IDAHO POWER®

IRP

INTEGRATED RESOURCE PLAN

2025

APPENDIX D: System Reliability and Regulating Reserves

June 2025

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SYSTEM RELIABILITY MODELING

As utilities continue to add more renewable energy to the electric grid, it is becoming more critical to analyze the effect Variable Energy Resources (VER) and Energy Limited Resources (ELR) have on system reliability.

VER: Variable energy resources include those whose generation is dependent upon weather, for example, solar and wind projects.

ELR: Energy limited resources are those whose generation can be called upon but are only able to dispatch for a limited amount of time and under certain conditions, for example, battery storage projects and demand response programs.

For the 2025 Integrated Resource Plan (IRP), Idaho Power used the risk-based equations and methodologies described in this section to 1) assess resource capacity contribution during system high-risk hours, 2) calibrate system reliability modeling with the Aurora Long-Term Capacity Expansion (LTCE) model and 3) quantitatively analyze the risk associated with all Aurora-produced portfolios.

The 2025 IRP continues to develop and integrate advanced reliability modeling that accounts for the intermittency of VER output, increasing renewable resource saturation, interaction between resource types, and impacts from weather and environmental conditions. Leveraging probabilistic methods, portfolio analyses, and high-resolution data, Idaho Power provides a detailed assessment of resource adequacy and system reliability under a rapidly evolving resource mix.

Methodology

The Loss of Load Probability (LOLP) is the likelihood of the system load exceeding the available generating capacity during a given time period (typically an hour). The LOLP can be calculated by determining the probability the available generation at any given hour is unable to meet the net load during that same hour. The LOLP can be defined as:

$$LOLP = P_i(G_i - L_i)$$

where P_i is the cumulative probability of the available generation required to meet the net system demand at hour i, G_i is the available generation required to meet the net system demand at hour i, and L_i is the net system demand at hour i.

The Loss of Load Hour (LOLH) is the expected number of hours per time period that a system's hourly demand is projected to exceed the generating capacity. The LOLH can be calculated by summing together all LOLP values from a specified time period (typically over the course of a year). The LOLH duration metric can be defined as:

$$LOLH = \sum_{i=1}^{h} LOLP_i$$

where $LOLP_i$ is the LOLP value at hour i and h represents the last hour in the specified time period (i.e., the upper bound of the summation).

The Loss of Load Expectation (LOLE) is the expected number of days per time period for which the available generation capacity is insufficient to serve the demand at least once per day. The LOLE can be calculated by adding the maximum LOLP from each day for a time period (typically over the course of a year). The LOLE frequency metric can be defined as:

$$LOLE = \sum_{d=1}^{D} max[_{i=1}^{H} (LOLP_i)]$$

where $LOLP_i$ is the LOLP value at hour i, H is the hours in the day, and D represents the last day in the specified period (i.e., the upper bound of the summation).

Reliability Thresholds

For the 2025 IRP, Idaho Power continued to use and plan to an LOLE threshold of 0.1 event-days per year (i.e., 1 loss of load event-day in 10 years) where the projected generation capacity is insufficient to meet the forecasted demand.

The power sector has undergone significant transformation in recent decades due to technology, policy, and market shifts, and in response the industry has begun its transition towards the use of multi-metric criteria for assessing resource adequacy. While LOLE focuses on the frequency of shortfall events, a multi-metric framework would allow for the consideration of magnitude, frequency, and duration of shortfall events. Idaho Power is committed to expanding and improving reliability assessments, and for the 2025 IRP the company has evaluated the implementation of a duration metric through the calculation of LOLH. While the LOLE threshold of 0.1 event-days per year is fairly standard across the industry, the company's findings on LOLH have shown entities using a wide range of LOLH thresholds. The company calculated the LOLH results for each portfolio buildout but did not implement a portfolio tuning process for the duration metric and plans to continue to research an appropriate LOLH threshold for its system.

Calculating Effective Load Carrying Capability

The Effective Load Carrying Capability (ELCC) is a reliability-based metric used to assess the capacity contribution of any given generation unit or power plant. ELCC decomposes an individual generator's contribution to the overall system reliability and is driven by the timing of high LOLP hours. To calculate the ELCC of a resource, there are two definitions that should first be stated:

EFORd:	The Equivalent Forced Outage Rate during Demand represents the number of hours a generation unit is forced off-line compared to the number of hours the unit runs; for example, an EFORd of 3% means a generator is forced off 3% of its running time.
Perfect Generator:	A proxy generation unit whose EFORd value is 0%, meaning that it is always available and never forced off-line.

The ELCC of a resource is determined by first calculating the perfect generation required to achieve an LOLE of 0.1 event-days per year. Then, the resource being evaluated is added to the system and the perfect generation required is calculated once again. The ELCC (%) of a given resource will be equal to the difference in the size of the perfect generators from the two runs divided by the resource's nameplate:

$$ELCC\ (\%) = \frac{PG_1 - PG_2}{Resource_{NM}} * 100$$

where PG_1 is the perfect generation required to achieve an LOLE of 0.1 event-days per year without including the evaluated resource, PG_2 is the perfect generation required to achieve the same LOLE of 0.1 event-days per year with the evaluated resource included, and $Resource_{NM}$ is the nameplate of the evaluated resource.

Modeling Idaho Power's System

Idaho Power developed the Reliability and Capacity Assessment Tool (RCAT) to implement the loss of load methodologies and maximize computational efficiency for modeling Idaho Power's existing and potential resource buildout. Within this tool, the company's resources were split into three categories: dispatchable resources, VERs, and ELRs. Dispatchable resources were modeled using a monthly outage table that was calculated using each unit's monthly capacity and corresponding EFORd. The outage table is comprised of the following four components:

Capacity In:	Capacity available to serve load (megawatt [MW])
Capacity Out:	Forced outage capacity (MW)
Individual Probability:	Probability that a specific event will occur
Cumulative Probability:	Cumulative distribution of the individual probabilities

Existing dispatchable resources include hydro with reservoir storage (the Hells Canyon Complex), thermal resources, and various transmission assets with access to the market.

VERs were modeled by using seven years of historical hourly output data to maintain the relationship between load and renewable generation. Other resources for which Idaho Power does not have direct control over dispatch were also modeled using the seven years of historical hourly output data. Examples of these resources include dairy digestors, non-wind and non-solar PURPA projects, run-of-river hydroelectric plants, and geothermal generation. In the model, these variable resources are subtracted from the system-adjusted load to produce a net load that is then used in the loss of load calculations.

Because resources such as battery storage and demand response are dispatched based on the daily load shape, Idaho Power devised a separate way to model ELRs. The RCAT begins by sorting the days in a year from high-to-low based on their net load. After verifying the operating parameters of the demand response portfolio or storage resource are met on that day, the algorithm optimizes the daily dispatch based on the sorted updated net load.

This functionality of the RCAT allows for a detailed approach to modeling Idaho Power's system. As system needs continue to change, analyses such as LOLP are essential in best evaluating the company's reliability and highest-risk hours.

Load Forecast Percentile Selection

Electricity demand, or system load, is not a constant as it changes due to many factors such as weather, economics, behavioral and technological shifts, and system uncertainty. However, the source of variance that is certain to occur within the above list is that the median climatological conditions within the load forecast of Idaho Power's service area will not occur over the course of a year. As such, when forecasting system load, a range of possible outcomes are produced in the form of different percentiles based on historic weather ranges. Further, in recognition of recent extreme load events on the company's system and knowing that a single percentile of load cannot be expected month-over-month every year, Idaho Power used the LOLE methodology to determine which peak load forecast percentile should be used for reliability studies in the 2025 IRP. The analysis steps are as follows:

1. Select a peak load forecast decile as a baseline.
2. Calculate the annual capacity position to meet the 0.1 event-days per year LOLE threshold under the selected peak load forecast decile.
3. Apply the calculated annual capacity position to all other peak load forecast deciles (ranging from 0^{th} decile to 100^{th} decile) and determine the corresponding LOLE.
4. Average the LOLE results across all peak load forecast deciles.
5. Repeat steps 1-4 until the average LOLE that is closest to the 0.1 event-days per year LOLE threshold is found.

Performing this analysis on the 2026 load and resource buildout resulted in the 70^{th} percentile peak load forecast being selected for reliability studies in the 2025 IRP. A comparison of the results when the 50^{th} percentile peak load forecast is set as the baseline and when the 70^{th} percentile peak load forecast is set as the baseline is provided below.

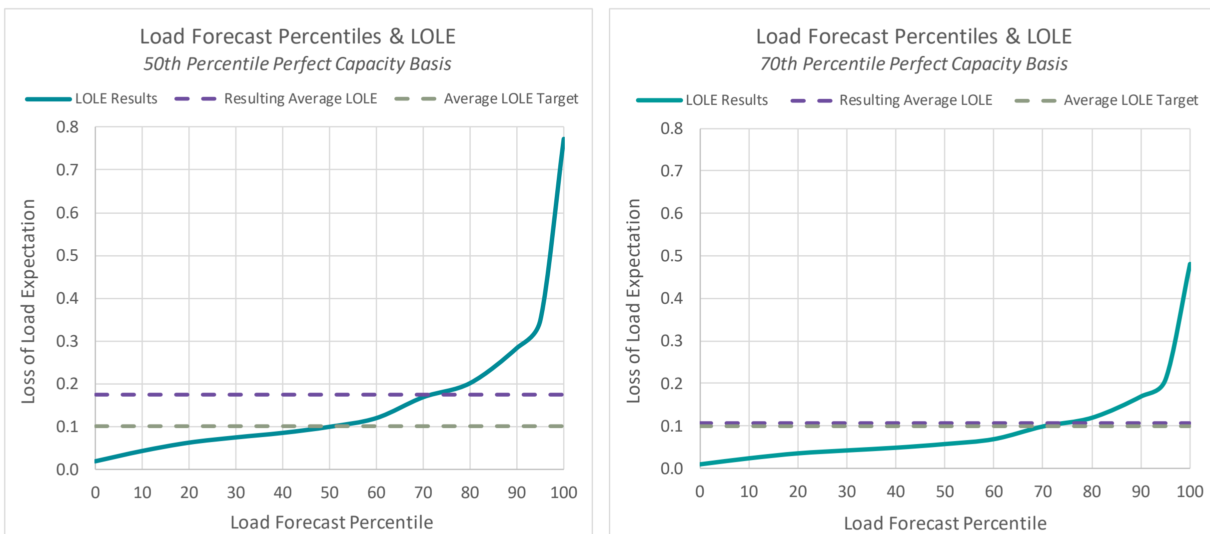

Figure 1. Load forecast percentiles and LOLE

As depicted above, the relationship between LOLE and peak load is non-linear, meaning as the peak load increases, the LOLE rises exponentially. Selecting the baseline peak load forecast percentile that produces an average LOLE across all peak load forecast deciles of approximately 0.1 event-days per year allows the company to better capture the impact of high-risk load levels in corresponding system reliability studies.

Due to the exponential tail of the analysis results, representing increased risk at the higher peak load forecast deciles, the resulting average LOLE suggests a peak load forecast beyond the 50^{th} percentile is best suited for Idaho Power's reliability studies. The selection of the 70^{th} percentile peak load forecast indicates that the system risk at the higher peak load forecast percentiles is significantly higher than the risk at lower peak load forecast percentiles.

Modeling Wildfire Impact

Idaho Power has experienced wildfire-related outages on major tie lines used to import power. The company is fortunate to have diversity in transmission lines, and that diversity will continue to expand in the future with additions to the transmission system. However, given the prevalence of wildfires in the recent past and the increase in proactive de-energization of transmission lines when wildfire encroachment occurs, the company incorporated an adjustment to the availability of certain transmission facilities in the 2025 IRP reliability studies. This wildfire-related adjustment in the RCAT increases the likelihood the transmission facility will be out of service, thus impacting the annual capacity position calculation starting summer 2026 of the portfolio analyses.

Western Resource Adequacy Program Modeling

The Western Resource Adequacy Program (WRAP) is a regional planning and capacity-sharing program that Idaho Power is currently a non-binding participant. Because the WRAP is designed as a program of last resort, Idaho Power continued to assume for the 2025 IRP that it will leverage WRAP only once per year. As Idaho Power gains operational experience with WRAP, the company will develop a more refined understanding of how often it is likely to leverage the WRAP operations program.

To model the benefit of leveraging WRAP once per year in the company's reliability studies, Idaho Power first performed an LOLP analysis on all historical test years of load and resource data and identified the highest-risk day in each historical test year. Using Idaho Power's RCAT, 100 MW of capacity was then added to the resource stack for each of the identified highest-risk days. The 100 MW resource addition represents the amount of capacity leveraged from WRAP.

The 2023 IRP RCAT analysis found that, on average, an additional 100 MW from WRAP on the company's highest-risk day resulted in Idaho Power needing 14 MW *less* perfect generation to meet a 0.1 event-days per year LOLE. In other words, leveraging WRAP to reduce the risk of the highest-risk day each year was the equivalent of avoiding 14 MW of perfect generation. Reconducting the WRAP analysis for the 2025 IRP produced similar results; 14 MW of WRAP capacity benefit was included in the portfolio reliability modeling beginning in 2027—the currently assumed date of binding participation—and continuing each year through the planning period.

Portfolio Analysis

For reliability planning purposes, Idaho Power plans to meet an LOLE threshold of 0.1 event-days per year, which corresponds with a position of capacity length. For the Aurora LTCE model and the RCAT to see similar capacity positions, the company uses the PRM and ELCC inputs to the Aurora LTCE model to calibrate with the RCAT.

PRM: Planning reserve margin is the percentage of expected capacity resources above forecasted peak demand.

ELCC: The effective load carrying capability is a reliability-based metric used to assess the capacity contribution of any given generation unit or power plant.

After Aurora solves for and produces portfolios, the resource buildouts are analyzed with the LOLE methodology and tested to ensure they meet the 0.1 event-days per year reliability hurdle through the calculation of annual capacity positions. This model calibration process is laid out in Figure 2.

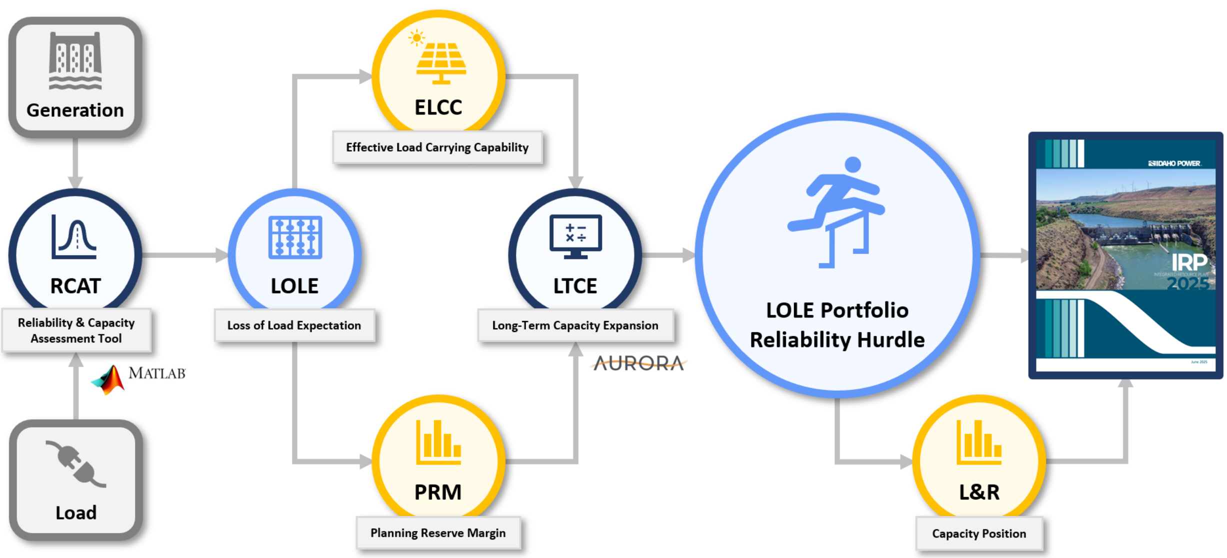

Figure 2. Model calibration process

Historically, the PRM was based on the peak load of a given year plus some additional amount to account for abnormal weather events or equipment outages. This method worked well to ensure reliability for Idaho Power as a summer peaking utility with mostly flexible generation resources. As the company, and the wider industry, continue to increase VER penetration, whose hour-to-hour and season-to-season generation changes, it is no longer viable to only contemplate peak hour requirements.

Aurora and RCAT Calibration

Figure 3. The dance between RCAT and Aurora [1]

To ensure Aurora would recognize similar capacity needs as identified by the RCAT, the company developed minimum seasonal PRM targets for the 20-year planning period. The capacity position calculated to assess reliability is still evaluated on an annual basis because of Idaho Power's 0.1 event-days per year LOLE threshold. Summer and winter PRM values were developed to ensure the dance between RCAT and Aurora resulted in the models seeing similar capacity needs.

In addition, recognizing that the ELCC values of different VERs and ELRs fluctuate by season and change from year-to-year and are dependent on 1) the portfolio resource mix, 2) system saturation, and 3) positive or negative resource diversity benefit, Idaho Power continued to utilize seasonal resource-specific ELCC saturation curves for VERs and ELRs in the 2025 IRP Aurora LTCE model. The Aurora LTCE model used in the 2025 IRP cannot currently calculate the dynamic diversity benefit caused by a changing resource mix. To overcome this limitation, a feedback process was implemented between the Aurora LTCE model and the RCAT. After calculating the LOLE-derived capacity position of a preliminary portfolio resource buildout, ELCC curves were recalculated in the RCAT, and the PRM in the Aurora LTCE model was modified so that both models identified a similar capacity position. The feedback loop continued until both models converged to a similar capacity position.

Annual Capacity Positions

Idaho Power utilized the RCAT to calculate the annual capacity positions of all 2025 IRP Aurora-produced portfolios to ensure the 20-year load and resource buildouts achieved the pre-determined reliability threshold. The annual capacity position is obtained by averaging the resulting size of a perfect generating unit required to achieve a 0.1 event-days per year LOLE from each of the RCAT's seven test years. If the LOLE-derived reliability evaluation found any select portfolio to have one or more years that resulted in a capacity shortfall, the company recalibrated the seasonal PRM points in Aurora and reran the LTCE that would again be tested for reliability.

[1] Image generated by Microsoft Copilot.

The LOLE-derived evaluation is a minimum requirement for portfolios to be considered reliable from a capacity perspective; however, there are other factors that drive resource selections and the resulting annual capacity positions. The Aurora LTCE model can select resources to address regulating reserves, energy requirements and economic conditions. Also, while VERs and ELRs can be added in more granular increments to meet the different Aurora LTCE requirements, other resources (i.e., natural gas units, coal-to-gas conversions, and hydrogen units) must be selected at their identified nameplate capacity and at a specific time. Historically, Idaho Power has been capacity constrained, meaning peak capacity was the driving factor for acquiring resources. However, with the increased penetration of energy storage, energy needs and economics can also drive resource additions.

For Idaho Power's system reliability assessments, a calculated position of capacity length does not represent that the company would have surplus capacity. Surplus capacity implies Idaho Power has extra capacity on the system it could sell at peak, which is not what a position of capacity length represents. The company determines its annual capacity position with the inclusion of firm transmission imports modeled as available 24/7, including transmission that does not have a resource behind it. For reliability studies, Idaho Power uses the term capacity length to indicate there is extra capacity if all firm transmission were used 24/7. For the operations horizon, the company evaluates how many purchases are required to maintain reliability and avoid over-procurement. An identified position of capacity length from the RCAT gives Idaho Power flexibility to procure less resources in the market and maintain reliability but it does not represent surplus capacity that can be sold to the market.

The annual capacity positions for the Preferred Portfolio are provided in Figure 4, that shows an annual position of capacity length for all 20 years of the planning period, thus meeting the company's reliability threshold. All portfolios were tested for reliability and were in a position of capacity length for all 20 years of the planning period.

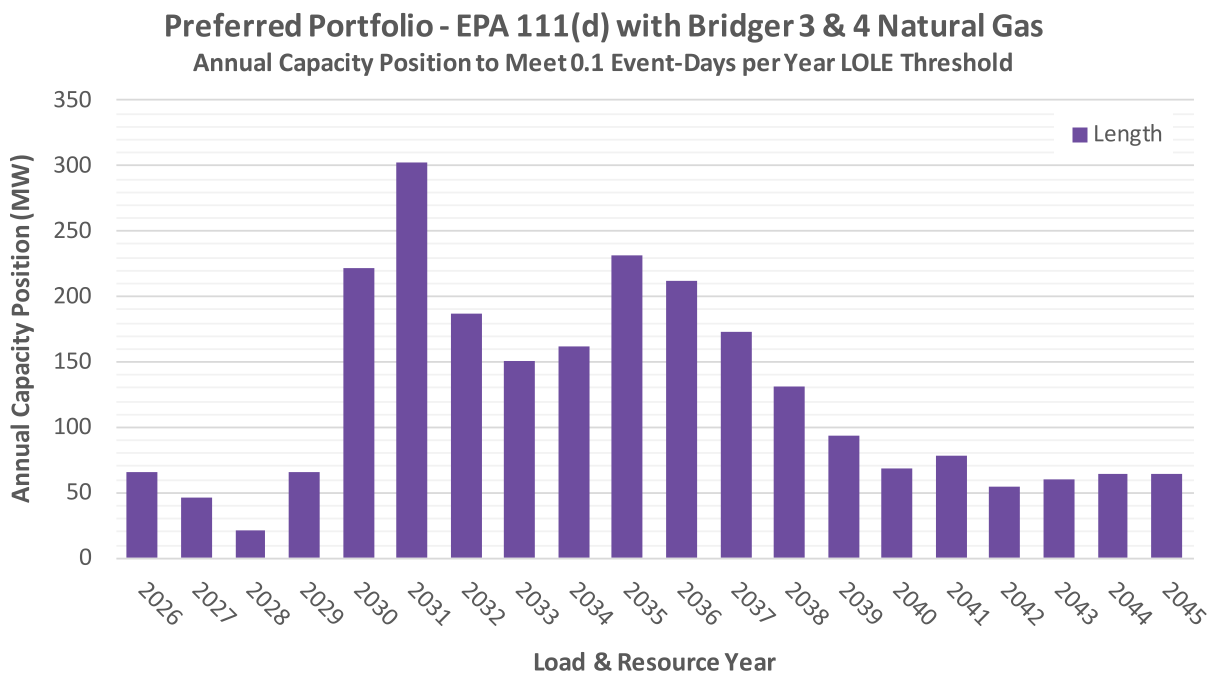

Figure 4. Preferred portfolio annual capacity positions

Effective Load Carrying Capability Snapshot

The ELCC of future VERs and ELRs is dependent upon the resources built before them, making the ELCC calculation of future resources challenging. For the 2025 IRP Aurora LTCE model, Idaho Power continued to utilize seasonal saturation ELCC curves for each type of VER and ELR. The seasonal saturation ELCC curves assist in synchronizing the RCAT and Aurora models in terms of recognizing similar capacity needs and identifying how quickly a particular resource type can become saturated.

The ELCC of future and existing resources can be calculated by using the “last-in” ELCC method, where each resource is assumed to be the last one added to the mix independent of the order they were added to the system. For example, the ELCC of demand response appears to be lower than in past IRPs but it is primarily due to the amount of battery energy storage included in the resource buildout. The average annual last-in ELCC for Idaho Power’s existing resources were calculated based on the 2026 load and resource year; expected resources were calculated based on their corresponding in-service year. The ELCC values of existing and expected resources in the table below are provided for informational purposes.

Table 1. ELCC of existing and expected resources

Resource	Technology	Nameplate	Average ELCC	ELCC Year
Solar (online before 2025)	Solar	576 MW	52.4%	2026
Pleasant Valley Solar	Solar	200 MW	31.2%	2025
PVS2 Solar	Solar	125 MW	31.5%	2026
Blacks Creek Solar	Solar	320 MW	18.4%	2028
Crimson Orchard Solar + BESS	Solar + 4-Hour BESS	100 MW	66.0%	2027
Idaho Wind (online before 2025)	Wind	706 MW	21.1%	2026
Jackalope Wind Project	Wind	600 MW	16.5%	2027
Demand Response Programs	Demand Response	323 MW	19.2%	2026
Battery Storage (online before 2025)	4-Hour BESS	227 MW	97.2%	2026
Happy Valley and Kuna BESS	4-Hour BESS	230 MW	70.4%	2025
Boise Bench	4-Hour BESS	150 MW	44.0%	2026
Hemingway and Boise Bench Expansions	4-Hour BESS	100 MW	36.0%	2026

The average annual last-in ELCC for Idaho Power's future resources were calculated based on the 2029 load and resource year from the Preferred Portfolio resource buildout, as 2029 is the first year that the Aurora LTCE model is allowed to select resources. The ELCC values of future resources in the table below are provided for informational purposes.

Table 2. ELCC of future resources

Resource	Nameplate	Average ELCC
Solar	100 MW	13.9%
Idaho Wind	100 MW	18.7%
Existing Demand Response Program Expansion	20 MW	13.6%
4-Hour Battery Storage	50 MW	33.1%
8-Hour Battery Storage	50 MW	56.6%

Timing of Highest Risk

The calculation of LOLE involves determining the LOLP for each hour, which Idaho Power performs for each of the test years used in the RCAT. The capacity-based hourly LOLP values were used to determine the seasons and hours of highest risk for the 2025 IRP. While the identified timing of highest risk generally captures the company's most critical hours to serve demand, the analysis was specifically designed to inform Demand-Side Management (DSM) avoided costs in the 2025 IRP.

The seasons of highest risk were determined by first selecting the LOLP values that made up a majority of the total hourly risk (i.e., sum of all LOLPs). These LOLPs were then grouped by their time of occurrence to determine the months of highest risk. Historical system load and monthly temperatures were evaluated and used as adjustment factors to create the seasons of highest risk. The seasons of highest risk for the 2025 IRP were identified to be November 15 through February 15 for winter and June 15 through September 15 for summer.

To establish the hours of medium risk, the RCAT was set to select the top LOLP daily hours that resulted in 50% of the risk of each month in the season for each of the test years; the results from the different test years were then combined. The test-year combined top LOLP hours were used to identify the medium risk hours from the low-risk hours.

To establish the hours of highest risk, the modeling assumptions were adjusted and the RCAT was set to select the top LOLP daily hours that resulted in 5% of the risk each month of the season for each test year; the results from the different test years were then combined. The identified highest risk hours were required to be within the band of identified medium-risk hours.

The 2025 IRP hours of high, medium, and low risk by season are provided in Tables 3 through 5.

Table 3. Summer risk hours

	June 15 – September 15							
Hour End	**Sunday**	**Monday**	**Tuesday**	**Wednesday**	**Thursday**	**Friday**	**Saturday**	**Holiday**
1	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR
2	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR
3	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR
4	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR
5	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR
6	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR
7	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR
8	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR
9	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR
10	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR
11	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR
12	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR
13	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR
14	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR
15	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR
16	SLR	SMR	SMR	SMR	SMR	SMR	SMR	SLR
17	SLR	SMR	SMR	SMR	SMR	SMR	SMR	SLR
18	SLR	SMR	SMR	SMR	SMR	SMR	SMR	SLR
19	SLR	SHR	SHR	SHR	SHR	SHR	SHR	SLR
20	SLR	SHR	SHR	SHR	SHR	SHR	SHR	SLR
21	SLR	SHR	SHR	SHR	SHR	SHR	SHR	SLR
22	SLR	SHR	SHR	SHR	SHR	SHR	SHR	SLR
23	SLR	SHR	SHR	SHR	SHR	SHR	SHR	SLR
24	SLR	SLR	SLR	SLR	SLR	SLR	SLR	SLR

SLR: Summer Low Risk

SMR: Summer Medium Risk

SHR: Summer High Risk

Table 4. Winter risk hours

	November 15–February 15							
Hour End	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Holiday
1	WLR	WLR	WLR	WLR	WLR	WLR	WLR	WLR
2	WLR	WLR	WLR	WLR	WLR	WLR	WLR	WLR
3	WLR	WLR	WLR	WLR	WLR	WLR	WLR	WLR
4	WLR	WLR	WLR	WLR	WLR	WLR	WLR	WLR
5	WLR	WLR	WLR	WLR	WLR	WLR	WLR	WLR
6	WLR	WMR	WMR	WMR	WMR	WMR	WMR	WLR
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22	WLR	WMR	WMR	WMR	WMR	WMR	WMR	WLR
23	WLR	WLR	WLR	WLR	WLR	WLR	WLR	WLR
24	WLR	WLR	WLR	WLR	WLR	WLR	WLR	WLR

WLR:	Winter Low Risk
WMR:	Winter Medium Risk
WHR:	Winter High Risk

Table 5. Off-season risk hours

February 16–June 14 and September 16–November 14								
Hour End	**Sunday**	**Monday**	**Tuesday**	**Wednesday**	**Thursday**	**Friday**	**Saturday**	**Holiday**
1	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR
2	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR
3	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR
4	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR
5	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR
6	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR
7	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR
8	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR
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21	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR
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23	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR
24	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR	OFLR

OFLR: Off-Season Low Risk

While the identified seasons and hours capture a majority of the total hourly risk, the magnitude of LOLP values vary. Planning to the 0.1 event-days per year LOLE threshold, the percentage of risk distribution can be visualized through the lens of the monthly LOLE results, as shown in Table 6.

Table 6. Monthly LOLE percentage

Month	LOLE Percentage
January	5.9%
February	0.7%
March	0.0%
April	0.0%
May	0.0%
June	9.0%
July	69.6%
August	4.4%
September	0.3%
October	0.0%
November	8.6%
December	1.5%
Total	**100.0%**

REGULATION RESERVES

The nature of maintaining a reliable electric system with changing demand and VERs is one where constant adjustment is needed to maintain the balance of generation and demand. Regulation reserves are an operating reserve that allows for the system to maintain the balance between generation and load. In general, regulation reserves are held by resources that are in a state where their output can be altered to respond to system imbalances with each type of resource both providing and requiring regulation reserves.

Types of Regulation Reserves

The 2025 IRP considered four distinct types of reserves in its analysis, either explicitly through the modeling effort or, where accounted for in other exercises, implicitly regarding the need to maintain them. When discussing these different regulation reserves, this section attempts to align with the North American Reliability Corporation (NERC) terminology.

Contingency Reserve

The shortest reserve contemplated in the IRP is the contingency reserve. This type of reserve represents the system's ability to quickly recover from the loss of a resource like a generator or transmission line. Within the context of the IRP, contingency reserves are accounted for in the Equivalent Forced Outage Rate during demand (EFORd) and Planning Reserve Margin (PRM).

Regulating Reserve

The next type of reserve accounted for in the IRP is regulating reserve. This reserve product represents the system's ability to rapidly adjust to variability in either demand or generation. Demand regularly fluctuates as customers adjust their consumption for typical reasons. Examples include items like HVAC system cycling and variable industrial processes as well as any other reason a customer might change their consumption rate. On the other side of the demand and generation balance, with the adoption and deployment of VERs, the need to hold regulating reserves for generation has become necessary. For use in this IRP, the regulating reserve product represents the short-term random component of load and VER generation that occurs in time frames of 1-10 minutes. For the 2025 IRP, the determination of regulating reserves for VERs was updated using the recent historical variation in wind and solar generation.

Following Reserve

Following reserves are the resources needed to follow changing load or generation from VER resources hour-to-hour. On typical days, system load varies on an hourly basis because of diurnal weather patterns and for non-weather-related reasons such as when businesses open and close. VER resource output also varies on an hourly basis. For solar resources, the timing of when the sun rises and sets as well as the altitude it achieves causes solar output to vary predictably while cloud cover causes solar variance to change less predictably and much more rapidly. For wind resources, diurnal variance does little to help anticipate typical wind output changes. In all cases, resources must be available to adapt to changing load and VER output.

In the Aurora model, the load forecast accounts for the following reserve anticipated for load. For the following reserve required by VERs, the model handles these reserves with typical generation shapes that include typical hour-to-hour variability.

Ramping Reserve

Related to the following reserve is the ramping reserve. Both account for the hour-to-hour variability of load and VER generation but different components thereof. The ramping reserve is the need to hold reserves to account for the unpredictable nature of wind and solar resources and, to a far smaller extent, load. These resources are held in a state where they can ramp up or down to respond to VER unpredictability. Even with the sophisticated weather prediction capabilities of today's world, there can exist substantial forecast-to-actual variance in weather forecasting. The ramping reserve is the amount of dispatchable generation that needs to be held in reserve to absorb the forecast-to-actual variance for weather dependent resources.

In the modeling, this reserve is accounted for by an input to the model that ensures generation is available to respond based on the historical hour-ahead variance from forecast for VER resources.

Calculation of Reserve Requirements

For the 2025 IRP, an analysis was completed to update the regulating reserve and the ramping reserve requirements. The contingency reserve is handled through the PRM and EFORd inputs and although they have been updated, the methods are consistent with similar recent analyses. VER generation profiles and the load forecast shape were used to account for following reserves and their calculation methods are similar to prior iterations or detailed elsewhere. Thus, the two major updates for calculation methods are related to regulating and ramping reserves with the details discussed below.

Data Sources and Process

Regulating Reserves

Although the calculation methods for wind and solar were the same and will be discussed as such, the calculations were performed independently for each resource type and distinct regulating reserve amounts were used in the 2025 IRP. To calculate the regulating reserve amount for the 2025 IRP, the data that was collected and analyzed was the minute-to-minute generation output for the wind and solar projects on the Idaho Power system. The data for 2023 was collected amounting to nearly 20 million data points. That data was then aggregated and passed through a Savitzky–Golay low-pass filter to remove the high frequency intermittency with the difference between the actual and filtered signal being used to represent the short duration regulating reserve.

Ramping Reserves

As this reserve is meant to account for the unpredictable nature of wind and solar generation due to their dependence on meteorological phenomenon, the data sources used to calculate the ramping reserve requirements were the hourly, hour-ahead solar and wind forecasts. At the time of the analysis, the data was available for the April 1, 2018 through January 21, 2024 period and the full history was used to calculate the historical unpredictability of wind and solar generation. The required ramping reserve amount was calculated as the mean absolute percentage error for the hour-ahead forecasts during periods where generation was greater than 50 MW so as not to overstate the percent error.

Quantification of Diversity Benefits

Through a VER integration study Technical Review Committee (TRC) process, the discussion of diversity benefits became a point of interest. With the help of the TRC, two separate diversity benefits were identified and studied independently. The first category was the geographical diversity benefit (diversity benefit) created through the addition of projects in different regions. For solar resources, having facilities sited over a wide geographical area can increase the predictability and reduce the short-term intermittency of the systems in aggregate because clouds affecting one area may not be affecting a different area. Similarly for wind, a low–pressure system moving through will reach different stations at different times smoothing out the change in wind speeds. Thus, the company endeavored to determine what the current geographical diversity benefit is and if additional projects would increase the future diversity benefit. To perform the analysis, the study analyzed the individual project shapes (20 separate solar and 16 wind projects) and then by generation type, randomly selected combinations of projects and determined their group intermittency. This Monte–Carlo style sampling occurred for random combinations with replacement from a single project up to the total number of projects. The analysis showed there is a diversity benefit based on the current geographical dispersal of solar and wind projects but because there is already significant geographical diversity captured in the system, additional projects within the region will not increase the diversity benefit on the system. Below are graphs showing the results of the analysis.

Figure 5 shows the solar intermittency as a function of the number of projects. The decline in the curve from fewer projects to more projects shows the geographical diversity benefit while the asymptotic behavior on the right shows that there are diminishing returns for the benefit.

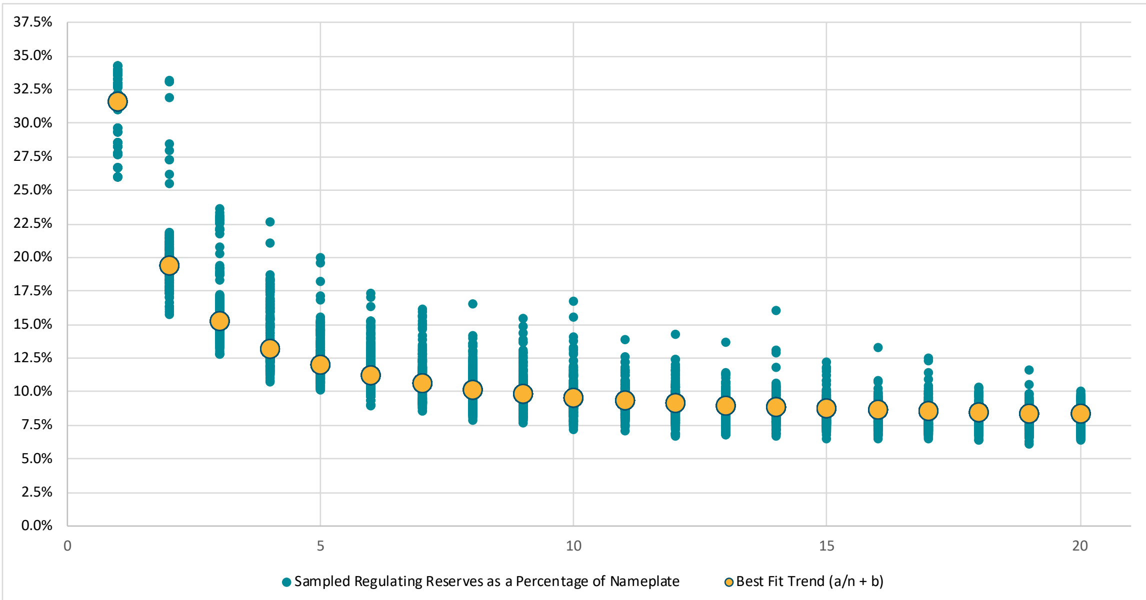

Figure 5. Solar intermittency as a percentage of nameplate by number of projects

Figure 6 shows the wind intermittency as a function of the number of projects. The decline in the curve from fewer projects to more projects shows the geographical diversity benefit while the asymptotic behavior on the right shows that there are diminishing returns for the benefit.

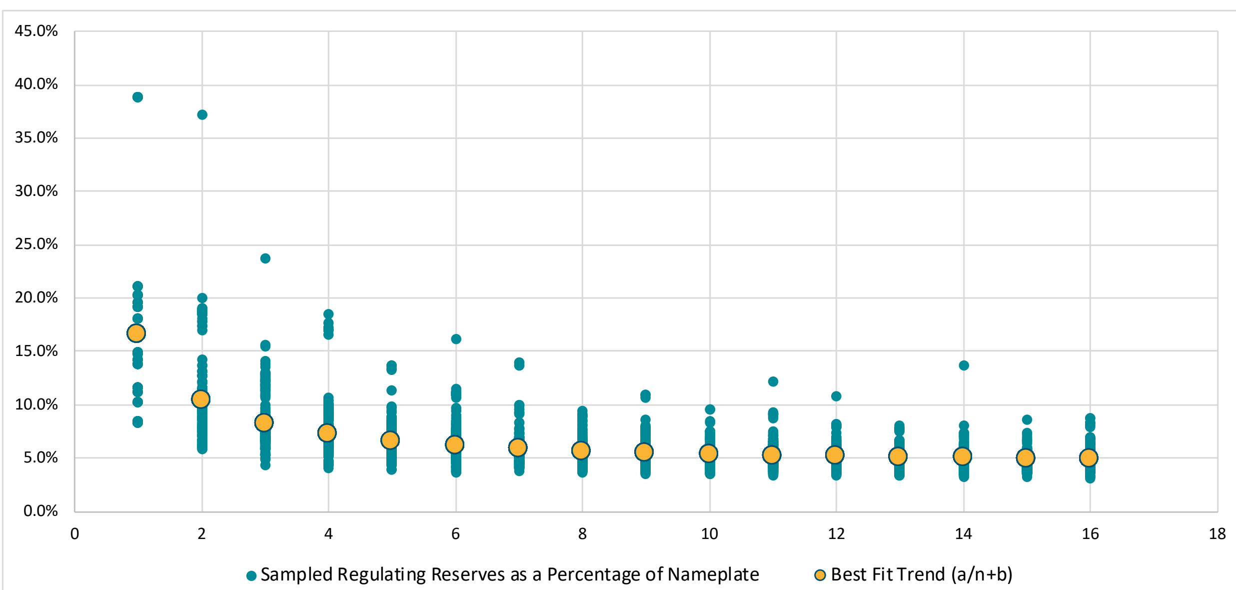

Figure 6. Wind intermittency as a percentage of nameplate by number of projects

The second diversity benefit considered by the study is the portfolio benefit. This analysis was done to determine if there is a benefit to having a mix of wind and solar projects. Logically, in the case of a low-pressure front blowing through, one would expect windy and cloudy conditions to occur. In this way, the decrease in solar generation could be offset by the increase in wind generation. To study this portfolio benefit, the same data as before was used except that wind and solar projects could be drawn together such that all 36 projects were studied concurrently in the Monte–Carlo simulation stage. If there is no portfolio benefit, the trend line would be expected to match the weighted average of the wind and solar trend lines. If there is a portfolio benefit, then one would expect the trend line to beat the weighted average. In doing the analysis, it was found that there is a portfolio benefit when there is a mix of wind and solar resources on the system. The results also showed that this portfolio benefit is already saturated by the projects currently on the system and that additional projects will not provide additional portfolio benefit.

Figure 7 shows the solar and wind intermittency as a function of the number of projects. The decline in the curve from fewer projects to more projects shows the diversity benefit while the asymptotic behavior on the right shows that there are diminishing returns for the benefit. Additionally, the portfolio trend being below the weighted average shows there is a portfolio benefit to a mix of wind and solar projects.

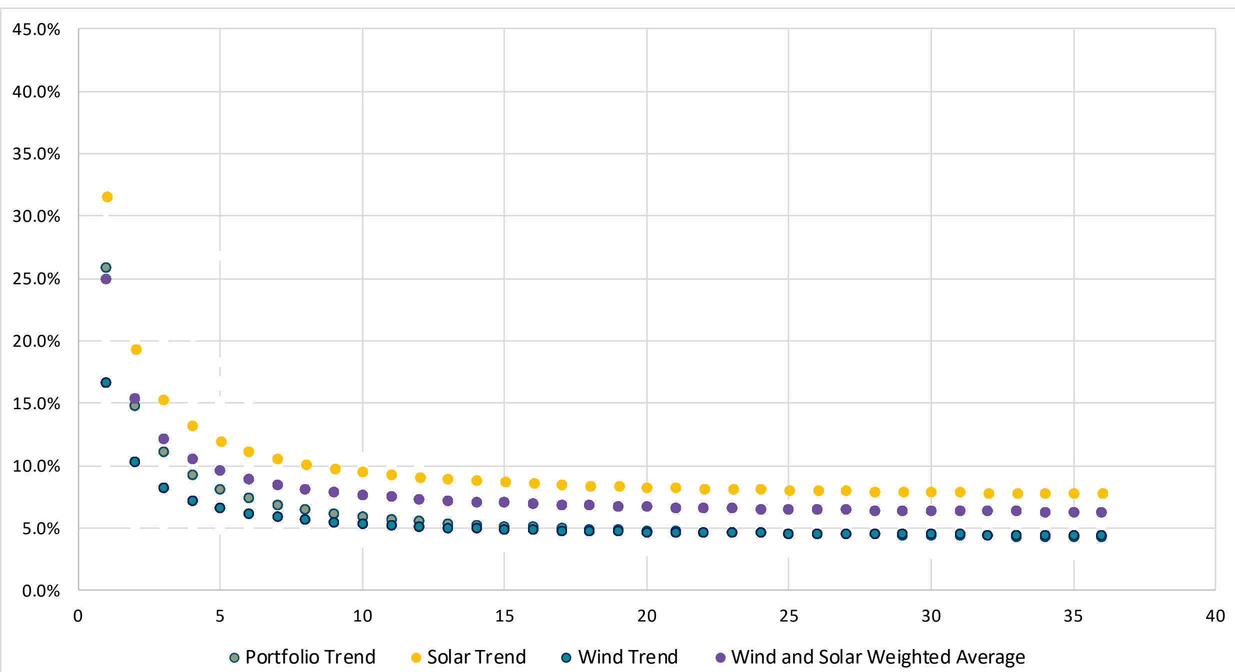

Figure 7. Portfolio intermittency as a percentage of nameplate by number of projects

To account for the portfolio benefit, the standalone wind and solar regulating reserve requirements were reduced proportionally until the weighted average of the reduced amounts matched the portfolio requirements. This allows the reserves to be calculated independently while accounting for the portfolio benefit.

The above methods detail how the regulating reserves were adjusted for the diversity benefit and the portfolio benefit. The TRC process highlighted that there could also be a benefit in the context of ramping reserve. Succinctly, the forecast error for solar generation may offset the forecast error for wind generation such that the combination of both could reduce the overall forecast error. While the hour-ahead generation forecasts are done on an aggregate basis and thus an explicit analysis cannot be done, the evidence for the geographical diversity already being captured based on the regulating reserve is strong. That same evidence pointed to the possibility of a portfolio benefit. To analyze if a portfolio benefit existed for ramping reserves, the wind and solar forecasts were aggregated together and the same analysis to calculate the mean absolute percentage error was performed. That analysis showed there is a portfolio benefit from the mix of wind and solar projects. Similarly, the ramping reserves were adjusted downward on a proportional basis so that the weighted average of the adjusted error matched the portfolio error.

Figure 7 shows the solar and wind mean absolute percentage forecast error by month in orange and blue respectively. The yellow line shows the capacity weighted average. The grey line showing the combined mean absolute error shows that there is a portfolio benefit that makes the aggregation more predictable than the individual parts.

Regulation Reserve Amounts

After the calculations were completed and aggregated, Table 7 shows the amounts of the different regulating reserves used for the 2025 IRP via percentage of hourly load MW, wind MW, and solar MW.

Table 7. Regulating reserves

	% of Load	% of Load	% of Wind	% of Wind	% of Solar	% of Solar
Month	**Spin (10 min)**	**Non-Spin (60 min)**	**Wind Reg (2 min)**	**Wind Ramp (60 min)**	**Solar Reg (2 min)**	**Solar Ramp (60 min)**
January	3.0%	3.0%	10.7%	32.7%	18.9%	36.3%
February	3.0%	3.0%	10.7%	37.2%	18.9%	36.0%
March	3.0%	3.0%	10.7%	37.8%	18.9%	32.9%
April	3.0%	3.0%	10.7%	36.8%	18.9%	27.0%
May	3.0%	3.0%	10.7%	43.8%	18.9%	26.0%
June	3.0%	3.0%	10.7%	37.2%	18.9%	20.7%
July	3.0%	3.0%	10.7%	38.9%	18.9%	16.3%
August	3.0%	3.0%	10.7%	39.9%	18.9%	20.9%
September	3.0%	3.0%	10.7%	40.1%	18.9%	24.2%
October	3.0%	3.0%	10.7%	37.2%	18.9%	29.1%
November	3.0%	3.0%	10.7%	39.3%	18.9%	33.3%
December	3.0%	3.0%	10.7%	36.3%	18.9%	36.3%

Inputs to Aurora Model

Calculated Reserve Amounts by Percentage of Corresponding Load/Generation