# CHAPTER 7
# RESOURCE ADEQUACY – REGIONAL MARKET

## Resource Adequacy and the Regional Market Impacts

### Background

On February 15, 2002 NorthWestern began providing service to retail customers without any owned generation assets to supply energy and load-serving capacity. Since NorthWestern did not own any generation resources at the time, it was forced to manage a market-based strategy based on purchase power agreements. A concerted program of resource acquisition over the past eight years has greatly reduced our reliance on the market and led to our current focused planning to address specific capacity needs and resource adequacy. Historically the Pacific Northwest has been dominated by excess capacity. However, continued load growth, substantial additions of intermittent wind resources, hydrologic flow restrictions, and planned coal retirements in the Pacific Northwest have reduced reserve margins to the point that the regional planning bodies are now concerned about meeting future capacity needs.

NorthWestern's previous resource plans did not directly address resource adequacy or planning reserve margins for several reasons. First, surplus capacity in the region was available to serve peak needs. Second, prior to the acquisition of the hydro assets, the gap between physical resource peaking capability and peaking resource need was so wide that it would have made the use of traditional capacity planning metrics of resource adequacy essentially meaningless. With the addition of the hydro assets to the resource portfolio, NorthWestern has reduced market dependence, and the gap between physical resource capability and peaking resource needs has been narrowed substantially. However, NorthWestern must still rely upon the market to meet its customers' needs during certain hours, including peak load hours. Use of this strategy in light of current and forecast capacity conditions within the region requires reexamination.

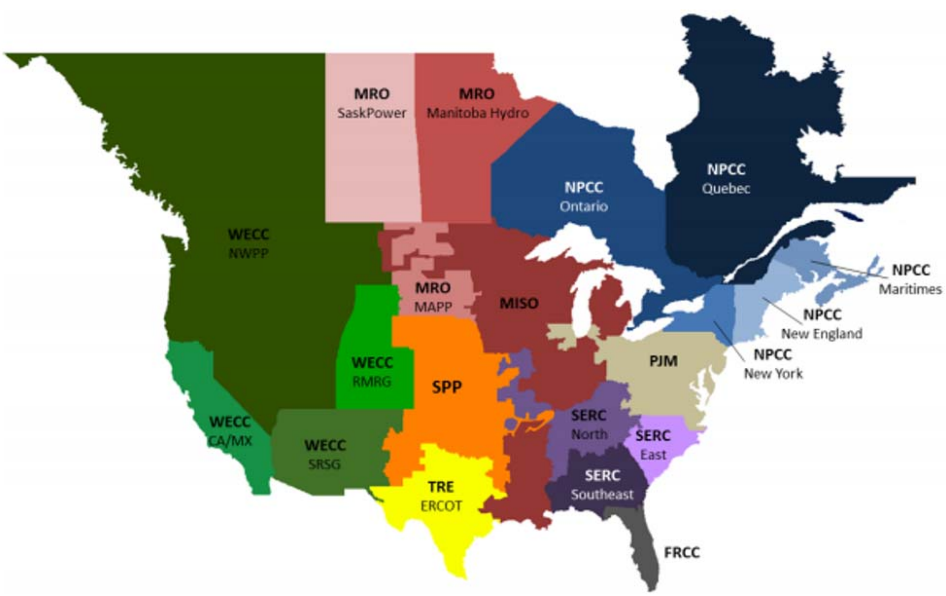
## NERC Resource Adequacy

Within the WECC, there is no industry standard for the level of planning reserve margin a utility must carry, and an examination of different utilities reveals widely varying levels of reserve margins. However, it is clear that nearly all utilities possess at least some level of planning reserve margin. NERC develops and enforces reliability standards and annually assesses seasonal reliability for the North American bulk power system.

NERC Reference Reserve Margin

NERC's Reference Reserve Margin is equivalent to the Target Reserve Margin Level provided by the Regional/sub-regional's own specific margin based on load, generation, and transmission characteristics as well as regulatory requirements. If not provided, NERC assigned 15 percent Reserve Margin for predominately thermal systems and 10 percent for predominately hydro systems.[1]

Figure 7-1 NERC Reliability Assessment Areas




[1] http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx

As shown in Table 7-1, the NERC reference margin level for NWPP-US, the region that includes NorthWestern, is 16.6%.

Table 7-1 NERC Reference Reserve Margin Levels

| NERC ASSESSMENT AREA | NERC Reference Margin Level |
|---|---|
| WECC - Western Electricity Coordinating Council | |
| WECC-NWPP - United States | 16.6% |
| WECC-NWPP - Canada | 11.6% |
| WECC-RMRG | 11.9% |
| WECC-SRSG | 12.3% |
| WECC-CAMX | 13.5% |
| MRO - Midwest Reliability Organization | |
| MISO | 14.3% |
| MRO - Manitoba | 12.0% |
| MRO - MAPP | 15.0% |
| MRO - SaskPower | 11.0% |
| SPP - Southwest Power Pool | 13.6% |
| TRE - Texas Reliability Entity | |
| TRE-ERCOT | 13.8% |
| NPCC - Northeast Power Coordinating Council | |
| Maritimes | 15.0% |
| New England | 16.7% |
| New York | 17.0% |
| Ontario | 19.0% |
| Québec | 11.7% |
| RF - Reliability First - PJM | 16.0% |
| SERC Reliability Corporation | |
| SERC-E | 15.0% |
| SERC-N | 15.0% |
| SERC-SE | 15.0% |
| FRCC - Florida Reliability Coordinating Council | 15.0% |

## Regional Resource Adequacy

In 2013, the NWPCC re-formed the Pacific Northwest Adequacy Forum into the Resource Adequacy Advisory Committee ("RAAC"). The RAAC produces an annual report on the adequacy of the Pacific Northwest power supply. The RAAC's most recent report shows that the region has adequate resources to meet its capacity needs through 2020. RAAC estimates that the likelihood of a power supply shortage in 2020 is just under the 5% LOLP standard set by the NWPPC in 2011. By 2021, the LOLP jumps to over 8% due to the planned retirements of the Boardman and Centralia-1 coal plants (1,330 MW nameplate capacity). The implication of the 8% LOLP is that the region will need to add peaking resources to maintain regional resource adequacy. The NWPCC concluded that the region would have to add 1.15 gigawatts ("GW") of gas-fired generation by 2021 to bring the LOLP back to 5%. Alternatively, the region could add 12.7 GW[2] of solar PV which, when combined with the storage capability of the Pacific Northwest hydropower system, would also bring the LOLP back to 5%. No amount of wind power, even in combination with the Columbia River hydropower system, was found to achieve a 5% LOLP.[3] The work of the RAAC feeds directly into the NWPCC's power planning efforts.

The NWPCC recently adopted the 7th Plan[4]. In prior plans, the primary emphasis was to meet the annual energy requirements of the region. In the 7th Plan, the NWPCC has switched the focus from energy to capacity planning. The future needs of the region can no longer be adequately addressed by only evaluating average annual energy requirements. Planning for capacity to meet peak load and flexibility to provide within-hour load-following and regulation services must also be evaluated and addressed regionally and by NorthWestern specifically.

Historically, NorthWestern has been able to take advantage of regional surplus capacity to maintain resource adequacy. However, as discussed above, the regional capacity surplus is expected to diminish over time and directly impact the supply-demand relationship in the region. NorthWestern as a market taker is at greater risk as the regional capacity surplus

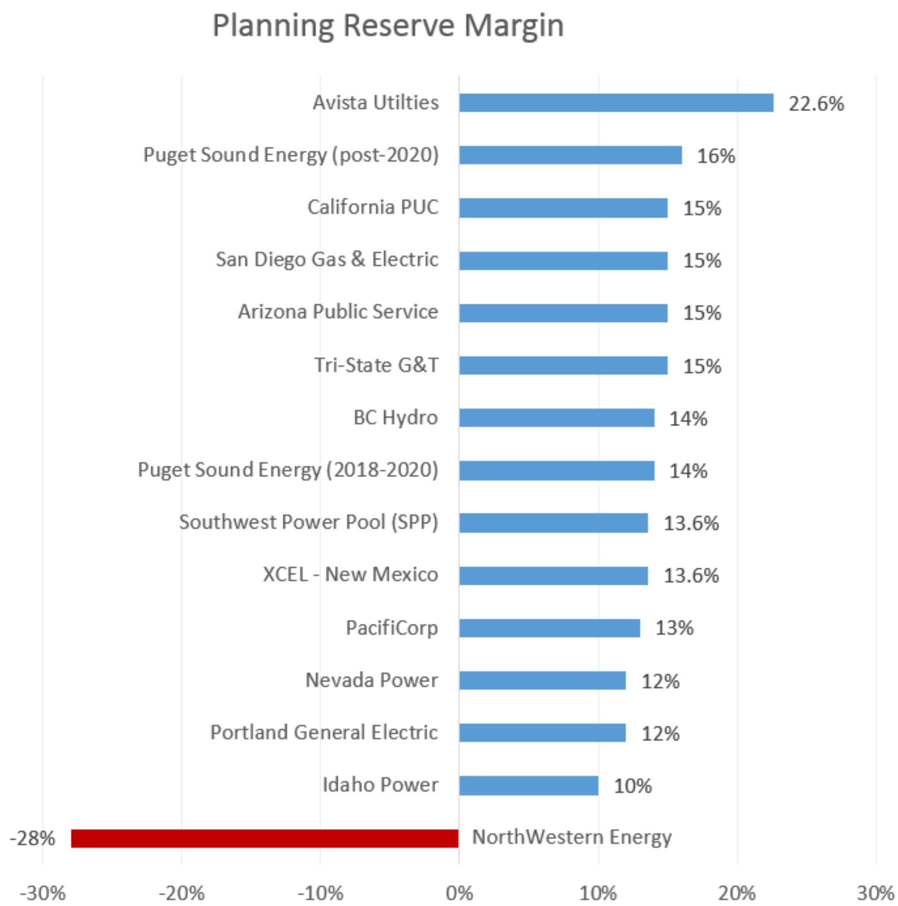
[2] The NWPCC estimated that total installed capacity of solar PV in the U.S. is currently 15.9 GW.

[3] 10 GW of wind power achieved a 6.9% LOLP.

[4] http://www.nwcouncil.org/energy/powerplan/7/plan/

diminishes. Figure 7-2 below shows a range of planning reserve margins for regional utilities and other select entities. NorthWestern's current physical reserve margin, which excludes market, is significantly less than zero. This is not new information, but it does highlight NorthWestern's need to address its current lack of capacity.

## Figure 7-2 Planning Reserve Margins for Selected Power Companies



# Regional Market Development and Regulatory Change

## Energy Imbalance Markets

The development of EIMs in the West has been a topic of discussion and analysis for several years. Despite the reference to "Imbalance," resources in an EIM are dispatched economically regardless of whether there is an imbalance to correct. EIMs share some characteristics of RTOs and ISOs, but there are key differences. The major similarity is that all of these entities operate markets which accept offers and dispatch resources on a sub-hourly basis to meet load requirements. Unlike RTOs and ISOs, EIMs do not provide ancillary services, manage congestion, or administer an OASIS site, and they do not take on reliability responsibility.

The efforts to develop these markets have occurred for both reliability and economic reasons. Both the reliability and economic aspects are driven in large part by the need to integrate increasing amounts of intermittent generation into the portfolios of virtually all utilities in the region. An energy imbalance market would be expected to improve reliability by providing increased region-wide situational awareness to Balancing Authorities ("BAs") and making better use of available generating capacity in the region. It would also be expected to improve economics by efficiently dispatching generators to meet loads across a regional footprint rather than within BAs.

While the individual BAs would retain their reliability responsibility, EIMs typically have resource sufficiency requirements that obligate participating BAs to carry enough capacity to meet their own internal needs. These requirements are designed to keep a participating BA from entering an hour in a capacity- or energy-short position and relying on the EIM to meet its load-serving obligations. Participation in an EIM would help make efficient use of resources, but it would not reduce a BA's need for capacity. Depending on the specifics of the resource sufficiency requirement, participation could drive the need for additional capacity.

Over the last two years, there has been significant progress in the development of these markets. Most notably, PacifiCorp and the California ISO announced, developed, and on October 1, 2014, implemented an EIM for their Balancing Authority Areas (now called the "Western EIM"). NV Energy began participating in the market on December 1, 2015. The CAISO/Pac EIM has reported benefits to customers in excess of $20 million over the first three quarters of the market operation. As of this writing, Arizona Public Service and Puget Sound Energy have plans to join that market in late 2016, and Portland General Electric expects to begin participating in 2017. The NWPP worked toward the development of an EIM for a number of years before pulling back from these efforts in late 2015.

## Regional Transmission Organizations / Independent System Operators

Development of full regional markets has materialized in the West. Currently, there are two ISOs in the WECC: the CAISO and the AESO. CAISO manages the transmission system owned by three large investor-owned utilities in California and operates full day-ahead and real-time markets. In April of 2015, CAISO and PacifiCorp announced a memorandum of understanding to explore the possibility of PacifiCorp becoming a full participating transmission owner ("PTO") in the CAISO.

PacifiCorp engaged a consultant to estimate the benefits of this integration. The benefits were studied in the areas of more efficient unit commitment and dispatch, more efficient over-generation management, lower peak capacity needs, and renewable procurement savings. The preliminary results of the study show the present value of these benefits over a 20-year period of between $3 billion and $9 billion for CAISO and PacifiCorp customers.

Another development of note is related to the Southwest Power Pool ("SPP"). NorthWestern's South Dakota utility, along with a number of other entities including the portion of the Western Area Power Administration's ("WAPA") Upper Great Plains entity located in the Eastern Interconnection joined SPP in October of 2015. NorthWestern's South Dakota operations, WAPA, and several other entities fully participate in the day-ahead and real-time SPP markets (the "Integrated Marketplace"), and their transmission systems are now operated by SPP.

In addition, SPP now acts as the Transmission Service Provider ("TSP") for the portion of WAPA's system located in the Western Interconnection in Montana. The Integrated Marketplace does not extend to this portion of the system, and it is not clear whether an extension of the market footprint to this area would be feasible given the limited transfer capability between the Eastern and Western Interconnections. However, the full implications of SPP's presence in Montana are not known at this time.

## Participation in Organized Markets

NorthWestern continues to assess the development of these markets and the potential for future participation. There are potential benefits – more efficient dispatch, improved reliability and renewable integration – but there are also challenges for NorthWestern's participation. Some of these challenges are as follows:

- Connectivity with the markets;
- Resource sufficiency and resource adequacy requirements;
- Implementation costs and staffing (software, metering, etc.);
- Development risk; and
- Regulatory risk.

NorthWestern must assess if and how its resources would fit with the requirements of these markets. The portfolio optimization efforts that NorthWestern has undertaken (as described elsewhere in this Plan) are aligned with potential participation in an EIM or ISO. However, such participation would potentially place additional requirements on NorthWestern from a resource adequacy perspective and could change the timing of the addition of resources to the portfolio. Participation in an EIM or ISO would also significantly change both market operations and transmission operations for NorthWestern.

Because a significant number of utilities are moving to organized markets, NorthWestern must also be aware of the potential consequences of not joining. Most notably, NorthWestern is evaluating the potential effects on the real-time bilateral markets as more entities join the Western EIM and potentially other markets. While the effects are difficult to measure at this time due to a limited number of parties currently participating in the Western EIM, the results could be significant for NorthWestern. Currently, NorthWestern relies heavily on the real-time market, particularly in times of peak load. A substantial decline in liquidity in the bilateral markets would increase the risk of this approach.

## Real Power Balancing and Reliability Based Control

NorthWestern is also facing changes with regard to reliability standards. In April of 2015, FERC approved NERC Standard Bal-001-2 – Real Power Balancing Control Performance, which replaces Standard Bal-001-1. This standard eliminates Control Performance Standard 2 (“CPS2”) and replaces it with what is sometimes referred to as Reliability Based Control (“RBC”).

Under CPS2, a BA is required to keep its Area Control Error (“ACE”) between bounds in 90% of the 10-minute periods during a calendar month. For NorthWestern, these bounds are approximately +/- 23 MW, so NorthWestern transmission operators need to control the system such that its ACE stays between -23 MW and +23 MW 90% of the time. The new

RBC standard requires a BA to operate such that its clock-minute average of ACE does not exceed its clock-minute Balancing Authority ACE Limit ("BAAL") for more than 30 consecutive clock minutes. Unlike the limits under CPS2, BAALs are not static; they vary based on the frequency in the interconnection.

Beginning on July 1, 2016, NorthWestern will be required to operate to the new standard, with potential penalties for failing to do so. NorthWestern has begun to participate in a field trial, which will allow the company to gain a better understanding of the requirements prior to the July 1 effective date. Based on our analysis to date, we expect that compliance with the new standard will require less frequent intra-hour ramping of generators than was required under CPS2. However, because of the nature of the standard, we expect that our need for capacity – particularly flexible capacity that can ramp up and down on short notice – will be greater than it was under CPS2.