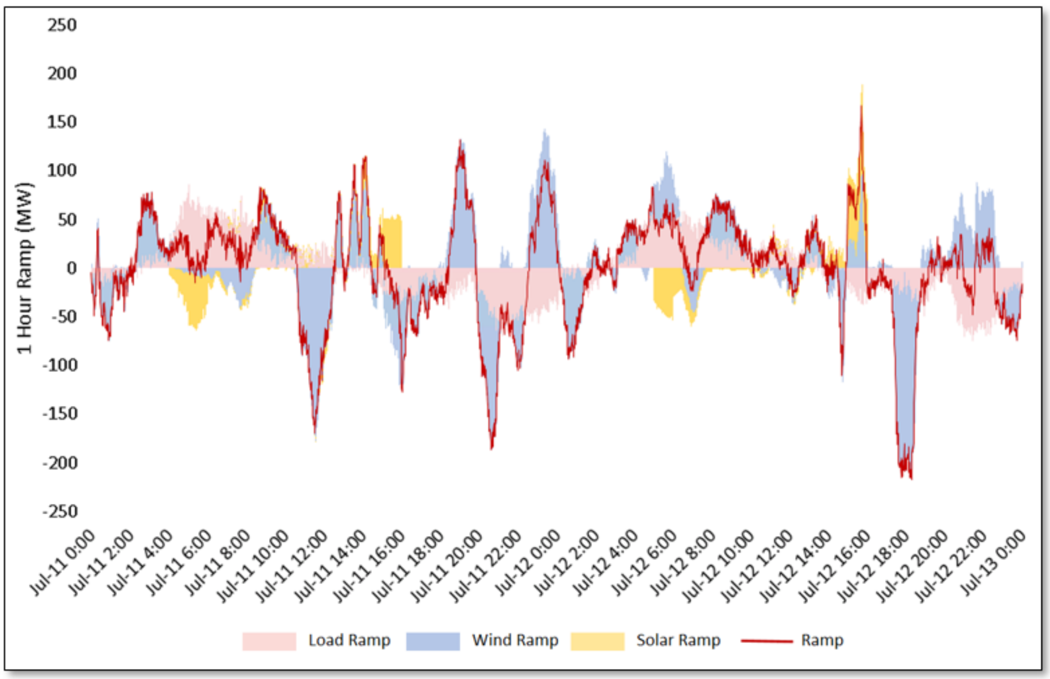

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Table 11-2 below summarizes the maximum 1-hour ramp up and maximum 1-hour ramp down for the planning year 2022. Maximum ramp rates are shown for the Economically Optimal Portfolio ("EOP"), the EOP plus 100 MW of incremental wind, and the EOP plus 100 MW solar PV. While 100 MW of incremental wind requires about 85 MW of ramping, an incremental 100 MW of solar PV has much less effect on ramping.

Table 11-2 2022 Ramp Requirements with Additional Wind and Solar PV

Year 2022 Ramp Requirement	Economically Optimal Portfolio	+100 MW Wind	Increment	+ 100 MW Solar PV	Increment
Solar PV Added	-	-	-	100 MW	100 MW
Wind Added	-	100 MW	100 MW	-	-
Regulation Requirement	34 MW	45 MW	12 MW	38 MW	1 MW
Total Solar Capacity	40 MW	40 MW	-	140 MW	100 MW
Total Wind Capacity	266 MW	366 MW	100 MW	266 MW	-
1-Hour Ramp-Up	287 MW	372 MW	85 MW	298 MW	11 MW
1-Hour Ramp-Down	292 MW	376 MW	84 MW	292 MW	-

Ramping capability is the key component of load following which has been mathematically identified and separated from regulation in the modeling analysis. While distinctly different from regulation, it is more challenging to isolate and evaluate independently because it is supplied concurrently from the same resources that are providing load-serving capacity and energy to the portfolio. In addition, load following is dynamic because conditions for generation resources change based on available physical capabilities (e.g. hydro conditions), unit outages, and economics.

The co-optimization of hydro and thermal resources to provide needed ancillary services shows cost savings opportunities. The reduced reliance on thermal units such as DGGS to provide regulation services lowers fuel and other costs of operation. This means that the capacity of DGGS units not being used to provide regulation services are economically deployed to provide other services such as load following, peaking and reserves. The inherent flexibility of DGGS allows it to perform multiple roles and to readily change operation because of its high level of dispatch capability over a wide operating range.

Cost of Regulation

The Hydros have been modeled to furnish up to 50% of the regulation requirements of the 33 MW needed for NorthWestern's current portfolio, decreasing the cost of regulation. For the Load + Existing Wind & Solar (Base) case, shown in Figure 11-10, the 20-year NPV of variable costs for regulation decrease from $14.3 million to $7.2 million when DGGS and the Hydros share regulation service responsibility. Regulation costs decrease by $4.4 million from DGGS to 50/50 in the case when an additional 200 MW of wind is added to the current resource portfolio, and by $2.8 million when an additional 200 MW of wind is added to the current resource portfolio.

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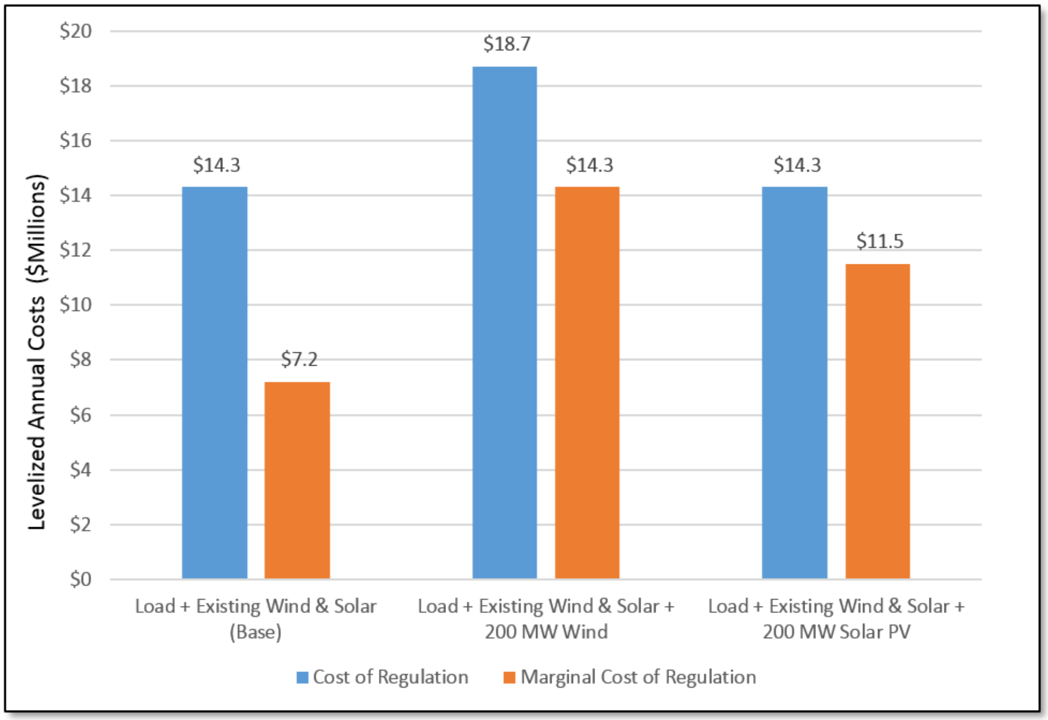
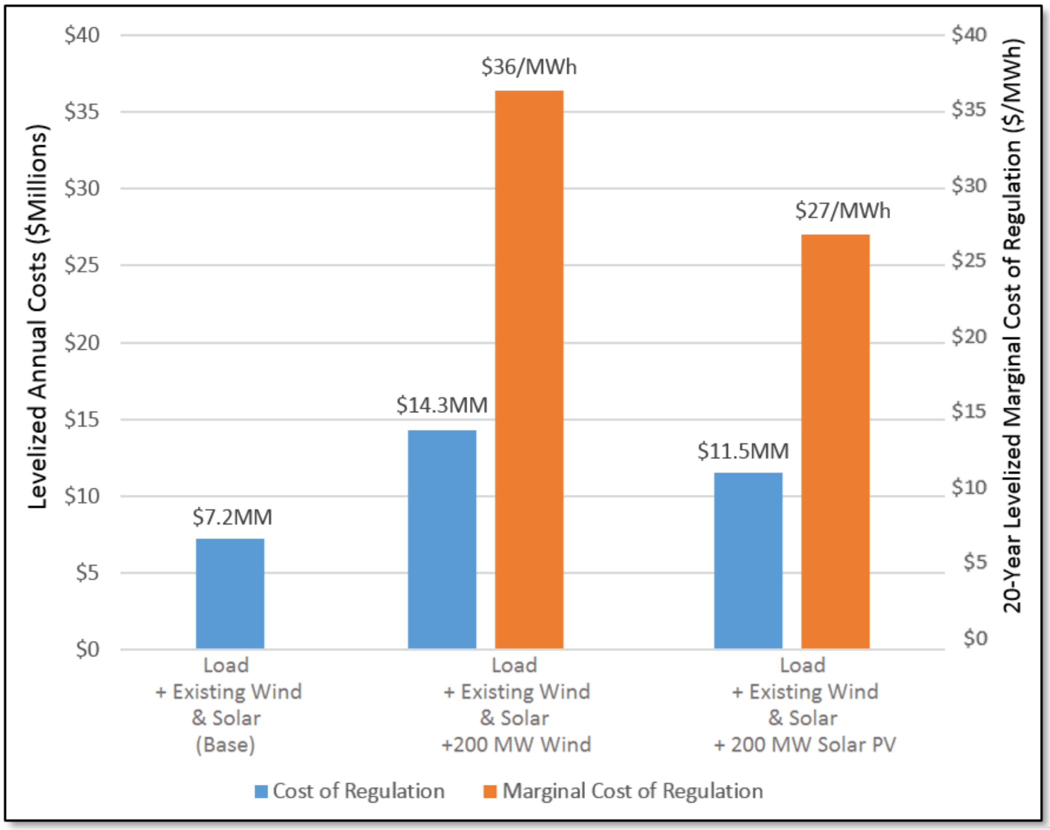
Figure 11-10 DGGS Regulation vs. 50/50 Regulation



NorthWestern is currently taking steps to enable implementing the 50/50 regulation operations that are modeled in PowerSimm. Successful completion of resource testing and updated operations are anticipated to lead to costs of regulation declining substantially. Figure 11-11 shows the regulation costs of serving loads at current levels of wind and solar PV, and the costs and marginal costs of serving loads at current levels of wind and solar PV and with additional amounts of wind and solar PV. Assuming 50/50 regulation, the cost of regulation needed to serve the current level of loads and wind and solar PV in NorthWestern's supply portfolio is approximately $7.2 million. Adding another 200 MW of wind roughly doubles the cost of regulation to $14.3 million, at a marginal cost of $36 per MWh. With the addition of 200 MW of wind, the regulation requirement increases by 12 MW, surpassing the Hydros' ability to continue to contribute 50% of the regulation, which drives the incremental cost of regulation higher. Adding another 200 MW of solar

PV increases regulation costs from $7.2 million to $11.5 million, at a marginal cost of $27 per MWh.

Figure 11-11 Cost of Supply Regulation 50% Hydros - 50% DGGS



Loss of Load Probability

LOLP or Loss of Load Expectation ("LOLE") is typically performed on an integrated utility system to determine the amount of capacity that needs to be installed to meet the desired reliability target. For planning purposes, NorthWestern does not need LOLP or LOLE to arrive at the conclusion that the physical resources in its resource portfolio fall far short of peak retail loads. However, LOLP analysis informs us of the amount of capacity additions necessary to maintain system reliability, and the supporting analysis also assesses the peak capacity contribution from intermittent resources, such as wind and solar

PV. Therefore, NorthWestern worked with Ascend to develop an LOLP metric for use in the 2015 Plan and other NorthWestern proceedings.

Traditional LOLP / LOLE analysis considers the peak hour of the days that have significant LOLP, which are generally peak demand days. Ascend calculates NorthWestern's LOLP using Load Hours ("LOLH") analysis, which jointly values the volumetric uncertainty of demand and supply to assess resource adequacy. The LOLH metric considers all hours during which there may be a risk of insufficient generation. According to NERC, LOLH is the more appropriate measure for resource adequacy, but its translation into a standard LOLP metric requires additional research.[4] In support of using LOLH, NERC states the following:

> *"With high penetrations of variable generation, this may be an advantageous metric because of the variability of these resources. The daily LOLE metric is coarse: it only considers one hour a day. The LOLH metric looks at each hour. This provides a more accurate assessment of adequacy in the sense that all hours are examined by the metric. However, unlike the daily LOLE, there is no generally accepted hourly target. For example, 2.4 hours/year is not the same as 0.1 days/year. Additional analysis is required to determine the relationship between LOLE and LOLH reliability targets."*[5]

To measure NorthWestern's LOLP, Ascend calculates the total annual LOLH from the simulations of net load and generating resource availability. Total annual LOLH is converted to the "LOLH in 10-years" metric by multiplying total annual LOLH by 10. NERC suggests that translating LOLH into LOLP "requires additional research". An industry standard LOLP metric is one day in ten years.

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[4] NERC, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*. March, 2011. [http://www.nerc.com/files/ivgtf1-2.pdf (Volume 2, Chapter 7)](http://www.nerc.com/files/ivgtf1-2.pdf)

[5] Ibid pp. 28.

The analysis uses an advanced integrated simulation framework that captures the joint probability of load and intermittent renewable generation over 100 simulated weather conditions. The net load follows from a simulated set of meteorological conditions that drive load, wind, and solar generation. Generation resource availability is simulated from plant generation data based on an expected outage rate distribution and outage duration.

Table 11-3 portrays the LOLP metrics for NorthWestern's 2016 portfolio of physical resources, which has a physical reserve margin of -28%. To realize the industry standard LOLP of one day in ten years for 2016, NorthWestern would need to add 500 MW of capacity. This corresponds to an expected reserve margin of 14%. The current reliability planning criteria of the NWPCC of a 5% outage limit corresponds to 1.5 days in ten years.[6] Under the NWPCC criteria, NorthWestern would carry a reserve margin of 13% and need to add 487 MW of capacity.

Expected LOLH per 10 years is converted to Expected LOLD per 10 years by looking at the expected duration of the hourly level events per day. In this study the average expected loss of load event was 2 hours in duration, so expected LOLH hours are converted to days (dividing by 24), and then scaled by the expected event duration (multiplying by 2).

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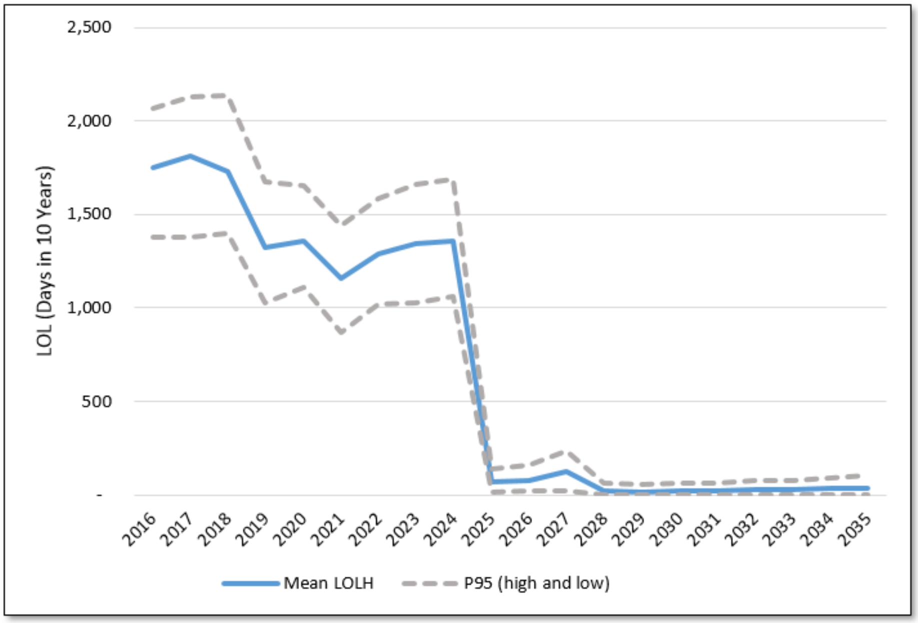
[6] Phone conversation with NWPCC staff, March 8, 2016.

Table 11-3 2016 Reserve Margins and LOLP with Capacity Resource Additions

Reserve Margin (%)	MW Additions	Expected LOLH in 10 years	Expected LOL Days in 10 years
-28%	0	21,020	1,752
-26%	25	17,382	1,449
-24%	50	14,075	1,173
-22%	75	11,167	931
-20%	100	8,692	724
-18%	125	6,618	551
-16%	150	4,921	410
-14%	175	3,608	301
-12%	200	2,571	214
-10%	225	1,804	150
-7%	250	1,236	103
-5%	275	833	69
-3%	300	532	44
-1%	325	332	28
1%	350	202	17
3%	375	116	10
5%	400	63	5
7%	425	36	3.0
9%	450	20	1.7
12%	475	10	0.8
14%	500	5	0.4
16%	525	1.2	0.1
18%	550	0.4	0.0

NorthWestern's optimal expansion planning analysis adds resources to increase the portfolio capacity level to a reserve margin of 0% in 2028, but still falls short of the normative planning capacity additions needed to realize an LOLP equal to one day in 10 years. Figure 11-12 shows the LOLP of the optimal expansion for the EOP. With capacity additions, the LOL Days in ten years falls to 16 days in 2029 and the rises to 36 days by the end of the planning period.

Figure 11-12 LOL Days in Ten Years – Economically Optimal Portfolio



As discussed previously, the wholesale market currently has an abundance of low-cost energy and a small surplus in capacity relative to load which is forecast to be deficit by 2021. NorthWestern can currently capitalize on these market conditions to meet its energy and capacity needs. Finding resources that are capable of meeting NorthWestern's future capacity requirements, as this surplus diminishes due in part to regional coal plant retirements and loss of flexibility in the region, while providing the most economic value to its customers, is a focus of this Plan.