# EXHIBIT 36

**Department of Energy**
Washington, DC 20585

**Order No. 202-25-9**

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

*Order Nos. 202-25-3 and 202-25-7*

J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, MI. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[3] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order No. 202-25-3, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until August 21, 2025. Subsequently, Order No. 202-25-7, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until November 19, 2025. Those orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO). Specifically, I determined that MISO likely faced tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety. I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability. My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. §7151(b).
[3] *See Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, Consumers Energy (June 23, 2021), https://www.consumersenergy.com/news-releases/newsrelease-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-cleanenergy-transformation.

Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[4] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[5]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[6] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[7] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. The Palisades plant remains unavailable, although according to a recent news report, "Holtec International expects the Palisades plant in Michigan to resume service early next year…."[8]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."[9]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which include Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[10] While the results "demonstrated sufficient

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[4] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

[5] *Id.*

[6] *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.

[7] *Id.*

[8] *Nuclear plants face decadelong timeline to meet AI energy needs,* Los Angeles Times. (Nov. 13, 2025), https://www.latimes.com/business/story/2025-11-13/despite-80-billion-commitment-nuclear-plants-face-decade-long-timeline-to-meet-ai-energy-needs.

[9] NERC 2025 Summer Reliability Assessment at 16.

[10] *Planning Resource Auction—Results for Planning Year 2025–2026,* Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).

capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and these results "reinforce the need to increase capacity."[11]

***Continuing Emergency Conditions***

The emergency conditions that led to the issuance of Order Nos. 202-25-3 and 202-25-7 continue, both in the near and long term.[12] The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the U.S. Environmental Protection Agency's data, the plant has generated an average of approximately 509,000 MWh per month, from June 2025 through September 2025,[13] providing vital generation capacity to the region. Additionally, between June 11 and November 5, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.

MISO's year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[14] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."[15] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[16]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[17] Among other things, this report described changes in the time of year during

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[11] *Id*. at 2,12. For further information regarding the determination that emergency conditions existed, *see* Order No. 202-25-7.

[12] Further, as noted in Order No. 202-25-7, as a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Consumers were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

[13] *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June, July, August, September." The data can then be filtered to only include the JH Campbell Plant.)*

[14] M*idcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. Midcontinent Independent System Operator, Inc.*,* 180 FERC ¶ 61,141 (2022).

[15] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

[16] Id. at 3-4.

[17] *Attributes Roadmap*, MISO (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf

which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[18]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative."*[19] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[20]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

While the 2025 – 2026 NERC Winter Reliability Assessment has not yet been released as of the date of this Order, two recent winter studies (2024 – 2025 NERC Winter Reliability Assessment[21] and the 2023 – 2024 NERC Winter Reliability Assessment[22]) have assessed the MISO assessment area as an elevated risk, with the "potential for insufficient operating reserves in above-normal conditions." Specifically, the 2024 – 2025 Winter Reliability Assessment noted that "[ge]nerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[23]

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased

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[18] *Id.* at 11.

[19] *MISO's Response to the Reliability Imperative*, MISO (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf

[20] *Id.* at 12.

[21] 2024 – 2025 NERC Winter Reliability Assessment at 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf

[22] 2023 – 2024 NERC Winter Reliability Assessment at 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf

[23] 2024 – 2025 NERC Winter Reliability Assessment at 15, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf

accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[24]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[25] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[26] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[27] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[28]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[29] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[30]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[31] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[32] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are

[24] MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.
[25] *OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf
[26] *Id.* at 2.
[27] *Id.* at 7.
[28] *Id.* at 9
[29] *Id.* at 7, 9.
[30] *Id.*
[31] M*idcontinent Independent System Operator, Inc.,* 192 FERC ¶ 61,064 (2025).
[32] 192 FERC ¶ 61,064 at P 84.

likely to further hinder rapid construction and exacerbate reliability concerns.[33] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-3 and 202-25-7 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[34] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[35] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[36]

The Department's July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[37] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[38] In addition, as just one example,

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[33] *See generally*, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global. "With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."

[34] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliabilityand-security-of-the-united-states-electric-grid/.

[35] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[36] *Id*.

[37] *See also Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[38] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[39]

Grid operators — including MISO itself — have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[40] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[41] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[42]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

## ***ORDER***

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[43] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has

[39] *See Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center*, Data Center Dynamics (August 05, 2025), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-toprovide-1gw-of-power-to-new-hyperscale-data-center/ (quoting Consumers Energy CEO Garrick Rochow).
[40] Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, https://democratsenergycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-mediadocument/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf
[41] *Id.* at 6.
[42] *Id.* at 7.
[43] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-3 and 202-25-7 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the increased demand and determined shortage and serve the public interest under FPA section 202(c).

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until February 17, 2026.[44]

Based on my determination of an emergency set forth above, I hereby order:

A. From November 19, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

[44] 16 U.S.C. § 824a(c)(4).

D. By December 3, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective from 00:00 Eastern Standard Time (EST) on November 19, 2025, and shall expire at 00:00 EST on February 17, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 5:58PM EST on this 18th day of November 2025.

Chris Wright

Chris Wright
Secretary of Energy

cc:

**FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

**Michigan Public Service Commissioners**

Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

# EXHIBIT 37

**Department of Energy**
Washington, DC 20585

**Order No. 202-25-12**

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

## *BACKGROUND*

The R.M. Schahfer Generating Station (Schahfer) is an electric generating facility in Wheatfield, Indiana. Schahfer is owned and operated by Northern Indiana Public Service Company (NIPSCO), a division of NiSource Inc. Schahfer consists of two 129 MW natural-gas fired units and two coal-fired units, Unit 17 (423.5 MW) and Unit 18 (423.5 MW).[3] Unit 17 and Unit 18 began operations in 1983 and 1986 respectively. Unit 17 and Unit 18 are both slated to cease operations in December 2025.[4]

## *EMERGENCY SITUATION*

Midcontinent Independent System Operator, Inc.'s (MISO) year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[5] MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."[6] MISO noted that over 60% of all

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024), https://www.eia.gov/electricity/data/eia860/.
[4] As coal-fired facilities, it would be difficult for the Schahfer Units 17 and 18 to resume operations once they have been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Schahfer were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.
[5] *Midcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).
[6] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

"MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[7]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[8] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[9]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative."*[10] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season:

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[11]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area is at an elevated risk "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[12]

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[13]

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[7] *Id.* at 3-4.
[8] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[9] *Id.* at 11.
[10] MISO, *MISO's Response to the Reliability Imperative* (Updated February 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[11] *Id.* at 12.
[12] *NERC 2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[13] MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[14] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[15] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[16] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[17]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[18] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[19]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[20] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[21] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[22] Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025 and April 8, 2025, underscored the dire energy challenges facing the Nation due to growing

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[14] OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[15] *Id.* at 2.

[16] *Id.* at 7.

[17] *Id.* at 9.

[18] *Id.* at 7, 9.

[19] *Id*.

[20] *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[21] *Id.* P 84.

[22] *See generally*, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025), ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[23] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[24] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[25]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[26]

*ORDER*

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[27] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Schahfer Units 17 and 18 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety. Given the responsibility of MISO to

[23] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.
[24] *Id*.
[25] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.
[26] U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025.07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.
[27] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of Energy. *See* 42 U.S.C. § 7151(b).

identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Schahfer Units 17 and 18 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

To ensure Schahfer Units 17 and 18 will be available if needed to address emergency conditions, Schahfer Units 17 and 18 shall remain in operation until March 23, 2026.

Based on my determination of an emergency set forth above, I hereby order:

A. From December 23, 2025, MISO and NIPSCO, shall take all measures necessary to ensure that Schahfer Units 17 and 18 are available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Schahfer Units 17 and 18 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. NIPSCO is directed to comply with all orders from MISO related to the availability and dispatch of the Schahfer Units 17 and 18.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Schahfer Units 17 and 18 has operated in compliance with the allowances contained in this Order.

C. All operation of Schahfer Units 17 and 18 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Schahfer Units 17 and 18 consistent with this Order. MISO and NIPSCO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. NIPSCO is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Schahfer Units 17 and 18 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Schahfer Units 17 and 18 shall not be considered capacity resources.

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

**Indiana Utility Regulatory Commission**
Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

# EXHIBIT 38

**Department of Energy**
Washington, DC 20585

**Order No. 202-25-13**

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

*BACKGROUND*

The F.B. Culley Generating Station (Culley) is an electric generating facility in Warrick County, Indiana. Culley is owned and operated by CenterPoint Energy and consists of two coal-fired generation units, Unit 2 (103.7 MW) and Unit 3 (265.2 MW), with a combined name plate capacity of 368.9 MW. Unit 2 and Unit 3 began operations in 1966 and 1973, respectively. Unit 2 is slated to cease operations in December 2025.[3]

*EMERGENCY SITUATION*

Midcontinent Independent System Operator, Inc.'s (MISO) year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[4] MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."[5] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[6]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] As a coal-fired facility, it would be difficult for Culley Unit 2 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Culley were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.
[4] *Midcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).
[5] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).
[6] *Id.* at 3-4.

transforming energy landscape."[7] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[8]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative."*[9] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season:

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[10]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area is at an elevated risk "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[11]

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[12]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to

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[7] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[8] *Id.* at 11.
[9] MISO, *MISO's Response to the Reliability Imperative* (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[10] *Id.* at 12.
[11] *NERC 2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[12] MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

which expected capacity resources satisfy planning reserve margin requirements.[13] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[14] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[15] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[16]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[17] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[18]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[19] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[20] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[21] Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

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[13] OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[14] *Id.* at 2.

[15] *Id.* at 7.

[16] *Id.* at 9.

[17] *Id.* at 7, 9.

[18] *Id.*

[19] *Midcontinent Independent System Operator, Inc.,* 192 FERC ¶ 61,064 (2025).

[20] *Id.* P 84.

[21] *See generally*, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, (May 2025), ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, underscore the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump likewise declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[22] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[23] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[24]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[25]

## *ORDER*

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[26] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Culley Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

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[22] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[23] *Id*.

[24] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[25] U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[26] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of Energy. *See* 42 U.S.C. § 7151(b).

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Culley Unit 2 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

To ensure Culley Unit 2 will be available if needed to address emergency conditions, Culley Unit 2 shall remain in operation until March 23, 2026.

Based on my determination of an emergency set forth above, I hereby order:

A. From December 23, 2025, MISO and CenterPoint Energy shall take all measures necessary to ensure that Culley Unit 2 is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Culley Unit 2 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. CenterPoint Energy is directed to comply with all orders from MISO related to the availability and dispatch of Culley Unit 2.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Culley Unit 2 has operated in compliance with the allowances contained in this Order.

C. All operations of Culley Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Culley Unit 2 consistent with this Order. MISO and CenterPoint Energy shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. CenterPoint Energy is directed to file with the Federal Energy Regulatory Commission tariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Culley Unit 2 to comply with applicable state, local, or Federal laws or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Culley Unit 2 shall not be considered a capacity resource.

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

**Indiana Utility Regulatory Commission**
Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

# EXHIBIT 39

# PJM Manual 18:

PJM Capacity Market

Revision: 61

Effective Date: July 23, 2025

Prepared By
Capacity Market & Demand Response Operations

PJM © 2025

# Table of Contents

**Table of Exhibits** ..... 5

**Approval** ..... 6

**Current Revision** ..... 7

**Introduction** ..... 8

About PJM Manuals ..... 8
About This Manual ..... 8
Using This Manual ..... 10

**Section 1: Overview of the PJM Capacity Market** ..... 11

1.1 Overview of the PJM Capacity Market ..... 11
1.2 Participation in the PJM Capacity Market ..... 12
1.3 Definition and Purpose of the Reliability Pricing Model ..... 14
1.4 Implementation of the Reliability Pricing Model ..... 15
1.5 Transition to Capacity Performance ..... 15

**Section 2: Resource Adequacy** ..... 17

2.1 Overview of Resource Adequacy ..... 17
2.2 Role of Load Deliverability in the Reliability Pricing Model ..... 20
2.3 Locational Constraints in the Reliability Pricing Model ..... 21
2.4 Reliability Requirements ..... 24

**Section 3: Demand in the Reliability Pricing Model** ..... 27

3.1 Overview of Demand in the Reliability Pricing Model ..... 27
3.2 Definition and Purpose of the Variable Resource Requirement ..... 28
3.3 Parameters of the Variable Resource Requirement ..... 28
3.4 Plotting the Variable Resource Requirement Curve ..... 34
3.5 Demand Curves in the Incremental Auctions ..... 38

**Section 3A: Integration of Price Responsive Demand** ..... 40

3A.1 Overview of Price Responsive Demand in PJM Capacity Market ..... 40

3A.2 Deleted ..... 42
3A.3 Eligibility Requirements of Price Responsive Demand ..... 42
3A.4 PRD Plan Requirements ..... 43
3A.5 Registration of Price Responsive Demand ..... 48
3A.6 Performance Requirements of Price Responsive Demand ..... 49
3A.7 PRD Bilaterals ..... 54

**Section 4: Supply Resources in the Reliability Pricing Model ..... 56**

4.1 Overview of Supply in the Reliability Pricing Model ..... 56
4.2 Generation Resources ..... 57
4.3 Load Management Products ..... 68
4.4 Energy Efficiency Resources ..... 79
4.5 Qualified Transmission Upgrades ..... 83
4.6 Bilateral Transactions ..... 84
4.7 Resource Portfolio ..... 94
4.8 Credit Requirements ..... 99
4.9 Aggregate Resources ..... 106
4.10 Seasonal Capacity Performance Resources ..... 108

**Section 5: RPM Auctions ..... 111**

5.1 Overview of RPM Auctions ..... 111
5.2 RPM Auction Timeline ..... 112
5.3 RPM Auction Parameters ..... 116
5.4 Sell Offers in RPM ..... 117
5.5 Buy Bids in RPM ..... 137
5.6 Energy Market Offer Requirements ..... 138
5.7 Base Residual Auction ..... 138
5.8 Incremental Auctions ..... 143
5.9 Auction Clearing Results ..... 148
5.10 Reliability Backstop ..... 150

**Section 6: Capacity Transfer Rights ..... 152**
6.1 Definition and Purpose of Capacity Transfer Rights ..... 152
6.2 Determination of Capacity Transfer Rights ..... 156
6.3 Allocation of Capacity Transfer Rights ..... 157
6.4 Capacity Transfer Rights Credits ..... 158
6.5 Capacity Transfer Rights Transfers ..... 158

**Section 7: Load Obligations ..... 159**
7.1 Overview of Load Obligations ..... 159
7.2 Unforced Capacity Obligations ..... 159
7.3 RPM Zonal Scaling Factors ..... 161
7.4 Obligation Peak Load ..... 162
7.5 Daily Unforced Capacity Obligations ..... 163
7.6 Process for Determining Load Obligations ..... 164
7.7 Treatment of Non-Zone Load ..... 164

**Section 8: Resource Performance Assessments ..... 166**
8.1 Overview of Resource Performance Assessments ..... 166
8.2 RPM Commitment Compliance ..... 167
8.3 Commitment Level Used in Summer/Winter Capability Tests (Through the 2024/2025 Delivery Year) ..... 172
8.4 Deleted ..... 174
8.4A Non-Performance Assessment ..... 174
8.5 Summer/Winter Capability Testing ..... 179
8.6 Measuring Compliance during Performance Assessment Interval for Demand Resources ..... 184
8.7 Load Management Test Compliance ..... 187
8.8 Replacement Resources ..... 193

**Section 9: Settlements ..... 197**
9.1 Deficiency and Penalty Charges ..... 197
9.2 Locational Reliability Charges ..... 203
9.3 Auction Credits and Charges ..... 203

9.4 Penalties for Non-Performance of Price Responsive Demand ..... 206

**Section 10: Capacity Exchange ..... 210**

10.1 Overview ..... 210

**Section 11: Fixed Resource Requirement Alternative ..... 212**

11.1 Overview ..... 212
11.2 Load Obligations ..... 215
11.3 Capacity Plan ..... 218
11.4 Supply Resources in the FRR Alternative ..... 221
11.5 Locational Constraints in the FRR Alternative ..... 229
11.6 Conditions on Sales by FRR Entities ..... 230
11.7 Delivery Year Activity ..... 231
11.8 Deficiency Charges & Penalties ..... 231
11.9 Allocation of Deficiency Charges ..... 234
11.10 Auction Specific MW Transactions ..... 234

**Attachment A: Glossary of Terms ..... 235**

**Attachment B: Authorization to Self-Schedule Capacity ..... 250**

**Attachment C: Demand Resource Sell Offer Plan ..... 252**

**Attachment D: Demand Resource Officer Certification Form ..... 257**

**Revision History ..... 258**

## Table of Exhibits

Exhibit 1: Illustrative Example of a Variable Resource Requirement Curve... 37

Exhibit 2: RPM Auction Timeline ..... 112

Exhibit 3: Process for determining Load Obligations..... 164

Exhibit 4: RPM Auction Subsystems ..... 210

## Approval

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Peter Langbein, Manager

Capacity Market and Demand Response Operations

## Current Revision

**Administrative Change (Pete Langbein approved 08/01/2025):**

- Added missing changes from Revision 60 back into Revision 61

**Revision 61 (07/23/2025):**

- Conforming changes were made to the following sections to incorporate provisions of FERC orders (ER25-682) and (ER25-785) and (er24-2995-000).
- 2.4.5 Adjustments to RPM Auction Parameters for EE Resources
- 3.3 Parameters of the Variable Resource Requirement
- 3.3.1 Cost of New Entry
- 3.4 Plotting the Variable Resource Requirement Curve
- 4.7.1 Resource Position for Generation Capacity Resources
- 5.1 Overview of RPM Auctions
- 5.4.1 Resource-Specific Sell Offer Requirements
- 5.4.8.4 Default MOPR Floor Offer Prices
- 8.4A Non-Performance Assessment

# Introduction

Welcome to the ***PJM Manual for PJM Capacity Market***. In this Introduction you will find information about PJM Manuals in general, an overview of this PJM Manual in particular, and information on how to use this manual.

- What you can expect from the PJM Manuals (see “About PJM Manuals”).
- What you can expect from this PJM Manual (see “About This Manuals).
- How to use this manual (see “Using This Manual”).

## About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by PJM for the operation, planning, and accounting requirements of PJM and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- Energy Market
- Regional Transmission Planning Process
- Reserve
- Accounting and Billing
- Administration
- Miscellaneous

For a complete list of all PJM manuals, go to the Library section on PJM.com.

## About This Manual

The ***PJM Manual for PJM Capacity Market*** is one of the PJM reserve manuals. This manual focuses on the capacity markets, including the Reliability Pricing Model and the Fixed Resource Requirement Alternative, and the requirements for resource providers and Load Serving Entities (LSEs) to participate in these markets and their responsibilities as signatories to the Open Access Transmission Tariff, Reliability Assurance Agreement and Operating Agreement of PJM Interconnection, L.L.C.

This manual also refers to other PJM manuals, which define in detail the operating procedures, obligations, reporting requirements, and accounting procedures established to ensure reliable and efficient capacity market operation.

The ***PJM Manual for PJM Capacity Market*** consists of 11 sections and 4 attachments (labeled A through D). Both the sections and the attachments are listed in the table of contents beginning on page 2.

### Intended Audience

The intended audiences for this PJM Manual for PJM Capacity Market are:

- Applicants to the RAA, OA and OATT Operating Agreement of PJM Interconnection, L.L.C.
- Resource providers and those interested in providing adequate Capacity Resources that will be made available to provide reliable service to loads within the PJM Region.
- Load Serving Entities (LSEs) for load served in the PJM Region.
- PJM Members
- PJM staff

### References

There are other PJM documents that provide both background and detail on specific topics. These documents are the primary source for specific requirements and implementation details. This manual does not replace any of the information in those reference documents. The references for the PJM Manual for *PJM Capacity Market* are:

- Control Center and Data Exchange Requirements (M-01)
- Pre-Scheduling Operations (M-10)
- Energy & Ancillary Services Market Operations (M-11)
- Balancing Operations (M-12)
- Regional Transmission Planning Process (14B)
- Generator Operational Requirements (M-14D)
- Energy Efficiency Measurement & Verification (M-18B)
- Load Forecasting & Analysis (M-19)
- Reserve Adequacy Analysis (M-20)
- Reserve Adequacy Analysis (M-20A)
- Rules and Procedures for Determination of Generating Capability (M-21)
- Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis (M-21A)
- Rules and Procedures for Determination of Generating Capability (M-21B)
- Generator Resource Performance Indices (M-22)
- Open Access Transmission Tariff Accounting (M-27)
- Billing (M-29)

## Using This Manual

We believe that explaining concepts is just as important as presenting procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with the “big picture.” Then we present details, procedures or references to procedures found in other PJM manuals.

### What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections and attachments
- An approval page that lists the required approvals and a brief outline of the current revision
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and PJM Member actions
- Attachments that include additional supporting documents, forms, or tables
- A section at the end detailing all previous revisions of this PJM Manual.

**Note:**

Prior to the Transition Date, the Interconnection Service Agreement (ISA) was the form agreement included in the Tariff used to facilitate interconnection to PJM’s transmission system, which used the term “Interconnection Customer” to refer to generation interconnection customers, similar to the Project Developer”. While the ISA is no longer used for interconnection to the transmission system, pre-existing ISAs remain active. On and after the Transition Date, the Generation Interconnection Agreement (GIA) is used as the form agreement included in the Tariff to facilitate interconnection to PJM’s transmission system.

The Tariff defines the Transition Date as the later of: (i) the effective date of PJM’s Docket No. ER22-2110 transition cycle filing seeking FERC acceptance of Tariff, Part VII (Which is January 3, 2023) or (ii) the date by which all AD2 and prior queue window Interconnection Service Agreements or wholesale market participation agreements have been executed or filed unexecuted. Because this section condition happened last, this date establishes the Transition Date.

# Section 1: Overview of the PJM Capacity Market

Welcome to the *Overview of the PJM Capacity Market* section of the ***PJM Manual for the PJM Capacity Market***. In this section, you will find the following information:

- An overview description of the PJM Capacity Market (see “Overview of the PJM Capacity Market”)
- The business rules for participation in the PJM Capacity Markets (see “Participation in the PJM Capacity Market”)
- A definition and purpose of the Reliability Pricing Model (see “Definition and Purpose of the Reliability Pricing Model”)
- The timeframe for implementation of the Reliability Pricing Model (see “Implementation of the Reliability Pricing Model”)
- A summary of the transition to Capacity Performance (see “Transition to Capacity Performance”)

## 1.1 Overview of the PJM Capacity Market

The PJM Capacity Market is designed to ensure the adequate availability of necessary resources that can be called upon to ensure the reliability of the grid. In PJM, the Capacity Market structure, through either the Reliability Pricing Model (RPM) consisting of a Base Residual Auction and three Incremental Auctions for a Delivery Year or the Fixed Resource Requirement (FRR) Alternative, provides transparent information to enable forward capacity market signals to support infrastructure investment. The capacity market design provides a forward mechanism to evaluate the ongoing reliability requirements in a transparent way to provide opportunity for generation, demand response, energy efficiency, price responsive demand, and transmission solutions.

In the PJM Region, the basis for the Capacity Market design is the Reliability Pricing Model (RPM). The goal of RPM is to align capacity pricing with system reliability requirements and to provide transparent information to all market participants far enough in advance for actionable response to the information. In RPM, the fundamental elements to achieve this are:

- Locational capacity pricing to recognize and quantify the locational value of capacity
- Variable Resource Requirement mechanism to adjust price based on the level of resources procured
- Forward commitment of supply by generation, demand resources, energy efficiency resources, and qualified transmission upgrades cleared in a multi-auction structure
- A Reliability Backstop mechanism to ensure that sufficient generation, transmission and demand response solutions will be available to preserve system reliability

The PJM Capacity Market also contains an alternative method of participation, known as the Fixed Resource Requirement (FRR) Alternative. The Fixed Resource Requirement Alternative provides a Load Serving Entity (LSE) with the option to submit a FRR Capacity Plan and meet a fixed capacity resource requirement as an alternative to the requirement to participate in the PJM Reliability Pricing Model (RPM), which includes a variable capacity resource requirement.

Effective with the 2018/2019 Delivery Year, the Capacity Market design was enhanced to recognize two product types for Capacity Resources, Capacity Performance Resources and Base Capacity Resources, to ensure that capacity resources committed to meet the PJM Region's reliability and resource adequacy needs will deliver the promised energy and reserves when called upon in emergencies. The Base Capacity Resource product-type was phased out such that all capacity resources used to meet the PJM Region's reliability and resource adequacy needs are the Capacity Performance Resource product-type effective with the 2020/2021 Delivery Year.

Effective with the 2020/2021 Delivery Year, the Capacity Market design includes the ability to offer Seasonal Capacity Performance Resources directly into the RPM Auction as an alternative to entering into a commercial arrangement to establish and offer an Aggregate Resource. Capacity Market Sellers may submit sell offers of either Summer-Period Capacity Performance Resources or Winter-Period Capacity Performance Resources and the auction clearing optimization algorithm will be designed to clear equal quantities of off-setting seasonal capacity sell offers thereby creating an annual capacity commitment by matching a Summer-Period Capacity Performance Resource with a Winter-Period Capacity Performance Resource.

Unless otherwise specified, the rules presented throughout this Manual are focused on the Reliability Pricing Model. Information on the Fixed Resource Requirement Alternative can be found in ***Section 11 of this Manual*** and on PJM.com.

## 1.2 Participation in the PJM Capacity Market

Participants in the PJM Capacity Market, both Load Serving Entities and resource providers, must comply with all applicable provisions of the PJM Open Access Transmission Tariff, PJM Operating Agreement, and the PJM Reliability Assurance Agreement. PJM Capacity Market participants must be signatories of the appropriate Agreements and Full Members of PJM. All participants must comply with the procedures and requirements as set forth by these agreements and in PJM Manuals.

### 1.2.1 Participation of Load Serving Entities

Participation by Load Serving Entities (LSEs) in the RPM for load served in the PJM region is mandatory, except for those LSEs that have elected the Fixed Resource Requirement (FRR) Alternative and submitted an approved FRR Capacity Plan for their load served in an FRR Service Area. Under RPM, each LSE that serves load in a PJM Zone during the Delivery Year shall be responsible for paying a Locational Reliability Charge equal to their Daily Unforced

Capacity Obligation in the Zone multiplied by the Final Zonal Capacity Price applicable to that Zone. LSEs may choose to hedge their Locational Reliability Charge obligations by directly offering and clearing resources in the Base Residual Auction and Incremental Auctions or by designating self-supplied resources (resources directly owned or resources contracted for through unit-specific bilateral purchases) as self-scheduled to cover their obligation in the Base Residual Auction. Such action may wholly or partially offset an LSE's Locational Reliability Charges during the Delivery Year depending upon how the clearing prices of the resources compare to the Final Zonal Capacity Prices that apply to their unforced capacity obligations.

Participants with Non-Zone Load, as defined in the PJM Agreements, may be included in the Reliability Pricing Model depending if the load that is located outside of the PJM Region is included in the PJM load forecasts and served by generation resources located within the PJM Region. The treatment of Non-Zone Load is described in ***Section 7 of this Manual***.

### 1.2.2 Participation of Resource Providers

Resource providers with Existing Generation Capacity Resources, Planned Generation Capacity Resources, bilateral contracts for unit-specific Capacity Resources, existing Demand Resources, Planned Demand Resources, Energy Efficiency Resources, and Qualifying Transmission Upgrades may participate in PJM's Capacity Market, either in PJM's Reliability Pricing Model or the Fixed Resource Requirement Alternative, if these resources meet the requirements specified in this Manual. Existing generation that is located outside of the PJM market footprint may also be offered into PJM's Capacity Market, either in the Reliability Pricing Model or the Fixed Resource Requirement Alternative, if the external generation meets the requirements specified in the PJM Manuals and PJM Agreements.

Participation is mandatory for resource providers with:

- Available unforced capacity from Existing Generation Capacity Resources located within the PJM market footprint; or
- Bilateral contracts for available unit-specific Capacity Resources that are Existing Generation Capacity Resources located within the PJM market footprint.
- Generation is treated as existing for the purpose of must-offer requirement and mitigation provisions when the generation is (a) in service at the commencement of an RPM Auction or (b) not yet in service but has cleared an RPM Auction for any prior Delivery Year.
- External Generation Capacity Resource with an effective External Resource Must Offer Agreement
- Beginning with the 2025/2026 Delivery Year and subsequent Delivery Years, a Planned Generation Capacity Resource associated with a notice of intent to offer submitted pursuant to Tariff, Attachment DD, section 5.5 shall be required to be offered by the Capacity Market Seller of such resource in the relevant RPM Auction.

Resource providers do have the option to export available capacity outside the PJM market footprint if the generator is exporting per the requirements specified in PJM Manuals and PJM Agreements.

Participation is voluntary for resource providers with:

- External Generation Capacity Resource without an effective External Resource Must Offer Agreement
- Planned Generation Capacity Resource (which includes new Generation Capacity Resources and planned upgrades to Existing Generation Capacity Resources); however, effective with the 2025/2026 Delivery Year, a Planned Generation Capacity Resource must satisfy the requirements of the binding notice of intent in section 4.2.3.1 in order to submit a Sell Offer in an RPM Auction
- Planned External Generation Capacity Resources (which includes new Generation Capacity Resources and planned upgrades to Existing Generation Capacity Resources )
- Existing Demand Resources
- Planned Demand Resources
- Energy Efficiency Resources
- Qualifying Transmission Upgrades.

All participation by resource providers is subject to the market power mitigation rules described in ***Attachment DD, Section 6 of the PJM Open Access Transmission Tariff***.

### 1.2.3 Participation of PRD Providers

PRD Providers may participate in PJM's Capacity Market, either in PJM's Reliability Pricing Model or the Fixed Resource Requirement Alternative. A PRD Provider is a PJM Member that has entered contractual arrangements with end-use customers that satisfy the eligibility criteria for PRD as specified in this Manual.

## 1.3 Definition and Purpose of the Reliability Pricing Model

The Reliability Pricing Model is the PJM resource adequacy construct that ensures that adequate Capacity Resources, including planned and existing Generation Capacity Resources, Energy Efficiency Resources and planned and existing Demand Resources will be made available to provide reliable service to loads within the PJM Region.

The purpose of the RPM is to develop a long term pricing signal for Capacity Resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM is also designed to add stability and a locational nature to the pricing signal. The RPM is a multi-auction structure designed to procure resource and PRD

commitments to satisfy the region's unforced capacity obligation through the following market mechanisms: a Base Residual Auction, Incremental Auctions and a Bilateral Market.

- *Base Residual Auction* - The Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year. The Base Residual Auction (BRA) allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the Load Serving Entities (LSEs) through a Locational Reliability Charge.
- *Incremental Auctions* – At least three Incremental Auctions are conducted after the Base Residual Auction to procure additional resource commitments needed to satisfy potential changes in market dynamics that are known prior to the beginning of the Delivery Year.
    - The First, Second, and Third Incremental Auctions are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments.
    - A Conditional Incremental Auction may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a Locational Deliverability Area to address the corresponding reliability problem.
- *The Bilateral Market* – The bilateral market provides resource providers an opportunity to cover any auction commitment shortages. The bilateral market also provides LSEs the opportunity to hedge against the Locational Reliability Charge. The bilateral market is facilitated through the Capacity Exchange system.

## 1.4 Implementation of the Reliability Pricing Model

The implementation of the Reliability Pricing Model began with the 2007/2008 Delivery Year. PJM's Planning Period is defined as an annual period from June 1 to May 31. The Delivery Year is the Planning Period for which resources are being committed and for which a constant load obligation for the entire PJM region exists. For example, the 2012/2013 Delivery Year corresponds to the June 1, 2012 - May 31, 2013 Planning Period.

The Transition Period of the RPM took place during the 2007/2008 through 2010/2011 Delivery Years.

The steady-state condition of the RPM began with the 2011/2012 Delivery Year. Unless otherwise specified, the rules and time frames presented throughout this Manual are for the steady-state condition of RPM.

## 1.5 Transition to Capacity Performance

Effective with the 2018/2019 Delivery Year[1], PJM introduced Capacity Performance requirement that requires Capacity Resources to meet their commitments to deliver electricity whenever PJM determines they are needed to meet power system emergencies and procured two capacity

product types through RPM Auctions: Capacity Performance Resources and Base Capacity Resources. The Base Capacity Resource product-type was phased out such that only resources that meet the requirements of the Capacity Performance Resource product-type are used to meet the PJM Region's reliability and resource adequacy needs effective with the 2020/2021 Delivery Year.

For a Capacity Resource to qualify as a Capacity Performance Resource product type, the resource must be capable of sustained, predictable operation that allows the resource to be available throughout the entire Delivery Year to provide energy and reserves whenever PJM determines an emergency condition exists. Internal and external Generation Capacity Resources, Capacity Storage Resources, and Aggregate Resources that can qualify as Capacity Performance Resource product type, Demand Resources that meet Capacity Performance DR product type requirements, Energy Efficiency resources that provide permanent, continuous load reduction during both summer and winter peak seasons in accordance with the Capacity Performance EE product type requirements, and Qualifying Transmission Upgrades are eligible to offer as the Capacity Performance product-type. Resources that clear and have a Capacity Performance Resource Commitment are subject to Non-Performance Assessment during the relevant Delivery Year in accordance with ***Section 8.4A of this Manual***.

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[1] For FRR Entities, Capacity Performance and Base Capacity resources are effective for the 2019/2020 Delivery Year. Limited DR, Extended Summer DR, and Annual Resources remain effective for FRR Entities through the 2018/2019 Delivery Year. Capacity Performance Resources are solely effective for 2020/2021 Delivery Year.

# Section 2: Resource Adequacy

Welcome to the *Resource Adequacy* section of the ***PJM Manual for the PJM Capacity Market***. In this section, you will find the following information:

- An overview description of resource adequacy (see “Overview of Resource Adequacy”)
- The role of load deliverability in the Reliability Pricing Model (see “Role of Load Deliverability in the Reliability Pricing Model”)
- The business rules for Locational Constraints in the Reliability Pricing Model (“see Locational Constraints in the Reliability Pricing Model”)
- The definitions of Reliability Requirements (see “Reliability Requirements”)

## 2.1 Overview of Resource Adequacy

The purpose of PJM RTO resource adequacy is to determine the amount of Capacity Resources that can be required to serve the forecast load and satisfy the PJM reliability criterion. PJM performs an assessment of resource adequacy each year for an eleven-year future period. The analysis considers load forecast uncertainty, forced outages of Generation Capacity Resources, as well as planned and maintenance outages. In PJM, studies are performed using the installed capacity values of resources. The reliability value of a resource depends on two variables: the installed capacity of the resource and a measure of the probability that a resource will not be available due to forced outages or forced de-ratings. The reliability criterion is based on Loss of Load Expectation (LOLE) not exceeding one occurrence in ten years. The resource requirement to meet the reliability criterion is expressed as the Installed Reserve Margin (IRM) as a percentage of forecast peak load.

### 2.1.1 Installed Reserve Margin

The Installed Reserve Margin (IRM) for the Delivery Year is the measure calculated to establish the level of installed capacity resources that will provide an acceptable level of reliability consistent with the PJM Reliability Principles and Standards. The IRM is determined by PJM in accordance with the ***Resource Adequacy Analysis Manual (M-20) and (M-20A).***

**Note:**
The Installed Reserve Margin (IRM) is approved by the PJM Board of Managers no later than 75 days in advance of Base Residual Auction for the Delivery Year and posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website. An Updated IRM is approved by the PJM Board of Managers and posted one month prior to its use in an Incremental Auction for the Delivery Year. The Updated IRM that is posted for the Third Incremental Auction for the Delivery Year is the final IRM for the Delivery Year.

### 2.1.2 Peak Load Forecasts

PJM produces peak load forecasts for use in the RPM auction clearing processes and for planning purposes. In RPM, the load forecasts will be used to determine the RTO Reliability Requirement. PJM will determine ***annual peak load forecasts*** for the RTO and zones for use in the RPM Auction clearing process.

The RTO Peak Load Forecast and the Zonal Peak Load Forecasts for the Delivery Year are determined by PJM in accordance with the ***Load Forecasting and Analysis Manual (M-19).***

**Note:**
The Preliminary RTO and Zonal Peak Load Forecasts are determined and posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website .

Updated RTO and Zonal Peak Load Forecasts are posted no later than one month prior to the First and Second Incremental Auctions.

The ***Final RTO and Zonal Peak Load Forecasts*** are posted no later than one month prior to the Third Incremental Auction.

Load forecasts are also used in the determination of other planning and auction parameters such as Capacity Emergency Transfer Limit (CETL), Capacity Emergency Transfer Objective (CETO), Capacity Import Limits, and RPM Zonal Scaling Factors. These parameters are discussed in detail in later sections of this Manual.

#### 2.1.3.1 Pool-wide Average EFORd (Through 2024/2025 Delivery Year)

To account for the forced outage rates of generation capacity resources, an Equivalent Forced Outage Rate (EFORd) for each generating unit in the PJM RTO is calculated. Equivalent Demand Forced Outage Rate (EFORd) is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate. See ***Generator Resource Performance Indices Manual (M-22)*** for equations and details.

The Pool-wide Average EFORd for the Delivery Year is the average of the EFORd values based on five years history, weighted for unit capability and expected time in service, attributable to all units that are expected to be in service during the Delivery Year. The Pool-Wide Average EFORd includes forced outage events that are outside management control (referred to as OMC events). The Pool-wide Average EFORd is determined by PJM in accordance with the ***Resource Adequacy Analysis Manual (M-20).***

**Note:**
The ***Pool-wide average EFORd*** is posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website. An updated Pool-wide average EFORd is posted one month prior to its use in an Incremental Auction for the Delivery Year. The Pool-wide average EFORd that is posted for the Third Incremental Auction for the Delivery Year is the final pool-wide average EFORd for the Delivery Year.

#### 2.1.3.2 Pool-wide average Accredited UCAP Factor (Starting 2025/2026 Delivery Year)

The Pool-wide average Accredited UCAP Factor for the Delivery Year is the ratio of the total Accredited UCAP to total installed capacity of all resources, as determined pursuant to RAA, Schedule 9.2, that are included in the determination of the Forecast Pool Requirement, stated in percent. The Pool-wide average Accredited UCAP Factor is determined by PJM in accordance with the Resource Adequacy Analysis Manual (M-20A).

**Note:** The **Pool-wide average Accredited UCAP Factor** is posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website. An updated Pool-wide average Accredited UCAP Factor is posted one month prior to its use in an Incremental Auction for the Delivery Year. The Pool-wide average Accredited UCAP Factor that is posted for the Third Incremental Auction for the Delivery Year is the final Pool-wide average Accredited UCAP Factor for the Delivery Year.

### 2.1.4 Forecast Pool Requirement

While IRM multiplied by peak load forecasts provides the installed capacity required to meet the reliability criterion, the Forecast Pool Requirement (FPR) multiplied by peak load forecasts provides unforced capacity values, required to meet the reliability criterion.

The Forecast Pool Requirement is the measure determined for the specified Delivery Year to establish the level of unforced capacity (UCAP) that will provide an acceptable level of reliability consistent with PJM Reliability Principles and Standards.

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For Delivery Years through the 2024/2025 Delivery Year, the Forecast Pool Requirement (FPR) for the Delivery Year is equal to (1 + Installed Reserve Margin) times (1-Pool-wide Average EFORd).[2]

$$ForecastPoolRequirement(FPR) = (1 + InstalledReserveMargin)* (1 - PoolWideAverageEFORd)$$

[2] The terms in this equation are expressed in decimal form.

Starting with the 2025/2026 Delivery Year and for all subsequent Delivery Years, the Forecast Pool Requirement (FPR) for the Delivery Year is equal to (1 + Installed Reserve Margin) times (Pool-wide average Accredited UCAP Factor).

$$ForecastPoolRequirement(FPR) = (1 + InstalledReserveMargin) * (Pool-wide\ average\ Accredited\ UCAP\ Factor)$$

**Note:**
The ***Forecast Pool Requirement (FPR)*** is approved by the PJM Board of Managers by no later than 75 days in advance of Base Residual Auction for the Delivery Year and posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website . An Updated FPR is approved by the PJM Board of Managers and posted one month prior to its use in an Incremental Auction for the Delivery Year. The Updated FPR that is posted for the Third Incremental Auction for the Delivery Year is the final FPR for the Delivery Year.

### 2.1.5 Effective Load Carrying Capability and ELCC Resources in Capacity Exchange

Effective Load Carrying Capability (ELCC) establishes the Accredited UCAP value for ELCC Resources. Through the 2024/2025 Delivery Year, an ELCC Resource is a Generation Capacity Resource that is a Variable Resource, a Limited Duration Resource, or a Combination Resource. Beginning with the 2025/2026 Delivery Year, an ELCC Resource includes all Generation Capacity Resources and Demand Resources. ELCC analyzes historical hourly weather and load shapes relative to hourly output of ELCC Resources in order to quantify the ability of such resources to satisfy the reliability criterion. The ELCC method is described in **Manual 20 and Manual 20A** (**PJM Resource Adequacy Analysis**), and the calculation of Accredited UCAP for an ELCC Resource is described in **Manual 21A** (**Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis**) **and Manual 21B (Rules and Procedures for Determination of Generating Capability)**.

## 2.2 Role of Load Deliverability in the Reliability Pricing Model

The process of determining the Installed Reserve Margin (IRM) that meets the PJM reliability criterion assumes that the internal RTO transmission is adequate and any generation can be delivered to any load without transmission constraints. This process helps in determining the minimum possible IRM for the RTO. However, since transmission may have limitations, after IRM is determined, a Load Deliverability analysis is conducted. The RTO is divided into different sub-regions for this analysis. These sub-regions are referred to as Locational Deliverability Areas (LDAs) in the Reliability Pricing Model.

The first step in the Load Deliverability analysis is to determine the Capacity Emergency Transfer Objective (CETO) of each LDA which is used to determine the amount of generation required to meet the locational reliability standard. For more details regarding the CETO analysis, please see ***Resource Adequacy Analysis Manual (M-20) and M20A.***

The second step in Load Deliverability analysis is to determine the transmission import capability limit for each LDA using the transmission analysis models. For this analysis, a Transmission Upgrade including transmission facilities at voltages of 500 kV or higher that is in an approved Regional Transmission Expansion Plan ("Backbone Transmission") will be included in the system model only if it satisfies the project development milestones set forth in the tariff. This import capability limit is called Capacity Emergency Transfer Limit (CETL), expressed in megawatts and valued as unforced capacity. For more details regarding CETL analysis, please see ***Manual 14B: Regional Transmission Planning Process, Attachment C: PJM Deliverability Testing Methods*.**

If CETL value is less than CETO value, transmission upgrades are planned under the Regional Transmission Expansion Planning Process (RTEPP). However, higher than anticipated load growth and unanticipated retirements may result in the CETL value being less than CETO value with no lead time to build transmission upgrades to increase CETL value. These conditions could result in locational constraints in the RTO.

## 2.3 Locational Constraints in the Reliability Pricing Model

When a capacity market does not have the ability to price capacity on a locational basis, all the resources in the market are valued equally. When this occurs, it is possible to have excess reserves in the RTO and relatively low capacity prices. This market signal will result in generation capacity retirements. In some areas of the RTO these retirements will create reliability violations. These conditions will indicate that a higher value for resources is required to be recognized in constrained locations to incent existing generating capacity to remain in service, and new capability to be built in the form of generation resources, demand resources, energy efficiency resources, or merchant transmission upgrades. One of the key features of RPM is the recognition of locational value of capacity.

Locational Constraints are localized intra-PJM capacity import capability limitations (low CETL margin over CETO) that are caused by transmission facility limitations or voltage limitations that are identified for a Delivery Year in the PJM Regional Transmission Expansion Planning Process (RTEPP) prior to each Base Residual Auction. Such locational constraints are included in the RPM to recognize and to quantify the locational value of capacity within the PJM region.

**Note:**
CETOs and CETLs for the LDAs to be modeled in all RPM Auctions for the Delivery Year are posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website. Updated CETOs and CETLs for the modeled LDAs are posted one month prior to its use in an Incremental Auction for the Delivery Year.

### 2.3.1 Locational Deliverability Areas

In the development of the Reliability Pricing Model, the RTEP Process identified 27 sub-regions referred to as Locational Deliverability Areas for evaluating the locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

The 27 LDAs (highlighted in boldface) and an LDA's relationship to an immediate parent LDA are listed below:

- RTO=> **Western PJM**
- RTO => Western PJM => **ComEd**
- RTO => Western PJM => **AEP**
- RTO => Western PJM => **Dayton** (may be listed as DAY)
- RTO => Western PJM => **Duquesne** (may be listed as DLCO or DUQ)
- RTO => Western PJM => **APS**
- RTO => Western PJM => **ATSI**
- RTO => Western PJM => ATSI => **Cleveland** (may be listed as ATSI-Cleveland)
- RTO => Western PJM => **DEOK**
- RTO => Western PJM => **EKPC**
- RTO => Western PJM => OVEC
- RTO => **Dominion (**may be listed as DOM)
- RTO => **MAAC**[3]
- RTO => MAAC => **WMAAC**[4]
- RTO => MAAC => WMAAC => **MetEd**
- RTO => MAAC => WMAAC => **PPL** (may be listed as PL)
- RTO => MAAC => WMAAC => **Penelec** (may be listed as PENLC)
- RTO =>MAAC => **EMAAC**[5]
- RTO => MAAC => EMAAC => **AE (**may be listed as AECO)
- RTO => MAAC => EMAAC => **PSEG** (may be listed as PS)
- RTO => MAAC => EMAAC => PSEG => **PSEG northern region** (may be listed as PSEG N or PSNORTH)
- RTO => MAAC => EMAAC => **PECO**
- RTO => MAAC => EMAAC => **JCPL**

3 MAAC LDA represents the Mid-Atlantic Region (MAR).

4 WMAAC LDA represents the Western Mid-Atlantic Region (WMAR)

5 EMAAC LDA represents the Eastern Mid-Atlantic Region (EMAR)

- RTO => MAAC => EMAAC => **DPL**
- RTO => MAAC => EMAAC => DPL => **DPL southern region (**may be listed as DPL S or DPLSOUTH)
- RTO => MAAC => EMAAC =>RECO
- RTO => MAAC => **SWMAAC**[6]
- RTO => MAAC => SWMAAC => **BGE**
- RTO => MAAC => SWMAAC => **PEPCO**

### 2.3.2 Constrained Locational Deliverability Areas (LDAs)

An LDA with Capacity Emergency Transfer Limit (CETL) less than 1.15 times Capacity Emergency Transfer Objective (CETO) will be modeled as a constrained LDA in RPM. In addition, an LDA will be modeled if (a) such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; (b) such LDA is determined by PJM to likely have a Locational Price Adder based on historic offer price levels; and (c) EMAAC, SWMAAC, and MAAC LDAs will be modeled as constrained LDAs regardless of the outcome of the above tests. PJM may decide to model the LDA as a constrained LDA regardless of the outcome of the above tests if there are other reliability concerns. A Reliability Requirement and a Variable Resource Requirement Curve will be established for each constrained LDA to be modeled in the RPM Base Residual Auction. See Section 2.4, 3, and 5 of this Manual for the details on Reliability Requirement, Variable Resource Requirement Curve, and RPM Auctions, respectively. The constrained Locational Deliverability Areas that will be modeled for a particular Delivery Year with their Reliability Requirements and the VRR Curves will be posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website.

If an LDA clears with a Locational Price Adder in any Base Residual Auction, PJM shall perform an analysis to determine if any new generation, new demand resource or Qualifying Transmission Upgrades were cleared in that LDA in such Base Residual Auction. New generation or new demand resources include incremental upgrades to existing resources beyond historic installed capacity levels or new resource installations. If any LDA has a Locational Price Adder and if no new generation, new demand resource or Qualifying Transmission Upgrades have cleared in the LDA for two consecutive Base Residual Auctions, then PJM shall evaluate a transmission upgrade as part of the RTEPP that would reduce the Locational Price Adder to zero.

The evaluation of such transmission upgrade shall include an evaluation of the cost of the upgrade as compared to the incremental benefit of reducing Locational Price Adder to zero in the LDA. If the transmission upgrade is feasible and cost beneficial over the next ten year period, then the transmission upgrade shall be included in the Regional Transmission

6 SWMAAC LDA represents the Southwest Mid-Atlantic Region (SWMAR).

Expansion Plan as soon as possible. The annual costs of such upgrade shall (1) be allocated across zones based on each zone's pro-rata share of load in such LDA and (2) within each zone to all LSEs serving load in the LDA, pro rata based on such loads.

### 2.3.3 Creation of New Locational Deliverability Areas (LDAs)

A prudent planning practice is to continuously monitor system performance and study transmission constraints as they develop. Triggers and criteria to consider a new LDA are specified in ***Manual 14B:PJM Regional Transmission Planning Process, Attachment C, PJM Deliverability Testing Methods***, based on RTEP Market Efficiency Analysis and RTEP Long Term Planning. PJM will make a filing with FERC to amend RAA Schedule 10.1 to add a new LDA (including a new LDA that is an aggregate of Zones), if such new area is projected to have a CETL less than 1.15 times the CETO of the area, or if warranted by other reliability concern. In addition, any Party may propose, and PJM would evaluate, possible LDAs under such standards.

## 2.4 Reliability Requirements

In the PJM Capacity Market, reliability requirements, or reserve requirements, represent the target level of reserves required to meet PJM Reliability Standards and Principles. It is important to note that the Installed Reserve Margin (IRM) and the Forecast Pool Requirement (FPR) represent the level of reserves required, but are expressed in different capacity values. The IRM is expressed as the **installed capacity** reserve as a percent (e.g. 15%) of the forecast peak load, whereas the FPR (e.g., 1.079) when multiplied by forecast peak load provides the total **unforced capacity** required.

In the RPM clearing process, the Reliability Requirements for the RTO and the LDA are used to establish the target reserve levels, valued as unforced capacity that will be cleared in the RPM Auctions.

The final Reliability Requirements, used in the clearing of RPM Auctions, will be adjusted to account for entities that have elected the Fixed Resource Requirement Alternative and for EE Resources as described in Section 2.4.5 of this manual. Therefore, when known, the Unforced Capacity Obligations for FRR entities will be removed from the calculation of the Reliability Requirements for the RTO and any LDAs. Reliability Requirements for the region and for any affected LDA are further adjusted for PRD proposed in an approved PRD Plan or committed following an RPM Auction.

### 2.4.1 PJM Region Reliability Requirement

The PJM Region Reliability Requirement, valued in unforced capacity terms, is the RTO Peak Load Forecast, multiplied by the approved Forecast Pool Requirement for the PJM Region, less the sum of Preliminary Unforced Capacity Obligations of the FRR Entities in the PJM Region, plus any necessary adjustment for EE Resources per Section 2.4.5 of this manual, and less any

necessary adjustment for PRD proposed in an approved PRD Plan or committed following an RPM Auction.

$$RTORelReq =$$

$$\left(RTOPeakLoadForecast * FPR\right) - \Sigma\, PrelimUCapOblig_{FRR\ Entity} + Adj_{EE} - Adj_{PRD}$$

### 2.4.2 Reliability Requirement in Locational Deliverability Areas

The Locational Deliverability Area Reliability Requirement is the projected internal capacity[7] (in UCAP terms) in the LDA plus the Capacity Emergency Transfer Objective (CETO) for the Delivery Year, as determined by the RTEP process, less the minimum internal resources (in UCAP terms) required for the FRR Entities located in the LDA, plus any necessary adjustment for EE Resources per Section 2.4.5 of this manual, and less any necessary adjustment for PRD proposed in an approved PRD Plan or committed in any RPM Auction for PRD located in the LDA.

$$LDARelReq =$$

$$(LDAInternalCapacity + LDACETO -$$

$$MinInternalResources_{FRR\ Entity}) + Adj_{EE} - Adj_{PRD}$$

### 2.4.3 Deleted

### 2.4.3A Deleted

### 2.4.4 Adjustments to RPM Auction Parameters for PRD

After PRD Providers propose PRD commitments in their PRD Plans, and PJM reviews and accepts those commitments, PJM will use the resulting PRD values to reduce the reliability requirement to be satisfied for the region and for any affected Zones (or sub-Zonal LDAs). The reliability requirement will be reduced by the quantity of UCAP that would have been procured on behalf of the PRD load but that is now not needed due to the PRD loads' commitment to reduce consumption. The Reliability Requirement of the RTO and each affected LDA will be reduced by a quantity equal to the Nominal PRD Value multiplied by the FPR. These reliability requirement reductions will be considered in the development of the RTO/LDA Variable Resource Requirement Curves as explained in Section 3.4 of this manual.

[7] See Manual 20: PJM Resource Adequacy Analysis and Manual 20A.

### 2.4.5 Adjustments to RPM Auction Parameters for EE Resources (through the 2025/ 2026 Delivery Year only)

An Energy Efficiency (EE) Resource is a project that involves the installation of more efficient devices/equipment, or the implementation of more efficient processes/systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a permanent, continuous reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the EE Resource is proposed. Because energy efficiency measures are reflected in the peak load forecast for a Delivery Year for which an auction is being conducted, the auction parameters must be adjusted as described below for the EE Resource(s) that are proposed for that auction in order to avoid double-counting of the energy efficiency measures.[8]

For each auction, the Reliability Requirement of the RTO and each affected LDA will be increased by the total UCAP Value of all EE Resource(s) for which PJM accepted an EE M&V Plan for that auction, and upon which PJM created an EE Resource to be offered into that upcoming auction.[9] If a first-pass auction solution clears fewer EE Resource MW than the amount by which the Reliability Requirement of the RTO and each affected LDA was increased, the Reliability Requirement increase of the RTO and each affected LDA will be reduced such that it is set equal to the cleared EE MW quantity of the first-pass auction solution and the auction will be solved again. This step is repeated until the cleared EE Resource MW across the RTO equals the total EE Addback MW quantity of the RTO or until the sum of squares of the differences across all LDAs increases relative to the previous iteration. The RTO/LDA reliability requirement increases will be considered in the development of the RTO/LDA VRR Curves as explained in Section 3.4 of this manual.

[8] Effective for RPM Auctions conducted after January 2016.

[9] The increase in Reliability Requirement is accomplished in each BRA by shifting the VRR Curve of the RTO and each affected LDA to the right by the MW quantity of the increase. The increase in Reliability Requirement is accomplished in each IA by the submittal of a PJM Buy Bid in each affected LDA with the buy bid MW quantity set equal to the increase.

# Section 3: Demand in the Reliability Pricing Model

Welcome to the *Demand in the Reliability Pricing Model* section of the ***PJM Capacity Market Manual***. In this section, you will find the following information:

- An overview description of demand in the Reliability Pricing Model (see "Overview of Demand in the Reliability Pricing Model")
- The definition and purpose of the Variable Resource Requirement (see "Definition and Purpose of the Variable Resource Requirement")
- The parameters of the Variable Resource Requirement (see "Parameters of the Variable Resource Requirement")
- The method for plotting the Variable Resource Requirement Curve (see "Plotting the Variable Resource Requirement Curve")
- A description of the demand curves in the Incremental Auctions (see "Demand Curves in the Incremental Auction")

## 3.1 Overview of Demand in the Reliability Pricing Model

In the Reliability Pricing Model, the demand for installed capacity reserve is met when supply is procured as a function of the clearing of the RPM Auctions. A demand curve is defined in advance of each RPM Auction.

In the Base Residual Auction, the demand curve is downward sloping and based on the variable resource requirement concept. In RPM, a variable resource requirement is defined as a function of price. The variable resource requirement is a family of price/quantity points that provide a specified price for various levels of resources procured relative to the Installed Reserve Margin. If the price exceeds the limit on the VRR, then the quantity of resources that is procured may be less than the IRM requirement. Alternatively, if the price is low, additional resources may be procured at a level greater than the IRM requirement. The cost of the supply that is procured at the clearing price will be allocated to the Load Serving Entities. Therefore, a variable resource requirement curve will reflect the reality that additional capacity above a target installed reserve margin nevertheless has value.

There are at least four sources of this value:

1. One source of value is that in the face of uncertain load growth, weather, and capacity availability, the probability of available capacity being less than what is required to meet load and operating reserves never reaches zero, even for large reserve margins. Thus, reserves beyond the target are valuable for reducing the risk of capacity shortfalls.
2. The second source of value is that the slope of the curve can lessen the risk of large suppliers being pivotal or otherwise able to exercise market power.

3. A third source of value is that excess resources can reduce the frequency and duration of scarcity energy prices in the system and provide energy savings to Load Serving Entities.
4. The fourth source of value is the reduction in capacity price volatility and the resulting investment risk to capacity resources, in particular to the generating resources. Lower investment costs would tend to reduce capacity prices

## 3.2 Definition and Purpose of the Variable Resource Requirement

As mentioned in the previous section, the Variable Resource Requirement Curve is a demand curve used in the clearing of the Base Residual Auction that defines the price for a given level of Capacity Resource commitment relative to the applicable reliability requirement. Variable Resource Requirement Curves are defined for the PJM Region and each of the constrained LDAs within the PJM region.

The purpose of the Variable Resource Requirement concept is to recognize the value of excess resources above the reliability requirement and provide revenue to resources. The price on the Variable Resource Requirement is higher when the resources are less than the reliability requirement and lower when the resources are in excess.

## 3.3 Parameters of the Variable Resource Requirement

Prior to the clearing of the Base Residual Auction, Variable Resource Requirement Curves are defined for the PJM Region and each of the constrained Locational Delivery Areas (LDAs) within the PJM region that are to be modeled in the auction. The Variable Resource Requirement Curves for the PJM Region and each Locational Delivery Area (LDA) are based on the following parameters defined prior to the RPM Auctions:

- A target level of reserve
- Cost of New Entry
- Net Energy & Ancillary Services (E&AS) Revenue Offset
- The Nominal PRD Value and PRD Reservation Prices that have been elected

The initial posting of the Variable Resource Requirement Curves will be based on no adjustments related to FRR Entities' Preliminary Unforced Capacity Obligations. A later posting of the Variable Resource Requirement Curves with the FRR adjustments will be made shortly after the approval of the FRR Capacity Plans for the RPM Auction Delivery Year considering any changes in the FRR elections for RPM Auction.

**Note:**
The parameters of the Variable Resource Requirement Curve (i.e., RTO and LDA Reliability Requirements, Cost of New Entry, and Net E&AS Revenue Offsets) will be posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website.

The Variable Resource Requirement Curve for the PJM Region is based on a target level (i.e., the PJM Region Reliability Requirement ), Cost of New Entry, and Net Energy & Ancillary Services (E&AS) Revenue Offset.

For each LDA, the LDA Variable Resource Requirement Curve is based on a target level (i.e., the LDA Reliability Requirement ), Cost of New Entry, and Net E&AS Revenue Offset.

Inclusion of Variable Resource Requirement Curves in the Base Residual Auction clearing may result in the level of resources being committed for a Delivery Year exceeding the applicable PJM Region Reliability Requirement or the LDA Reliability Requirement , if the total cost of resource procurement for the PJM Region or LDA is lower at the higher level of reliability than it would be at the target level and the associated Variable Resource Requirement Curve price.

### 3.3.1 Cost of New Entry

The value for Cost of New Entry (CONE) (in ICAP terms) is determined in accordance with Attachment DD of the Open Access Transmission Tariff (OATT), Section 5.10 (a) (iv). The Reference Resource is a combustion turbine (CT) generating station, configured with a single General Electric Frame 7HA turbine as defined in the OATT.

The gross Cost of New Entry values for the following four CONE Areas for the 2022/2023 Delivery Year are specified in the OATT, Attachment DD, Section 5.10 (a) (iv)(A). :

1. AE, DPL, JCPL, PECO, PSEG, RECO (“CONE Area 1”);
2. BGE, PEPCO (“CONE Area 2”);
3. AEP, APS, COMED, DAYTON, DLCo, ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”); and
4. METED, PENELEC, PPL (“CONE Area 4”).

For the 2023/2024 Delivery Year, the gross CONE values specified in the OATT for the 2022/2023 Delivery Year shall be adjusted to reflect changes in generating plant construction costs based on changes in the applicable United States Bureau of Labor Statistics (BLS) Composite Index, and then adjusted further by a factor of 1.022 to reflect the annual decline in bonus appreciation scheduled under federal tax law, to establish the CONE values used in the development of the Variable Resource Requirement Curves for the PJM Region and the modeled LDAs for all RPM Auctions for the 2023/2024 Delivery Year.

The applicable BLS Composite Index for a Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Index for Construction Materials and Components (weighted 55%), and the BLS Producer Price Index for Turbines and Turbine Generator Sets (weighted 25%). The Quarterly Census of Employment and Wages for Utility System Construction will be based on the state of New Jersey for CONE Area 1, Maryland for CONE Area 2, Ohio for CONE Area 3, and Pennsylvania for CONE Area 4.

For subsequent Delivery Years, up to and including the 2025/2026 Delivery year, the Benchmark CONE values for all CONE areas except CONE area 5 will be the CONE values used in the development of the Variable Resource Requirement Curves for the prior Delivery Year. The applicable BLS Composite Index for the Delivery Year will be applied to the Benchmark CONE values, and then multiplying the result by 1.022, to establish the CONE values for such Delivery Year for CONE areas 1 through 4 listed above.

For the 2025/2026 Delivery Year, a new CONE Area 5 encompassing only the ComEd Zone shall be established and the ComEd Zone will be removed from CONE Area 3. For the 2025/2026 Delivery Year, the Cost of New Entry for CONE Area 5 will be equal to the product of the Cost of New Entry determined for CONE Area 3 for the 2025/2026 Delivery Year multiplied by an asset life factor of 1.0069.

Through the 2024/2025 Delivery Year, the gross Cost of New Entry value for the PJM Region shall be the average of the gross CONE values for the four CONE Areas listed above. For the 2025/2026 Delivery Year, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for all five CONE Areas.

The gross Cost of New Entry values for the following five CONE Areas for the 2026/2027 Delivery Year are specified in the OATT, Attachment DD, Section 5.10 (a) (iv)(C):

1. AE, DPL, JCPL, PECO, PSEG, RECO ("CONE Area 1");

2. BGE, PEPCO ("CONE Area 2");

3. AEP, APS, DAYTON, DLCo, ATSI, DEOK, EKPC, Dominion, OVEC ("CONE Area 3"); and

4. METED, PENELEC, PPL ("CONE Area 4").

5. COMED ("CONE Area 5")

For the 2026/2027 Delivery Year and subsequent Delivery Years, the gross Cost of New Entry value for the PJM Region shall be the average of the gross CONE values for the five CONE Areas. For the 2027/2028 Delivery Year, the gross CONE values specified in the OATT for the 2026/2027 Delivery Year for each CONE Area (except for CONE Area 5) shall be adjusted to

reflect changes in generating plant construction costs based on changes in the applicable United States Bureau of Labor Statistics (BLS) Composite Index to establish the CONE values used for the 2027/2028 Delivery Year for CONE Areas 1 through 4.

The applicable BLS Composite Index for a Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 40%), the BLS Producer Index for Construction Materials and Components (weighted 45%), and the BLS Producer Price Index for Turbines and Turbine Generator Sets (weighted 15%). The Quarterly Census of Employment and Wages for Utility System Construction will be based on the state of New Jersey for CONE Area 1, Maryland for CONE Area 2, Ohio for CONE Area 3, and Pennsylvania for CONE Area 4.

For subsequent Delivery Years, the Benchmark CONE values for all CONE areas except for CONE Area 5 will be the CONE values used in the development of the Variable Resource Requirement Curves for the prior Delivery Year. The applicable BLS Composite Index for the Delivery Year will be applied to the Benchmark CONE values to establish the CONE values used for such Delivery Year for CONE Areas 1 through 4.

For the 2027/2028 Delivery Year through and including the 2029/2030 Delivery Year, the CONE for CONE Area 5 for a given delivery year shall be set equal to the product of the CONE of CONE Area 3 as determined for the relevant Delivery Year, multiplied by the asset life factor applicable to that Delivery Year where such asset life factors are 1.0376 for the 2027/2028 Delivery Year, 1.0581 for the 2028/2029 Delivery Year, and 1.0818 for the 2029/2030 Delivery Year.

### 3.3.2 Net Energy and Ancillary Services Offset

Pursuant to Attachment DD, Section 5.10(a)(v and v-1 ) of the PJM Tariff, PJM determines a Net Energy and Ancillary Services (E&AS) Revenue Offset for the PJM Region and for each Zone.

**For Delivery Years 2023/2024 through and including 2025/2026**

The Net E&AS Revenue Offset for the PJM Region for a Delivery Year is (a) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the Base Residual Auction for such Delivery Year plus (b) an assumed value for ancillary services revenues ($/MW-year) as set forth in Attachment DD, Section 5.10(a)(v) of the PJM Tariff.

The annual average of energy revenues for the PJM Region is based on (1) heat rate and other characteristics of such Reference Resource; (2) daily natural gas prices averaged across the fuel pricing points specified in the table below with a fuel transmission adder appropriate for the PJM region; (3) assumed variable operation and maintenance expenses for such Reference

Resource as set forth in Attachment DD, Section 5.10(a)(v) of the PJM Tariff; (4) actual PJM hourly average LMP prices recorded in the PJM Region during such period; and (5) an assumption that the Reference Resource would be dispatched for both Day-Ahead and Real-Time Energy Markets on Peak-Hour Dispatch basis.

The Net E&AS Revenue Offset for each Zone for a Delivery Year is determined using the same procedures and methods used to determine the Net E&AS Revenue Offset for the PJM Region; provided, however, that (1) actual hourly average LMPs for such Zone shall be used in place of the PJM Region hourly average LMPs; and (2) daily natural gas prices at the fuel pricing points specified in the table below in this section 3.3.2 with a fuel transmission adder appropriate to the zone.

Peak-Hour Dispatch means, for purposes of calculating the energy revenues in the Energy and Ancillary Services Revenue Offset, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

**For the 2026/2027 Delivery Year and subsequent Delivery Years**

The Net E&AS Revenue Offset for the PJM Region for a Delivery Year is the annual average of the revenues that the Reference Resource is projected to receive from the PJM energy and ancillary service markets from three separate simulations, with each simulation using forward prices shaped using historical data from one of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such shapes. The projected Net E&AS Revenue Offset will be determined for the PJM Region and each Zone as specified in Attachment DD, Section 5.10(a)(v-1) of the PJM Tariff

The annual average of energy revenues for the PJM Region is based on (1) heat rate and other characteristics of such Reference Resource; (2) forward daily natural gas prices averaged across the fuel pricing points specified in the table above with a fuel transmission adder appropriate for the PJM region; (3) assumed variable operation and maintenance expenses for such Reference Resource; (4) Forward Hourly LMPs for the PJM Region; (4) Forward Hourly Ancillary Services Prices; and (5) an assumption that the Reference Resource would be dispatched on a Projected EAS Dispatch basis.

Projected EAS Dispatch means, for purposes of calculating the Net Energy and Ancillary Services Revenue Offset, a simulated dispatch with the objective of committing and dispatching a resource for the purpose of maximizing its net revenues. The calculation shall take inputs including Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and Forward Daily Natural Gas Prices or forecasted fuel prices, as applicable, in addition to the operating parameters and costs of the specific resource, including the cost emission allowances. Using operating parameters, forward or forecasted fuel prices, as applicable and other cost pricing inputs, a composite, cost-based energy offer is created for the resource such that its commitment and dispatch is co-optimized between energy and ancillary services in the Day-Ahead Energy Market and then the Real-Time Energy Market considering the electricity and ancillary service price inputs. In the Real-Time Energy Market co-optimization, the resource is assumed to be operating in the hours it was scheduled in the Day-Ahead Energy Market but is dispatched according to the real-time price inputs. In the hours where the resource was not committed in the Day-Ahead Market, the resource may be committed and dispatched in real-time only subject to the real-time electricity and ancillary service price inputs and the resource's offer and operating parameters.

The Net E&AS Revenue Offset for each Zone is determined using the same procedures and methods used to determine the Net E&AS Revenue Offset for the PJM Region; provided, however, that (1) Forward Hourly LMPs of each such Zone are used in place of the Forward Hourly LMPs of the PJM Region; and (2) forward daily natural gas prices are used for each such Zone based on the fuel price point to Zone mapping shown in the table below.

The Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and Forward Daily Natural Gas Prices used in the calculation of the Net E&AS Revenue Offset are determined as defined in Attachment DD, Section 5.10(a)(v-1) of the PJM Tariff.

In the determination of Forward Hourly LMPs, the ComEd Zone is mapped to N. Illinois Hub, the AEP, ATSI, DAY, DEOK, DUQ, EKPC and OVEC Zones are mapped to the AEP-Dayton Hub, and all other Zones are mapped to the Western Hub. In addition, several of the fuel pricing points of the table below lack sufficient liquidity and are therefore mapped to more liquid hubs for the purposes of calculating Forward Daily Natural Gas Prices. For the purpose of calculating Forward Daily Natural Gas Prices, Transco-Z6 (non-NY) is used in place of Transco-Z5 Dlv and Transco-Z6 (NY)

**Zone to Fuel Pricing Point Mapping**

The fuel pricing point used for the purpose of establishing the Net E&AS Offset for each Zone is provided in the table below.

| Zone | Fuel Pricing Point |
|---|---|
| AE, BGE, DPL, & JCPL | Transco-Z6 (non-NY) |

| Zone | Fuel Pricing Point |
|---|---|
| COMED | Chicago Citygates |
| DUQ, METED, PECO, & PPL | TETCO M3 |
| PEPCO & DOM | Transco Z5 DIv |
| AEP, OVEC | Columbia-Appalachia TCO |
| DAY, DEOK, ATSI, EKPC | Mich Con |
| APS & PENELEC | Dominion South |
| PSEG & RECO | Transco Z6 (NY) |
| | |

### 3.3.3 Net Cost of New Entry

The Net Cost of New Entry (Net CONE) for the PJM Region is the gross Cost of New Entry for the PJM Region minus the Net E&AS Revenue Offset for the PJM Region.

PJM shall determine the Net Cost of New Entry for each Zone that comprises the modeled LDA. The Net Cost of New Entry for a Zone is the applicable gross Cost of Net Entry value for such Zone minus the Net E&AS Revenue Offset for such Zone. The Net Cost of New Entry for the Zone is used for a sub-zonal LDA. The Net Cost of New Entry for a modeled LDA shall be the average of the Net CONE values of all zones within the modeled LDA.

## 3.4 Plotting the Variable Resource Requirement Curve

For the 2022/2023 Delivery Year through and including the 2024/2025 Delivery Year, the Variable Resource Requirement Curve is plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis using the following three points a, b, and c:

a. The price is equal to the greater of [the Cost of New Entry or 1.5 times (the Cost of New Entry minus the Net E&AS Revenue Offset, referred to as “Net CONE”)] divided by (one minus Pool-Wide Average EFORd) and Unforced Capacity is equal to [PJM Region Reliability Requirement[10] multiplied by (100% plus the approved IRM% minus 1.2%) divided by (100% plus approved IRM %)].

[10] The Reliability Requirement used in the unforced capacity quantity equation for points (a), (b), and (c) excludes any adjustment for PRD or EE (through the 2025/2026 Delivery Year for EE only). The VRR Curve that results is adjusted leftward to reflect the impact of PRD and rightward to reflect the impact of EE through the 2025/2026 Delivery Year as explained in section 3.4.1 of this manual.

Basis for Price at Point a:

$$\frac{Greaterof\ [CONEor1.5\ (CONE - E\ \&\ AS)]}{1 - Pool\ Wide\ EFORd}$$
$$\frac{Greaterof\ [CONEor1.5\ (CONE - E\ \&\ AS)]}{1 - Pool\ Wide\ EFORd}$$

Basis for Quantity at Point a:

$$\begin{bmatrix} RelReq\ \frac{(100\% + IRM - 1.2\%)}{(100\% + IRM)} \\ RelReq\ \frac{(100\% + IRM - 1.2\%)}{(100\% + IRM)} \end{bmatrix}$$

b. The price is equal to 0.75 times Net CONE divided by (one minus Pool-Wide Average EFORd) and Unforced Capacity equals [PJM Region Reliability Requirement multiplied by (100% plus the approved IRM% plus 1.9%) divided by (100% plus approved IRM%)]..

Basis for Price at Point b:

$$\frac{[0.75\ (CONE - E\ \&\ AS)]}{1 - Pool\ Wide\ EFORd}$$
$$\frac{[0.75\ (CONE - E\ \&\ AS)]}{1 - Pool\ Wide\ EFORd}$$

Basis for Quantity at Point b:

$$\begin{bmatrix} RelReq\ \frac{(100\% + IRM + 1.9\%)}{(100\% + IRM)} \\ RelReq\ \frac{(100\% + IRM + 1.9\%)}{(100\% + IRM)} \end{bmatrix}$$

c. The price is equal to zero and Unforced Capacity equals [PJM Region Reliability Requirement multiplied by (100% plus the approved IRM% plus 7.8%) divided by (100% plus approved IRM %)].

Basis for Price at Point c:

$$\$0\ /\ MW - day$$
$$\$0\ /\ MW - day$$

Basis for Quantity at Point c:

$$\begin{bmatrix} RelReq\ \frac{(100\% + IRM + 7.8\%)}{(100\% + IRM)} \\ RelReq\ \frac{(100\% + IRM + 7.8\%)}{(100\% + IRM)} \end{bmatrix}$$

For the 2025/2026 Delivery Year only, the Variable Resource Requirement Curve is plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis using the following three points a, b, and c:

a. The price is equal to the greater of [the Cost of New Entry or 1.5 times (the Cost of New Entry minus the Net E&AS Revenue Offset, referred to as "Net CONE")] divided by (the applicable

ELCC Class Rating of the Reference Resource) and Unforced Capacity is equal to (PJM Region Reliability Requirement multiplied by 98.9%).

b. The price is equal to 0.75 times Net CONE divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals (PJM Region Reliability Requirement multiplied by 101.6%).

c. The price is equal to zero and Unforced Capacity equals (PJM Region Reliability Requirement multiplied by 106.8%).

For the 2026/2027 and 2027/2028 Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by a horizontal line from the y-axis equal to $256.75/MW-day ICAP divided by the applicable ELCC Class Rating for the Reference Resource until such line intersects the curve that is based on the following: (i) a straight line connecting points (1) and 2), and (ii) a straight line connecting points (2) and (3), where:

- For point (1), price equals: {the greater of [the Cost of New Entry] or [1.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 99%];
- For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 101.5%]; and
- For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 104.5%].

Once the horizontal line intersects above the curve, the Variable Resource Requirement Curve shall follow the curve that is based on the above points until the price reaches $138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource, at which point it shall be extended as a horizontal line at $138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource to infinity.

### 3.4.1 Plotting the Variable Resource Requirement Curves

The graph below illustrates the process for plotting the Variable Resource Requirement curve. The VRR Curve is plotted by combining a horizontal line from the y-axis to point (a), a straight line connecting points (a) and (b), a straight line connecting points (b) and (c).

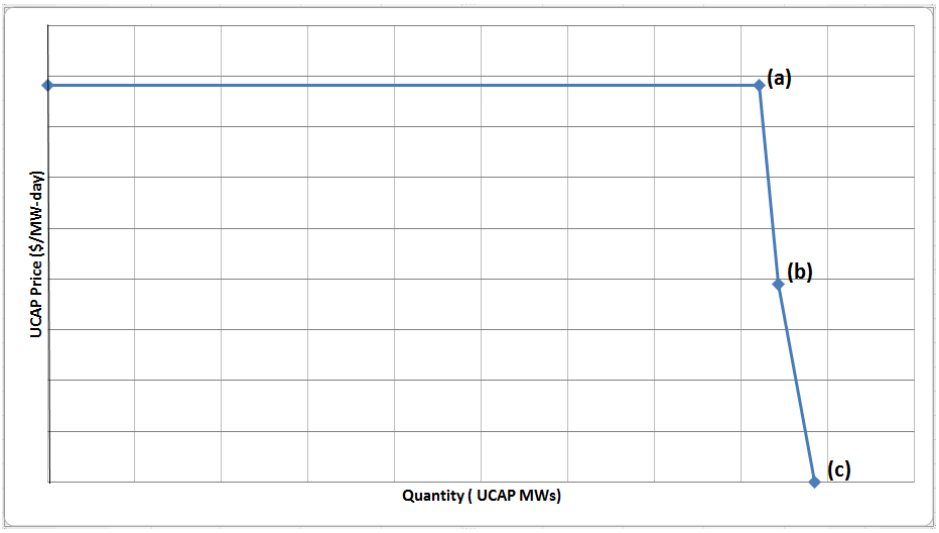



*Exhibit 1: Illustrative Example of a Variable Resource Requirement Curve*

The same process shall be used to establish the Variable Resource Requirement Curve for each LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement, and the FRR adjustments will be for the FRR Entities in the LDA.

Beginning with the 2018/2019 Delivery Year and continuing no later than for every fourth Delivery Year thereafter, PJM will perform a review of the shape of the Variable Resource Requirement Curve, CONE values, and Energy & Ancillary Services methodology, and any FERC approved changes resulting from this review will be incorporated into the appropriate BRA Auctions.

The Variable Resource Requirement Curve will be further adjusted to reflect the impact of any PRD that is proposed in a PRD Plan and that is reviewed and accepted by PJM. To reflect accepted PRD Plans, the Variable Resource Requirement Curve will be shifted leftward along the horizontal axis by a quantity equal to the Nominal PRD Value multiplied by the FPR. This quantity represents the quantity of Unforced Capacity that would have been procured in the RTO on behalf of the PRD load but that is now not needed due to the PRD loads' commitment to reduce consumption. The curve will be shifted leftward in this manner only for those portions of the curve that are at or above the PRD Reservation Price, since the PRD load can be excluded only if the auction clears at or above that price. The Variable Resource Requirement Curve for each LDA in which the PRD resides (including the RTO curve) will be shifted in the exact same manner.

The Variable Resource Requirement Curve will be further adjusted to reflect the impact of any EE addback through the 2025/2026 Delivery Year. The Variable Resource Requirement Curve

will be shifted rightward along the horizontal axis by a quantity equal to the EE addback MW quantity as explained in Section 2.4.5. The Variable Resource Requirement Curve for each LDA in which EE resides (including the RTO curve) will be shifted in the exact same manner.

## 3.5 Demand Curves in the Incremental Auctions

The First, Second and Third Incremental Auctions provide both a forum for capacity suppliers to purchase replacement capacity, and a means for PJM to adjust previously committed capacity levels due to reliability requirement increases or decreases. The demand curve in these auctions will be built based on a combination of buy bids submitted by market participants and buy bids, if any, submitted by PJM.

PJM will recalculate the RTO and each LDA Reliability Requirement prior to each of the First, Second, and Third Incremental Auctions based on an updated peak load forecast, updated Installed Reserve Margin, and an updated Capacity Emergency Transfer Objective. The recalculated Reliability Requirements are compared to the Reliability Requirements used in the prior auction for the same Delivery Year and a determination is made as to the need for the procurement and/or sale of capacity by PJM.

For the RTO and each LDA, PJM will sum the following component quantities to determine the total quantity that it will seek to procure or release in each Incremental Auction:

- The difference between the Updated Reliability Requirement minus the Reliability Requirement utilized in the most recent prior auction conducted for that Delivery Year. For a 1st or 2nd Incremental Auction, this difference is only considered if the change in Reliability Requirement is greater than the lesser of 500 MW or 1% of the prior auction's Reliability Requirement. Note that this quantity is negative if the Updated Reliability Requirement is less than the Reliability Requirement utilized in the most recent prior auction.
- Plus/minus the amount of committed capacity that PJM sought to procure/release that did not clear in the prior Incremental Auction for the same Delivery Year.
- Plus the amount of non-viable commitments associated with transition provision of OATT, Attachment DD, Section 5.5A(c)(i)(B) (i.e., Prior CIL Exception External Resources electing prior to Delivery Year Third Incremental Auction to be relieved of their capacity obligation for such Delivery Year) and RAA, Schedule 6, section L.9 (i.e., EE Resources electing prior to Delivery Year Third Incremental Auction to be relieved of their capacity obligation for such Delivery Year due to prohibition of EE participation by a Relevant Electric Retail Regulatory Authority).
- Minus any capacity PJM seeks to release in a parent LDA as a result of any Conditional Incremental Auction commitments for the same Delivery Year.

If the result of such summation is a positive quantity, PJM will seek to procure such quantity by employing a PJM buy bid represented by the portion of the Updated VRR Curve Increment extending right from the left-most portion on that curve in a MW amount equal to the positive

quantity. PJM will employ a PJM buy bid represented by the entire portion of the Updated VRR Curve if the prior auction's RTO/LDA Reliability Requirement exceeds the total capacity committed in all prior auction's by the threshold (lesser of 500 MW or 1% of prior auction's Reliability Requirement).The Updated VRR Curve Increment is the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year (adjusted, if applicable, by change in Unforced Capacity commitments associated with transition provision of OATT, Attachment DD, Section 5.5A(c)(i)(B) and RAA Schedule 6, section L.9).

If the result of such summation is a negative quantity, PJM will seek to release such quantity by employing a PJM sell offer represented by the portion of the Updated VRR Curve Decrement extending and ascending to the left from the right-most portion on that curve in a MW amount equal to the negative quantity. The Updated VRR Curve Decrement is the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year (adjusted, if applicable, by change in Unforced Capacity commitments associated with transition provision of OATT, Attachment DD Section 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9).

In a Conditional Incremental Auction, the quantity at the appropriate location required to address the identified reliability violation will be procured using a Buy Bid equal to 1.5 times Net CONE.

# Section 3A: Integration of Price Responsive Demand

Welcome to the *Integration of Price Responsive Demand* section of the ***PJM Manual for the PJM Capacity Market***. In this section, you will find the following information:

- An overview of Price Responsive Demand in PJM Capacity Market (see “Overview of Price Responsive Demand in PJM Capacity Market”)
- The transition period for price responsive demand (see “Transition Period”)
- The eligibility requirements for price responsive demand participation in PJM Capacity Market (see “Eligibility Requirements for Price Responsive Demand”)
- The PRD Plan requirements (see “PRD Plan Requirements”)
- The registration requirements of price responsive demand (see “ Registration of Price Responsive Demand”)
- The performance requirements of price responsive demand in the delivery year (see “Performance Requirements of Price Responsive Demand”)
- The bilateral transfer of a price responsive demand obligation (see “PRD Bilaterals”)

## 3A.1 Overview of Price Responsive Demand in PJM Capacity Market

The development and implementation of dynamic and time-differentiated retail rates, together with utility investment in advanced metering infrastructure (AMI) has lead an increasing quantity of load in PJM to be responsive to changing wholesale prices. Through enabling technology and behavioral changes, consumers modify their demand as prices change without being centrally dispatched by PJM or bidding demand reductions into the PJM markets. Given the linkage between dynamic retail rate structures and wholesale prices, this price responsiveness is predictable and needs to be accounted for in the wholesale market design and operations. This predictable reduction in consumption in response to changing wholesale prices is known as Price Responsive Demand (PRD).

Although Price Responsive Demand is not directly dispatchable by PJM, automated retail customer response to real time energy prices signals can produce a predictable demand curve as a function of real time energy price. Prices typically increase during capacity emergencies and as a consequence demand drops. Price Responsive Demand will therefore be able to reduce the installed capacity required to meet Loss of Load Expectation (LOLE) based reliability standards.

PRD is provided by a PJM Member that represents retail customers that have the capability to reduce load in response to price. PJM Member acting on behalf of such retail customers for the purpose of providing PRD is referred to as the PRD Provider. A PRD Provider for a given retail customer must meet all of the eligibility requirements for providing PRD.

In the PJM Capacity Market, a PRD Provider may voluntarily make a firm commitment of the quantity of Price Responsive Demand that will reduce its consumption in response to real time energy price during a Delivery Year.

In order to commit PRD for a Delivery Year, a PRD Provider must submit a PRD Plan in advance of the Base Residual Auction or Third Incremental Auction for such Delivery Year that demonstrates to PJM's satisfaction that the maximum nominated amount of price responsive demand will be available by the start of the Delivery Year. Additional PRD may participate in the Third Incremental Auction only in the event, and to the extent that the LDA final peak load forecast for the Delivery Year increases relative to the LDA preliminary peak load forecast used for the Base Residual Auction.

A PRD Provider that is committing PRD in Base Residual Auction or Third Incremental Auction must also submit a PRD election in the Capacity Exchange system which indicates the Nominal PRD Value in MWs that the PRD Provider is willing to commit at different reservation prices ($/MW-day). The PRD election by PRD Providers will result in a change in the shape of the RTO/LDA VRR Curves used in the RPM Auctions. Based on the PRD elections and Resource Clearing Price in the RPM Auction, PJM will determine the Nominal PRD Value committed by each PRD Provider. Those PRD Providers that elected to provide PRD at reservation prices equal to or less than the Resource Clearing Price will have the corresponding value of PRD committed in the RPM Auction.

A PRD Provider that is committing PRD which is associated with load being served under the Fixed Resource Requirement Alternative is not required to submit a PRD election. The FRR Entity's Preliminary Daily Unforced Capacity Obligation to be satisfied in the FRR Entity's initial submittal of their FRR Capacity Plan for the Delivery Year will be reduced by the Nominal PRD Value associated with their FRR load that was approved by PJM in advance of the BRA, multiplied by the BRA Forecast Pool Requirement. The Final Daily Unforced Capacity Obligation of the FRR Entity that must be satisfied in the FRR Entity's FRR Capacity Plan for the Delivery Year will be reduced by the total Nominal PRD Value associated with their FRR load that was approved by PJM in advance of the Base Residual Auction and Third Incremental Auction for the Delivery Year, multiplied by the final Forecast Pool Requirement. The approval of the PRD Provider's PRD Plan associated with the FRR load shall establish a firm commitment of the PRD Provider to the PJM approved sub-zonal/zonal Nominal PRD Value.

Once committed in a Base Residual Auction, Third Incremental Auction or committed for load served under the FRR Alternative, Price Responsive Demand may not be uncommitted or replaced by available capacity resources or Excess Commitment Credits. However, a PRD Provider may transfer the PRD obligation to another PRD Provider bilaterally.

A PRD Provider with a committed sub-zonal/zonal Nominal PRD Value through an RPM Auction or through the FRR Alternative will be required to register sub-zonal/zonal PRD prior to the start of the Delivery Year to satisfy their PRD commitment. Failure to register enough price responsive loads to meet their sub-zonal/zonal PRD commitment prior to the start of the

Delivery Year or failure to maintain enough price responsive loads to meet their sub-zonal/zonal PRD commitment throughout the Delivery Year will result in a PRD Commitment Compliance Penalty.

A PRD Provider is subject to Non-Performance Assessment during the Delivery Year. Failure to comply during a Performance Assessment Interval will result in a Non-Performance Charge for such interval. If PJM does not have an Emergency Action that triggers a Non-Performance Assessment during the Delivery Year that requires a PRD registration to reduce to the Firm Service Level (FSL) in the registration, then PRD registrations in the zone that did not have compliance measured for a Performance Assessment Interval during the Delivery Year must demonstrate that such registrations were tested for a one-hour period during any hour from 10:00 AM EPT to 10:00 PM EPT during June through October or the following May of the relevant Delivery Year. Failure of such PRD registrations in the zone to reduce to the aggregate FSL levels of such registrations in a test will result in a PRD Test Failure Charge.

The PRD Provider will receive a Daily PRD Credit ($/MW-day) during the Delivery Year. A PRD Provider under the FRR Alternative will not be eligible to receive a Daily PRD Credit ($/MW-day) during the Delivery Year.

## 3A.2 Deleted

## 3A.3 Eligibility Requirements of Price Responsive Demand

In order for load to be eligible to be considered as Price Responsive Demand, the end-use customer load must be:

- served under a dynamic retail rate structure with an LSE or subject to a contractual arrangement with a PRD Provider where such rate or compensation arrangement can change on an hourly basis, is linked to or based upon a PJM real-time LMP trigger at a substation location within a transmission zone as electrically close as practical to the applicable load, and results in predictable response to varying wholesale electricity prices;
- subject to advanced metering capable of recording electricity consumption at an interval of one hour or less;
- subject to Supervisory Control as defined in the Reliability Assurance Agreement to curtail the demand should PJM declare an emergency condition; and
- Shall exclude Critical Natural Gas Infrastructure

Supervisory Control of customer load registered as Price Responsive Demand is required on the part of the PRD Provider consistent with any Relevant Electric Retail Regulatory Authority (RERRA) requirements. RERRA shall have the meaning specified in the PJM Operating Agreement. Prior to the 2022/2023 Delivery Year, to the extent load was not already reduced, the PRD Provider is required to have the remote capability to decrease the load at each location contained in the PRD Registration to the required service level when a PJM Maximum

Emergency event has been declared and the Real-time LMP at the applicable location has exceeded the level at which the load has committed to reduce. Effective with the 2022/2023 Delivery Year, to the extent load was not already reduced, the PRD Provider is required to have remote capability to decrease the load at each location contained in the PRD Registration to the required service level when an Emergency Action triggers a Performance Assessment Interval and the Real-time LMP at the applicable location has exceeded the level at which the load was committed to reduce. PRD Providers with committed PRD are required to have automation of PRD that is needed to respond to Real Time LMPs for the PRD Curves that are submitted in the PJM Energy Market. Automation of load response to LMP trigger without manual intervention is required to be PRD.

However, PRD Providers may request an exception to the automation requirement for end-use customers that are a single site, a single location and a single end-use customer with supervisory control over processes with which load reduction would be accomplished. In this case, the end use customer site is eligible for this specific exception from standard automation requirement, but the end-use customer is still required to respond within 15 minutes to Real Time LMPs for the PRD Curves that are submitted in the PJM Energy Market. Effective with 2022/2023 Delivery Year, PRD registrations with an approved exception to the automation requirement will not have compliance measured during the Performance Assessment Intervals that fall within the 15 minute response allowance.

The customer load must be on a dynamic retail rate structure with an LSE or subject to a contractual arrangement with a PRD Provider that results in retail charges or credits to the end use customer that are linked to or based on the Real Time LMP. Multiple retail rates or contractual arrangements could qualify for this requirement, such as a structure where the retail charge or credit to the end-use customer is greater than or equal to the Real-time LMP, or applies only when the Real Time LMP exceeds a preset threshold. Dynamic retail rate structures, based on PJM Real-time LMP, that qualify as Price Responsive Demand may include:

- Critical Peak Pricing that allows retail rates to rise when the wholesale market price exceeds a threshold level;
- Critical Peak Rebate pricing which provides bill credits to consumers who reduce their usage below a baseline quantity during periods when the wholesale market price exceeds a threshold level; or
- Real-Time Pricing based on LMP.

## 3A.4 PRD Plan Requirements

### 3A.4.1 PRD Plan Submission & Approval Process

A PRD Provider that wishes to nominate PRD load for a Delivery Year's Base Residual Auction or nominate PRD to reduce an FRR Entity's preliminary unforced capacity obligation must submit a PRD Plan by email via the RPM Hotline at rpm_hotline@pjm.com no later than

January 15 immediately prior to the Delivery Year's Base Residual Auction. Additional PRD may be nominated in an LDA in the Third Incremental Auction in the event and to the extent that the LDA final peak load forecast used in Third Incremental Auction increases relative to LDA preliminary peak load forecast used in the Base Residual Auction. Nomination of additional PRD load in an LDA for a Delivery Year's Third Incremental Auction when LDA peak load forecast increases may be made by submitting a PRD Plan by email via the RPM Hotline at rpm_hotline@pjm.com no later than January 15 immediately prior to the Delivery Year's Third Incremental Auction. Nomination of additional PRD for use in reducing an FRR Entity's final unforced capacity obligation for the Delivery Year may also be made by submitting a PRD Plan by email via the RPM Hotline at rpm_hotline@pjm.com no later than January 15 prior to the Delivery Year's Third Incremental Auction.

Once received by PJM, the PRD Provider will receive an email confirmation that their plan has been received and will be reviewed by PJM. PJM will review the content to ensure the PRD Plan contains all the necessary detail and information. PJM will notify the PRD Provider within 10 days of receipt of the PRD Plan and indicate whether or not the PRD Plan is approved or rejected. Any submitted plan that is incomplete or falls short of meeting the informational requirements of a PRD Plan by such January 15 deadline shall be rejected.

A PRD Provider must submit a PRD Plan no later than January 1, prior to a Base Residual Auction or Third Incremental Auction if the PRD Provider wants PJM to conduct an advance review of their PRD Plan. PJM will review the content of the PRD Plan and will notify the PRD Provider within 10 days of receipt of the PRD Plan if the submitted PRD Plan is approved or rejected. If the PRD Plan is rejected, PJM will provide to the PRD Provider a list of the areas in the PRD Plan that were not adequate. PRD Plans that are denied by PJM in an advance review may be corrected and resubmitted no later than January 15, prior to the Base Residual Auction or Third Incremental Action. Alternately, PJM may approve a lower maximum Nominal PRD Value supported by the PRD Plan.

To help a PRD Provider prepare and submit a PRD Plan by the January 15 deadline, the following information will be made available:

- Prior year summer weather normalized zonal peak loads posted by PJM by October 31. The summer weather normalized zonal peak loads will be developed from hourly metered zonal loads that include add backs due to demand response and price responsive demand in accordance with ***PJM Manual 19, Load Forecasting and Analysis***.
- Customer PLCs developed and made available by EDCs based on prior year summer weather normalized Zonal peak loads by December 31.

### 3A.4.2 Required Components of a PRD Plan

The PRD Plan is a document submitted by the PRD Provider that defines and provides data to support a PRD Provider's maximum Nominal PRD Value in a Zone or sub-zone LDA (for example, if nominating PRD in DPL South or PS North). The PRD plan must identify any methods and techniques that will be used to determine and verify the quantity of load consumed

at varying wholesale price levels. A single PRD Plan may be submitted to cover multiple Sub-zone/Zone locations, provided that the price-demand curves are submitted on a Sub-zone/Zone level. All of the assumptions, procedures, and data for the PRD Plan should be clearly documented. The data included should be sufficient for a third party to audit the procedures and verify the PRD Provider's maximum Nominal PRD Value in a Sub-zone/Zone.

The PRD Plan must detail the price responsive characteristic of the customer load at a zonal or sub-zonal LDA (for example, if load is in PSEG-North or DPL-South) level. If known, the PRD Plan should detail the price responsive characteristics at a substation level. The price responsive characteristic of such customer loads must be provided in terms of the quantity of load that will continue to consume at various levels of price.

Estimates of the substation/sub-zonal/zonal peak load contribution (PLC) values of such PRD Provider's price responsive load for the Delivery Year if such load were not to be reduced in response to price are to be provided in the PRD Plan. The substation/ sub-zonal/zonal PLC values will be aggregated to determine the Zonal/LDA PLC value for the PRD Provider in such Zone/LDA. In addition, an estimate of the representative loss factor for the Zone/LDA is to be provided. The Firm Service Level (FSL) is the level to which the price-responsive load will be reduced during the Delivery Year when an Emergency Action triggers a Performance Assessment Interval during the Delivery Year. The quantity of load that will be consumed at a price equal to the applicable energy market offer cap for the relevant Delivery Year represents the FSL. The locational FSL quantities (at substation/sub-zonal/zone) will be aggregated to determine the Zonal/LDA FSL quantity for the PRD Provider in such zone/LDA. For the purposes of the PRD Plan, the PRD Provider's Nominal PRD Value for a Zone/LDA is the Zonal/LDA PLC value minus (the Zonal/LDA FSL quantity times the loss factor).

A Price Responsive Demand (PRD) Plan submitted to PJM must include:

- Company name
- Submission date
- Company address and contact information
- Indication of whether price responsive demand is being nominated for an RPM Auction or for use in reducing an FRR Entity's unforced capacity obligation
- Location of Price Responsive Demand by applicable electrical location within a transmission zone (i.e., PNODE), if available at the time of submittal of PRD Plan, or by Sub-zone/Zone. At the time of the submittal of PRD Plan, the PRD Provider may provide data at the smallest LDA level, but the PRD Provider is required to provide final locational detail (i.e., PNODE) prior to Delivery Year.
- Peak Load Contribution Value of PRD by applicable electrical location, if available, or by Sub-zone/Zone Firm Service Level (FSL) of Price Responsive Demand by applicable electrical location, if available, or by Sub-zone/Zone Nominal PRD Value by applicable electrical location, if available, or by Sub-zone/Zone. The smallest increment that may be submitted for a Sub-zone/Zone is .1 MW.

- PRD Reservation Price, elected by PRD Provider as defined in section 3A.4.2.3
- Price-Demand curves at the applicable electrical location, (PNODE)/Sub-zone/Zone level, detailing the base electricity consumption level as well as the decreasing consumption levels (i.e., demand levels) at increasing wholesale energy prices (i.e., real-time LMPs).
- A description of the methodologies, analysis, or pilot programs used to determine the aggregate Zonal/LDA Peak Load Contribution value, aggregate Zonal/LDA FSL value, and Price-Demand Curves. Specifications of the equipment used to meet the advanced metering and supervisory control requirements, including a project plan and timeline with the milestones that demonstrates that the AMI and supervisory control will be available and operational for the start of the Delivery Year.
- Documentation conformation to Section 3A.4.2.3 below, verifying that the contractual arrangement with relevant end-use customers establishing a time-varying retail rate structure that conforms to any RERRA requirements and adheres to PRD implementation standards as specified in PJM RAA, PJM Operating Agreement, PJM OATT and PJM Manuals.
- AMI is required in support of the PRD installation:
    - In jurisdictions where the PRD program is under the jurisdiction of a RERRA, the PRD Provider shall use the AMI infrastructure in conformance with RERRA requirements. Furthermore, the AMI system shall be designed to allow for full implementation of PRD including metering reading requirements, supervisory control requirements, and all other requirements developed under the PJM RAA, PJM Operating Agreements, OATT and PJM Manuals.
    - In jurisdictions where PRD Provider is not required to obtain RERRA approval for the PRD program, the PRD Provider shall use an automated metering infrastructure that effects the needed operational requirements for PRD. Furthermore, the metering infrastructure shall be designed to allow for full implementation of PRD including meter reading requirements, supervisory control requirements, and all other requirements developed under the PJM RAA, PJM Operating Agreements, OATT and PJM Manuals.
    - The meter utilized to measure consumption for the purpose of retail billing shall also be the meter utilized to measure consumption for the purpose of PRD participation.

### 3A.4.2.1 Deleted

### 3A.4.2.2 Verification of Contractual Arrangement with PRD Provider

PJM will require the PRD Provider to provide documentation, within (10) business days of PJM's request, that verifies that their contractual arrangement with the relevant end-use customers establishing a time-varying retail rate structure that conforms any RERRA requirements and adheres to PRD implementation standards specified in the PJM RAA, PJM Operating Agreement, PJM OATT or PJM Manuals. The PRD Provider shall provide to PJM, within ten (10) business days of PJM's request, copies of their applicable contracts with end-use

customers capable of reducing load in response to price (including any proposed contracts). If the PRD Provider fails to provide any of the required documentation, including but not limited to end-use customer contracts within the ten business days, PJM shall reject the PRD Provider's PRD Plan.

In RERRA jurisdictions where a PRD Provider is not required by the RERRA to seek approval from the RERRA for its contractual arrangement for the referenced load, the PRD Provider shall provide to PJM, within ten (10) business days of PJM's request, an opinion of either the PRD Provider's legal counsel or the RERRA's legal counsel attesting that the PRD Provider does not need to obtain approval from the RERRA for the PRD Provider's contractual arrangement for the referenced load, and that the PRD Provider's contractual arrangement for the referenced load adheres to any guidelines established by the RERRA. If the PRD Provider fails to provide the required documentation within the ten business days, PJM shall reject the PRD Provider's PRD Plan.

### 3A.4.2.3 PRD Election Requirements

A PRD Provider that is nominating PRD for an RPM Auction must also submit a PRD election (indicating the Sub-zonal/Zonal Nominal PRD Value to be provided at different reservation prices) in the Capacity Exchange system by January 15, prior to the Base Residual Auction or Third Incremental Auction for the relevant Delivery Year.

A PRD election must include:

- Zonal/Sub-zonal Nominal PRD Value (MW) and Reservation Price ($/MW-day) pair(s) that meet the following requirements.
    - Up to ten quantity(MW)-price($/MW-day) pair segments for a zone/sub-zone may be submitted
    - A minimum and maximum Nominal PRD Value quantity must be submitted for each segment
    - The smallest increment that may be submitted for a Nominal PRD Value MW quantity is 0.1 MW.
    - The sum of the maximum Nominal PRD Values in the segments must not exceed the sub-zonal/zonal Nominal PRD Value requested for approval by PJM in the PRD Provider's PRD Plan. If PJM approves a lower sub-zonal/zonal Nominal PRD Value than the requested value in their PRD Plan, the PRD Provider will be asked to resubmit their PRD election such that the maximum Nominal PRD Values in the segments does not exceed the final sub-zonal/zonal Nominal PRD Value approved by PJM.
    - A Reservation Price submitted in a segment must be equal to or greater than $0/MW-day. If a PRD Provider does not submit a reservation price for a segment, the reservation price will default to $0/MW-day. A PRD Provider is willing to commit the Nominal PRD level specified in a segment if the RPM Auction Resource Clearing

Price applicable to Annual Resources in the zone/sub-zone is equal to or greater than the Reservation Price specified in such segment.

- The PRD Provider is willing to accept the commitment of any amount of Nominal PRD Value equal to or greater than the minimum MW amount quantity specified in a segment and equal to or less than the maximum MW amount quantity specified in a segment.
- If a PRD Provider's PRD Plan is not approved by PJM, the PRD Provider's Election will be rejected by PJM and not considered in the RPM Auction clearing.

Upon posting of the RPM Auction Results, PJM will notify the PRD Provider via the Capacity Exchange system of their sub-zonal/zonal committed Nominal PRD Value. Upon notification by PJM, the PRD Provider has a binding commitment to provide sub-zonal/zonal PRD at the committed level during the relevant Delivery Year.

## 3A.5 Registration of Price Responsive Demand

A PRD Provider will be required to register price responsive load in DR Hub system prior to the start of the Delivery Year and maintain the registration of enough price responsive load in a zone/sub-zone throughout the Delivery Year to satisfy their zonal/sub-zonal PRD commitments.

Only load that meets all the eligibility requirements of PRD can be registered as PRD. The registration of price responsive load must be identified at the substation location within a transmission zone as electrically close as practical to the applicable load (i.e., PNODE).

If during the Delivery Year, the load no longer meets all the eligibility requirements of PRD, the PRD Provider must terminate the initial registration on the date the load no longer meets the eligibility requirements. The PRD Provider may also register new customers throughout the Delivery Year to cover loss of PRD load when customers drop out of the PRD Provider's program.

End-use customer loads identified in a PRD Plan or PRD registration for a Delivery Year as Price Responsive Demand may not, for such Deliver Year, (i) be registered as Economic Load Response or Emergency Load Response; (ii) be used as the basis of any Demand Resource Sell Offer or Energy Efficiency Sell Offer in any RPM Auction; (iii) be identified in a PRD Plan or PRD registration of any other PRD Provider.

An individual site registration must be submitted for each end-use customer site that is price responsive and has a peak load contribution equal to or greater than 10 KW. The site registration must identify the EDC, PLC, FSL, EDC-assigned loss factor, PNODE, and whether the load is being served under the RPM or the FRR Alternative. The FSL in the registration represents the load level that the site is committing to be at during a Performance Assessment Interval in the Delivery Year.

An aggregate registration may be submitted to aggregate end-use customer sites that have peak load contributions below 10 KW provided such aggregate registration must represent end-use customers located at the same PNODE.

The Nominal PRD Value calculated for a registration is equal to the PLC in the registration minus (the FSL in the registration times the EDC-assigned loss factor).

PJM will aggregate the Nominal PRD Values of effective, approved registrations in a zone/sub-zone to determine the PRD Provider's actual Daily Nominal PRD Value in zone/sub-zone for each day during the Delivery Year.

The deadline for the submittal of a PRD registration in the DR Hub system is one day before the tenth business day prior to the start date that a PRD registration is effective so that adequate time is provided for the EDC to confirm the registration data. During the Delivery Year, if the load identified in the approved PRD registration will no longer meet the PRD eligibility requirements, a request to terminate the PRD registration on the last day that such load meets the PRD eligibility requirements must be submitted in DR Hub within two business days prior to the date that the PRD registration is to terminate. A PRD registration must be in an approved status by the start date of the registration and be effective on the delivery day in order for such registration to be counted towards meeting the PRD Provider's committed sub-zonal/zonal Nominal PRD Value for the relevant delivery day.

For a PRD Provider, the MW amount of PRD that is currently registered by the PRD Provider at the time of PRD Plan submittal may be considered as Existing PRD and not be subject to a Price Responsive Demand Credit Requirement.

## 3A.6 Performance Requirements of Price Responsive Demand

Once a PRD Provider commits PRD for the Delivery Year, the PRD Provider will be subject to both daily commitment compliance during the Delivery Year Non-Performance Assessment during the Delivery Year in accordance with Section 8.4A. In the absence of a Performance Assessment Interval during the relevant Delivery Year that required the PRD registration to respond, such registration would be required to test during the Delivery Year

A PRD Provider cannot use replacement capacity to reduce a MW shortfall for PRD commitment compliance, failure to perform during a Performance Assessment Interval, or failure to perform during a test. However, a PRD provider may register additional price responsive demand throughout the Delivery Year to cure a daily commitment compliance shortfall or avoid additional Non-Performance Assessment shortfalls. In addition, a PRD Provider may transfer the obligation to provide PRD to another PRD provider through a bilateral transaction.

### 3A.6.1 PRD Commitment Compliance

A PRD Provider must register enough PRD prior to the start of the Delivery Year and maintain enough Price Responsive Demand registrations throughout the Delivery Year to satisfy their sub-zonal/zonal PRD commitment for RPM or FRR.

PRD commitment compliance will be evaluated on a daily basis throughout the Delivery Year. PJM will determine the actual Daily Nominal PRD Value of the PRD Provider in a Sub-Zone/ Zone for RPM or FRR based on the registration information provided in the DR Hub system. If a PRD Provider's actual Daily Nominal PRD Value in a Sub-Zone/Zone for RPM is less than their committed Nominal PRD Value in Sub-Zone/Zone for RPM, the PRD Provider will be subject to a Daily PRD Commitment Compliance Penalty in the Sub-zone/Zone for the MW shortfall. If a PRD Provider's actual Daily Nominal PRD Value in a Sub-Zone/Zone for FRR is less than their committed Nominal PRD Value in Sub-Zone/Zone for FRR, the PRD Provider will be subject to a Daily PRD Commitment Compliance Penalty in the Sub-zone/Zone for the MW shortfall.

### 3A.6.2 Deleted

### 3A.6.2A Compliance during a Performance Assessment Interval

A PRD Provider is subject to a Non-Performance Assessment in accordance with Section 8.4A. Compliance is measured for a PRD registration upon declaration of a Performance Assessment Interval in same sub-zone/zone of such PRD registration and when the PRD Curve associated with such registration in the PJM Real-time Energy Market has a price point where demand reduction is expected at Real Time LMP recorded during the Performance Assessment Interval. A PRD registration shall not be considered in the calculation of a Performance Shortfall or Bonus Performance when the PRD Curve associated with such registration in the Real-time Energy Market indicates a price point where no demand reduction is expected at the real-time LMP recorded during the Performance Assessment Interval.

A PRD registration with an approved exception to the automation requirement will not have compliance measured during Performance Assessment Intervals that fall within the 15 minute response allowance. A PRD Provider will only be subject to Non-Performance Assessment and associated Non-Performance Charges/Bonus Performance Credits for those PRD registrations that were measured for compliance.

PRD Providers are responsible for the submittal to PJM of all meter information required to complete this measurement and verification for each Performance Assessment Interval during the Delivery Year that the PRD was required to respond. PJM requires that actual metered data at the end-use customer site for all hours during the day of a Performance Assessment Interval be submitted to PJM via DR Hub system within 45 days after the end of the month in which a Performance Assessment Interval occurs, with accountability for failure to do so. PJM verifies compliance on a registration basis by reviewing the data submitted by the PRD Provider through the DR Hub system.

The actual load reduction provided by the registration for the Performance Assessment Interval is calculated as the registration's Peak Load Contribution minus (the metered load multiplied by the loss factor). A load reduction will only be recognized if metered load multiplied by the loss factor is less than the Peak Load Contribution. When five minute revenue meter data is not available to determine compliance of a PRD registration for a Performance Assessment Interval, the actual load reduction for a Performance Assessment Interval is calculated as the actual hourly load reduction for the hour ending that includes the Performance Assessment Interval(s) multiplied by (twelve divided by the number of five minute intervals the PRD registration was to be measured for compliance). The actual load reduction for a registration for a Performance Assessment Interval is capped at the Peak Load Contribution of the registration. If the PRD Provider failed to submit actual metered data for the registration for all hours during the day of a Performance Assessment Interval, the actual load reduction for such registration will be equal to zero MWs.

For each registration in an Emergency Action Area, the Actual Performance is equal to the actual load reduction for such registration for the Performance Assessment Interval. The Actual Performance for a PRD Provider in the Emergency Action Area for the Performance Assessment Interval is equal to the sum of the Actual Performance of the PRD registrations that were measured for compliance for such Emergency Action Area and Performance Assessment Interval. If a PRD Provider registered PRD to satisfy RPM PRD commitments and PRD to satisfy FRR PRD commitments, an Actual Performance quantity will be calculated for registrations tied to RPM and a separate Actual Performance quantity will be calculated for registrations tied to FRR.

The Expected Performance for a PRD Provider for the Emergency Action Area and Performance Assessment Interval is equal to the Nominal PRD Value committed by PRD Provider in the Emergency Action Area, adjusted to account for any PRD registrations in the Emergency Action Area that were not subject to compliance measurement. If a PRD Provider committed PRD to RPM and committed PRD to FRR, an Expected Performance quantity will be calculated for RPM commitments and a separate Expected Performance quantity will be calculated for FRR commitments.

The Performance Shortfall for a PRD Provider is calculated as Expected Performance minus the Actual Performance. If the Performance Shortfall related to RPM commitments is negative number, the PRD Provider is subject to a Non-Performance Charge, in accordance with Section 8.4A. If the Performance Shortfall related to RPM commitments is a negative number, the PRD Provider may be eligible for a Bonus Performance Credit, in accordance with Section 8.4A. Performance Shortfalls related to FRR commitments are subject to Non-Performance Charge or Bonus Performance Credit if the FRR Entity elected the financial non-performance assessment as opposed to the physical non-performance option described in Section 11.8.7

### 3A.6.3 PRD Test Compliance (Effective for 2022/2023 Delivery Year)

If a PRD registration is not measured for compliance for a Performance Assessment Interval in a Delivery Year, then such registered PRD must demonstrate that it was tested for a one hour

period between 10:00 AM EPT to 10:00 PM EPT during June through October or May of the relevant Delivery Year. If a PRD registration is measured for compliance for a Performance Assessment Interval in a Delivery Year, then no PRD Test Failure Charges will be assessed for such PRD registration.

All PRD registrations in a zone must be tested simultaneously except that, when less than 25 percent (by megawatts) of a PRD Provider's total PRD registered in a Zone fails a test, the PRD Provider may conduct a re-test limited to all registered PRD that failed the prior test, provided that such re-test must be at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registered PRD must test simultaneously, where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. If less than 25 percent of a PRD Provider's total PRD registered in a Zone fails the test and the PRD Provider chooses to conduct a retest, the PRD Provider may elect to maintain the performance compliance result for registered PRD achieved during the test if the PRD Provider: (1) notifies PJM 48 hours prior to the re-test under this election; and (2) the PRD Provider retests affiliated registered PRD under this election.

Multiple tests may be conducted; however only one test result may be submitted for each end use customer site in DR Hub for test compliance evaluation. Test data must be submitted in DR Hub on or after June 1 and no later than July 14th after the Delivery Year. Actual load reduction for a PRD registration in a test is calculated in a manner similar to calculating actual hourly load reduction during an emergency action.

The MW testing shortfall for a PRD registration is equal to the nominal load reduction value of the registration, capped at daily Nominal PRD Value committed by such registration on the day of the test, minus the actual hourly load reduction for such registration.

The PRD Provider's daily committed Zonal (or Sub-Zonal LDA) Nominal PRD Value is allocated to the PRD Provider's registrations in the zone (or sub-zonal LDA) pro-rata based on the Nominal PRD Value of the registrations to determine the PRD commitment level for such registrations.

Positive MW shortfalls represent underperformance for a PRD registration. Negative MW shortfalls represent over performance for a PRD registration. The test compliance results of the PRD Provider's PRD registrations in a zone that were expected to test are aggregated to determine a PRD Provider's net zonal testing shortfall. If a PRD Provider committed PRD to RPM and committed PRD to FRR, a net zonal testing shortfall will be calculated for their PRD registrations linked to RPM and a separate net zonal testing shortfall will be calculated for their PRD registrations linked to FRR.

### 3A.6.3A PRD Test Compliance (Effective with 2023/2024 Delivery Year)

For the 2023/2024 Delivery Year and subsequent Delivery Years, if the registered PRD is not required to reduce the load for a Performance Assessment Interval during the relevant Delivery Year, then such registered PRD shall test for a two hour period between 11:00 EPT to 18:00

EPT on a weekday that is a non-NERC holiday during the relevant Delivery Year and in accordance with the following provisions. The date and time of such test shall be selected by the Office of the Interconnection and notice of such test shall be provided to the PRD Provider in accordance with the procedure described in sections (2) and (3) listed below. If a PRD registration is measured for compliance for a Performance Assessment Interval in a Delivery Year, then no PRD Test Failure Charges will be assessed for such PRD registration.

1. For the 2023/2024 Delivery Year and subsequent Delivery Years, all PRD registered in a zone will be tested simultaneously for two hours. Performance will be calculated as the two hour average reduction. The Office of the Interconnection may, at its discretion, cancel a test and retest to ensure system reliability.
    a. If less than 25 percent (by megawatts) of a PRD Provider's total PRD registered in a Zone fails a test, the PRD Provider may conduct re-tests limited to all registered PRD that failed the prior test, provided that such re-test must be at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registered PRD must test simultaneously, where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. The PRD Provider may elect to maintain the performance compliance result for registered PRD achieved during the test if the PRD Provider: (1) notifies the Office of the Interconnection 48 hours prior to the re-test under this election; and (2) the PRD Provider retests affiliated registered PRD under this election as set forth in the PJM Manuals.
    b. If 25 percent or more (by megawatts) of a PRD Provider's total PRD registered in a Zone fails the test the PRD Provider may request PJM to schedule a one-time retest limited to all registrations that failed the prior test, provided that all affiliated registrations must test simultaneously where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. The request must be made before the 46th day after the test. The Office of the Interconnection will select the date and time of the retest during the same season period (except if test was conducted in March in which case retest can be conducted in May) and notice is provided consistent with the following procedure.
2. Notification of the initial Office of the Interconnection scheduled test will be provided as follows:
    a. On the first business day of a week, PJM will provide notice of all zones to be tested during the following two week test window. The test window opens the first business day of the week following the notice. By 10:00 EPT the day before the test, the Office of the Interconnection will post on its website the test date and zones. The Office of the Interconnection will also notify the PRD Providers the test date. On the test date, PRD Providers will receive the start time through web service communications with a 15 minute lead time and as defined in the PJM Manuals.

3. Notification of any scheduled retest by the Office of the Interconnection will be provided as follows:
    a. By 10:00 EPT the day before the retest, the Office of the Interconnection will post the retest date on its website. PJM will also notify the PRD Providers the retest date. On retest date PRD Providers will receive start time through web service communications with a 15 minute lead time and as defined in the PJM Manuals.

The MW testing shortfall for a PRD registration is equal to the nominal load reduction value of the registration, capped at daily Nominal PRD Value committed by such registration on the day of the test, minus the actual load reduction for such registration.

The PRD Provider's daily committed Zonal (or Sub-Zonal LDA) Nominal PRD Value is allocated to the PRD Provider's registrations in the zone (or sub-zonal LDA) pro-rata based on the Nominal PRD Value of the registrations to determine the PRD commitment level for such registrations.

Positive MW shortfalls represent underperformance for a PRD registration. Negative MW shortfalls represent over performance for a PRD registration. The test compliance results of the PRD Provider's PRD registrations in a zone that were expected to test are aggregated to determine a PRD Provider's net zonal testing shortfall. If a PRD Provider committed PRD to RPM and committed PRD to FRR, a net zonal testing shortfall will be calculated for their PRD registrations linked to RPM and a separate net zonal testing shortfall will be calculated for their PRD registrations linked to FRR.

## 3A.7 PRD Bilaterals

A PRD Provider may transfer the obligation to provide PRD bilaterally to another PRD Provider during the Delivery Year.

The following are the business rules that apply to PRD bilateral transactions:

- PRD bilateral transactions must be reported in the Capacity Exchange system.
- Both parties of the PRD transaction must confirm the transfer of a PRD commitment from the seller (transferor) to the buyer (transferee) via the Capacity Exchange system prior to the start date of the transaction.
- PRD bilateral transactions must be in the "Approved" status by the start date of the transaction or the status of such transaction will be changed to "PJM Withdrawn".
- The smallest increment of committed Nominal PRD Value that may be transferred is 0.1 MW.
- PRD transactions must specify:
    - start and end data for the transaction
    - the amount of Nominal PRD Value (in MW) to be transferred

  - the sub-zone/zone in which the Nominal PRD Value to be transferred was committed
  - whether the Nominal PRD Value to be transferred was committed to RPM or the FRR Alternative
  - the RPM Auction (BRA or Third IA) for which the Nominal PRD Value to be transferred was committed (if committed to RPM)
- The Capacity Exchange system will validate that the Seller has the committed Nominal PRD Value in the sub-zone/zone to transfer for the term of the transaction.
- To the extent that the Nominal PRD Value to be transferred has a Price Responsive Demand Credit Requirement, the Buyer must have sufficient credit in place prior to PJM approving the PRD transaction.
- As a result of an approved PRD transaction, the buyer that is assuming the seller's PRD commitment and obligations will be subject to PRD performance requirements to the extent of such transfer and for the term of the transaction.
- The seller shall be relieved of its PRD commitment and any Price Responsive Demand Credit Requirements for the Nominal PRD Value transferred for the term of the transaction.

# Section 4: Supply Resources in the Reliability Pricing Model

Welcome to the *Supply Resources in RPM* section of the ***PJM Manual for the PJM Capacity Market***. In this section, you will find the following information:

- An overview description of supply in the Reliability Pricing Model (see "Overview of Supply in the Reliability Pricing Model")
- The business rules for generation resources (see "Generation Resources")
- The business rules for load management products (see "Load Management Products")
- The business rules for energy efficiency resources (see "Energy Efficiency Resources")
- The business rules for qualified transmission upgrades (see "Qualified Transmission Upgrades")
- The business rules for bilateral transactions (see "Bilateral Transactions")
- The business rules for resource portfolios in RPM (see "Resource Portfolios")
- The credit requirements in RPM (see "Credit Requirements")
- The business rules for Aggregate Resources (see "Aggregate Resources")
- The business rules for Seasonal Capacity Resources (see "Seasonal Capacity Resources")

## 4.1 Overview of Supply in the Reliability Pricing Model

In the Reliability Pricing Model, the supply of installed capacity is procured to meet demand as a function of the clearing of the RPM Auctions. In each auction, a supply curve is defined based on the offers submitted by providers with installed capacity resources. Supply, valued as unforced capacity, which is procured in the RPM multi-auction clearing process, ensures that sufficient resources are committed to meet the PJM Reliability Principles and Standards.

A party's supply resource portfolio in Capacity Exchange may consist of:

- Generation Capacity Resources;
- Load Management Resources;
- Energy Efficiency Resources;
- Aggregate Resources
- Qualifying Transmission Upgrades.

Key qualifications and requirements for generation resources are presented in Existing Generation, Planned Generation, and Bilateral Unit-Specific Transaction sections of this Manual. Key qualifications and requirements for load management products are presented in the Load Management section of this Manual. Key qualifications and requirements for Energy Efficiency Resources are presented in the Energy Efficiency Resources section of this Manual.

Key qualifications and requirements for Aggregate Resources are presented in the Aggregate Resources section of this Manual. Key qualifications and requirements for Qualified Transmission Upgrades are presented in the Qualified Transmission Upgrade section of this Manual.

**Note:**
Prior to any RPM auction, RPM suppliers must confirm the modeling of each of their capacity resources. RPM suppliers must verify the following characteristics of generation units, demand resources, energy efficiency resources, and aggregate resources:

Zone assignment

LDA assignment

Unit Location by State (generation resources only)

Unit Type (generation resources only)

Product Type (Annual)

Fuel type (generation resources only)

Seasonal eligibility

## 4.2 Generation Resources

A party's Generation Capacity Resource portfolio may consist of Existing Generation Capacity Resources, Planned Generation Capacity Resources, and bilateral contracts for unit-specific Capacity Resources. Qualifications and requirements for Generation Capacity Resources are presented in the sections below. A Generation Capacity Resources that is being committed to the initial FRR Capacity Plan must satisfy the same qualification requirements as a Generation Capacity Resource offering into a Base Residual Auction; however, the qualification requirements must be satisfied in advance of the FRR Capacity Plan submittal deadline.

### 4.2.1 Existing Generation Capacity Resources - Internal

Existing Generation Capacity Resource located within the PJM region is eligible to be offered into RPM Auctions or traded bilaterally if it meets the following requirements:

- The unit is pre-certified by PJM as meeting the generation deliverability test. PJM's certification process for internal generating resources is described in the ***Open Access Transmission Tariff and the Operating Agreement.***
- The resource owner or operator submits the required operating and maintenance information into PJM's eDART and eGADs systems.

- The resource owner or operator performs winter and summer testing as described in ***PJM's Rules and Procedures for Determination of Generating Capability (M-21) and M-21B*** to verify the net capability of each unit.
- The unit resides in the Capacity Exchange resource portfolio of a signatory of the PJM Operating Agreement. This is accomplished by having an "Approved" Capacity Modification in the Capacity Exchange system.
- The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year.
- Unoffered MWs for a unit as a result of not satisfying the RPM must offer requirement in the Base Residual Auction or an Incremental Auction for the Delivery Year, are ineligible to be offered in any subsequent Incremental Auctions for that Delivery Year and are ineligible to take on any RPM or FRR commitment for such Delivery Year.

### 4.2.2 Existing Generation Capacity Resources - External

Existing Generation Capacity Resources located outside the PJM region is eligible to be offered into an RPM Auction if it meets the following requirements:

- For an external Generation Capacity Resource offering as Capacity Performance, the external resource satisfies the requirements to offer as Capacity Performance or qualifies for an exception to such requirements as a Prior CIL Exception External Resource. A Prior CIL Exception External Resource is defined as an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of Capacity Import Limit as set forth in Article 1 of the Reliability Assurance Agreement or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided in the definition of Capacity Import Limit. In the event only a portion (in MW) of an external Generation Capacity Resource has a Pseudo-Tie into the PJM Region, that portion of the external Generation Capacity Resource, which can include up to the maximum megawatt amount cleared in any prior RPM auction or committed in an FRR Capacity Plan (and no other portion thereof), is eligible for treatment as a Prior CIL Exception External Resource if such portion satisfies the requirements of the first sentence of this definition.
- For a Capacity Market Seller to offer an external Generation Capacity Resource as Capacity Performance, the Capacity Market Seller must demonstrate to PJM, by no later than five (5) business days prior to the commencement of the offer period for the relevant RPM Auction, that such resource meets the following requirements:
    - The Capacity Market Seller has obtained a determination that the Pseudo-Tie required for its External Generation Capacity Resource is feasible, including (without limitation) that such Pseudo-Tie meets the requirements in ***PJM Balancing Operations Manual (M-12)*** and the Capacity Market Seller has committed in writing, via the submittal of an Officer Certification Form, that it will take all steps necessary to implement such Pseudo-Tie prior to the start of the relevant Delivery Year. A template for the Officer Certification Form is posted on the PJM website.

- The Capacity Market Seller has demonstrated that it has, for transmission outside PJM, obtained long-term firm point-to-point transmission service (evaluated for deliverability from the unit-specific physical location of the resource to PJM load pursuant to a study that is reviewed and approved by PJM in accordance with PJM deliverability criteria to ensure uniformity for internal and external resource deliverability requirements), with rollover rights for the term of the transmission service that is confirmed by the Balancing Authority where such external resource is geographically located.
- The Capacity Market Seller has demonstrated that it has, for transmission service within PJM, obtained Network External Designated Transmission Service.
- The Capacity Market Seller has demonstrated by written commitment via the Officer Certification Form that such external resource is subject to the same obligations to offer into RPM Auctions imposed on Generation Capacity Resources located in the PJM Region by section 6.6 of Attachment DD of OATT. A Capacity Market Seller that satisfies the requirements to offer as Capacity Performance with respect to an external Generation Capacity Resource Sell Offer submitted in an RPM Auction for a Delivery Year is required to demonstrate satisfaction of such requirements for any Sell Offer with respect to such external resource submitted in an RPM Auction for any subsequent Delivery Year, including without limitation, demonstration that the required external transmission service continues to satisfy PJM's deliverability standards.

- To qualify for an exception to satisfy the above requirements to offer as Capacity Performance for a Delivery Year RPM Auction , the Prior CIL Exception External Resource must demonstrate that the external resource is (1) owned by a Load Serving Entity and used to self-supply (under arrangements initiated before June 1, 2016, with a duration of at least ten years) such LSE's PJM Region load, for any Delivery Year during the life of such resource or (2) the subject of a contract for energy or capacity or equivalent written agreement entered into on or before June 1, 2016 for a term of ten years or longer with a purchaser that is an internal PJM load customer, for any Delivery Year that covers the term of the agreement.
- The Prior CIL Exception External Resource must continue to comply with all the conditions in place on the grant of its exception to the Capacity Import Limit, subject to the following additional conditions:
  - The Prior CIL Exception External Resource must be Operationally Deliverable, as defined in the Open Access Transmission Tariff. If PJM determines that a Prior CIL Exception Resource is not Operationally Deliverable for a Delivery Year and notifies the Capacity Market Seller of such a determination by no later October 1 immediately preceding such Delivery Year, the Capacity Market Seller may elect to:
    - Take the necessary actions to make the Prior CIL Exception External Resource Operationally Deliverable, in PJM's sole judgement, prior to the beginning of such Delivery Year. If transmission upgrades are required to make the external resource Operationally Deliverable, PJM will facilitate the performance of

transmission studies and otherwise cooperate with the external Transmission Provider of the system on which such upgrades are required to identify the upgrades required to meet PJM's deliverability standards;

- Be relieved of the external resource's capacity obligation for such Delivery Year by providing written notice of such election to the RPM Hotline at rpm_hotline@pjm.com no later than seven (7) days prior to the posting of planning parameters for the Third Incremental Auction for such Delivery Year. As a result of such election, the Capacity Market Seller will not receive any RPM Auction Credits for the external resource's cleared MWs for such Delivery Year, will be relieved of all commitments and any resource performance obligations for such Delivery Year, and will have no further must-offer obligation in RPM Auctions. PJM will consider all such elections from Capacity Market Sellers in the determination of the PJM Buy Bid/Sell Offer for the Third Incremental Auction.
- Procure and specify replacement capacity in a sufficient quantity to replace the entire commitment on the Prior CIL Exception External Resource for the Delivery Year.

◦ A Capacity Market Seller's continued ability to offer as a Prior CIL Exception External Resource in RPM Auctions is conditioned on external Transmission Providers continuing to honor the firm status of the Capacity Market Seller's transmission service for all Delivery Years that such Capacity Market Seller offered as a Prior CIL Exception Resource.

◦ A Capacity Market Seller offering and clearing a Prior CIL Exception Resource shall be relieved of its must offer obligation in future Delivery Year RPM Auctions after the last Delivery Year for which it qualifies for an exception to requirements to offer as a Capacity Performance Resource.

- The unit resides in the Capacity Exchange resource portfolio of a signatory of the PJM Operating Agreement. This is accomplished by having a "Provisionally Approved" or "Approved" unit-specific transaction with "External Party" (i.e., "EXT") as the "Seller" of the transaction in the Capacity Exchange system.
- At least twelve months of NERC/GADs unit performance data in PJM format is required to establish a unit's Accredited UCAP Factor.
- The resource owner or operator submits the required operating and maintenance information into PJM's eDART and eGADs systems.
- The resource owner or operator performs winter and summer testing as described in ***PJM's Rules and Procedures for Determination of Generating Capability (M-21 and M-21B)*** to verify the net capability of each unit.
- The external capacity without firm transmission service confirmed on the complete transmission path must establish an RPM Credit Limit prior to an RPM Auction.
- Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.

- The resource owner provides a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area.
- A communication path (acceptable to PJM Dispatching/Operations personnel) must be established between the PJM Dispatchers and the operator of the unit.
- The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year.

An Existing Generation Capacity Resource located outside the PJM region is eligible to be traded bilaterally if the unit resides in the Capacity Exchange resource portfolio of a signatory of the PJM Operating Agreement through the accomplishment of an "Approved" unit-specific transaction with "External party" (i.e., "EXT") as the "Seller" of the transaction in the Capacity Exchange system. For an external resource offering or committing as Capacity Performance, an "Approved" unit-specific transaction status will not be granted until the pseudo-tie for such resource is actually implemented and the external resource has satisfied PJM's deliverability standards, which for CIL Exception External Resource may include completing the necessary actions to make such CIL Exception External Resource Operationally Deliverable for the relevant Delivery Year. Demonstrating deliverability may require transmission upgrades on an external Transmission Provider's system or PJM's system to be completed prior to June 1st of the delivery year. The study process for participant-funded upgrades is defined in Part VI of the PJM Open Access Transmission Tariff. The following requirements for existing external generation are still applicable for external resources traded bilaterally:

- At least twelve months of NERC/GADs unit performance data in PJM format is required to establish a unit's Accredited UCAP Factor.
- The resource owner or operator submits the required operating and maintenance information into PJM's eDART and eGADs systems.
- The resource owner or operator performs winter and summer testing as described in ***PJM's Rules and Procedures for Determination of Generating Capability (M-21 and M-21B)*** to verify the net capability of each unit.
- The resource owner provides a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area.
- A communication path (acceptable to PJM Dispatching/Operations personnel) must be established between the PJM Dispatchers and the operator of the unit.
- The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year.

If an existing Generation Capacity Resource located outside the PJM region cleared as Capacity Performance Resource in the Base Residual Auction, First Incremental, Second Incremental Auction, Third Incremental Auction, or Conditional Incremental Auction and does not have the pseudo-tie implemented and generation deliverability demonstrated by the start date of associated unit-specific transaction, the status of the associated unit-specific transaction

in the Capacity Exchange system will be changed from “Provisionally Approved” to “PJM Withdrawn”.

### 4.2.3 Planned Generation Capacity Resources - Internal

A Planned Generation Capacity Resource that is participating in PJM’s Regional Transmission Expansion Planning Process (RTEPP) is eligible to be offered into PJM’s RPM Auctions if it meets the following requirements:

- The planned unit’s start date of Interconnection Service is on or before the start of Delivery Year.
- At a minimum, planned generation resources greater than 20 MW must be in the Phase III System Impact Study and planned generation resources less than or equal to 20 MW must be in the Phase II System Impact Study, for the unit to participate in the Base Residual Auction.
- A Generation Interconnection Agreement (GIA) or Wholesale Market Participant Agreement (WMPA) has been executed for the unit to participate in an Incremental Auction.
- A Capacity Modification for the planned unit has been submitted and “Provisionally Approved” in Capacity Exchange.
- Planned Generation Capacity Resources must establish an RPM Credit Limit prior to an RPM Auction.
- Credit requests should be made to PJM’s Treasury Department at least two weeks prior to an RPM Auction.
- If the Planned Generation Capacity Resource was committed through the Base Residual Auction and the GIA is not received prior to opening of the bid window for the First Incremental Auction, the status of the Capacity Modification will be changed from “Provisionally Approved” to “Denied” so that the planned generation will no longer be included in a resource provider’s Capacity Exchange Generation Resource portfolio.
- If a GIA is eventually executed with a start date of Interconnection Service that is on or before the start of the Delivery Year, a new Capacity Modification will need to be submitted and “Provisionally Approved” in order to be re-included in a resource provider’s Capacity Exchange Generation Resource portfolio.
- If the Planned Generation Capacity Resource is delayed and has not commenced Interconnection Service by the start date of the Capacity Modification, the status of the Capacity Modification will be changed from “Provisionally Approved” to “Denied”. A new Capacity Modification will need to be submitted and approved with a start date that corresponds to the start date of Interconnection Service.
- Planned Generation Capacity Resources are required to submit an acceptance test to PJM Planning prior to the start date of the submitted CAPMOD in accordance with Manual 21 Section 1.3

- If PJM Planning determines a portion of a Planned Generation Capacity Resource has commenced Interconnection Service, or considered Partially In-Service, the status of the Capacity Modification may be changed from "Provisionally Approved" to "Approved" up to the amount of MWs deemed in-service by PJM Planning. A Capacity Modification for the remaining Planned MWs should be submitted and remain "Provisionally Approved" until PJM Planning confirms the MWs are in-service.
- Effective with the 2025/2026 Delivery Year, an internal Planned Generation Capacity Resource must satisfy the requirements of the binding notice of intent in section 4.2.3.1 in order for the internal Planned Generation Capacity Resource to be included in a Sell Offer for an RPM Auction.

#### 4.2.3.1 Binding Notice of Intent to Offer (Effective with the 2025/2026 Delivery Year)

Any Planned Generation Capacity Resource, including planned Intermittent Resources, Capacity Storage Resources, and Hybrid Resources, will be required to provide a binding notice of intent to offer, in the format requested by PJM, in order to participate in the RPM Auction. A Capacity Market Seller must provide a binding notice of intent no later than (a) the immediately preceding December 1 for a Base Residual Auction (except that for the 2025/2026 auction the deadline was 12/12/23, and 2026/2027 and 2028/2029 Delivery Years, such notice shall be submitted by 180 days prior to the commencement of the offer period), or (b) ninety (90) days prior to the commencement of the offer period for an Incremental Auction. A notice of intent to offer should be made by the Capacity Market Seller that intends to offer the Planned Generation Capacity Resource/uprate into the auction. The resource associated with a binding notice of intent is required to be offered into the auction even if a different Capacity Market Seller will offer the resource into the RPM Auction. Any bilateral unit-specific transaction involving the Planned Generation Capacity Resource prior to the auction will transfer the binding notice of intent to the new Capacity Market Seller. If a resource associated with a binding notice of intent is not offered in the auction, then the resource will not be permitted to offer into any subsequent auctions for the relevant Delivery Year or take on a RPM commitment through Locational UCAP or Replacement Capacity transaction during the relevant Delivery Year, or take on a FRR Commitment during the relevant Delivery Year.

### 4.2.4 Planned Generation Capacity Resources – External

A Planned External Generation Capacity Resource is eligible to be offered into PJM's RPM Auctions. Such resources will be treated in a manner comparable to planned internal generation resources and existing external generation resources. Prior to participation in any RPM Auction, the Resource Provider must demonstrate that it has executed an interconnection agreement (functionally equivalent to being in the Phase II or Phase III System Impact Study as outlined below fora Base Residual Auction and a Generation Interconnection Agreement for an Incremental Auction) with the transmission owner to whose transmission facilities or distribution facilities the resource is being connected, and if applicable with the transmission provider. A planned external generation resource must provide evidence to PJM it has been studied as a Network Resource, or such other similar interconnection product in the external Control Area. A

Planned External Generation Capacity Resource is eligible to be offered into RPM Auction if it meets the following requirements:

- A Planned External Generation Capacity Resource offering as Capacity Performance Resource must satisfy the same requirements for existing external generation capacity resources offering as a Capacity Performance Resource in Section 4.2.2 of this manual.
- The planned unit's start date of Interconnection Service is on or before the start of Delivery Year.
- At a minimum, planned generation resources greater than 20 MW must be in the Phase III System Impact Study and planned generation resources less than or equal to 20 MW must be in the Phase II System Impact Study, for the unit to participate in the Base Residual Auction.A functionally equivalent Generation Interconnection Agreement has been executed for the unit to participate in an Incremental Auction.
- The unit resides in the Capacity Exchange resource portfolio of a signatory of the PJM Operating Agreement. A Capacity Modification for the planned unit has been submitted by PJM and "Provisionally Approved" in Capacity Exchange in an External Party (i.e., EXT) account. A unit-specific transaction with External Party as the "Seller" has been submitted by the provider and "Provisionally Approved" in the Capacity Exchange system to represent the import of capacity into PJM.
- External Planned Generation Capacity Resources must establish an RPM Credit Limit prior to an RPM Auction.
- Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.
- If the Planned Generation Capacity Resource was committed through the Base Residual Auction and the GIA is not received prior to opening of the bid window for the First Incremental Auction, the status of the Capacity Modification and any unit-specific transaction(s) representing the capacity import will be changed from "Provisionally Approved" to "Denied" so that the planned generation will no longer be included in a resource provider's Capacity Exchange Generation Resource portfolio.
- If a GIA is eventually executed with a start date of Interconnection Service that is on or before the start of the Delivery Year, a new Capacity Modification and any unit-specific transaction(s) representing the import will need to be submitted and "Provisionally Approved" in order to be re-included in a resource provider's Capacity Exchange Generation Resource portfolio.
- If the Planned Generation Capacity Resource is delayed and has not commenced Interconnection Service by the start date of the Capacity Modification, the status of the Capacity Modification and any unit-specific transaction representing the import will be changed from "Provisionally Approved" to "Denied". A new Capacity Modification and unit-specific transaction representing the import will need to be submitted and approved with a start date that corresponds to the start date of Interconnection Service.
- Once operational, the resource owner or operator submits the required operating and maintenance information into PJM's eDART and eGADs systems.

- Once operational, the resource owner or operator performs winter and summer testing as described in ***PJM's Rules and Procedures for Determination of Generating Capability (M-21 and M-21B)*** to verify the net capability of each unit.
- The resource owner provides a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area.
- The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year.
- Effective with the 2025/2026 Delivery Year, an external Planned Generation Capacity Resource must satisfy the requirements of the binding notice of intent in section 4.2.3.1 in order for the external Planned Generation Capacity Resource to be included in a Sell Offer for an RPM Auction.

### 4.2.5 Equivalent Demand Forced Outage Rate (EFORd) (Through 2024/2025 Delivery Year)

Equivalent Demand Forced Outage Rate (EFORd) is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate. See ***Generator Resource Performance Indices Manual (M-22)*** for the equations and derivations used in calculating a unit's EFORd.

The EFORd of a unit is based on forced outage data from an October through September period. If a unit does not have a full one-year history of forced outage data, the EFORd will be calculated using class average EFORd and the available history as described in the ***Reliability Assurance Agreement, Schedule 5, Section B***.

The EFORd based on forced outage data from an October through September period prior to the Delivery Year is based on all forced outage data and does not exclude forced outage data for Outside Management Control events.

Since no forced outage data is collected for Variable Resources, an EFORd is not calculated for Variable Resources. The EFORd of Variable Resources is set to zero in the Capacity Exchange system.

New units are initially assigned a class average EFORd. The class average EFORds that are used by PJM to calculate a unit's EFORd are posted to the PJM website by November 30 prior to the Delivery Year.

The Effective EFORd is the EFORd that is effective for the delivery day in the Capacity Exchange system. Prior to the Delivery Year, the Effective EFORd is the most recently calculated EFORd that has been bridged to the Capacity Exchange system. During the Delivery Year, the Effective EFORd is based on forced outage data from the October through September period prior to the Delivery Year.

The EFORd that is effective for the Delivery Year is considered locked in the Capacity Exchange system by November 30 prior to the execution of the Third Incremental Auction.

**Note:** Through and including the 2024/2025 Delivery Year, the UCAP value of a Generation Capacity Resource (except for a Generation Capacity Resource that is a Variable Resource, a Limited Duration Resource or a Combination Resource) is based on the resource's EFORd. Effective with the 2025/2026 Delivery Year, the UCAP value of all Generation Capacity Resources is based on the Accredited UCAP Factor of each resource as determined by ELCC analysis (see Section 4.2.7 Accredited UCAP for ELCC Resources).

### 4.2.6 Capacity Modifications (CAP Mods)

Capacity Modifications (CAP MODs) are a type of Capacity Exchange transaction used by generation owners to request the addition of a new unit or the removal of an existing unit from their resource portfolio in Capacity Exchange, or to request a MW increase or decrease in the summer or winter installed capacity rating of an existing unit.

The purpose of a CAP MOD is to establish the installed capacity value of a generation resource in the Capacity Exchange system. CAP MOD transactions represent permanent changes to the installed capacity value of a generation unit.

CAP MODs are also used by a generation owner to establish the capacity value of an ELCC Resource to be offered into the PJM Capacity Market and by PJM to establish the Delivery Year capacity value of an ELCC Resource.

A CAP MOD may also be submitted by PJM to establish the capacity value of a Winter-Period Capacity Performance Resource for November through April of the Delivery Year.

The following are business rules that apply to Capacity Modifications (CAP Mods):

- CAP MODs with a start date that occurs on or before the start of the Delivery Year must be submitted and “Provisionally Approved” or “Approved” by PJM in the Capacity Exchange system prior to the opening of the Base Residual Auction’s or Incremental Auction’s bidding window in order for the CAP MODs to be considered in a party’s Generation Resource Position and the calculation of Available ICAP to offer for a Base Residual Auction, Incremental Auction or bilateral unit-specific transaction.
- All other CAP MODs must be submitted a minimum of 2 business days prior to the start date of the CAP MOD. The CAP MOD must be “Approved” by PJM in the Capacity Exchange system prior to the start date of the CAP MOD in order to be considered in a party’s final Daily Generation Resource Position.
- If the status of a “Provisionally Approved” CAP MOD changes to “Denied” or “PJM Withdrawn”, there will be no change to any party’s RPM Resource Commitments[11].
- CAP MODs cannot be created during an RPM Auction’s bidding window and clearing week.

- CAP MODs that are not in the “Approved” status by the start date of the CAP MOD will have their status changed to “PJM Withdrawn”.
- CAP MODs that would cause the summer rating of a generation resource or the capacity value of an ELCC Resource to exceed such unit’s Capacity Interconnection Rights plus transitional resource MWs will be “Denied” by PJM.

### 4.2.7 Accredited UCAP for ELCC Resources

Effective Load Carrying Capability (ELCC) establishes the Accredited UCAP value for ELCC Resources. Through the 2024/2025 Delivery Year, an ELCC Resource is a Variable Resource, a Limited Duration Resource, or a Combination Resource. Beginning with the 2025/2026 Delivery Year, an ELCC Resource is a Generation Capacity Resource or Demand Resources. Through the 2024/2025 Delivery Year, for the sole purpose of Manual 18 and the Capacity Exchange tool, the “ICAP” and “UCAP” for an ELCC Resource are set equal to the lesser of its Accredited UCAP or its Capacity Interconnection Rights plus transitional resource MW, and the EFORd of an ELCC Resource is shown as zero because the actual EFORd of an ELCC Resource, if applicable, has already been used in the determination of its Accredited UCAP.

Through the 2024/2025 Delivery Year, the Accredited UCAP Factor shall mean one minus the EFORd. For the 2025/2026 Delivery Year and subsequent Delivery Years, Accredited UCAP Factor is the ratio of the Capacity Resource's Accredited UCAP to the Capacity Resource's installed capacity.

The ELCC method is described in Manual 20 and Manual 20A (**PJM Resource Adequacy Analysis**), and the calculation of Accredited UCAP for an ELCC Resource is described in Manual 21A and Manual 21B (**Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis**).

### 4.2.8 Interim Provisions for RMR Generation Resources

For Delivery Years up to and including the 2027/2028 Delivery Year (unless an extension of these provisions are proposed by PJM and approved by FERC), Reliability Must Run (RMR) Generation Capacity Resources that meet the criteria specified in Tariff, Attachment DD, section 5.3(b) will be included in the Base Residual Auction and to the extent there is an increase in Accredited UCAP, the additional MWs shall be included in the Third Incremental Auction with a Sell Offer of $0/MW-day and settled in accordance with the provisions specified in Tariff, Attachment DD, sections 5.3, 5.4 and 5.14. To the extent there is a reduction in Accredited UCAP for such resources between the Base Residual Auction and Third Incremental Auction, PJM will adjust the quantity that it seeks to procure or release in the Third Incremental Auction in accordance with Tariff, Attachment DD, section 5.3 (b) (ii) and 5.4(c). Furthermore, such

11 RPM Resource Commitments are placed on a resource when the resource clears or receives make-whole MWs through an RPM Auction, when the resource is specified as a replacement resource, or when the resource is used as the source of a Locational UCAP transaction.

resources shall not be subject to the rights and obligations of a committed Capacity Resource, and shall not be eligible for Non-Performance Charges or bonus payments. The performance and cleared Unforced Capacity of such Generation Capacity Resources shall also be excluded from the Balancing Ratio, as specified in Tariff, Attachment DD, section 10A.

## 4.3 Load Management Products

Load management is the ability to reduce metered load, either manually or automatically by the customer, after a request from the resource provider which holds the load management rights or its agent.

A load management program (e.g., Firm Service Level (FSL) or Guaranteed Load Drop (GLD) program) is eligible to (1) be offered by a resource provider as a Demand Resource (DR) into the Base Residual Auction or an Incremental Auction and is paid the applicable LDA product-specific Resource Clearing Price if such resource clears in the auction; or (2) be committed by an FRR Entity to an FRR Capacity Plan.

### 4.3.1 Requirements of Load Management Products in RPM

In order to offer a Demand Resource in an RPM Auction or commit a Demand Resource in an FRR Capacity Plan, a demand resource provider must submit no later than 30 days prior to the RPM Auction or prior to the deadline for submitting the FRR Capacity Plan a Demand Resource Sell Offer Plan (DR Sell Offer Plan) in accordance with Attachment C of this Manual. Actual deadline date for a DR Sell Offer Plan for an RPM Auction or FRR Capacity Plan is provided in the RPM Auction Schedule posted on the PJM website. A demand resource provider with a PJM approved DR Sell Offer Plan for the RPM Auction will be permitted to offer their Demand Resource(s) into such RPM Auction or commit such Demand Resource in an FRR Capacity Plan, provided the additional demand resource requirements in section 4.3.3 are met.

Demand resources that clear in an RPM Auction will have an RPM Resource Commitment for the relevant Delivery Year. Demand resources that are committed to an FRR Capacity Plan will have an FRR Capacity Plan Commitments for the relevant Delivery Year. A resource provider who has RPM Resource Commitments or FRR Capacity Plan Commitments for their demand resource must meet the following requirements:

- Must be registered in the Pre-Emergency or Emergency Load Response Program (see more detail below in the Pre-Emergency and Emergency Load Response Registration section) prior to the start of the relevant Delivery Year.
- Have the capability to retrieve electronic messages from PJM which notify curtailment service providers of a load management event in accordance with **PJM Manual 1: Control Center and Data Exchange Requirements.**
- Provide (or contract with another party to provide) customer-specific compliance and verification information within 45 days after the end of the month in which a Performance Assessment Interval occurred, in accordance with the Measuring Compliance during

Performance Assessment Interval section, Section 8.6 of this manual. Provide (or contract with another party to provide) customer-specific compliance and verification information in accordance with the timelines established in the Load Management Test Compliance section, Section 8.7 of this manual. Statistical sampling may be used instead of customer-specific compliance and verification information for residential customers without interval metering when approved by PJM in accordance with **PJM Manual 19: Load Forecasting & Analysis, Attachment D**.

- Provide load drop estimates for all Load Management events (whether initiated by PJM or the resource provider) and provider initiated test event, in accordance with **PJM Manual 19: Load Forecasting & Analysis.**
- Provide accurate estimates of the amount of energy that will be reduced in direct response to PJM dispatch of demand response during the Delivery Year (see more detail in the Load Reduction Reporting section).

These requirements are described in terms of the customer response and qualifications. The specifics of the customer contract and tariffs are the responsibility of the resource provider and the regulatory process. PJM does not have direct involvement with customers.

The entity requesting load management must verify that each customer's load management meets the following criteria:

- Availability for PJM-initiated interruptions in accordance with the availability requirements of the demand resource product type.
    - Capacity Performance DR – Capacity Performance DR is available for an unlimited number of interruptions during the Delivery Year, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.
    - Summer-Period DR – Summer-Period DR is available for an unlimited number of interruptions during an extended summer period of June through October and the following May, and will be capable of maintaining such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time.
- Load management must be able to be implemented within two hours of notification to the resource provider of a PJM-initiated load management event. Load management is required to fully respond within 30 minutes of notification unless an exception request for 60 or 120 minutes notification time is approved by PJM. If qualified for one of the following exceptions, then CSP shall elect either 60 minute or 120 minute lead time based on the resources physical capability to provide the load reduction:
    - The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing

process, or damage to the product generated or feedstock used in the manufacturing process; or

- Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes; or
- On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or
- The Demand Resource Registration is comprised of mass market residential customers or similarly situated mass market small commercial customers which collectively cannot be notified of a Load Management event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.
- The intent of these exemptions is to accommodate Demand Resource Registrations with legitimate, physical reasons as to why the load reduction cannot be achieved in the default, 30 minute notification time period and require up to 120 minutes to fully provide the load reduction. CSP must provide additional data and information within three business days of PJM request to substantiate the request for a longer lead time (60 or 120 minutes). PJM will make its determination within ten business days of receiving such additional information regarding the appropriate lead time for the registration.

- Initiation of load interruptions upon request of PJM must be within the authority of the resource provider dispatcher without any additional approvals being required.

### 4.3.2 Types of Load Management Programs

PJM recognizes three types of Load Management programs:

- Firm Service Level (FSL) – Load management achieved by a customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the resource provider's market operations center or its agent.
- Guaranteed Load Drop (GLD) – Load management achieved by a customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the resource provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

For each type of recognized Load Management Program, there can be three notification periods:

- 30 Minute Lead Time – Load management which must be fully implemented in 30 minutes or less from the time the PJM dispatcher notifies the market operations center of a curtailment event.
- 60 Minute Lead Time – Load management which requires more than 30 minutes but no more than one hour, from the time the PJM dispatcher notifies the market operations center of a curtailment event, to be fully implemented.

- 120 Minute Lead Time - Load management which requires more than one hour but no more than two hours, from the time the PJM dispatcher notifies the market operations center of a curtailment event, to by fully implemented.

### 4.3.3 Demand Resources

Both Existing and Planned Demand Resources may participate in RPM Auctions or commit to FRR Capacity Plan if a demand resource provider has a PJM approved Demand Resource Sell Offer Plan.

Existing Demand Resources are those MWs on a demand resource identified in a pre-registration process in the Capacity Exchange system prior to the RPM Auction.[12]The Nominated DR Values (in MWs) associated with end-use customer sites that the Curtailment Service Provider (CSP) has under contract for the current Delivery Year (i.e., end-use customer sites registered in PJM DR Hub system for the current Delivery Year)[13] and that the CSP intends to have under contract for the auction Delivery Year are considered Existing MWs. The summer Nominated DR Value of a Demand Resource Registration is used in the calculation of Existing MWs. A CSP may request an adjustment to the summer Nominated DR Value (in MWs) associated with an end-use customer site and used in the determination of a CSP's Existing MWs if the following three criteria are satisfied:

- The original Nominated DR Value for the end-use customer was determined based on one registration in DR Hub.
- The peak load contribution (PLC) reported in the DR Hub registration for the end-use customer is at least 2 MW lower than it should have been due to an anomaly. An anomaly is a condition at the end-use customer site that resulted in significantly low usage that is not expected to occur in the future, such as a lighting strike or a major mechanical failure to an end use device.
- The CSP provides supporting information including historical load data to support an adjustment to the Nominated DR Value for the end-use customer.

A CSP request for an adjustment to the summer Nominated DR Value of an end-use customer and supporting information must be submitted via email to rpm_hotline@pjm.com at least five business days prior to the opening of the pre-registration window in the Capacity Exchange system for an RPM Auction. PJM will notify the CSP of the approval or rejection of their request

[12] For an FRR Entity, a pre-registration process is performed manually through spreadsheets provided by PJM.

[13] For a Base Residual Auction and a Third Incremental Auction, end-use customer sites registered in the PJM DR Hub system for the subsequent Delivery Year may also be considered as existing DR provided the registrations are in "Confirmed" status by specified deadlines established by PJM and communicated to CSPs in advance of the DR Sell Offer Plan submittal deadline.

prior to the opening of the pre-registration window in the Capacity Exchange system for an RPM Auction.

Planned Demand Resources are defined as resources that do not currently have the capability to provide reduction in demand or to otherwise control load in PJM, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year. Planned Demand Resources are those MWs on a demand resource that the CSP intends to offer in the RPM Auction or commit to an FRR Capacity Plan in excess of the CSP's Existing MWs on such demand resource.

**Note:**
Planned Demand Resources must establish an RPM Credit Limit prior to an RPM Auction. Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.

A resource provider may offer Demand Resources (Planned or Existing) associated with Behind the Meter Generation for an entire Delivery Year into the Base Residual or Incremental Auctions. If the DR offer clears in an RPM auction for a given Delivery Year, the operating Behind the Meter Generation cannot be netted from load for the purposes of calculating he Peak Load Contributions for the subsequent Delivery Year in accordance with ***Generator Operational Requirements Manual (M-14D), Appendix A: Behind the Meter Generation Business Rules.***

If offering as a Demand Resource in the Base Residual Auction or Incremental Auction, a sell offer must be submitted in the Base Residual Auction or Incremental Auction. Demand Resources offered and cleared in a Base Residual or Incremental Auction will receive the corresponding LDA product-specific Resource Clearing Price determined by the optimization algorithm.

### 4.3.4 Demand Resource Modifications (DR Mods)

A Demand Resource Modification (DR MOD), a type of Capacity Exchange transaction, can be used to track an increase or decrease of the nominated value of a provider's DR Resource in the Capacity Exchange system. DR MODs are no longer submitted by DR Providers. PJM may submit a DR MOD for an FRR Entity to establish the Daily Nominated DR Value for an FRR Entity's Demand Resource based on PJM's approval of the FRR Entity's DR Sell Offer Plan. After the Delivery Year demand resource registration process begins in DR Hub system, the Daily Nominated DR Value for a Demand Resource is established based on confirmed Demand Resource Registrations in "completed" status linked to the DR Resource in the DR Hub system. The Daily Nominated DR Value for a Capacity Performance Demand Resource during the summer period of June through October and May of the Delivery Year is based on the sum of the summer nominated DR values of the registrations linked to such Demand Resource. The Daily Nominated DR Value for a Demand Resource during the non-summer period of November through April is based on the lesser of (a) the sum of the summer nominated DR values of the

registrations linked to such Demand Resource or (b) the sum of the winter nominated DR values of the registrations linked to such Demand Resource.

### 4.3.5 Pre-Emergency and Emergency Load Response Registration

Pre-Emergency and Emergency Load Response Registration is the process of providing the following information through the submittal of a Pre-Emergency or Emergency Load Response registration into PJM's DR Hub system. As part of this process, resource providers will submit the following types of information:

- Customer-specific load management information for planning and verification purposes (i.e., EDC account number, Zone, etc.)
- Customer-specific information to establish nominated load management levels (i.e., Peak Load Contribution, Winter Peak Load, EDC Loss Factor, notification period, Firm Service Level data (summer and winter), Guaranteed Load Drop data (summer and winter). Winter Peak Load and winter Firm Service Levels are required for Capacity Performance DR registrations. However, Winter Peak Load and winter Firm Service Levels are not required if such registration indicates that it is a Summer-Period DR Only registration. Economic, Pre-Emergency, or Emergency Load Response registrations that would like to be eligible for Bonus Performance for a Performance Assessment Interval must have both customer-specific summer and winter based data provided in the registration.
- Demand Resource name to link the Demand Resource Registration to the appropriate Demand Resource modeled in the Capacity Exchange system.
- Load Management product type for customer site (Capacity Performance DR, Summer-Period DR[14]).
- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process

A resource provider who has RPM or FRR Resource Commitments for their demand resource must register customers in the Full Program Option or as a Capacity Only Option of the Emergency Load Response or Pre-Emergency Load Response Program.

The Full Program and Capacity Only Option enable a resource provider that has approved registrations for the Delivery Year prior to the applicable registration deadline to receive capacity credits, in the form of RPM Auction Credits, if the resource provider cleared their demand resource in an RPM Auction, for that Delivery Year. Full Program Option resource providers

[14] Summer-Period DR is included in Capacity Performance DR registration when a Nominated DR Value based on summer data is greater than Nominated DR Value based on winter data. If Summer- Period DR Only is checked on the registration, such registration is only required to provide Nominated DR Value based on summer capability when dispatched in the summer period. If Summer-Period DR Only is not checked on the registration, the registration is required to provide Nominated DR Value based on summer capability and Nominated DR Value based on non-summer capability.

may claim an energy settlement for a PJM-initiated Load Management Event. Capacity Only Option resource providers may not claim an energy settlement for a PJM-initiated Load Management Event for Capacity Only Option registrations.

Customer sites registered in the Energy Only Program are not eligible to receive capacity credits.

A provider with RPM or FRR Resource Commitments for their Demand Resource must register customer sites that are the Capacity Performance product-type.[15]

A completed Load Response registration in DR Hub for a DR resource must be submitted no later than one day before the tenth business day preceding the relevant Delivery Year. All registrations that have not been approved on or before May 31st preceding the relevant Delivery year shall be rejected by PJM.

Full details of the Pre-Emergency and Emergency Load Response registration and approval process may be found in ***Energy & Ancillary Services Market Operations Manual (M-11), Section 10.***

### 4.3.6 End-Use Customer Aggregation

A resource provider may aggregate multiple end-use customer sites to create a single Demand Resource for the purposes of submitting an offer in the RPM Auctions, if all the end-use customer sites have the same following characteristics:

- Curtailment Service Provider
- Electric Distribution Company (EDC)
- Transmission Zone (or sub-zonal LDA)

The mechanism for aggregating end-use customer sites to create a single Demand Resource is to select the same Demand Resource for multiple end-use customer sites during the registration process.

### 4.3.7 Determination of Nominated Values for Load Management

Once an end-use customer is registered in the Pre- Emergency or Emergency Load Response Program (Full Program Option or Capacity Only), a nominated load reduction value is calculated for that customer. A summer and winter nominated load reduction value may be calculated for a registration depending on the product-type registration and Delivery Year. The determination of the value of the load reduction is consistent with the process for determination of the capacity obligation for the customer. Nominated value of a load management resource is equivalent to the Installed Capacity value of a generation resource.

[15] A Capacity Performance product-type registration includes Summer-Period DR when a Nominated DR Value based on summer data is greater than Nominated DR Value based on winter data.

For an end-use customer registration, the summer nominated DR value for the registration is based on the Peak Load Contribution in place at the time of the registration in the DR Hub system. The winter nominated DR value for a Capacity Performance registration is based on the Winter Peak Load at the time of the registration in the DR Hub system.

**Nominated Value of Firm Service Level Resources**

A registration for a Firm Service Level (FSL) customer includes a summer nominated DR value. Registrations of the Capacity Performance product-type also include a winter nominated DR value.

The summer nominated DR value for a Firm Service Level customer on Capacity Performance DR and Summer-Period DR Only product-type registrations is equal to the difference between its Peak Load Contribution (PLC) and its pre-determined summer firm service level load adjusted for system losses.

$$Summer\ NominatedValueofFSLCustomer = PLC - (SFSL * LossF)$$

**Where:**

| | |
|---|---|
| **PLC** | the customer's EDC-assigned Peak Load Contribution; |
| **SFSL** | Summer Firm Service Load level; |
| **LossF** | the customer's EDC-assigned loss factor. |

The winter nominated DR value for a Firm Service Level customer on a Capacity Performance product-type registration is calculated as (Winter Peak Load for customer multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service Level) times the loss factor.

If a Capacity Performance product-type registration indicates that such registration is for Summer-Period DR Only, the winter nominated DR value for a Firm Service Level registration will be zero.

The Winter Peak Load is determined by the Curtailment Service Provider based on the average of the Demand Resource customer's specific peak hourly load between hours ending 7:00 EPT through 21:00 EPT on the PJM defined 5 coincident peak days from December through February two Delivery Years prior to the Delivery Year for which the registration is submitted. Notwithstanding, if the average use between hours ending 7:00 EPT through 21:00 EPT on a winter 5 coincident peak day is below 35% of the average hours ending 7:00 EPT through 21:00 EPT over all five of such peak days, then up to two such days and corresponding peak demand

values may be excluded from the calculation. If no hourly load data exists for December through February two Delivery Years prior to the Delivery Year, or if more than two days meet the exclusion criteria, then the CSP may use the most recent December through February hourly load data to calculate the Winter Peak Load, upon PJM verification. If no hourly load data for the customer exists for the last two December through February periods prior to the Deliver Year, or if more than two days meet the exclusion criteria for the last two December through February periods prior to the Delivery Year, the CSP may provide alternative data to support a Winter Peak Load subject to PJM's review and approval of the use of alternative data.

The Zonal Winter Weather Adjustment Factor is equal to the zonal winter weather normalized peak divided by the zonal average of five coincident peak loads in December through February. PJM posts the RTO winter 5 CP days on the PJM website. PJM calculates and posts the Zonal Winter Weather Adjustment Factors on the PJM website.

**Nominated Value of Guaranteed Load Drop Resources**

A registration for a Guaranteed Load Drop (GLD) customer includes a summer nominated DR value. Registrations of the Capacity Performance product-type also include a winter nominated DR value and an annual nominated DR value.

The summer nominated DR value for a Guaranteed Load Drop customer on a Capacity Performance DR and Summer-Period DR Only product-type registrations will be the summer guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the resource provider. The summer nominated value shall not exceed the customer's Peak Load Contribution.

$$Summer\ NominatedValueofGLD = SGLD\ (LossF)$$

**Where:**

| | |
|---|---|
| **GLD** | Customer's Summer Guaranteed Load Reduction; |
| **LossF** | the customer's EDC-assigned loss factor. |

The winter nominated DR value for a GLD customer on a Capacity Performance product-type registration shall equal the winter guaranteed load drop amount multiplied by the loss factor, as established by the customer's contract with the resource provider. The winter nominated DR value shall not exceed the Winter Peak Load for customer multiplied by Zonal Winter Weather Adjustment Factor times the loss factor. If a Capacity Performance product-type registration indicates that such registration is for Summer-Period DR Only, the winter nominated DR value for the GLD customer on the registration will be zero.

### 4.3.8 Determination of the UCAP Value of Load Management

Prior to the 2025/2026 Delivery Year, unforced capacity (UCAP) value of a Load Management product is equal to the Nominated Value of that product multiplied by the Forecast Pool Requirement.

$$UCAPValue_{LM} = NominatedValue * FPR$$

Beginning with the 2025/2026 Delivery Year, the unforced capacity (UCAP) value of a Load Management product is equal to the Nominated Value of that product multiplied by the applicable ELCC Class Rating.

$$UCAPValue_{LM} = Nominated \quad Value * \quad applicable \quad ELCC \quad Class \quad Rating$$

### 4.3.9 Load Reduction Reporting

PJM requires an accurate estimate of the amount of energy that will be reduced in direct response to PJM dispatch of Pre-Emergency and Emergency Demand Response capacity resources. This information will be used by PJM to determine the amount of DR resources to dispatch during a pre-emergency or emergency event. The Curtailment Service Provider will contact DR resources, as necessary, to determine a reasonably accurate load reduction capability. The CSP will analyze and review the load reduction capability on a periodic basis to ensure it is reasonably accurate before it is provided to PJM.

**Load Reduction Capability**

The Load Reduction Capability provided by the CSP should represent the expected future incremental load reduction of energy that will be provided by the DR resources if dispatched by PJM under pre-emergency or emergency conditions. The Load Reduction Capability should only include energy load reductions expected to occur if a pre-emergency or emergency DR event is declared. This is independent of the committed capacity MW on the registration(s) and represents the operational expectations regarding the ability to reduce load for the specific time period. The Load Reduction Capability should not include load reductions that have already occurred or are already planned such as the following:

- Planned or unplanned outages at the facility
- Load reductions based on high expected prices, peak shaving or existing contract provisions

PJM will adjust, downward, the reported Load Reduction Capability values to account for any real time or day ahead economic market dispatch that has been assigned to the registered

location(s) by PJM. The difference between the Load Reduction Capability and any economic dispatch reductions will indicate the estimated load reductions still available and able to respond to a PJM call for Pre-Emergency or Emergency DR.

**Reporting**

Curtailment Service Providers that have active Full Program Option or Capacity Only registrations shall provide PJM the Load Reduction Capability by zone, by lead time, and by product-type on a monthly basis, to be submitted by the last business day of a given month and effective on the first business day of the following month. During the months of June through September, CSPs will provide any updates to this information for each day by no later than 4 p.m. on the day prior to the operating day.

On days for which a Maximum Emergency Generation/Load Management Alert or Action has been issued as communicated through the PJM ALL CALL and/or published on Data Viewer emergency messages, the Curtailment Service Provider shall on an hourly basis provide any updates to their information for the remaining hours of the day beginning at 10 a.m. and continuing until 7 p.m.

The Curtailment Service Provider shall submit the information electronically to the appropriate PJM system.

### 4.3.10 Maintenance Outage Reporting for Annual Demand Resource

A Capacity Performance product Pre-Emergency or Emergency Load Response registration may request a maintenance outage during the months of October through April. The maintenance is defined as:

- maintenance to a device or generator used to reduce load at the end use customer location that cannot be reasonably scheduled outside of the annual product availability window, or
- maintenance of a CSP's system used to dispatch DR, but such maintenance shall be limited to no more than two times per quarter, shall not exceed one day in duration, and shall be on a Saturday or Sunday.

The outage request must be submitted at least four business days before the requested start date in the appropriate PJM system and will be evaluated on a first come first served basis. If a request is submitted less than four business days in advance, PJM may approve the request up to one day prior to operating day. The maintenance outage must be between one and thirty days and an extension may be requested during an approved outage at least four business days before the beginning of the extension period. PJM may deny a maintenance outage request if the outage is expected to create reliability issues. A maintenance outage denied by PJM may be resubmitted by the CSP to request another time period for the outage. CSPs should make a best effort not to request outages during weekday Capacity Performance product availability hours for the months of January and February. A CSP may cancel maintenance

outage at any time and the associated registration(s) will be required to respond to a PJM initiated Load Management Event and shall be measured for event compliance or Non-Performance Assessment if the event or Performance Assessment Interval starts after PJM receives the cancellation. PJM may cancel a previously approved maintenance outage one day prior to the start of the outage for reliability concerns.

A registration associated with an approved maintenance outage that is in effect during a Performance Assessment Interval will not be considered as dispatched for such Performance Assessment Interval.

## 4.4 Energy Efficiency Resources

An Energy Efficiency (EE) Resource is a project that involves the installation of more efficient devices/equipment, or the implementation of more efficient processes/systems, exceeding then current building codes, appliance standards, or other relevant standards, at the time of installation, as known at the time of commitment, and meets the requirements of ***Schedule 6 (section L) of the Reliability Assurance Agreement***. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption at the End Use Customer's retail site (during the defined EE Performance Hours and during winter performance period if such EE Resource is a Capacity Performance Resource) that is not reflected in the peak load forecast used for the Auction Delivery Year for which the EE Resource is proposed. The EE Resource must be fully implemented at all times during the Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Because energy efficiency measures are reflected in the peak load forecast for a Delivery Year for which an auction is being conducted, the auction parameters must be adjusted through the 2025/2026 Delivery Year, as described is Section 2.4.5, for the EE Resource(s) that are proposed for that auction in order to avoid double-counting of the energy efficiency measures.

The EE Performance Hours are defined as the hours between the hour ending 15:00 Eastern Prevailing Time (EPT) and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year, that is not a weekend or federal holiday.

An EE installation is eligible to offer through the 2025/2026 Delivery Year into an RPM auction or commit to an FRR Capacity Plan if it meets the following criteria:

- EE installation must be scheduled for completion prior to DY;
- EE installation is not reflected in peak load forecast used for the auction for which the EE is offered (is not reflected in peak load forecast used as basis for FRR Capacity Plan requirements if committing to an FRR Capacity Plan);
- EE installation exceeds relevant standards at time of installation as known at time of commitment;
- EE installation achieves load reduction during defined EE Performance Hours; and

- EE installation is not dispatchable[16].

An Existing EE Resource is defined as an EE Resource with a PJM approved Post-Installation Measurement & Verification (M&V) Report. A Planned EE Resource is defined as an EE Resource that does not have a PJM approved Post-Installation M&V Report.

If cleared in an RPM Auction, a Capacity Performance EE Resource will receive a Capacity Performance Resource Clearing Price for the LDA in which the EE Resource resides and a Summer-Period EE Resource will receive a Resource Clearing Price applicable to the EE Provider's cleared Seasonal Capacity Performance sell offer as described in Section 4.10 of this manual.

An EE Resource may participate in RPM Auctions or commit to FRR Capacity Plan for a maximum of up to four consecutive Delivery Years. The time period of an Energy Efficiency installation determines whether an installation is eligible to be a capacity resource for a Delivery Year. The time period of Energy Efficiency installations and their associated eligibility, in addition to the modeling of EE Resources in the PJM Capacity Market, is presented in ***PJM Manual 18B: Energy Efficiency Measurement &Verification.***

An EE Resource must meet the following minimum requirements:

- Submit Initial Measurement & Verification (M&V) Plan no later than 30 days prior to RPM Auction in which the EE Resource is initially offered or 30 days prior to the FRR Capacity Plan in which the EE Resource is initially offered;
- Submit Updated M&V Plan no later than 30 days prior to next RPM auction in which EE Resource is subsequently offered or no later than 30 days prior to next FRR Capacity Plan update in which the EE is subsequently committed;
- Submit a completed Nominated EE Value Template with the M&V Plan using the current Nominated EE Value Template posted on the PJM website;
- Establish credit with PJM Credit Department prior to RPM Auction or prior to committing EE Resource to FRR Capacity Plan (for Planned EE Resources);
- Submit Initial Post-Installation M&V Report no later than 15 business days prior to first Delivery Year that the EE Resource is committed;
- Submit Updated Post-Installation M&V Reports no later than 15 business days prior to each subsequent Delivery Year that the EE Resource is committed; and
- Permit Post- Installation M&V Audit(s) by PJM or Independent Third Party.

***PJM Manual 18B: Energy Efficiency Measurement & Verification*** establishes the requirements for the Initial M&V Plan, Updated M&V Plans, Initial Post-Installation M&V Report, Updated Post-Installation M&V Reports, and the M&V Audit.

16 Dispatchable demand may be offered as a Demand Resource in the PJM Capacity Market.

The following rules apply for Energy Efficiency Resources to facilitate the implementation of any restrictions that may be imposed on Energy Efficiency Resources by a Relevant Electric Retail Regulatory Authority (RERRA) authorized by FERC to opt-out and restrict the sale of Energy Efficiency Resources into PJM Capacity Market (i.e., the Authorized RERRA).

- If a RERRA receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of PJM the following process applies:
  - PJM will publicly post a reference to the FERC authorization of a RERRA order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable EDC(s), and applicable auction(s), and/or Delivery Years.
  - A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources located in the jurisdiction of the Authorized RERRA within the Zone or LDA, as required, and those outside the area but within the Zone or LDA, as required, in the such Seller's Energy Efficiency M&V Plan for the Delivery Year RPM Auction or Seller's Delivery Year Post-Installation M&V Report.
  - PJM shall provide a list of Capacity Market Sellers to the relevant EDC for the specific area(s) to review compliance with the Authorized RERRA. PJM shall provide the list of Capacity Market Sellers within two business days after the deadline for submitting an EE M&V Plan for a DY Auction and within two business days of receipt of Delivery Year Post Installation M&V Report.
  - The relevant EDC shall review compliance with the rules from an Authorized RERRA and provide a response to PJM within five business days after receiving the list of Capacity Market Sellers offering or certifying EE Resources.
  - PJM shall not allow a Capacity Market Seller to offer or certify EE Resources if an EDC denies such Capacity Market Seller to deliver EE Resources in compliance with rules of Authorized RERRA.

A Capacity Market Seller that cannot satisfy its obligations for the relevant Delivery Year due to the prohibition of participation by Authorized RERRA may be relieved of its Capacity Resource Deficiency Charge by notifying PJM no later than seven calendar days prior to the posting of the Planning Parameters for the Third Incremental Auction of such Delivery Year. After providing such notice, the affected Capacity Market Seller shall not be required to obtain replacement capacity for the affected EE Resource and no Capacity Resource Deficiency Charges shall be assessed for the Seller's deficiency in satisfying its RPM obligation for such EE Resource for the relevant Delivery Year. The Capacity Market Seller shall not be entitled to, nor be paid, any RPM Auction Credits for such EE Resource for the relevant Delivery Year. PJM shall apply corresponding adjustment to the quantity of PJM Buy Bids or Sell Offers in the Third Incremental Auction for such Delivery Year.

### 4.4.1 Determination of Nominated Value of EE Resource

The Nominated EE Value of an EE Resource is the expected average demand (MW) reduction during the defined EE Performance Hours in the Delivery Year. EE Resources that qualify as a Capacity Performance product type shall also have an expected average load reduction during

winter performance period (i.e., all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and hour ending 9:00 EPT, and between the hour ending 19:00 EPT and hour ending 20:00 EPT), that is not less than the Nominated EE Value determine during the defined EE Performance Hours. If the Nominated EE Value determined during the defined EE Performance hours is greater than the expected average demand during the defined winter hours, the expected demand during the defined winter hours will be the Capacity Performance value of the Capacity Performance EE Resource. The Nominated EE Value of a Summer-Period Energy Efficiency Resource is the expected average demand reduction during the defined EE Performance Hours in the Delivery Year. The minimum Nominated EE Value accepted in the PJM Capacity Market is 0.1 MW.

The Measurement & Verification (M&V) Plan describes the methods and procedures for determining the Nominated EE Value of an EE Resource (value based on load reduction provided during EE Performance Hours) and the Capacity Performance value (value based on the consideration of load reduction provided during EE Performance Hours and winter performance period) and confirming that the Nominated EE Value and Capacity Performance value is achieved.

The Nominated EE Value approved by PJM in EE Resource Provider's Initial/Updated M&V Plan establishes the Nominated EE Value that may be offered in an RPM Auction or committed to an FRR Capacity Plan (on a summer period basis). The Capacity Performance value approved by PJM in the EE Resource Provider's Initial/Updated M&V Plan provides guidance to the EE Resource Provider on the maximum amount of MWs that should be offered in Capacity Performance Offer Segments or committed as Capacity Performance in an FRR Capacity Plan on an annual basis.

The last Post-Installation M&V Report submitted and approved by PJM prior to the Delivery Year that the EE Resource is committed establishes the final Nominated EE Value and final Capacity Performance value that is used to measure RPM Commitment Compliance and FRR Capacity Plan compliance during the Delivery Year. Failure to submit an Initial/Updated Post-Installation M&V Report or failure to demonstrate that post-installation M&V activities were performed in accordance with the timeline in the approved M&V Plan will result in a final Nominated EE Value and final Capacity Performance value equal to zero MWs for the relevant Delivery Year. If an M&V Audit is performed and results finalized prior to the start of a Delivery Year, the Nominated EE Value or Capacity Performance value confirmed by the Audit becomes the final Nominated EE Value or final Capacity Performance value that is used to measure RPM Commitment Compliance during the Delivery Year. If the M&V Audit is performed and results finalized after the start of a Delivery Year, the Nominated EE Value or Capacity Performance value confirmed by the M&V Audit becomes the basis to determine if any incremental RPM Commitment Compliance Shortfall needs to be assessed retroactively from June 1 of the Delivery Year to May 31 of the Delivery Year.

### 4.4.2 Determination of the UCAP Value of EE Resource

The UCAP value of a Capacity Performance Resource is the Capacity Performance value of the EE Resource multiplied by the Forecast Pool Requirement. The UCAP value of a Summer Period Energy Efficiency Resource is Nominated EE Value multiplied by the Forecast Pool Requirement.

$$UCAPValue_{CP\ EE} =$$

$$Capacity\ Performance\ Value * FPR$$

$$UCAPValue_{SummerPeriod\ EE} = NominatedEEValue * FPR$$

### 4.4.3 Energy Efficiency Resource Modifications (EE MODs)

An Energy Efficiency Modification (EE MOD), a type of Capacity Exchange transaction, is used to track an increase or decrease of the EE Nominated Value of a provider's EE Resource in the Capacity Exchange system. EE MODs are no longer submitted by EE Resource Providers. Prior to the commitment of an EE Resource to an FRR Entity's FRR Capacity Plan, PJM submits an EE MOD in the Capacity Exchange system to represent the Nominated EE Value of an EE Resource to be effective June through October and May of the Delivery Year and an EE Mod to represent the Capacity Performance Value of an EE Resource to be effective for November through April of the Delivery Year based on an EE Provider's approved initial/updated EE M&V Plan. Prior to the Delivery Year, PJM submits an EE MOD to represent the final Nominated EE Value of an EE Resource to be effective for June through October and May of the Delivery Year and an EE MOD to represent the Capacity Performance value of the EE Resource to be effective for November through April of the Delivery Year based on PJM's approval of the provider's Post Installation M&V Report for such Delivery Year.

## 4.5 Qualified Transmission Upgrades

A Qualifying Transmission Upgrade may be offered into the Base Residual Auction to increase import capability into a transmission-constrained LDA (Sink LDA) from a Source LDA. Such transmission upgrade must meet the following minimum requirements.

- Must have been approved and an incremental import capability value must have been assigned by the PJM Planning Department at least 45 days prior to the auction.
- The planned transmission upgrade in-service date must be on or before the start of the Delivery Year.
- At a minimum, Upgrade Customers must be in the Facilities Study phase for the proposed transmission upgrade, in order for approval to be granted and the transmission upgrade must conform to all applicable standards of the PJM Regional Transmission Expansion Planning Process.
- Qualified Transmission Upgrades must establish an RPM Credit Limit prior to an RPM Auction.

- Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.

If a Qualifying Transmission Upgrade that was cleared in the Base Residual Auction is not completed by the start of the Delivery Year, the party who submitted the offer shall provide a replacement in the form of an equivalent amount of capacity resource of the Capacity Performance product type within the Sink LDA by the start of the delivery Year. If replacement capacity is not provided, a Transmission Upgrade Delay Penalty shall apply.

A Qualifying Transmission Upgrade that cleared in the Base Residual Auction will be paid the Locational Price Adder of the Sink LDA less the Locational Price Adder of the Source LDA, multiplied by the megawatt quantity of incremental import capability cleared. A cleared Qualifying Transmission Upgrade is not automatically included in CETL analysis for future delivery years.

Once the Qualifying Transmission Upgrade is in service, the Qualifying Transmission Upgrade is no longer eligible to continue to offer the approved incremental import capability value into future RPM Auctions. Once in service, the transmission upgrade is included in the CETL analysis for future Delivery Years and the approved incremental import capability of the upgrade is valued as an Incremental Capacity Transfer Right as described in section 6.1.2 of this manual.

## 4.6 Bilateral Transactions

Bilateral Transactions in the Reliability Pricing Model are transactions for capacity between a buyer and seller. Bilateral Transactions may be reported to PJM for inclusion in the PJM billing process for unit-specific capacity or Auction Specific MW capacity. Parties in all bilateral transactions reported to PJM agree to indemnify PJM against non-performance by their counterparties in such transactions.

PJM posts reference prices at various points in order to facilitate bilateral trading on the part of market participants. The posted pricing points include LDA and Hub pricing points (associated with a Base Residual Auction (BRA) Resource Clearing Price in a LDA), Net Load pricing points (associated with a Final Zonal Capacity Price less Final Zonal CTR Credit Rate), PZonal pricing points (associated with Preliminary Zonal Capacity Price), FZonal (associated with Final Zonal Capacity Price), and 1IA, 2IA, and 3IA pricing points (associated with a First Incremental Auction (1IA), Second Incremental Auction (2IA), or Third Incremental Auction (3IA) Resource Clearing Price in an LDA). The available pricing points and their definitions are posted on the PJM website.

Additional pricing points will be added by PJM if requested by stakeholders. However, the definition of the pricing points will remain static once created.

### 4.6.1 Unit-Specific Bilateral Transactions

The purpose of reporting a unit-specific bilateral transaction to PJM (regardless of the type of capacity transacted) is to transfer the rights to or control of a specified amount of installed capacity from the Seller to the Buyer. Bilateral contracts for unit-specific capacity resources may be offered into PJM's RPM if these products meet the requirements specified in this Manual.

PJM will provide electronic bulletin board functionality in Capacity Exchange. The bulletin board allows participants to post and view requests to buy or offers to sell capacity resources. The purpose of the bulletin board functionality is to facilitate bilateral transaction activity.

### 4.6.2 Entering Unit-Specific Bilateral Transactions

Unit-specific bilateral transactions reported to PJM may wholly or partially offset an LSE's Locational Reliability Charges in the PJM billing process provided that Available installed capacity purchased through the bilateral transaction is directly offered and cleared in a Base Residual Auction or Incremental Auction or is designated as a self-scheduled resource in a Base Residual Auction (i.e., the RPM Auction Credits received may offset the Locational Reliability Charges assessed in your PJM bill).

The smallest increment of installed capacity that may be reported to PJM as unit-specific transactions is 0.1 MW.

PJM does not recognize "slice of system" or unforced capacity credit bilateral transactions in RPM Auctions.

Both parties of a unit-specific transaction must confirm the transfer of installed capacity from the seller to the buyer via the Capacity Exchange system prior to the start date of the transaction.

Unit-specific transactions to an "External Party" (i.e., "EXT") must be in "Pending PJM" status two business days prior to the start date of the transaction.

All unit-specific bilateral transactions that cover the Delivery Year must be in "Provisionally Approved" or "Approved" status in the Capacity Exchange system prior to the opening of the Base Residual Auction or an Incremental Auction's bidding window in order for the transactions to be considered in a party's Generation Resource Position and the calculation of Available ICAP to offer for a Base Residual Auction or an Incremental Auction or to be used for self-scheduling in the Base Residual Auction.

Unit-specific transactions cannot be created during an RPM Auction's bidding window and clearing week.

Unit-specific transactions that are not in the "Approved" status by the start date of the transaction will have their status changed to "PJM Withdrawn".

Unit–specific bilateral transactions may be reported for the following installed capacity types: Available, Unoffered, or Cleared.

Unit specific transactions reported for either Available or Unoffered capacity must specify:

- The unit to be transacted
- A start and end date for the transaction
- An installed capacity (ICAP) MW value

Unit specific transactions reported for Cleared capacity must specify:

- The unit to be transacted
- A start and end date for the transaction
- The auction in which the unit cleared (Base Residual Auction, First Incremental Auction, Second Incremental Auction, Third Incremental Auction).
- The Capacity Performance offer segment-type applicable to the MWs cleared: Annual, Seasonal-summer, or Seasonal-winter
- The Resource Clearing Price applicable to the MWs cleared in Seasonal Capacity Performance Resource sell offer
- An unforced capacity (UCAP) MW value. Once approved, the unforced capacity MW value will be converted to an installed capacity MW value using the then-current Accredited UCAP Factor for the specified unit. The installed capacity MW value is capped at the ICAP Owned by the Seller.

The following are business rules that apply to Unit-Specific Bilateral Transactions:

- An Aggregate Resource may not be specified as a unit transacted in a Unit-specific transaction.
- If available capacity type is selected, the Capacity Exchange system will validate that the Seller has Daily Available ICAP to offer for the entire term of the transaction. The Daily Available ICAP to offer on a unit is equal to Daily ICAP Owned – Daily Unoffered ICAP - (Daily RPM Resource Commitments/(Accredited UCAP Factor)) – Daily FRR Capacity Plan Commitments.
- Available installed capacity purchased through a bilateral unit-specific transaction that is registered in PJM's Capacity Exchange system may be directly offered into the Base Residual Auction or Incremental Auctions or designated as a self-scheduled resource in the Base Residual Auction.
- If unoffered capacity type is selected, the Capacity Exchange system will validate that the Seller has Daily Unoffered ICAP to offer for the entire term of the transaction and validate that the Buyer is an External Party (EXT).
- The unoffered capacity type may be selected for a unit-specific bilateral transaction if selling a unit externally (formerly known as "delisting") after the Base Residual Auction has been cleared for the specified transaction dates. To delist a unit before the Base Residual Auction has been run, a party may select the Available capacity type to transact installed capacity to an External Party (EXT).

- If cleared capacity is selected, the Capacity Exchange system will validate that the Seller has cleared capacity of the specified Capacity Performance offer segment-type from the specified auction to offer for the entire term of the transaction.
- An approved unit-specific transaction reported to PJM for Cleared capacity will result in a transfer of the applicable product-specific Auction Credit for the specified number of UCAP MW from the Seller to the Buyer for the entire term of the transaction. In addition, the applicable product-specific RPM Resource Commitment for the specified number of UCAP MWs is also transferred from the Seller to the Buyer for the entire term of the transaction.
- The Seller in a unit-specific transaction for cleared capacity will indemnify PJM Settlement, the LLC, and the Members for any failure by the Buyer of such transaction to pay deficiency penalties and charges owed to PJM Settlement and associated with the capacity that is the basis of the unit-specific capacity transaction for cleared capacity.
- To the extent that capacity identified in the unit-specific transaction for cleared capacity is a resource that has an RPM Credit Requirement, the Buyer must have sufficient credit in place with respect to the credit exposure associated with the obligations of the acquired RPM Resource Commitment.

### 4.6.3 Exporting a Generation Resource

Exporting (formerly known as “Delisting”) a generation resource is accomplished by reporting a bilateral transaction with “External Party” (i.e., “EXT”) listed as the “Buyer” in the unit-specific transaction.

Exporting any portion of a generation resource below a party’s Daily RPM Resource Commitments/(Accredited UCAP Factor) plus Daily FRR Capacity Plan Commitments for the term of the transaction is not permitted. Only Available or Unoffered ICAP on the unit may be exported.

Exporting of a generation resource may only be done by the party that submitted the Capacity Modification for the unit.

If a portion of a generation resource is to be exported, appropriate documentation must be submitted to PJM to demonstrate that the party exporting the generation resource has a financially and physically firm commitment to an external sale of its capacity and therefore, is exempt from the offer requirement for capacity resources in ***Attachment DD, Section 6.6 of the PJM Open Access Tariff.***

In order for a generation resource that is being exported to be reflected in a party’s Available ICAP Position for an RPM Auction, the associated unit-specific transaction must be in an “Approved” status by the opening of the RPM Auction’s bidding window.

**Capacity Export Charge**

A Capacity Export Transmission Customer may procure capacity in one PJM Zone and export the capacity from another Zone to outside PJM. Under the FERC approved tariff effective June 1, 2008, the Capacity Export Transmission Customer will pay a Capacity Export Charge and receive a credit similar to the CTR credit if the Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported is higher than the Final Zonal Capacity Price for the Zone in which the resource designated for the export is located. The Capacity Export Charge collected less the credit will be allocated to the LSEs in the Zone from which capacity is exported.

This Capacity Export Charge and credit are assessed daily and billed monthly. These calculations are independent from the CTR calculations based on Base Residual Auction and all Incremental Auctions. The LSE CTR credits and the Incremental CTR credits will not be changed due to Capacity Export Charge/credit calculations.

A Capacity Export Charge is applicable when Long-Term Firm Transmission Service is reserved from export source to export interface.

If more than one Zone forms the interface with the Control Area to which capacity is exported, the Export Reserved Capacity will be apportioned among the Zones. The Export Reserved Capacity is completely apportioned to the Zone if a fully controllable facility crosses the interface (e.g. dc line). The power flow distribution among multiple interface zones for a capacity export would be based on the PJM RTEP Base Power Flow case for the applicable Delivery Year. The power flow distribution calculations are done by modeling the de-listed generator as the source and the designated external load as the sink for the specific capacity exports to be analyzed.

Capacity Export Transmission Customer incurs for each day a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service multiplied by (the Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported minus the Final Zonal Capacity Price for the Zone in which the resource designated for the export is located).

To recognize the value of firm Transmission Service held, the Capacity Export Transmission Customer receives a credit similar to Capacity Transfer Rights (CTRs) credits. The credit is the Final Zonal Capacity price difference used in determining the Capacity Export Charge times Export Customer’s Allocated Share of the Export Path Import.

### 4.6.4 Importing an External Generation Resource

Importing an external generation resource is accomplished by entering into a bilateral transaction with “External Party” (i.e., “EXT”) listed as the “Seller” in the unit-specific transaction. A unit-specific transaction that that represents a capacity import from an external resource that is offering as Capacity Performance product will not be granted a “Provisionally Approved” unit-specific transaction status until the requirements to offer as Capacity Performance in sections 4.2.2 or 4.2.4 are satisfied and will not be granted an “Approved” unit-specific transaction status until the pseudo-tie for such external resource is actually implemented and the external

resource has satisfied PJM's deliverability standards, which for a Prior CIL Exception External Resource may include completing the necessary actions to make a Prior CIL Exception External Resource Operationally Deliverable for the relevant Delivery Year. Demonstrating deliverability may require transmission upgrades on an external Transmission Provider's system or on PJM's system to be completed prior to June 1st of the delivery year.

See sections 4.2.2 and 4.2.4 for the requirements for offering existing or planned external generation resources into RPM Auctions.

Unit-specific transactions that are not in the "Approved" status by the start date of the transaction will have their status changed to "PJM Withdrawn".

Unit-specific transactions that are "Provisionally Approved" should refer to the RPM credit business rules for their associated credit requirements.

### 4.6.5 Treatment of Unit-Specific Capacity Transactions that Start/End Mid-Delivery Year

Unit-specific transactions reported with a Start Date that does not correspond to June 1 or an End Date that does not correspond to May 31 will result in installed capacity that cannot be offered into the Base Residual Auction since a single party does not own the installed capacity for the entire Delivery Year. In addition, this installed capacity will be tracked as Unoffered Capacity after the Base Residual Auction. To address this issue, PJM will facilitate a voluntary process to enable the installed capacity to be offered into the Base Residual Auction for the Delivery Year.

In order to participate, each party of the unit-specific transaction that starts/end Mid-Delivery Year must sign and submit a Self-Schedule Authorization Form found in Attachment B of this Manual, which authorizes PJM to self-schedule the capacity on behalf of the parties in the Base Residual Auction for the Delivery Year. The Authorization Form must be submitted to RPM_Hotline@pjm.com at least 5 business days prior to the opening of the bidding window.

Each party of the unit-specific transaction that starts/ends Mid-Delivery Year must submit a new unit-specific transaction in Capacity Exchange with "Self-Scheduling Coordinator (SELFSC)" as the Buyer prior to the opening of the Base Residual Auction bidding window, so the capacity will be transferred into the SELFSC account for the entire Delivery Year at the time of the Base Residual Auction.

Provided the Self-Schedule Authorization Forms are received and the required unit-specific transactions are submitted, PJM will self-schedule and clear the capacity on-behalf of the parties in the Base Residual Auction for the Delivery Year. The Accredited UCAP Factor at the time of the Base Residual Auction will be used in the resource-specific sell offer in the Base Residual Auction.

After the Base Residual Auction results are posted, PJM will submit unit-specific transactions for Cleared MWs with “SELFSC” as the Seller to transfer capacity back to the Parties (i.e., Buyer in the unit-specific transaction) for the appropriate time periods. No confirmation is required by the Buyer of the unit-specific transaction. The approved unit-specific transactions for Cleared MWs will result in the transfer of ICAP Owned, RPM Resource Commitments, and Auction Credits from the SELFSC account to the Buyer. The Buyer of the Cleared MWs is responsible for any Capacity Resource Deficiency Charges that may be assessed during the term of the unit-specific transaction. In addition, the Buyer of the Cleared MWs is responsible for their share of any Non-Performance Charges or Generation Resource Rating Test Failure Charges that may be assessed during the Delivery Year.

### 4.6.6 Auction Specific MW Transactions

RPM Market Participants have the ability to report Auction Specific MW Transactions to PJM through the Capacity Exchange system. Auction Specific MW Transactions must be for the transfer of physical MW of capacity from a seller to a buyer at the location of the physical resources identified as supplying the transaction.

The following are business rules that apply to Auction-Specific MW Transactions:

- Auction Specific MW Transactions are not eligible to be offered in an RPM auction.
- Auction Specific MW Transactions for a Delivery Year may be submitted following the completion of the RPM auction to which the transaction applies.
- Auction Specific MW Transactions may be submitted for MWs cleared for a seasonal period (summer or winter) of the Delivery Year following the completion of the RPM auction to which the transaction applies.
- Both the Buyer and the Seller of Auction Specific MW Transaction must confirm the Auction Specific MW Transaction via the Capacity Exchange system before the start date of the Delivery Year.
- An Auction Specific MW Transaction must specify the buyer, seller, start and end dates of the transaction.
- The Seller of the Auction Specific MW must also specify the resource(s) (generation resource, demand resource, or energy efficiency resource), Auction Type (Base, First, Second, Third, or Conditional), Capacity Performance offer segment type (Annual, Seasonal-Summer, or Seasonal-Winter), and the MW amount of Auction Specific MW to be transacted from each resource. PJM will verify that the MW of capacity from each of the resources identified as supplying the Auction Specific MW Transaction have cleared in an RPM auction and that at least the MW of cleared capacity indicated for each resource is not committed in any other bilateral transactions. If such sufficient cleared capacity does not exist on any of the indicated resources, PJM will reject reporting of the transaction.
- Auction Specific MW Transactions transfer the capacity rights of the cleared capacity from the Seller to the Buyer. PJM will verify that those capacity rights are not resold by the

Seller in a future bilateral transaction by tracking the Seller's remaining capacity rights for each resource identified in the Auction Specific MW Transaction.

- Auction Specific MW Transactions for MWs cleared on an annual basis must be reported on an annual basis prior to each Delivery Year, therefore, the start and end date of the transaction must correspond to a Delivery Year. Auction Specific MW Transactions for MWs cleared for a seasonal period must be reported for the seasonal period prior to each Delivery Year. Auction Specific MW Transaction for MWs cleared for summer period must be submitted as an Auction Specific MW Transaction with start date of June 1 of Delivery Year and end date of October 30 of Delivery Year and a separate Auction Specific MW Transaction with a start date of May 1 of the Delivery Year and end date of May 31 of the Delivery Year. Auction Specific MW Transaction for MWs cleared for winter period must be submitted with start date of November 1 of Delivery Year and end date of April 30 of the Delivery Year.
- Auction Specific MW Transactions are priced at the weighted average of the Resource Clearing Prices from the RPM auctions in which the MW from the units supplying the transaction cleared.
- The smallest increment that may be transacted through an Auction Specific MW Transaction is 0.1 MW.
- The Seller of the Auction Specific MW is subject to all applicable resource performance charges, including Capacity Resource Deficiency Charges, Non-Performance Charges, and Generation Resource Rating Test Failure Charges.
- The Buyer of the Auction Specific MW will receive any Capacity Performance bonus credits related to the resource(s) identified in the transaction that over-perform during a Performance Assessment Interval. The Buyer's share of bonus credits for each over-performing resource will be based on the ratio of the resource's cleared MWs (in UCAP) transferred in the Auction Specific MW Transaction to the greater of the (a) resource's cleared UCAP transferred or (b) Seller's daily Owned UCAP position for such resource.
- The Buyer will indemnify PJM Settlement, the LLC, and the Members for any failure by the Seller of the Auction Specific MW transaction to pay deficiency penalties and charges owed to PJM Settlement and associated with the capacity that is the basis of the Auction Specific MW transaction.
- PJM reserves the right under the PJM Operating Agreement and PJM Open Access Transmission Tariff, to deny reporting of Auction Specific MW Transactions in the event one of the parties fails to meet any requirements for such reporting.
- The Seller of an Auction Specific MW Transaction will receive a charge equal to the transaction amount (in MW) times the price associated with in the transaction for the term of the transaction.
- The Buyer of an Auction Specific MW Transaction will receive a credit equal to the transaction amount (in MW) times the price associated with the transaction for the term of the transaction.

- The resource(s) transferred to the Buyer in an Auction Specific MW Transaction cannot be subsequently resold in another bilateral transaction by the Buyer during the effective time period of the transaction.

### 4.6.7 Cleared Buy Bid Transactions

RPM Market Participants have the ability to report Cleared Buy Bid Transactions through the Capacity Exchange system. A Cleared Buy Bid Transaction allows the holder of a Cleared Buy Bid from an Incremental Auction to transfer Cleared Buy Bid MWs to another party for the term of the transaction. A Cleared Buy Bid Transaction will not change the resource position or load obligation of an entity. However, the Buyer may use the Cleared Buy Bid MWs as a replacement resource in a Replacement Capacity Transaction.

The following are business rules that apply to Cleared Buy Bid Transactions:

- Cleared Buy Bid MWs are not eligible to be offered in an RPM auction.
- Both the Buyer and the Seller of Cleared Buy Bid MWs must confirm the Cleared Buy Bid transaction via the Capacity Exchange system by 23:59 EPT before the start date of the transaction.
- A Cleared Buy Bid Transaction must specify the buyer, seller, start and end dates of the transaction, the transaction amount (in MW), the LDA, product-type (and Incremental Auction associated with the Cleared Buy Bid. The product-type specified for a Cleared Buy Bid transaction may only be Capacity Performance product type.
- The smallest increment that may be transacted through a Cleared Buy Bid Transaction is 0.1 MW.
- Cleared Buy Bid transaction results in the “Buyer” receiving the Cleared MWs in the applicable LDA and the associated Incremental Auction Charges that would have been assessed to the Seller for the term of the transaction.

### 4.6.8 Locational Unforced Capacity (UCAP) Transactions

RPM Market Participants have the ability to report Locational UCAP Transactions through the Capacity Exchange system. A Locational UCAP Transaction allows a party with available resource-specific capacity to transfer Locational UCAP (MWs) to another party. A Locational UCAP Transaction will not change the resource position or load obligation of an entity. However, the Buyer may use the Locational UCAP as a replacement resource in a Replacement Capacity Transaction.

The following are business rules that apply to Locational UCAP Transactions:

- Locational UCAP MWs are not eligible to be offered in an RPM auction.
- Both the Buyer and the Seller of Locational UCAP MWs must confirm the Locational UCAP Transaction via the Capacity Exchange system by 23:59 EPT before the start date of the transaction.

- Locational UCAP transactions for a Delivery Year will be restricted as follows during the following periods:
  - Prior to the locking of the Delivery Year Accredited UCAP Factor: Locational UCAP transactions will not be accepted.
  - After the locking of the Delivery Year Accredited UCAP Factor, but before the Delivery Year's Third Incremental Auction bidding window opens: Locational UCAP transactions may be accepted; however, the Buyer of the Locational UCAP transaction must demonstrate prior to the Third Incremental Auction that the Locational UCAP was used in a replacement capacity transaction. If the Buyer fails to enter into a replacement capacity transaction prior to the Third Incremental Auction, the Locational UCAP transaction will be denied by PJM.
  - During the Delivery Year's Third Incremental Auction: Locational UCAP transactions will not be accepted.
  - After the Delivery Year's Third Incremental: Locational UCAP transactions will be accepted.
- A Locational UCAP Transaction must specify the buyer, seller, product type, start and end dates of the transaction. The product type specified must be Capacity Performance.
- The Seller of the Locational UCAP must also specify the resource (generation resource, demand resource, energy efficiency resource, or aggregate resource) and the MW amount of locational UCAP to be transacted. The resource specified in the transaction must be must be capable of meeting the requirements of the product type specified in the Locational UCAP transaction.
- The smallest increment that may be transacted through a Locational UCAP Transaction is 0.1 MW.
- A Locational UCAP transaction results in a product-specific RPM Resource Commitment (in UCAP terms), equal to the MW amount of locational UCAP transacted, being placed on the Seller's resource for the term of the transaction.
- The Seller of the Locational UCAP retains ownership of the resource specified in the Locational UCAP Transaction.
- The Seller of the Locational UCAP is subject to all applicable resource performance assessments.
- The Buyer in a Locational UCAP transaction will indemnify PJM Settlement, the LLC, and the Members for any failure by the Seller of such transaction to pay deficiency penalties and charges owed to PJM Settlement and associated with the capacity that is the basis of the Locational UCAP transaction.

## 4.7 Resource Portfolio

A party's resource portfolio in Capacity Exchange may consist of Generation Capacity Resources, Demand Resources, Energy Efficiency Resources, and Qualifying Transmission Upgrades.

A party's Generation Capacity Resource portfolio may consist of existing generation, planned generation, and bilateral contracts for unit-specific capacity resources. Qualification requirements for generation resources are presented in Existing Generation Capacity Resources, Planned Generation Capacity Resources, and Bilateral Unit-Specific Transaction Sections of this Manual.

### 4.7.1 Resource Position for Generation Capacity Resources

A party's Daily Generation Capacity Resource Position in unforced capacity terms is calculated dynamically by the Capacity Exchange system for each unit and is equal to the party's Daily ICAP Owned on a unit multiplied by the unit's Accredited UCAP Factor.

A party's Daily ICAP Owned on a unit is calculated by adding the ICAP Value of a unit as determined by a party's approved Capacity Modifications to ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases. The Installed Capacity (ICAP) Value of a unit is determined in accordance with ***PJM Manual for the Rules and Procedures for the Determination of Generating Capability (M-21 and M-21B).*** Through the 2024/2025 Delivery Year, for an ELCC Resource, the term "ICAP" in this manual refers to the lesser of the Accredited UCAP or the resource's CIRs plus any awarded transitional resource MWs in accordance with Manual 21 Section 1.2. The ICAP value of a Winter-Period Capacity Performance Resource is based on an Intermittent or Environmentally Limited Resource's certified Capacity Interconnection Rights for the winter period of the Delivery Year.

A unit that is in a party's Generation Capacity Resource portfolio may be traded bilaterally if the party has Daily Available ICAP to offer from the unit for the entire term of the bilateral unit-specific transaction. If the Daily Available ICAP for the unit varies for the term of the bilateral unit-specific transaction, only the minimum Daily Available ICAP may be sold in the bilateral unit-specific transaction.

For a party, the Daily Available ICAP on a unit is equal to Daily ICAP Owned – Daily Unoffered ICAP - (Daily RPM Resource Commitments/(Accredited UCAP Factor)) – Daily FRR Capacity Plan Commitments.

$$DailyAvailICAP_{GEN} =$$

$$DailyICAPOwned - DailyUnofferICAP -$$

$$\left(\frac{DailyRPMResourceCommitments}{Accredited\ \ UCAP\ \ Factor}\right) - DailyFRRCommitments$$

A unit that is in a party's Generation Capacity Resource portfolio may be offered into RPM Auctions if the party has available capacity to offer from the unit for the entire term of the RPM Auction Year. A Seasonal Capacity Performance Resource may be offered into RPM Auctions if the party has available capacity to offer from the unit for the entire summer/winter season. For each RPM Auction, PJM will calculate a Current Available ICAP Position.

A party's Current Available ICAP Position on a unit for an RPM Auction is equal to the minimum Daily Available ICAP for such unit during the entire Delivery Year or summer/winter season.

$$CurrentAvailableICAPPosition_{GEN} = Min\left(DailyAvailableICAP_{GEN}\right)$$

A party's Daily Unoffered ICAP for a specific unit is calculated by adding the sum of any Daily Unoffered ICAP for such unit in RPM Auctions to Daily Unoffered ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases.

$$DailyUnofferICAP_{GEN} =$$

$$DailyUnofferICAP_{RPMAuction} + DailyUnofferICAP_{BilateralSales\,/\,Purchases}$$

For an RPM Auction, a party's Daily Unoffered ICAP for a generation resource is equal to the party's Current Available ICAP Position minus the Offered ICAP in the party's sell offer. A FRR Entity's Daily Unoffered ICAP for a generation resource is set equal to 0 MW.

$$DailyUnofferICAP_{GEN} = CurrentAvailableICAPPosition_{GEN} - OfferedICAP$$

A party's Daily RPM Resource Commitments for a specific generating unit are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such unit in RPM Auctions to decreases/increases of RPM Resource Commitments due to approved unit-specific bilateral sales/purchases of cleared capacity, the specification of replacement resources, and increases of RPM Resource Commitments due to approved Locational UCAP transactions.

A party's Daily FRR Capacity Plan Commitments for a specific unit are equal to the total amount of installed capacity that was committed from the unit for the FRR Capacity Plan.

A party's Daily RPM Generation Capacity Resource Position for a specific unit is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP)*(Accredited UCAP Factor).

$$DailyRPMPosition_{GEN} =$$

$$(DailyICAPOwned - DailyFRRCommittments - DailyUnofferICAP)*$$

$$(Accredited\ \ UCAP\ \ Factor)$$

During the Delivery Year, a party's Daily RPM Generation Capacity Resource Position is compared to their Daily RPM Resource Commitments for the generating unit to determine if a Capacity Resource Deficiency Charge is to be assessed.

### 4.7.2 Resource Position for Demand Resources

A party's Demand Resource portfolio may consist of existing Demand Resources or Planned Demand Resources. Qualification requirements for Demand Resources are presented in Load Management Products Section of this Manual.

A party's Daily ICAP Owned for a specific demand resource is equal to the Daily Nominated DR Value adjusted for the ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such demand resource in effect for such day. The Daily Nominated DR Value for a Demand Resource for a Delivery Year is established based on confirmed Demand Resource Registrations in "completed" status linked to such Demand Resource in the DR Hub system. The Daily Nominated DR Value for a Capacity Performance Demand Resource during the summer period of June through October and May of the Delivery Year is based on the sum of the summer nominated DR values of the registrations linked to such Demand Resource. The Daily Nominated DR Value for a Demand Resource during the non-summer period of November through April is based on the lesser of (a) the sum of the summer nominated DR values of the registrations linked to such Demand Resource or (b) the sum of the winter nominated DR values of the registrations linked to such Demand Resource.

A party's Daily Resource Position for a Demand Resource (in unforced capacity terms) is calculated dynamically by the Capacity Exchange system and is equal to the Daily ICAP Owned multiplied by the Forecast Pool Requirement prior to the 2025/2026 Delivery Year, or, multiplied by the applicable ELCC Class Rating beginning with the 2025/2026 Delivery Year.

A Demand Resource that is in a party's Demand Resource portfolio may be offered into RPM Auctions, if there is Available ICAP to offer from the Demand Resource. A Demand Resource's Available ICAP for an RPM Auction is determined based on pre-registration confirmation process in the Capacity Exchange system for such RPM Auction and PJM's approval of the Curtailment Service Provider's DR Sell Offer Plan for such RPM Auction. A Demand Resource's Existing Available ICAP is determined based on the CSP's completion of the pre-registration process and the DR Existing Setup process in the Capacity Exchange system. A Demand Resource's Planned Available ICAP is determined based on PJM's approval of the CSP's DR Sell Offer Plan and the CSP's completion of the DR Planned Setup process in the Capacity Exchange system. A Demand Resource's Available ICAP is equal to the Existing Available ICAP and Planned Available ICAP. A Demand Resource's Existing Available ICAP and Planned Available ICAP is further classified by CSP in the DR Existing/Planned Setup process as MWs intend to offer as Annual Capacity Performance, MWs intend to offer Summer-Period Capacity Performance, and MWs intend to offer as part of an Aggregate Resource.

A party's Daily RPM Resource Commitments for a specific demand resource are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such demand resource in RPM Auctions to decreases/increases of RPM Resource Commitments due to approved unit-specific bilateral sales/purchases of cleared capacity and the specification of replacement resources, and to increases of RPM Resource Commitments due to approved Locational UCAP transactions.

A party's Daily FRR Capacity Plan Commitments for a specific demand resource are equal to the total amount of Nominated DR that was committed from the demand resource for the FRR Capacity Plan.

Through the 2024/2025 Delivery Year, a party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily ICAP Value – Daily FRR Capacity Plan Commitments) * Forecast Pool Requirement.

$$DailyRPMPosition_{DR} = (DailyNomDRValue - DailyFRRCommittments) * FPR$$

Starting with the 2025/2026 Delivery Year, a party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily ICAP Value - Daily FRR Capacity Plan Commitments) * applicable ELCC Class Rating.

$$= (DailyNomDRValue - DailyFRRCommittments) * Applicable \quad ELCC \quad Class \quad Rating$$

During the Delivery Year, a party's Daily RPM Demand Resource Position is compared to their Daily RPM Resource Commitments for the demand resource to determine if a Capacity Resource Deficiency Charge is to be assessed on the delivery day.

### 4.7.3 Resource Position for Energy Efficiency Resources

A party's EE Resource portfolio may consist of existing or planned EE Resources. Qualification requirements for EE Resources are presented in Energy Efficiency Resource Section of this Manual. A party's Daily ICAP Owned for a specific EE Resource is equal to the Daily Nominated EE Value as determined by party's "Approved" EE Modifications (submitted by PJM to represent the final Nominated EE Value or Capacity Performance value of a provider's EE Resource for the Delivery Year based on PJM's approval of the provider's Post- Installation M&V Report for such Delivery Year) adjusted for any ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such EE Resource in effect for such day.

A party's Daily EE Resource Position for an EE Resource (in unforced capacity terms) is calculated dynamically by the Capacity Exchange system and is equal to the Daily ICAP Owned * Forecast Pool Requirement.

$$DailyResourcePosition_{EE} = DailyICAPOwned * FPR$$

An EE Resource that is in a party's EE Resource portfolio may be offered into RPM Auctions, if there is Available ICAP to offer from the EE Resource. An EE Resource's Available ICAP for an RPM Auction is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such RPM Auction and the provider's completion of the EE Setup process in the Capacity Exchange system prior to the RPM Auction. An EE Resource's Existing Available ICAP is determined based on Nominated EE Value approved by PJM in the most recent Post-Installation M&V Report, prior commitments for such Delivery Year (if applicable), and the EE Provider's completion of the EE Existing Setup process in the Capacity Exchange system. A Energy Efficiency Resource's Planned Available ICAP is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such RPM Auction and the provider's completion

of the EE Planned Setup process in the Capacity Exchange system. An EE Resource's Available ICAP to offer into an RPM Auction is equal to the Existing Available ICAP and Planned Available ICAP for such EE Resource for the relevant RPM Auction Delivery Year. An Energy Efficiency Resource's Existing Available ICAP and Planned Available ICAP is further classified by the EE Resource Provider in the EE Existing/Planned Setup process as MWs intend to offer as Annual Capacity Performance, MWs intend to offer as Summer-Period Capacity Performance, and MWs intend to offer as part of an Aggregate Resource.

A party's Daily RPM Resource Commitments for a specific EE Resource are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such EE Resource in RPM Auctions to decreases/increases of RPM Resource Commitments due to approved unit-specific bilateral sales/purchases of cleared capacity, the specification of replacement resources or the use of EE Resource in a Locational UCAP transaction.

A party's Daily FRR Capacity Plan Commitments for a specific EE Resource are equal to the total Nominated EE Value that was committed from the EE Resource for the FRR Capacity Plan.

A party's Daily RPM EE Resource Position for a specific EE Resource is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments * Forecast Pool Requirement.

$$DailyRPMPosition_{EE} = \left(DailyICAPOwned - DailyFRRCommittments\right)*FPR$$

During the Delivery Year, a party's Daily RPM EE Resource Position is compared to their Daily RPM Resource Commitments for the EE Resource to determine if a Capacity Resource Deficiency Charge is to be assessed on the delivery day.

### 4.7.4 Resource Position for Qualified Transmission Upgrades

A party's Qualifying Transmission Upgrade portfolio may consist of planned Qualifying Transmission Upgrades. Qualification requirements for Qualifying Transmission Upgrades are presented in Qualifying Transmission Upgrade Section of this manual.

A Qualifying Transmission Upgrade that is in a party's Qualifying Transmission Upgrade portfolio may be offered into a Base Residual Auction if incremental import capability value into Sink LDA from a Source LDA has been approved by PJM System Planning Department.

A party's Daily Qualifying Transmission Upgrade Position for a Qualifying Transmission Upgrade is calculated dynamically by the Capacity Exchange system and is equal to the incremental import capability value into Sink LDA from a Source LDA that has been assigned by PJM System Planning Department.

A party's Daily RPM Resource Commitments for a specific Qualifying Transmission Upgrade are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such Qualifying Transmission Upgrade in RPM Auctions to any decreases of RPM Resource Commitments due to the specification of replacement resources.

During the Delivery Year, a party's Daily RPM Qualifying Transmission Upgrade Position for a qualifying transmission upgrade is compared to their Daily RPM Resource Commitments for the qualifying transmission upgrade to determine if a Transmission Upgrade Delay Penalty is to be assessed.

## 4.8 Credit Requirements

The purpose of the RPM credit requirement is to encourage future physical performance, but not necessarily fully guarantee financial obligations related to Capacity. Credit requirements for participating in the RPM, therefore, may be different from the other requirements established separately in the PJM Credit Policy, which are intended for other activities and general financial obligations to PJM.

These business rules are intended to be descriptive of the credit requirements for participants in the RPM, but if any conflict arises between provisions in these rules and provisions in the PJM Operating Agreement or PJM Open Access Transmission Tariff (which includes the PJM Credit Policy as Attachment Q), then the provisions in the Operating Agreement and/or Tariff shall govern.

Since LSE payments due to PJM are included in monthly PJM bills, LSE payment obligations are considered to already be measured and covered by provisions of PJM's Credit Policy. Accordingly, no separate credit requirement will be imposed on LSEs under the RPM.

Participants offering into an RPM Auction existing resources (whether generators, demand resources, energy efficiency resources, or external generation resources with firm transmission), are not required to establish credit for the RPM Auctions.

Participants offering into an RPM Auction any Planned Demand Resource, Planned Energy Efficiency Resource, Planned Generation Resource (including External and Financed), Qualified Transmission Upgrade, or external capacity without firm transmission (these five together considered herein to be Resources Requiring Credit for RPM) must establish a separate RPM Credit Limit prior to and for each RPM Auction in which the participant offers planned MWs from a Resource Requiring Credit for RPM.

Participants nominating PRD in advance of a BRA or Third Incremental Auction (for use in RPM Auction or FRR) must establish an RPM Credit Limit before submitting the PRD Plan in advance of the BRA or Third Incremental Auction.

### 4.8.1 RPM Credit Limit

Acceptable sources of credit for the RPM Credit Limit may be either of the following:

- Any unsecured credit or collateral available, according to provisions of the PJM Credit Policy, which has not already been designated or required for financial obligations under the Credit Policy or for other financial obligations within PJM.

- For RPM credit purposes only, if a supplier has a history of being a net seller into PJM, on average, over the past 12 months, then PJM will count as available unsecured credit twice the average of that participant's total net PJM bills over the past 12 months.
- A supplier may combine more than one source of credit for RPM credit purposes. Credit provided for RPM must be non-cancelable until at least 10 days after payment is due for the last month for which a committed financial obligation could be created or owed.

For Resources Requiring Credit for RPM, credit requests should be made to PJM's Credit Department at least two weeks prior to an RPM Auction. For price responsive demand requiring credit, credit requests should be made to PJM's Credit Department at least two weeks prior to the deadline for submitting the PRD Plan. Credit previously established with PJM for general market activity will not be available for RPM unless the participant specifically makes such a request to the PJM Credit Department.

Although credit provided by a participant may be administratively separated for RPM (or FTR, etc.), all credit supplied by a PJM member or customer, whether or not designated for RPM (or FTR, or any other PJM obligation), may be utilized to cover any PJM financial obligation, should the member or customer default.

PJM will return or release RPM credit provided by participants upon request, as long as such release would not cause a participant's RPM Credit Requirement and/or Price Responsive Demand Credit Requirement to exceed its RPM Credit Limit. Furthermore, PJM reserves the right to establish a maximum frequency of such returns or releases, but no less frequent than once per calendar quarter.

A participant must, at all times, maintain its RPM Credit Limit at least sufficient to meet its RPM Credit Requirement and/or Price Responsive Demand Credit Requirement. If a participant's RPM Credit Requirement and/or Price Responsive Demand Credit Requirement ever exceeds its RPM Credit Limit, PJM may exercise any of the remedies afforded by the Credit Policy, Tariff, Operating Agreement, or other agreements, business rules or manuals, including demand for additional credit and/or declaration of default. Failure to exercise a remedy at any given time shall not preclude PJM from exercising such remedy at a later time.

### 4.8.2 RPM Credit Requirement

An RPM Credit Requirement will be established for all participants that are offering into an RPM Auction or have already committed into RPM any Resources Requiring Credit for RPM. The RPM Credit Requirement will be equal to the sum of the individual credit requirements for such resources. The credit requirement for a given resource offered into an RPM auction will be a fixed Auction Credit Rate times the unforced MW offered, times an RPM Credit Adjustment Factor. However, the credit requirement for Planned Financed Generation Capacity Resources and Planned External Financed Generation Capacity Resources shall be one half of the product of the RPM Auction Credit Rate, as provided in Section .VI.B.4 of OATT, Attachment Q, times the megawatts to be offered for sale from such resource in a Reliability Pricing Model Auction (though for Planned External Financed Generation Capacity Resources, this reduction may be

limited subject to limits based on firm transmission secured, as further explained herein). The credit requirement for a given resource committed into RPM will be a fixed Auction Credit Rate times the unforced MW committed, times an RPM Credit Adjustment Factor.

**RPM Credit Adjustment Factor**

The RPM Credit Adjustment Factor for a given resource depends on its status in becoming a fully qualified resource as follows The Credit Adjustment Factor for all Resources Requiring Credit for RPM will be one ("1") except as follows:

- For Planned Demand Resources, the Credit Adjustment Factor will be (1-X), where "X" is the Nominated DR that is certified through an Emergency Load Response Registration divided by the Nominated DR value offered/committed by the Planned Demand Resource.
- For Planned Energy Efficiency Resource, the Credit Adjustment Factor will be (1-X), where “X” is the Nominated EE Value that is confirmed through a PJM approved Post-Installation M&V Report divided by the Nominated EE value offered/committed by the planned energy efficiency resource.
- For existing external generation resources without firm transmission service, the Credit Adjustment Factor will (1-X), where “X” is the MWs of firm transmission service that has been secured for the complete transmission path divided by the MWs of existing external generation resource offered/committed and shall be zero if the Participant has demonstrated that firm transmission service for the complete transmission path has been secured.
- For Planned generation resources (internal and external, financed and non-financed), please see the incremental reduction and associated credit milestones in Section 4.8.5 .
- For Qualifying Transmission Upgrades, the Credit Adjustment Factor will be 0.5 (50%) if a full (not provisional) Generation Interconnection Agreement has been successfully executed but Interconnection Service has not yet begun, and will be zero on the date the Qualifying Transmission Upgrade is placed in service.
- PJM will consider credit adjustment factors other than these on a case-by-case basis.

If a Participant offers a Resource Requiring Credit for RPM into an RPM auction, but the Participant's RPM Credit Limit is insufficient for the participant's RPM Credit Requirement including the new offer, then the offer will be rejected. If the offer was made as part of a sell offer upload file (multiple resources offered simultaneously), then the entire file upload will be rejected. Previous offers made and accepted into an auction will not be rejected solely because a subsequent offer was rejected.

### 4.8.3 Auction Credit Rate

An Auction Credit Rate is calculated prior to each RPM Auction for such Delivery Year as follows:

- Prior to the posting of the BRA results, the RPM Auction Credit Rate for planned Capacity Performance Resources is equal to the greater of (i) $20/MW-day or (ii) 0.5 times

applicable Delivery Year's Net CONE for modeled LDA where the resource resides (in $/MW-day), times the number of days in the Delivery Year. If the resource does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the RPM Credit Rate. The RPM Auction Credit Rate for planned Seasonal Capacity Resources is the same as the RPM Auction Credit Rate for planned Capacity Performance Resources; however, the rate is reduced to be proportional to the number of days in the relevant season.

- Upon posting the BRA clearing results, the RPM Auction Credit Rate used for planned Capacity Performance commitments in the BRA is equal to the greater of [(i) $20/MW-day, (ii) .2 times the Capacity Performance Resource Clearing Price for the LDA that applies to the planned Capacity Performance resource, or (iii) the lesser of (a) 0.5 times Net CONE for modeled LDA where the resource resides for such Delivery Year (in $/MW-day) or (b) 1.5 times Net CONE (stated in installed capacity terms as $/MW-day) for the modeled LDA where the resource resides for such Delivery Year minus the Capacity Performance Resource Clearing Price for the LDA that applies to the planned Capacity Performance Resource], times the number of days in the Delivery Year. If the resource does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the RPM Credit Rate. The RPM Auction Credit Rate used for planned Seasonal Capacity Resource commitments in the BRA is the same as the RPM Credit Rate for planned Capacity Performance commitments in the BRA; however, the rate is reduced to be proportional to the number of days in the relevant season.
- For any planned resource not previously committed for a Delivery Year that participates in an Incremental Auction, the RPM Auction Credit Rate for all planned Capacity Performance Resources is equal to the greater of (i) 0.5 times applicable Delivery Year's Net CONE for modeled LDA where the resource resides (in $/MW-day) or (ii) $20 per MW-day, times the number of days in the Delivery Year. If the resource does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the RPM Auction Credit Rate. The RPM Auction Credit Rate for any planned Seasonal Capacity Resource not previously committed for a Delivery Year that participates in an Incremental Auction is the same as the RPM Auction Credit Rate for planned Capacity Performance Resources; however, the rate is reduced to be proportional to the number of days in the relevant season.
- Upon posting the results of an Incremental Auction, the RPM Auction Credit Rate used for planned Capacity Performance commitments is equal to the greater of [(i) $20/MW-day, (ii) 0.2 times the Capacity Performance Resource Clearing Price in such Incremental Auction for the LDA that applies to the planned resource, or (iii) the lesser of (a) 0.5 times Net CONE for the modeled LDA where resource resides for such Delivery Year (in $/MW-day) or (b) 1.5 times Net CONE(stated in installed capacity terms as $/MW-day) minus the Capacity Performance Resource Clearing Price in such Incremental Auction for the LDA that applies to the planned capacity Performance Resource], times the number of days in the Delivery Year. If the resource does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the RPM Auction Credit Rate. The RPM Auction Credit Rate for planned Seasonal Capacity Resource commitments in an Incremental Auction is the same as the RPM Auction Credit Rate for planned Capacity Performance Resource

commitments in an Incremental Auction; however, the rate is reduced to be proportional to the number of days in the relevant season.

- One rate is calculated for each Auction, binding LDA, and resource product type, and applied according to the Auction, LDA, and resource product type in which the capacity was committed.
- For Qualified Transmission Upgrades, the Auction Credit Rate applied will be based on the Locational Deliverability Area in which such upgrade was to increase the Capacity Emergency Transfer Limit (CETL).

### 4.8.4 Price Responsive Demand Credit Requirement

A PRD Provider seeking to commit PRD in the Base Residual Auction, Third Incremental Auction, or the FRR Alternative, and for which there is a materially increased risk of non-performance for such PRD, must satisfy the Price Responsive Demand Credit Requirement prior to the deadline for submitting the PRD Plan.

The Price Responsive Demand Credit Requirement shall be based on the maximum Nominal PRD Value in the PRD Plan * Forecast Pool Requirement*Price Responsive Demand Credit Rate. For a PRD Provider, the maximum Nominal PRD Value in the PRD Plan may be reduced by the amount of existing PRD that is currently registered and approved in DR Hub system by such PRD Provider on January 1 in advance of the PRD Plan submittal deadline.

Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Price Responsive Demand Credit Rate shall be (the greater of (i) 0.5 times applicable Deliver Year's Net Cone for the modeled LDA where the price responsive demand resides or (ii) $20/MW-day times the number of days in such Delivery Year. If the price responsive demand does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the Price Responsive Demand Credit Rate.

After the posting of the Base Residual Auction results, the Price Responsive Demand Credit Rate used for on-going credit requirements for price responsive demand committed in the Base Residual Auction or to the FRR Alternative prior to the Base Residual Auction, shall be the (greater of (i) $20/MW-day, (ii) 0.2 times the Capacity Performance Resource Clearing Price in such auction for the LDA where the PRD load is located, or (iii) the lesser of (a) 0.5 times Net CONE for the modeled LDA where the price responsive demand resides or (b) 1.5 times Net CONE (stated in installed capacity terms as $/MW-day) for the modeled LDA where the price responsive demand resides minus the Capacity Performance Resource Clearing Price for such modeled LDA)times the number of days in the Delivery Year. If the price responsive demand does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the Price Responsive Demand Credit Rate.

For any additional PRD that seeks to commit in a Third Incremental Auction or seeks to commit PRD to reduce the final unforced capacity obligation of an FRR Entity, the Price Responsive Demand Credit Rate shall be (the greater of (i) 0.5 times applicable Deliver Year's Net Cone for

the modeled LDA where the price responsive demand resides or (ii) $20/MW-day) times the number of days in such Delivery Year. If the price responsive demand does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the Price Responsive Demand Credit Rate.

After the posting of the Third Incremental Auction results, the Price Responsive Demand Credit Rate used for on-going credit requirements for Price Responsive Demand committed in the Third Incremental Auction or committed to the FRR Alternative to reduce the final unforced capacity obligation of an FRR Entity, shall be (the greater of (i) $20/MW-day, (ii) 0.2 times the Capacity Performance Resource Clearing Price in such auction for the LDA where the price responsive demand resides, or (iii) the lesser of (a) 0.5 times Net CONE for the modeled LDA where the price responsive demand resides or (b) 1.5 times Net CONE (stated in installed capacity terms as $/MW-day) for the modeled LDA where the price responsive demand resides minus the Capacity Performance Resource Clearing Price in such Incremental Auction for such modeled LDA ) times the number of days in such Delivery Year. If the price responsive demand does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the Price Responsive Demand Credit Rate.

### 4.8.5 Credit Milestones for Planned Generation Capacity Resources

For Planned Generation Capacity Resources, Planned External Generation Capacity Resources and the RPM Credit Requirement shall be reduced by applying the appropriate Incremental Credit Reduction from the tables below as the resource attains the stated milestones. The incremental credit reductions are summed cumulatively to get the total credit reduction from the achieved milestones. To obtain a reduction in RPM Credit Requirement (except for “GIA effective date” and “Commencement of Interconnection Service”), the Capacity Market Seller must submit a sworn, notarized certification of an independent engineer in a form acceptable to PJM, certifying that the engineer has personal knowledge, or has engaged in a diligent inquiry to determine, that the milestone has been achieved and that, based on its review of the relevant project information, the independent engineer is not aware of any information that could reasonably cause it to believe that the Capacity Resource will not be in-service by the beginning of the applicable Delivery Year. The standard certification form can be found on the PJM website. The Capacity Market Seller, must, if requested by PJM, supply to PJM on a confidential basis all records and documents related to the independent engineer's certification. PJM may accept a certification by a Professional Engineer in lieu of a certification by an independent engineer. For Balance sheet financed resources a notarized officer certification of financial close can be used instead of an independent engineer certification of financial close.

The cumulative reduction in credit requirements for planned external resources and planned financed external resources, including the initial 50% reduction for financed resources, shall never be greater than the quotient of the division of firm transmission MW by offered (or cleared) MW.

| Credit Reductions (%) for Planned Generation Capacity Resources and Planned External Generation Capacity Resources | |
|---|---|
| **Credit Milestones Certified by an Independent Engineer (where applicable)** | **Incremental Credit Reduction from Initial Credit Requirements** |
| Effective date of fully executed GIA for Planned Generation Capacity Resources or agreement equivalent to GIA for Planned External Generation Capacity Resources | 50% |
| Financial Close | 15% |
| Full Notice to Proceed and Commencement of construction (e.g. footers or foundation poured) | 5% |
| Main power generating equipment delivered | 5% |
| Commencement of Interconnection Service | 25% |

The following definitions apply to the terms in the tables above:

- "Effective Date of fully executed GIA" shall be as defined in the relevant GIA.
- "Full Notice to Proceed" means that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.
- "Commencement of construction" means the beginning of major construction of the customer facility or customer interconnection facility.
- "Main power generating equipment delivered" means the main power generating equipment has been delivered to the site.
- "Financial Close" shall mean the resource demonstrated, as supported by a sworn, notarized certification of an independent engineer, certifying that the engineer has personal knowledge, or has engaged in a diligent inquiry to determine, that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. For resources that do not have external financing, PJM may accept instead a sworn, notarized certification by an officer of the company that the project has full funding available, specifying that the project has been duly authorized to proceed with full construction by the appropriate governing body of the company.
- All milestones refer to activities materially related to the delivery of electricity or electric services related to the resource's commitment in the RPM auction.

Example: A Planned Generation Capacity Resource that has committed 10 MW in a Base Residual Auction with an Auction Credit Rate of 36,500/MW-year would have an initial RPM credit requirement of $365,000. After the effective date of an executed GIA, the RPM credit requirement would be $182,500 (50% reduction). After Financial Close the credit requirement would be reduced to $127,750 (65% reduced). Once the Full notice to proceed and Commencement of construction milestone is met then the credit requirement would be $109,500 (70% reduced). Once the Main Power Generating Equipment Delivered milestone is met, the RPM credit requirement would be $91,250 (75% reduced). Upon Commencement of Interconnection Service, the credit requirement would be zero.

## 4.9 Aggregate Resources

Capacity resources which may not, alone, meet the operational requirements of a Capacity Performance product, may combine their capabilities and offer as a single, pseudo aggregate resource[17]. Capacity Market Sellers that own one or more Intermittent Resources, Capacity Storage Resources, Demand Resources, Energy Efficiency Resources, or environmentally limited resources may create and offer an Aggregate Resource located in the smallest modeled LDA common to the underlying aggregated resources for a PJM approved unforced capacity value that satisfies the requirements of a Capacity Performance product.

The following business rules apply to Aggregate Resources:

- Intermittent Resources, Capacity Storage Resources, Demand Resources, Energy Efficiency Resources, and environmentally limited resources that are combined to form an Aggregate Resource will be considered to be located in the smallest modeled LDA common to the underlying aggregated resources[18] and must reside in a single Capacity Market Seller account in Capacity Exchange.
- Market Sellers that intend to create an Aggregate Resource must submit a written email request to rpm_hotline@pjm.com at least two weeks prior to the opening of the RPM Auction in order to allow adequate time for PJM to review such request and model an Aggregate Resource in the Capacity Exchange system.
- Aggregate Resource requests must specify the capacity resources that are being combined to form the Aggregate Resource, the installed capacity owned on each

17 OATT Attachment DD, Section 5.6.2(h)

18 For example, if one resource is located in EMAAC and the other resource is located in Rest of RTO, the Aggregate Resource will be modeled and compensated in Rest of RTO and compensated at Rest of RTO clearing price. If one resource is located in EMAAC and the other is located in SWMAAC, the Aggregate Resource will be modeled and compensated in MAAC. If one resource is located in COMED and the other resource is located in EMAAC, the Aggregate Resource will be modeled and compensated in Rest of RTO.

generation capacity resource, the Nominated DR Value for a Demand Resource, or Nominated EE Value for an EE Resource, and the requested unforced capacity value of the Aggregate Resource. The request must also include an initial seasonal allocation of the Annual Capacity Performance capability of the Aggregate Resource to the underlying resources.

- Aggregate Resource requests must also include a written explanation, including supporting data, to justify how the Aggregate Resource realize a higher level of Annual Capacity Performance capability (in unforced MWs) than the individual resources could provide if offered separately into the RPM Auction.
- The unforced capacity value of the Aggregate Resource may not exceed the sum of the unforced capacity values of the individual resources that are being combined to form the Aggregate Resources.
- PJM will review the Aggregate Resource request and approve the requested unforced capacity value of the Aggregate Resource provided the unforced capacity value is based on satisfying the requirements of a Capacity Performance product.
- The Market Seller may not offer any of the capacity resources that make up the Aggregate Resource separately into the RPM Auction or use the capacity resources that make up the approved Aggregate Resource request in any bilateral capacity transaction while the Aggregate Resource is in effect. Once an Aggregate Resource is modeled for a Delivery Year and clears any amount in a Delivery Year RPM Auction, such Aggregate Resource must remain in effect for the entire Delivery Year and may not be terminated for the Delivery Year.
- An Aggregate Resource may be specified as a resource in a Locational UCAP transaction or Auction Specific MW transaction.
- An Aggregate Resource may not be specified as a resource in a unit-specific capacity transaction.
- An Aggregate Resource that includes Existing Generation Capacity Resource(s) is subject to the Must Offer requirement.
- An Aggregate Resource that includes an Existing Generation Capacity Resource is subject to mitigation and applicable market seller offer cap.
- An Aggregate Resource that includes a planned capacity resource must establish an RPM Credit Requirement prior to the RPM Auction.
- The total committed quantity of an Aggregate Resource must be allocated to its underlying capacity resources prior to the start of the Delivery Year and must be updated within the Delivery Year if the total commitment of the Aggregate Resource is revised due to replacement of all or any part of the Aggregate Resource’s commitment or due to the use of available capacity on the Aggregate Resource as a replacement resource. The total committed quantity must be allocated to the individual underlying resources on a monthly basis and may be updated no later than the last day of each month for months remaining in the Delivery Year. An individual resource may not receive a daily CP commitment allocation that applies for the entire month in excess of their CIRs. The daily commitment

allocation to an underlying capacity resource will be used in the calculation of Expected Performance for such underlying capacity resource in a Performance Assessment Interval for such day.

- If an Aggregate Resource commitment is removed or reduced by a replacement transaction, the Capacity Market Seller responsible for the Aggregate Resource must reduce the allocation of commitment to the underlying resources by a commensurate amount
- If an Aggregate Resource commitment is increased by a replacement transaction, the Capacity Market Seller responsible for the Aggregate Resource must increase the allocation of commitment to the underlying resources by a commensurate amount.
- Individual resources that are part of an Aggregate Resource will be expected to respond to a Performance Assessment Interval (PAI) in the area where they are physically located and its Non-Performance Charge Rate will be based on the location of the physical resources underlying the aggregate. If one or more individual resources that are part of an Aggregate Resource are in the same area where there is a PAI, the under-/over-performance of the Aggregate Resource will be based on the total commitment and performance of all of the individual resources included in the PAI. The Non-Performance Charge Rate applicable to an under-performing Aggregate Resource is based on the rate associated with the LDA in which the under-performing underlying resources are located weighted by the under-performance MW quantity of such resources. The annual non-performance charge limit of an Aggregate Resource is based on the limit applicable to the LDA in which the Aggregate Resource was modeled in the RPM Auction.
- The location of replacement capacity specified for an Aggregate Resource must be in accordance with the Replacement Capacity transaction business rules in Section 8.8 of this manual.

## 4.10 Seasonal Capacity Performance Resources

Capacity Market Sellers may offer Seasonal Capacity Performance Resources into RPM Auctions. A Seasonal Capacity Performance Resource is a Summer-Period Capacity Performance or Winter-Period Capacity Performance Resource, as described below.

A Summer-Period Capacity Performance Resource may include the following types of Capacity Resources that are eligible to submit a sell offer as a Summer-Period Capacity Resource: Summer-Period Demand Resource, Summer-Period Energy Efficiency Resource, Capacity Storage Resource, Intermittent Resources, or Environmentally-Limited Resource that has an average expected energy output during the summer peak-hour periods consistently and measurable greater than its average expected energy output during winter peak hour periods

Summer-Period Demand Resource is a resource that is placed under the direction of the PJM and will be available June through October and the following May of the Delivery Year, and will be available for an unlimited number of interruptions during such months by PJM, and will be

capable of maintaining each such interruption between hours of 10:00 AM to 10:00 PM Eastern Prevailing Time. The Summer-Period Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale in an RPM Auction, or included as Summer-Period Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

A Summer-Period Energy Efficiency Resource is a project, including the installation of more efficient devices or equipment or implementation of more efficient process or systems, meeting the requirements of Schedule 6 of the Reliability Agreement and exceeding then-current codes, appliance standards, or other relevant standards, designed to achieve continuous reduction in electric energy consumption at end use customer's retail site during the summer peak periods (i.e., the defined EE Performance Hours in Section 4.4 of this manual) that is not reflected in the peak load forecast used for the Auction Delivery Year for which the Summer-Period EE Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

To the extent that a Summer-Period Capacity Resource clears in an RPM Auction or is otherwise committed as a Summer-Period Capacity Performance Resource, such resource is obligated to deliver energy as scheduled and/or dispatched by PJM during Performance Assessment Intervals occurring during the calendar months of June through October and the following May of the Delivery Year, and must satisfy the requirements of a Capacity Performance Resource for such period of time. A committed Summer-Period Capacity Performance Resource will be subject to the relevant resource performance assessments for capacity performance commitments and the associated deficiency/penalty charges for such period of time.

A Summer-Period Capacity Performance Resource that clears in an RPM Auction will only receive a Daily RPM Auction Credit for the MWs cleared in such auction for the summer period of June through October and May of the Delivery Year.

A Winter-Period Capacity Performance Resource may include the following types of Capacity Resources that are eligible to submit a sell offer as a Winter-Period Capacity Performance Resource: Capacity Storage Resource, Intermittent Resource, and Environmentally-Limited Resource that has an average expected energy output during winter peak-hour periods consistently and measurably greater than its average expected energy output during summer peak hour periods.

By August 31 of each calendar year, PJM shall solicit requests from generation owners of Intermittent Resources and Environmentally Limited Resources which seek to obtain additional Capacity Injection Rights (CIRs) related to the winter period (November through April of a Delivery Year) for the purposes of creating a Winter-Period Capacity Performance Resource or an Aggregate Resource as described in Section 4.9. Such additional CIRs would be for a one year period as specified by PJM in the solicitation. Responses to such solicitation must be submitted by interested owners by October 31 prior to the upcoming Base Residual Auction.

Such requests shall be studied for deliverability similar to any Generation Project Developer seeking to enter the New Service Request study process; however, such requests shall not be required to enter the New Service Request study process. PJM shall study such requests in a manner so as to prevent infringement on available system capabilities on any resource which is already in service, or which has an executed Generation Interconnection Agreement, Transmission Service Agreement, Upgrade Construction Agreement, or has submitted a valid New Service Request. If the Intermittent Resource or Environmentally Limited Resource is accredited as deliverable for additional CIRs for the winter period, such generation owner shall receive the additional CIRs for the winter period of the relevant Delivery Year.

To the extent a Winter-Period Capacity Performance Resource clears an RPM Auction or is otherwise committed as a Winter-Period Capacity Performance Resource, such resource is obligated to delivery energy as scheduled and/or dispatched by PJM during Performance Assessment Intervals occurring in the calendar months of November through April of the Delivery Year, and must satisfy the requirements of a Capacity Performance Resource for such period of time. A committed Winter-Period Capacity Performance Resource will be subject to the relevant resource performance assessments for capacity performance commitments and the associated deficiency/penalty charges for such period of time.

A Winter Period-Capacity Performance Resource that clears in an RPM Auction will only receive a Daily RPM Auction Credit for the MWs cleared in such auction for the winter period of November through April of the Delivery Year.

A Capacity Market Seller that clears a Seasonal Capacity Resource in an RPM Auction will receive a Resource Clearing Price that is applicable to the Capacity Market Seller's Seasonal Capacity Performance sell offer and is reflective of the Locational Price Adder determined as a result of the seasonal matching process in the post-processing of the auction results as described in Section 5.7.2 and 5.8.5 and any make-whole price, if a make-whole payment is required, for such cleared sell offer.

# Section 5: RPM Auctions

Welcome to the RPM Auctions section of the **PJM Manual for the Reliability Pricing Model**. In this section, you will find the following information:

- An overview description of the RPM Auctions (see “Overview of the RPM Auctions”)
- The auction timeline for RPM Auctions (see “RPM Auction Timeline”)
- The auction parameters for the RPM Auctions (see “RPM Auction Parameters”)
- The business rules for sell offers in RPM (see “Sell Offers in RPM”)
- The business rules for buy bids in RPM (see “Buy Bids in RPM”)
- The requirements to offer in the PJM Energy Market (see “Energy Market Offer Requirements”)
- The business rules for the Base Residual Auction (see “Base Residual Auction”)
- The business rules for the Incremental Auctions (see “Incremental Auctions”)
- The business rules for the auction clearing results (see “Auction Clearing Results”)
- An overview description of the reliability backstop mechanism (see “Reliability Backstop”)

## 5.1 Overview of RPM Auctions

The Reliability Pricing Model (RPM) is a multi-auction structure designed to procure resource commitments to satisfy the region’s unforced capacity obligation through the following market mechanisms: a Base Residual Auction, Incremental Auctions and a Bilateral Market.

- Base Residual Auction – The Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year. Notwithstanding, the Base Residual Auction for the 2025/2026 through 2029/2030 Delivery years shall be conducted in accordance with the RPM Auction Schedule posted on the PJM website. Base Residual Auction (BRA) allows for the procurement of resource commitments to satisfy the region’s unforced capacity obligation and allocates the cost of those commitments among the Load Serving Entities (LSEs) through a Locational Reliability Charge.
- Incremental Auctions – Up to three Incremental Auctions are conducted after the Base Residual Auction to procure additional resource commitments needed to satisfy potential changes in market dynamics that are known prior to the beginning of the Delivery Year.
- The First, Second, and Third Incremental Auctions are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments.
- A Conditional Incremental Auction may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a Locational Deliverability Area to address the corresponding reliability problem.

- The Bilateral Market – The bilateral market provides resource providers an opportunity to cover any auction commitment shortages. The bilateral market also provides LSEs the opportunity to hedge against the Locational Reliability Charge determined as a result of the RPM Auction process. The bilateral market is facilitated through the Capacity Exchange system.

## 5.2 RPM Auction Timeline

The following Auction timeline provides the deadline for key RPM activities[19]:

| RPM Activity | Deadline |
|---|---|
| Submittal of binding notice of intent to offer Planned Generation Capacity Resource into Base Residual Auction (effective with 2025/ 2026 Delivery Year) | December 1st immediately preceding Base Residual Auction (except for 2025/2026, 2026/2027 and 2028/ 2029 Delivery Year); December 12th 2023 (for 2025/2026 Delivery Year); 180 days prior to commencement of offer period (2026/2027 and 2028/ 2029 Delivery Year) |
| Post Planning Parameters for BRA | Posting deadline provided in RPM Auction Schedule on PJM website |
| Post preliminary estimate of the MOPR Floor Offer Price for the relevant Delivery year | 150 days prior to commencement of offer period |
| Data Submittal (Avoidable Cost Data, Opportunity Cost, & Projected Market Revenues) to IMM if submitting non-zero sell offer price | 120 days prior to commencement of offer period |
| IMM to notify Capacity Market Sellers of Market Seller Offer Caps | 90 days prior to commencement of offer period |
| Participant notification to PJM and IMM whether it has reached agreement with the IMM on the level of Market Seller Offer Cap | 80 days prior to commencement of offer period |
| PJM to notify Capacity Market Seller of its determination on Market Seller Offer Cap | 65 days prior to commencement of offer period |

[19] For delivery years where FERC has approved a compressed auction schedule, the actual deadline may be different from the deadline listed in this activity table. Participants should adhere to the activity deadlines on the RPM Auction Schedule posted on the pjm website.

| RPM Activity | Deadline |
|---|---|
| Submittal of Minimum Offer Price Rule (MOPR) exemption request ( Unit-Specific) | 120 days prior to commencement of offer period |
| IMM to notify Capacity Market Seller of determination on MOPR exemption request | 90 prior to commencement of offer period |
| PJM to notify Capacity Market Seller of determination on MOPR exemption request | 65 days prior to the commencement of offer period |
| Submittal of minimum level of Sell Offer commitment consistent with Unit-Specific MOPR request | 5 days after receipt of PJM determination on Unit-Specific MOPR request |
| Submittal of preliminary request to remove a resource from Capacity Resource status and preliminary must-offer exemption request for BRA for the reason specified under OATT Attachment M-Appendix § II.C.4.A | Sept 1st immediately preceding BRA for applicable Delivery Year |
| Submittal of final request to remove a resource from Capacity Resource status and final must-offer exemption request for BRA for the reason specified under OATT Attachment M-Appendix § II.C.4.A | Dec 1st immediately preceding BRA for applicable Delivery Year |
| Submittal of preliminary request to remove resource from Capacity Resource status and preliminary must-offer exemption request for IA for the reason specified under OATT Attachment M-Appendix § II.C.4.A | 240 days prior to commencement of offer period |
| Submittal of final request to remove a resource from Capacity Resource status and final must-offer exemption request for IA for the reason specified under OATT Attachment M-Appendix § II.C.4.A | 120 days prior to commencement of offer period |
| Submittal of must-offer exemption request for any reason other than the reason specified under OATT Attachment M-Appendix § II.C.4.A | 120 days prior to commencement of offer period |
| PJM posts summaries of MW of Generation for which it has received requests to remove a resource from Capacity Resource status, and | No later than 5 Business Days after the request/notification deadline |

| RPM Activity | Deadline |
|---|---|
| for exceptions to the must-offer requirement for the reason specified under OATT Attachment M-Appendix § II.C.4.A, on an aggregate basis by Zone and LDA that comprises a subset of a Zone. Postings shall specify the following aggregate ranges: less than 100 MW; 100 to 500 MW; 500 to 1000 MW; and specific MW total if over 1000 MW | |
| IMM to notify Capacity Market Seller of determination on must-offer exemption request and removal of Capacity Resource status | 90 days prior to commencement of offer period |
| Participant notification to PJM and the MM if it disagrees with the IMM determination of its request to remove a resource from Capacity Resource status or must-offer exception request | 80 days prior to commencement of offer period |
| PJM notification to participant of its determination on must offer exemption request and removal of Capacity Resource status | 65 days prior to commencement of offer period |
| Participant notification to PJM and the IMM whether it intends to exclude from its Sell Offer some or all capacity from its generation resource on the basis of an identified exception to the RPM Must Offer Obligation | 65 days prior to commencement of offer period |
| Submittal of request for alternative maximum EFORd (prior to 2025/2026 Delivery Year) | 120 days prior to commencement of offer period |
| IMM provides determination on request for alternative maximum EFORd (prior to 2025/ 2026 Delivery Year) | 90 days prior to commencement of offer period |
| Participant notification to PJM and the IMM whether agreement has been reached on alternative maximum EFORd (prior to 2025/ 2026 Delivery Year). | 80 days prior to commencement of offer period |
| PJM notification to participant of its determination on alternative maximum EFORd (if no agreement reached with IMM) (prior to 2025/2026 Delivery Year). | 65 days prior to commencement of offer period |

| RPM Activity | Deadline |
|---|---|
| Preliminary ELCC Class Ratings and Accredited UCAP Factors | Posting deadline provided in RPM Auction Schedule on PJM website |
| Participant submits to PJM its Initial/Updated Energy Efficiency Resource Measurement & Verification Plan | 30 days prior to commencement of the offer period |
| Participant submits to PJM its Energy Efficiency Resource Measurement & Verification Report | 15 business days prior to start of Delivery Year for which the resource is committed |
| Participant submits to PJM its Demand Response Resource Plan | 30 days prior to commencement of offer period |
| Base Residual Auction | May, 3 years prior to the Delivery Year |
| Submittal of binding notice of intent to offer Planned Generation Capacity Resource into Incremental Auction | 90 days prior to commencement of offer period |
| Post Updated Planning Parameters for First Incremental Auction | 1 Month prior to First Incremental Auction |
| First Incremental Auction | September, 20 months prior to the Delivery Year |
| Post Updated Planning Parameters for Second Incremental Auction | 1 Month prior to Second Incremental Auction |
| Second Incremental Auction | July, 10 months prior to the Delivery Year |
| Final EFORd fixed for Delivery Year (prior to 2025/2026 Delivery Year) | By November 30$^{th}$ prior to the Delivery Year |
| Final Accredited UCAP Factor for Delivery Year (effective with 2025/2026 Delivery Year) | No later than 5 months prior to the start of the Delivery Year |
| Post Final Planning Parameters for Third Incremental Auction | 1 Month prior to Third Incremental Auction |
| Third Incremental Auction | February, 3 months prior to the Delivery Year |

| RPM Activity | Deadline |
|---|---|
| Conditional Incremental Auction | As Needed |

*Exhibit 2: RPM Auction Timeline*

## 5.3 RPM Auction Parameters

The following information shall be posted by PJM for each Base Residual Auction with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website:

- Preliminary RTO and Zonal Peak Load Forecasts
- LDAs modeled in the Base Residual Auction
- Installed Reserve Margin (IRM)
- Pool-wide Average EFORd (prior to 2025/2026 Delivery Year) and Pool-wide average Accredited UCAP Factor (beginning 2025/2026 Delivery Year)
- Forecast Pool Requirement (FPR)
- Reliability Requirements of the PJM Region and each modeled LDA
- Variable Resource Requirement (VRR) Curves of the PJM Region and each modeled LDA without FRR Entity adjustments. Adjusted VRR Curves with FRR Entity adjustments will be posted after FRR Capacity Plans are approved.
- CETO and CETL values for each modeled LDA
- Transmission Upgrades projected to be in service for the Delivery Year
- Bidding window schedule for the Base Residual Auction
- Cost of New Entry (CONE) for the PJM Region and each modeled LDA
- Net Energy and Ancillary Services Revenue Offset of the PJM Region and each modeled LDA
- Net Cost of New Entry (Net CONE) for the PJM Region and each modeled LDA
- Auction Credit Rate
- The amount(s) of unforced capacity to be procured by PJM and the buy bid price(s) due to increase in Reliability Requirement or the amount(s) to be released from the commitment and the sell offer price(s) due to a reduction in Reliability Requirement will be posted one month prior to the First, Second, or Third Incremental Auctions. The changes in the CETL values and the amount of unforced capacity to be procured for each LDA will be posted one month prior to an Incremental Auction.

## 5.4 Sell Offers in RPM

### 5.4.1 Resource-Specific Sell Offer Requirements

Sell Offers for the Base Residual and Incremental Auctions must be submitted in PJM's Capacity Exchange system. Sell offers are only accepted during a fixed bidding window which is open for at least five (5) business days. The bidding window for a Base Residual Auction and Incremental Auctions will be posted on the PJM website. Sell offers may not be changed or withdrawn after the bidding window for a Base Residual Auction or Incremental Auction is closed.

The following are business rules that apply to Resource-Specific Sell Offers**:**

- The smallest increment that may be offered into any auction is 0.1 MW
- A resource-specific sell offer will specify, as appropriate:
    - Specific Generating Unit, Demand Resource, Energy Efficiency Resource, or Aggregate Resource
    - Each Existing Generation Capacity Resource with available capacity that is capable or can reasonably become capable of qualifying as a Capacity Performance Resource must submit a Capacity Performance sell offer segment.
        - ELCC Resources that are Generation Capacity Resources may not offer or otherwise provide UCAP MW quantities above the greater of their Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling for the applicable Delivery Year, please see **Manual 14B: Regional Transmission Planning Process**. Notwithstanding, external resources may offer up to their Accredited UCAP.
        - Notwithstanding the above, ELCC Resources may not offer or otherwise provide UCAP MW quantities above their Accredited UCAP.
    - Exceptions to the capacity performance must-offer requirement will be permitted for a generation capacity resource which the Capacity Market Seller demonstrates is reasonably expected to be physically incapable of satisfying the requirements for a Capacity Performance Generation Resource by the start of the Delivery Year, the resource has a financially and physically firm commitment to an external sale of its capacity, or the resource is seeking to remove Capacity Resource status in accordance with Section 5.4.7 of this manual. The Seller must submit a request for an exception (with all supporting information) no later than 120 days before the offer window opens for the relevant RPM Auction. Nothing herein provides a defense to a claim of withholding, market manipulation, or the exercise of market power by any entity who is affiliated with or are under common ownership or control of a Capacity Market Seller that does not submit an offer into the capacity market.
        - Capacity Market Sellers seeking an exception for a BRA on the basis that the resource is incapable of meeting the Capacity Performance Resource requirements shall include a documented plan with the submission of their

exception request showing the steps the Capacity Market Seller intends to pursue for the resource to become physically capable of satisfying the requirements of a Capacity Performance Resource, and provide periodic updates on the progress of such plan in accordance with Tariff, Attachment DD, section 6.6A(c).

- Capacity Market Sellers may specify multiple auctions in a written must-offer exception request (with all supporting documentation) to be reviewed by the IMM and PJM with each applicable auction. Capacity Market Sellers must notify PJM and the IMM of any material changes related to the request up through the closing of the relevant auction(s) offer window.
  - When multiple auctions are specified in the written request, Capacity Market Sellers should continue to create a new request in the IMM's online system (MIRA) for each relevant subsequent auction and confirm that the documentation represents the best, current information.

- An Existing Generation Capacity Resource that can qualify as Capacity Performance product type, but requires substantial investment to do so, is not excused from the capacity performance must-offer requirement; however,
- Demand Resources are not required to submit a Capacity Performance sell offer segment.
- Minimum and maximum amount of installed capacity offered in MWs for the resource by Capacity Performance (annual) Offer Segment and Maximum amount of installed capacity offered in a Seasonal (summer or winter) Capacity Performance Offer Segment. The Seasonal Capacity Performance Offer Segment is considered a flexible offer segment with a minimum MW quantity set to zero MW.
- Offer Segment price willing to receive in $/MW-day (in UCAP terms)
- Regular Schedule, Self-Schedule or Flexible Self-Schedule flag
- New Unit Pricing participation flag for Planned Generation Capacity Resources requesting New Unit Pricing Adjustment.
- The ICAP MW quantity specified in the Offer Segment will be converted into an UCAP MW quantity for use in the auction clearing by multiplying the ICAP MW quantity specified by the applicable Accredited UCAP Factor for a Generation Capacity Resource, by the applicable ELCC Class rating for a Demand Resource, and by the Forecast Pool Requirement for an EE Resource. The sell offer price specified in the Offer Segment is in UCAP terms and will not be converted for use in the auction clearing.
- A Capacity Performance (annual), or Seasonal Capacity Performance Offer Segment may be offered as either a single price quantity for the capacity of the resource or divided into up to ten offer blocks with varying price-quantity pairs that represent various segments of capacity from the resource. The Offer Segment will consist of block segments at the specified price-quantity pairs.

- The auction specific Accredited UCAP Factor will be determined by PJM. The seller is willing to accept the clearing of any amount equal to or greater than the minimum MW amount offered and equal to or less than the maximum MW offered.
- If the self-scheduled flag is enabled in the Capacity Performance Offer segment, the sell offer price must be set to zero and the minimum and maximum amounts specified in the sell offer must be equal.
- The acceptance of the sell offer is based on the party's Current Available ICAP Position for the Delivery Year at the opening of the auction's bidding window. The acceptance of the sell offer is based on the party's Current Available ICAP Position for the entire Delivery Year (annual position) if Capacity Performance Resource, Current Available ICAP Position for summer period (summer position) if Summer-Period Capacity Performance Resource, Current Available ICAP Position for winter period (winter position) if Winter-Period Capacity Performance Resource.
- The total MWs offered across all Capacity Performance offer segments may not exceed the Current Available ICAP Position for the Delivery Year (i.e., the annual position). The total MWs offered across the Capacity Performance offer segments and the Seasonal Capacity Performance-Summer offer segments may not exceed the Current Available ICAP Position for summer period (i.e., the summer position). The total MWs offered across the Capacity Performance offer segments and the Seasonal Capacity Performance-Winter offer segments may not exceed the Current Available ICAP Position for winter period (i.e., the winter position).
- If a participant has a zero or negative Current Available ICAP Position, PJM will reject the sell offer.
- A sell offer in an RPM Auction that violates any "Conditions on Sales by FRR Entities" as presented in the FRR Business Rules will be rejected.
- For Planned Resources and external resources without firm transmission, sell offers for which the RPM Credit Requirement exceeds the credit available will be rejected.
- A Capacity Market Seller submitting a sell offer for an existing Generation Capacity Resource greater than $0/MW-Day must seek a unit-specific exception request for such sell offer by submitting Avoidable Cost Rate data to IMM and PJM 120 days prior to the RPM Auction, or may, at its election, utilize an offer cap based on the default gross Avoidable Cost Rate of the applicable resource type, if available. For any Third Incremental Auction, a Capacity Market Seller submitting a sell offer for an existing Generation Capacity Resource may elect to use a default offer cap equal to 1.1 times the Resource Clearing Price in the Base Residual Auction of the relevant LDA and Delivery Year.
- All sell offers for a supplier that fails the Three-Pivotal Supplier Test will be capped within the mitigated LDA.
- Cleared MWs and make-whole MWs for Capacity Performance Offer Segments are binding commitments to provide capacity for the entire Delivery Year. Cleared MWs for Seasonal Capacity Performance-Summer Offer Segments are binding commitments to

provide capacity for the summer period of June through October and May of the Delivery Year. Cleared MWs for Seasonal Capacity Performance-Winter Offer Segments are binding commitments to provide capacity for the winter period of November through April of the Delivery Year.

### 5.4.2 Flexible Self Scheduling

An LSE may specify offer segments as flexible self-scheduled in the Base Residual Auction to provide a mechanism to manage the quantity uncertainty related to the Variable Resource Requirement.

To specify a segment as a flexible self-scheduled segment, an LSE must specify the following:

- For each such segment, “flexible self-scheduled” must be selected as the offer type of the segment.
- A flexible self-schedule sell offer must specify an offer price that will be utilized in the market clearing in the event that the resource is not needed to cover the calculated capacity obligation. This is in addition to the data required of a self-schedule resource specific sell offer.
- In conjunction with an offer of a flexible self-schedule segment, the LSE must also submit through Capacity Exchange a percentage of the Preliminary Zonal Peak Load Forecast in each transmission zone the LSE wishes to cover with self-scheduled and flexible self-scheduled resources. This percentage of the peak load forecast will be used to calculate the LSE’s resulting capacity obligation through the auction clearing process that considers the Variable Resource Requirement.

If the same LSE offers both self-scheduled and flexible self-schedule segments to serve an Unforced Capacity Obligation within the same LDA, those segments that are self-scheduled will be used first to meet the obligation. The flexible self-scheduled segments will be automatically cleared in the auction if they are needed to supply the LSEs resulting capacity obligation. In the event that the LSE does not need all of the segments that were specified as flexible self-scheduled to meet its resulting capacity obligation, the RPM clearing function will consider the excess as offered into the market at the price specified with the flexible self-scheduled segment. The segments that are considered excess for this LSE will be those that have the highest specified offer prices.

### 5.4.3 New Entry Pricing Adjustment

New Entry Pricing Adjustment[20] is an incentive provided to Planned Generation Resources where the size of the new entry is significant relative to the size of the LDA and there is a potential for the clearing price to drop when all offer prices including that of the new entry are

20 OATT, Attachment DD, Section 5.14(c)

capped. New Entry Pricing Adjustment allows Planned Generation Capacity Resources to recover the amount of their cost of entry-based offer for up to two additional consecutive years under certain conditions.

New Entry Pricing Adjustment is applicable under the following conditions:

1. The new entry must select the New Entry Pricing Adjustment option at the time the sell offer into the initial BRA (Delivery Year 1 BRA) is submitted.
2. The capacity cleared from the new entry (including any make-whole MW) in the Delivery Year 1 BRA would move the total LDA resources committed in the BRA from below the LDA Reliability Requirement to a MW quantity at or above the MW quantity at the price-quantity point on the VRR Curve where the price is 40% of the Net CONE divided by the quantity one minus pool-wide average EFORd through the 2024/2025 Delivery Year, and beginning with the 2025/2026 Delivery Year, divided by the applicable ELCC Class Rating for the Reference Resource.
3. The seller submits offers into the two immediately following BRAs (Delivery Year 2 BRA and Delivery Year 3 BRA) to sell the entire capacity of the unit committed in the Delivery Year 1 BRA at a price equal to the lesser of (a) the price offered in the Delivery Year 1 BRA where the resource was classified as planned generation; or (b) 90% of the Net CONE applicable in the Delivery Year 1 BRA in UCAP basis.
4. Failure to submit a sell offer consistent with condition (3) above in the Delivery Year 3 BRA shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a sell offer consistent with condition (3) in the Delivery Year 2 BRA shall make the resource ineligible for New Entry Price Adjustment for Delivery Years 2 and 3.

New entry revenues:

1. If the new entry meets conditions (1) and (2) above and is the marginal offer in Delivery Year 1 BRA, it sets the resource clearing price for the LDA in Delivery Year 1 BRA and receives revenues based on this price in the Delivery Year 1 BRA.
2. If the new entry clears its capacity in either of the two subsequent BRAs (Delivery Year 2 BRA or Delivery Year 3 BRA), it will receive revenues based on the LDA clearing price in such subsequent year BRA.

3. If the new entry does not clear in either of the two subsequent year BRAs (Delivery Year 2 BRA or Delivery Year 3 BRA), it will be resubmitted at the highest offer price at which the unforced MW amount cleared in the Delivery Year 1 BRA will clear in the subsequent year BRA (Delivery Year 2 BRA or Delivery Year 3 BRA). The resource clearing price and the resources cleared for such subsequent year BRA will be determined from the clearing with the resubmitted sell offer. The new entry shall clear in such subsequent year BRA and be committed in the amount cleared plus any additional make-whole MW from its Sell Offer for such subsequent year BRA, but such make-whole MWs shall not be greater than the make-whole MWs committed in the Delivery Year 1 BRA. The new entry will receive revenues for the entire committed quantity in such subsequent year BRA based on the sell offer price initially submitted for such subsequent year BRA. The difference between the initially submitted sell offer price and the clearing price in such subsequent year BRA and any difference between cleared quantity and committed quantity in such subsequent year BRA will be paid as Resource Make-Whole payments to the new entry. The other capacity resources that clear such subsequent year BRA will receive the clearing price for such subsequent year BRA.

A Capacity Market Seller may make its Sell Offer in the initial BRA (Delivery Year 1 BRA) contingent upon qualifying for New Entry Price Adjustment. Prior to the close of the BRA offer window, a Capacity Market Seller must notify PJM of a NEPA contingent Sell Offer election via an email to rpm_hotline@pjm.com. PJM shall not clear a NEPA contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

While the New Entry Pricing Adjustment is effective, the LDA in which the New Entry was cleared will be modeled as an LDA in Years 2 and 3 regardless of the amount of LDA Capacity Emergency Transfer Limit margin over Capacity Emergency Transfer Objective in the PJM RTEP Process. After the New Entry Pricing Adjustment period, the LDA will be maintained only if deemed necessary in the PJM RTEP Process.

Market Monitor's existing authority and review responsibilities shall include "New Entry Pricing." Market Monitor shall analyze and report on "New Entry Pricing" in the State of the Market Report.

### 5.4.4 Sell Offer Caps

**Submission of the Avoidable Cost Rate (ACR) Data**

120 days prior to the commencement of the offer period for an RPM Auction, participants must submit the data specified in ***Section 6.7 of Attachment DD of the Open Access Transmission Tariff*** in order to submit a non-zero Sell Offer in the Auction.

Capacity resource owners must supply PJM with their avoidable cost data through the IMM's Member Information Reporting Application ("MIRA").

The avoidable cost calculation is based on the categories of cost that are specified in ***Section 6.8 of Attachment DD of the Open Access Transmission Tariff***. The calculation should be based on the annual costs that would be avoidable assuming the unit would otherwise retire.

Where multiple units exist at a single plant, the plant's total avoidable costs shall be allocated to each individual unit in an appropriate manner. The sum of such costs assigned to each unit shall equal the total plant costs.

The avoidable cost data should be for the 12 months preceding the month in which the data must be provided.

For units that are jointly-owned, only one owner, typically the operator is expected to provide avoidable cost data and Projected PJM Market Revenues for the unit.

All joint-owners of a unit can input their own bilateral revenues/costs, opportunity costs and transition adder.

If a unit is not expected to be operational during the Delivery Year, no avoidable cost and opportunity cost data are required, but notice of status is required.

**Calculation of Sell Offer Caps**

Sell offer caps shall be calculated as specified in ***Section 6.4 of Attachment DD of the Open Access Transmission Tariff.***

A unit must submit unit-specific ACR data, specify an opportunity cost, or use the default rate, in order to submit a sell offer greater than zero.

Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of energy and ancillary services market offers for such resource. The calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues from the three most recent whole calendar years prior to the year in which the BRA is conducted as described in ***Section 6.8(d) of Attachment DD of the Open Access Transmission Tariff.***

Sell Offer Cap(s) will be calculated for each Market Participant, by unit, by segment.

90 days prior to the commencement of the offer period, the IMM shall calculate and notify the Capacity Market Seller of their Sell Offer Cap consistent with ***Section 6 of Attachment DD of the Open Access Transmission Tariff***.

Planned Generation Resources may be mitigated in accordance with OATT, Attachment DD, Section 6.5.

No offer caps are applied to sell offers of Demand Resources or Planned Energy Efficiency Resources.

### 5.4.5 Deleted

### 5.4.6 Qualified Transmission Upgrade Sell Offer Requirements

A Qualifying Transmission Upgrade sell offer will specify, as appropriate:

- Increase in CETL provided by the upgrade (maximum MW, as certified by PJM Transmission Planning Department)
- Minimum MW offered (min = max for upgrades that involve a single equipment upgrade, min could be less than max where participant is proposing multiple upgrades or upgrades to several pieces of equipment)
- Source and sink LDAs associated with the upgrade
- Price willing to receive for each segment in $/MW-day specified as the price difference between the sink LDA price and the source LDA price

The increase in CETL provided by a Qualifying Transmission Upgrade must be certified by PJM at least 45 days prior to the Base Residual Auction.

Cleared sell offers and offers receiving Make-Whole payments are binding commitments to provide capacity.

### 5.4.7 Removal of Generation Capacity Resource Status

A Capacity Market Seller seeking to remove Capacity Resource status from a Generation Capacity Resource shall submit a preliminary and final written request to PJM and the IMM, along with supporting data and documentation, in accordance with Tariff, Attachment DD, section 6.6(g).

- Requests shall be submitted to PJM via email to the rpm_hotline@pjm.com and to the IMM through the MIRA application.
- Preliminary requests must be submitted no later than September 1 prior to a BRA, and 240 days prior to an IA. Final requests must be submitted no later than December 1 prior to a BRA, and 120 days prior to an IA.
- The preliminary request must provide the following information:
    - Identification of the Generation Capacity Resource and MW
    - The beginning Delivery Year in which the Seller is seeking to remove Capacity Resource status from the resource
    - Supporting data and documentation indicating the reasons and conditions upon which the Seller is relying in its analysis to remove Capacity Resource status from the resource

- PJM will post the preliminary and final requested MW of Capacity Resource status changes on an aggregate basis by Zone and LDA that comprises a subset of a Zone.

A request will not be accepted for a resource that holds a capacity commitment during the time period in which it seeks to no longer be a Capacity Resource.

The IMM will analyze the effects of removing Capacity Resource status with respect to potential market power concerns and notify the Seller and PJM of its determination no later than 90 days prior to the applicable RPM auction. Subsequently, PJM shall provide its final determination no later than 65 days prior to the applicable RPM auction.

PJM Planning will be notified of requests and final approvals to incorporate the loss of Capacity Resource status in the appropriate planning models and reliability studies.

Once the Capacity Resource status is removed from a Generation Capacity Resource:

- The generation unit will no longer qualify as an Existing Generation Capacity Resource, and as such, will be removed from the Capacity Resource model and no longer eligible to offer in RPM auctions or take on a capacity commitment.
- The Capacity Interconnection Rights associated with the resource shall be subject to termination in accordance with the rules described in Tariff, Part VI, section 230.3.3.
    - The relevant GIA or WMPA of a Generation Capacity Resource that is removed of its Capacity Resource status will be amended to reflect any such removal of Capacity Interconnection Rights.

### 5.4.8 Minimum Offer Price Rule

The Minimum Offer Price Rule (MOPR) provisions of Section 5.14(h-2) of Attachment DD of the PJM OATT are applicable to each Generation Capacity Resource that is offered into RPM Auctions for the 2023/2024 Delivery Year and all subsequent Delivery Years.

#### 5.4.8.1 MOPR-Related Business Rules and Process Timeline

The following business rules apply to the sell offer of any Generation Capacity Resource that in an RPM Auction is subject to the MOPR of Tariff, Attachment DD, section 5.14(h-2):

- The timeline for pre-auction activities related to MOPR is specified in the table below.
- The MOPR Floor Offer Price applicable to a Generation Capacity Resource that based on the certification process described below is subject to the MOPR is dependent upon whether the resource or uprate of the resource previously cleared in an RPM auction for any Delivery Year.
- For a Generation Capacity Resource that is subject to the MOPR and for which a Sell Offer based on that resource, or any uprate of the Generation Capacity Resource, has not previously cleared an RPM Auction for any Delivery Year, the applicable New Entry MOPR Floor Offer Price, based on the net cost of new entry for the resource, shall be, at the election of the Capacity Market Seller, either (i) the unit-specific value determined in

accordance with the unit-specific exception process for MOPR Floor Offer Prices, or (ii) the default New Entry MOPR Floor Offer Price, if available, of the applicable resource type. A Capacity Market Seller must seek a unit-specific MOPR Floor Offer Price if the resource is of a type for which there is no default New Entry MOPR Floor Offer Price, including hybrid resources. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer for such resource for the relevant RPM Auction.

- For a Generation Capacity Resource that is subject to the MOPR and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year, the applicable Cleared MOPR Floor Offer Price, based on the net Avoidable Cost Rate, shall be, at the election of the Capacity Market Seller, either (i) the unit-specific value determined in accordance with the unit-specific exception process for MOPR Floor Offer Prices, or (ii) based on the default gross Avoidable Cost Rate, if available, of the applicable resource type net of projected net energy and ancillary service revenues for the resource (Net ACR). A Capacity Market Seller must seek a unit-specific MOPR Floor Offer Price if the resource is of a type for which there is no default gross Avoidable Cost Rate, including hybrid resources. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer for such resource for the relevant RPM Auction.
- The MOPR Floor Offer Price of any Capacity Resource that is subject to the MOPR is expressed in terms of Unforced Capacity MW (“UCAP MW”). A resource’s MOPR Floor Offer Price in $/UCAP MW-Day is applicable to each MW offered by the resource that is subject to MOPR regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.
- If any of the individual underlying resources of a commercially aggregated resource are subject to a MOPR Floor Offer Price, the MOPR Floor Offer Price applicable to the Sell Offer of such an aggregate resource is equal to the time and MW-weighted average of the applicable MOPR Floor Offer Prices (zero if applicable) of the individual aggregated resources.

**MOPR-Related Process Timeline**

| Activity | Deadline |
|---|---|
| PJM posts preliminary estimate of MOPR Floor<br>Offer Prices | No later than 150 days prior to commencement of offer period for an RPM Auction |
| Capacity Market Seller certifies the status of each Generation Capacity Resource it intends to offer as it relates to Conditioned State Support and Exercise of Buyer-Side Market Power | No later than 150 days prior to commencement<br>of offer period for an RPM Auction |

| | |
|---|---|
| PJM and/or IMM notify Capacity Market Seller of fact-specific review of ability and incentive to exercise Buyer-Side Market Power | No later than 135 days prior to commencement of offer period for an RPM Auction |
| Capacity Market Seller submits request for a Unit Specific Exception with all required documentation simultaneously to both the IMM and PJM | No later than 120 days prior to commencement of the offer period for the RPM Auction |
| IMM reviews the request and provides its findings to the Capacity Market Seller and PJM of whether the proposed Sell Offer is acceptable | No later than 90 days prior to the commencement of the offer period of the RPM Auction |
| PJM reviews the request and provides determination to the Capacity Market Seller and the IMM of whether the proposed sell offer is acceptable and if not provides a minimum sell offer based on data and documentation | No later than 65 days prior to the commencement of the offer period of the RPM Auction |
| Capacity Market Seller notifies PJM and IMM of minimum level of Sell Offer to which it agrees to commit | No later than 60 days prior to the commencement of the offer period of the RPM Auction |

#### 5.4.8.2 Certification Requirement

By no later than 150 days prior to the commencement of the offer period of any RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year, each Capacity Market Seller must certify for each Generation Capacity Resource the Capacity Market Seller intends to offer into the RPM Auction: (i) whether or not the Generation Capacity Resource is receiving or expected to receive Conditioned State Support under any legislative or other governmental policy or program that has been enacted or effective at the time of the certification, and (ii) whether or not the Capacity Market Seller acknowledges and understands that the Exercise of Buyer-Side Market Power is not permitted in RPM Auctions, and does not intend to submit a Sell Offer for their Generation Capacity Resource as an Exercise of Buyer-Side Market Power.

All Capacity Market Sellers are responsible for the timeliness and accuracy of each certification which is undertaken through PJM's Capacity Exchange system. Any Generation Capacity Resource for which a Capacity Market Seller has not timely submitted the certifications shall be subject to the provisions of the Minimum Offer Price Rule. Notwithstanding the foregoing, if a Capacity Market Seller submits a timely unit-specific exception for the relevant Delivery Year,

and PJM approves the unit-specific MOPR Floor Offer Price, then the Capacity Market Seller may use such floor price regardless of whether it timely submitted the foregoing certifications.

Once a Capacity Market Seller has certified whether or not a Generation Capacity Resource is receiving or expected to receive Conditioned State Support, the status of such Capacity Resource will remain unchanged unless and until the Capacity Market Seller (or a subsequent Capacity Market Seller) that owns or controls such Capacity Resource provides a certification of a change in such status, the Office of the Interconnection removes such status, or by FERC order. All Capacity Market Sellers have an ongoing obligation to certify to PJM and the IMM a Generation Capacity Resource's material change in status regarding whether such resource is receiving or expected to receive Conditioned State Support within 30 days of such material change.

A Capacity Market Seller must certify for each Generation Capacity Resource the seller intends to offer into each RPM Auction that the seller acknowledges and understands that the Exercise of Buyer-Side Market Power is not permitted in RPM Auctions, and does not intend to submit a Sell Offer for their Generation Capacity Resource as an Exercise of Buyer-Side Market Power. In other words, this status does not carry forward from one auction to the next as does the status regarding Conditioned State Support.

**Conditioned State Support**

Conditioned State Support is any financial benefit required or incentivized by a state, or political subdivision of a state acting in its sovereign capacity, that is provided outside of PJM Markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction, where "conditioned on clearing in any RPM Auction" refers to specific directives as to the level of the offer that must be entered for the relevant Generation Capacity Resource in the RPM Auction or directives that the Generation Capacity Resource is required to clear in any RPM Auction. Conditioned State Support shall not include any Legacy Policy defined as any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

Government policies or programs that do not provide payments or other financial benefit outside of PJM markets and do not provide payment or other financial benefit in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction do not constitute Conditioned State Support. Examples of such government policies that do not constitute Conditioned State Support may include, but are not limited to: policies designed to procure, incent, or require environmental attributes, whether bundled or unbundled (e.g., Renewable Energy Credits, Zero Emission Credits; Regional Greenhouse Gas Initiative); economic development programs and policies; tax incentives; state retail default service auctions; policies or programs that provide incentives related to fuel supplies; any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state

administered federal regulatory program (e.g., Cross-State Air Pollution Rule). In addition, Conditioned State Support shall not be determined solely based on the business model of the Capacity Market Seller, such that the fact that a Self-Supply Entity is the Capacity Market Seller, for example, is not a basis for determining Conditioned State Support.

If PJM reasonably believes a government policy or program would provide Conditioned State Support or a Capacity Market Seller certifies that it is receiving or is expected to receive Conditioned State Support associated with a given Generation Capacity Resource, PJM shall submit a filing at FERC indicating the intent to classify the government policy or program from which that support is derived as Conditioned State Support (and adding such policy or program to the list in Tariff, Attachment DD-3) and apply the Minimum Offer Price Rule to each Generation Capacity Resource reasonably expected to receive such Conditioned State Support.

Upon FERC acceptance that a government policy or program or contract with a state entity constitutes Conditioned State Support, a Generation Capacity Resource for which a Capacity Market Seller certifies that it is receiving Conditioned State Support or is reasonably expected to receive such Conditioned State Support, as identified by PJM, with the advice and input of the IMM, will be subject to the provisions of the Minimum Offer Price Rule.

**Exercise of Buyer-Side Market Power**

The Exercise of Buyer-Side Market Power means anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller's (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest. Load Interest means, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.

If a Capacity Market Seller does not certify that it acknowledges the prohibition of the Exercise of Buyer Side Market Power and the Capacity Market Seller intends to exercise Buyer-Side Market Power for this Generation Capacity Resource, then the underlying Capacity Resource will be subject to the MOPR. If PJM and/or the IMM reasonably suspects that a certification contains fraudulent or material misrepresentations such that the Capacity Market Seller's Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or otherwise reasonably suspects that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power, then PJM and/or the IMM shall initiate a fact-specific review into the facts and circumstances regarding the Generation Capacity Resource and whether the Capacity Market Seller has the ability and incentive to exercise Buyer-Side Market Power with respect to such Generation Capacity Resource. During such fact-specific review, the Capacity Market Seller will

have the opportunity to explain and justify why a Sell Offer for the Generation Capacity Resource would not be an Exercise of Buyer-Side Market Power.

PJM and/or the IMM shall notify the Capacity Market Seller of the bases for inquiry and initiation of review at least 135 days in advance of the RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year. In initiating a review, PJM and/or the IMM shall provide the affected Capacity Market Seller, in writing, the basis for its inquiry, including, but not limited to, the Generation Capacity Resource(s), and the purported beneficiary of any price suppression. PJM and/or the IMM may request from the Capacity Market Seller additional information and documentation that is reasonably related to the basis for its inquiry, provided that, PJM and the IMM shall confer with the Capacity Market Seller in advance of any such requests. The Capacity Market Seller shall provide any additional supporting information and documentation requested by PJM and/or the IMM, and any other information and documentation the Capacity Market Seller believes may justify the conduct or action in question as not representing an Exercise of Buyer-Side Market Power, within 15 days or other such timeline as agreed to in writing by the PJM, Market Monitoring Unit and Capacity Market Seller.

The fact-specific review will determine, as necessary, whether a Capacity Market Seller has the ability and incentive to submit a Sell Offer for the Generation Capacity Resource that could be an Exercise of Buyer-Side Market Power, in accordance with the provisions of Sections 5.14(h-2)(2(B)(i)(a) and (b) of Attachment DD.

The following non-exhaustive list of circumstances would preclude an inquiry into or determination regarding an Exercise of Buyer-Side Market Power in the course of a review: (a) the Generation Capacity Resource is a merchant generation supply resources that is not contracted to an entity with a Load Interest; (b) the Generation Capacity Resource is acquired by or under the contractual control of the Capacity Market Seller through a competitive and non-discriminatory procurement process open to new and existing resources; or (c) the Generation Capacity Resource is owned by or bilaterally contracted to a Self-Supply Seller and such resource is demonstrated as consistent with or included in the Self-Supply Seller’s long-range resource plan (e.g., a long-range hedging plan) that is approved or otherwise reviewed and accepted by the RERRA, provided that any such plan approval or contracts do not direct the submission of an uneconomic offer to deliberately lower market clearing prices or for the Capacity Market Seller to otherwise perform an Exercise of Buyer-Side Market Power. In addition, to the extent a Generation Capacity Resource may receive compensation in support of characteristics aligned with well-demonstrated customer preferences, such compensation shall not, in and of itself, be a basis for the determination of Buyer-Side Market Power. For purposes of evaluating Buy-Side Market Power, Self-Supply Seller is a vertically integrated utility or public power entity where vertically integrated utility means a utility that owns generation, includes such generation in its state-regulated rates, and earns a state-regulated return on its investment in such generation; and public power entity means electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint

action agencies that are subject to direct regulation by a Relevant Electric Retail Regulatory Authority.

Based on the fact-specific review, including the facts and circumstances of the Generation Capacity Resource, with the advice and input of the IMM, PJM shall determine whether a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power. If PJM determines that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or the Capacity Market Seller certifies that it intends to exercise Buyer-Side Market Power, then such resource will be subject to the provisions of the Minimum Offer Price Rule. If the resource will be subject to the provisions of the Minimum Offer Price Rule, PJM shall include in the notice a written explanation for such determination. A Capacity Market Seller that is dissatisfied with the PJM's determination of whether a given Generation Capacity Resource is subject to the Minimum Offer Price Rule may seek any remedies available to it from FERC; provided, however, that PJM will proceed with administration of the Tariff and market rules based on its determination unless FERC by order directs otherwise.

### 5.4.8.3 Unit-Specific Exception Process for MOPR Floor Offer Prices

**A. Documentation Required in the Unit-Specific Exception Process for New Entry MOPR Floor Offer Price**

The Capacity Market Seller of a Generation Capacity Resource that is subject to the MOPR of OATT Attachment DD, section 5.14(h-2) and for which a Sell Offer based on that resource, or any uprate of the Generation Capacity Resource, has not previously cleared an RPM Auction for any Delivery Year may request a unit-specific MOPR Floor Offer Price based on the net CONE of the resource by no later than 120 days prior to the commencement of the offer period of the relevant RPM Auction. Such request must be made simultaneously to PJM and the IMM and must include all required documentation. The Capacity Market Seller must include in its request for an exception documentation to support the fixed development, construction, operation, and maintenance costs of the Capacity Resource, as well as estimates of the offsetting net revenues or sufficient data for PJM and the IMM to produce such net revenue estimates. Estimates of costs and revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the default New Entry MOPR Floor Offer Price established for various resource types. Supporting documentation for project costs may include, as applicable and available, the following:

- Complete project description;
- Environmental permits;
- Vendor quotes for plant or equipment;
- Evidence of actual costs of recent comparable projects;
- Bases for electric and gas interconnection costs and any costs contingencies;
- Bases for support for property taxes, insurances, operations and maintenance (O&M) contractor costs, and other fixed O&M and administrative or general costs;

- Financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments;
- Bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling; and
- Identification and support for any sunk cost that the Capacity Market Seller has reflected as a reduction to its Seller Offer.

The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of the resource-specific exception request and that to the best of their knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception; and (3) the request satisfies the criteria for the exception.

The financial modeling assumptions for calculating Cost of New Entry for Generation Capacity Resources shall be: (i) nominal levelization of gross costs, (ii) asset life of twenty years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues (which may include revenues from the sale of renewable energy credits for purposes other than state-mandated or state-sponsored programs), and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. Notwithstanding the foregoing, a Capacity Market Seller that seeks to utilize an asset life other than twenty years (but no greater than 35 years) shall provide evidence to support the use of a different asset life, including but not limited to, the asset life term for such resource as utilized in the Capacity Market Seller's financial accounting (e.g., independently audited financial statements), or project financing documents for the resource or evidence of actual costs or financing assumptions of recent comparable projects to the extent the seller has not executed project financing for the resource (e.g., independent project engineer opinion or manufacturer's performance guarantee), or opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects. Capacity Market Sellers may also rely on evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an asset life other than 20 years of similar asset projects.

The request shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in the region, employing input data from sources readily available to the public. Documentation for net

revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. Any evaluation of net revenues should be consistent with Operating Agreement, Schedule 2, including, but not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable.

The Capacity Market Seller shall provide any additional supporting information reasonably requested by PJM or IMM to evaluate the Sell Offer. Requests for additional documentation shall not extend the deadline by which PJM or IMM must provide their determinations of the MOPR exception request.

An evaluated Sell Offer shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the MOPR Floor Offer Price, based on competitive cost advantages, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's cost, or based on net revenues that are reasonably demonstrated to be higher than those used by PJM in the development of the MOPR Floor Offer Price. The Capacity Market Seller must demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection.

Failure to adequately support costs or revenues so as to enable PJM to make a determination of the MOPR exception request will result in a denial of an exception by PJM.

**B. Documentation Required in the Unit-Specific Exception Process for Cleared MOPR Floor Offer Price**

The Capacity Market Seller of a Generation Capacity Resource that is subject to the MOPR of OATT Attachment DD, section 5.14(h-2) and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year may request a unit-specific MOPR Floor Offer Price based on the net ACR of the resource by no later than 120 days prior to the commencement of the offer period of the relevant RPM Auction. Such request must be made simultaneously to PJM and the IMM and must include all required documentation. The Capacity Market Seller shall submit a Sell Offer based on the net ACR of the resource consistent with the unit-specific Market Seller Offer Cap process pursuant to Tariff, Attachment DD, section 6.8; except that the 10% uncertainty adder may not be included in the "Adjustment Factor." In addition and notwithstanding the requirements of Tariff, Attachment DD, section 6.8, the Capacity Market Seller may, at its election, include in its request documentation to support projected energy and ancillary services markets revenues. Such a request shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to

offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in the region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. Any evaluation of net revenues should be consistent with Operating Agreement, Schedule 2, including, but not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable.

The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of the unit-specific exception request and that to the best of their knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception; and (3) the request satisfies the criteria for the exception.

The Capacity Market Seller shall provide any additional supporting information reasonably requested by PJM or IMM to evaluate the Sell Offer. Requests for additional documentation shall not extend the deadline by which PJM or IMM must provide their determinations of the MOPR exception request.

An evaluated Sell Offer shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, fixed, cost-based offer level is below the MOPR Floor Offer Price, based on competitive cost advantages, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's cost, or based on net revenues that are reasonably demonstrated to be higher than those used by PJM in the development of the MOPR Floor Offer Price. The Capacity Market Seller must demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection.

Failure to adequately support costs or revenues so as to enable PJM to make a determination of the MOPR exception request will result in a denial of an exception by PJM.

#### 5.4.8.4 Default MOPR Floor Offer Prices

**A. Default New Entry MOPR Floor Offer Price**

The Default New Entry MOPR Floor Offer Price for a Generation Capacity Resource that is subject to the MOPR and for which a Sell Offer based on that resource, or any uprate of the Generation Capacity Resource, has not previously cleared an RPM Auction for any Delivery Year is based on the net cost of new entry ("CONE") of the applicable resource type. The net CONE values are determined by subtracting the estimated net energy and ancillary service revenues from the gross cost of new entry ("CONE") values shown in the table below. The gross CONE values of the table below are adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, as described below. The net energy and ancillary services revenue estimate is determined for each resource type and for each Zone as described in sections 5.14(h-2)(3)(A)(i) through (viii) of Attachment DD of the PJM OATT.[21]

For the capacity resource types listed in the table below, the Default New Entry MOPR Floor Offer Price is set equal to the net CONE of each resource type expressed in terms of Unforced Capacity ("UCAP") MW where the net CONE values are initially calculated for each resource type in terms of nameplate MW and then converted to UCAP MW. Through the 2024/2025 Delivery Year the net CONE is converted to UCAP MW terms based on the applicable class average EFORd for thermal generation resource types and battery energy storage resource types and the applicable ELCC Class Rating for battery storage, wind and solar generation resource types. Beginning with the 2025/2026 Delivery Year, the net CONE is converted to UCAP MW terms based on the applicable class average Accredited UCAP Factor (i.e., applicable ELCC Class Rating). The resultant net CONE in nameplate MW terms of the battery energy storage resource type is multiplied by 2.5 prior to converting to UCAP terms.

**Gross CONE Values used to Determine Default New Entry MOPR Floor Offer Prices**

| Resource Type | Through the 2025/2026 Delivery Years: Gross CONE (2022/2023 $/MW-Day) (Nameplate) | For the 2026/2027 Delivery Year and Subsequent Delivery Years: Gross Cost of New Entry (2026/2027 $/MW-day Nameplate) |
|---|---|---|
| Nuclear | $2,000 | $2,568 |

[21] For the coal resource type, the net energy and ancillary services revenue estimate uses Northern Appalachian delivered prices from rail and barge.

| | | |
|---|---|---|
| Coal | $1,068 | $1,480 |
| Combined Cycle | $320 | $540 |
| Combustion Turbine | $294 | 394 |
| Fixed Solar PV | $271 | $298 |
| Tracking Solar PV | $290 | $321 |
| Onshore Wind | $420 | $438 |
| Offshore Wind | $1,155 | $1,351 |
| Battery Energy Storage | $532 | $502 |

Beginning with the 2023/2024 Delivery Year, the gross CONE values of the table above will be adjusted annually based on changes in the Applicable United States Bureau of Labor Statistics ("BLS") Composite Index. The Applicable BLS Composite Index for the combustion turbine and combined cycle resource types shall be the same Applicable BLS Composite Index as that applied to adjust the gross CONE used to determine the VRR Curve for that Delivery Year (see Section 3.3.1 of this manual). For all other resource types, the "BLS Producer Price Index Turbines and Turbine Generator Sets" component shall be replaced with the "BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment." For the 2023/2024 through 2025/2026 Delivery Years, inclusive, the resultant value shall then be then adjusted further by a factor of 1.022 for nuclear and coal resource types or 1.01 for solar, wind, and storage resource types to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law. No such further adjustment shall be made to the resultant values for the 2027/2028 Delivery year and subsequent Delivery Years.

**B. Default Gross Avoidable Cost Rate for Determination of Cleared MOPR Floor Offer Prices**

For a Generation Capacity Resource that is subject to the MOPR and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year, the applicable Cleared MOPR Floor Offer Price is based on the net Avoidable Cost Rate determined by subtracting the estimated net energy and ancillary service revenues of the resource from the gross ACR of the resource. The Cleared MOPR Floor Offer Price of a Generation Capacity Resource shall be, at the election of the Capacity Market Seller, either (i) based on the unit-specific net Avoidable Cost Rate ("ACR"), or (ii) if available, the default gross ACR of the applicable resource type shown in the table below net of energy and ancillary services revenue determined for the resource as described in section 5.4.8.5 of this manual. The gross ACR values of the table below are adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, using the 10-year average Handy-Whitman Index to account for expected inflation.

For purposes of submitting a Sell Offer, the net ACR values are expressed in terms of Unforced Capacity ("UCAP") MW where the net ACR values are initially calculated for each resource in terms of nameplate MW and then converted to UCAP MW. Through the 2024/2025 Delivery Year the net ACR is converted to UCAP MW terms based on the unit-specific EFORd for thermal generation resource types and battery energy storage resource types and the unit-specific Accredited UCAP value for battery energy storage, solar and wind generation resource types (appropriately time-weighted for any winter Capacity Interconnection Rights). Beginning with the 2025/2026 Delivery Year, the net ACR is converted to UCAP MW terms for all generation resource types based on the resource-specific Accredited UCAP Factor.

**Default Gross ACR Values used to determine MOPR Floor Offer Price of Existing Capacity Resource**

| Existing Resource Type | Through the 2025/2026 Delivery Years: Default Gross ACR (2022/2023 $/MW-Day) (Nameplate) | For the 2026/2027 Delivery Year and Subsequent Delivery Years: Default Gross ACR (20267/ 2027) ($/MW-day) (Nameplate) |
|---|---|---|
| Nuclear – Single Unit | $697 | $591 |
| Nuclear – Multi Unit | $445 | $537 |
| Coal | $80 | $94 |
| Combined Cycle | $56 | $113 |
| Combustion Turbine | $50 | $52 |
| Steam Oil & Gas | NA | $64 |
| Solar PV (Fixed and Tracking) | $40 | $70 |
| Onshore Wind | $83 | 147 |

## 5.5 Buy Bids in RPM

Buy Bids for the Incremental Auctions must be submitted in PJM's Capacity Exchange system. Buy Bids are only accepted during a fixed bidding window which is open for at least five (5)

business days. Buy Bids may not be changed or withdrawn after the bidding window for an Incremental Auction is closed.

A Buy Bid must specify:

- Quantify of unforced capacity resources desired, in increments of 0.1 MWs;
- Maximum price willing to pay for unforced capacity resources in $/MW-day;
- All Buy Bids will be for Capacity Performance Resources
- Desired location (Locational Deliverability Area) for the replacement capacity.

Buy Bids may not specify a minimum MW amount. The Buy Bid may clear any MW amount equal to or less than the quantity of unforced capacity resources desired in the Buy Bid.

In the event of a delay or cancellation of a Qualifying Transmission Upgrade, the Buy Bid will specify the purchase of capacity resources (of the Capacity Performance Resource type) in the LDA for which the Qualifying Transmission Upgrade was to increase the CETL (Sink LDA).

Cleared Buy Bids are binding commitments to purchase capacity.

## 5.6 Energy Market Offer Requirements

All generation resources that have an RPM Resource Commitment must offer into PJM's Day Ahead Energy Market. Demand Resources that have an RPM Resource Commitment must be registered in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared emergency events. Please refer to the ***Energy & Ancillary Services Market Operations Manual (M-11)*** for details on PJM Energy Market participation.

## 5.7 Base Residual Auction

The Reliability Pricing Model includes a single Base Residual Auction for each Delivery Year. A Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year. Base Residual Auctions are conducted in accordance with the auction schedule posted on the PJM website.

### 5.7.1 Participation in the Base Residual Auction

Products that resource providers can offer into PJM's Base Residual Auction include:

- Existing Generation Capacity Resources
- Planned Generation Capacity Resources
- Existing Demand Resources
- Planned Demand Resources
- Energy Efficiency Resources

- Aggregate Resources
- Qualifying Transmission Upgrades

Existing Generation Capacity Resources in a party's RPM Resource Portfolio that have no exception to the RPM must offer requirement and that have available capacity to offer and are not offered into the Base Residual Auction for the Delivery Year shall be excluded from participation in any and all Incremental Auctions conducted for the Delivery Year. Generation is treated as existing when the generation is (a) in service at the commencement of the Base Residual Auction or (b) not yet in service but has cleared in an RPM Auction for any prior Delivery Year. These unoffered MWs from existing generation resources shall be ineligible to serve as capacity resources on behalf of any RPM or FRR Load Serving Entity for such Delivery Year, and are therefore prohibited from receiving any RPM capacity revenues for the Delivery Year and prohibited from being committed to an FRR Entity's FRR Capacity Plan for the Delivery Year. To enforce this business rule, PJM will track Daily Unoffered ICAP amounts for generation resources.

Effective with the 2025/2026 Delivery Year, a Planned Generation Capacity Resource must satisfy the requirements of the binding notice of intent in section 4.2.3.1 in order for the Planned Generation Capacity Resource to be included in a Sell Offer for an RPM Auction.

The following are business rules that apply to the Base Residual Auction:

- Existing Generation Capacity Resources, existing Demand Resources, and Energy Efficiency Resources that have an increase in Available ICAP after the Base Residual Auction are eligible to offer the capacity increase into an Incremental Auction for the Delivery Year if the increase is approved prior to the opening of the Incremental Auction bidding window. See Section 5.8.1 for business rules regarding participation in an Incremental Auction.
- For the Base Residual Auction, a party's Current Available ICAP Position for a specific unit for the Delivery Year are equal to the minimum of (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) for the Delivery Year.

$$AvailICAPPosition_{GEN} = Min_{DY}\left(DailyICAPOwned - DailyFRRCommitments\right)$$

- For the Base Residual Auction, a party's Current Available ICAP Position for a specific unit for the summer/winter season is calculated. A party's Current Available ICAP Position for the summer season are equal to the minimum (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) for June through October and May of the Delivery Year. A party's Current, Available ICAP Position for a specific unit for the winter season are equal to the minimum (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) for November through April of the Delivery Year.
- Following a Base Residual Auction, a party's Daily Unoffered ICAP for a generation resource is calculated and is equal to the Available ICAP Position minus the Offered ICAP

in the party's sell offer. A FRR Entity's Daily Unoffered ICAP for a generation resource is set equal to 0 MW.

$$DailyUnofferICAP_{GEN} = AvailICAPPosition_{GEN} - OfferedICAP$$

- A Demand Resource's Available ICAP to offer into a Base Residual Auction is determined based on pre-registration confirmation process in the Capacity Exchange system for such Base Residual Auction and PJM's approval of the Curtailment Service Provider's DR Sell Offer Plan for such Base Residual Auction. A Demand Resource's Existing Available ICAP is determined based on the CSP's completion of the pre-registration process and the DR Existing Setup process in the Capacity Exchange system. A Demand Resource's Planned Available ICAP is determined based on PJM's approval of planned MWs in the CSP's DR Sell Offer Plan and the CSP's completion of the DR Planned Setup process in the Capacity Exchange system. A Demand Resource's Available ICAP is equal to the Existing Available ICAP and Planned Available ICAP. A Demand Resource's Existing Available ICAP and Planned Available ICAP is further classified by the CSP in the DR Existing/Planned Setup process as MWs intend to offer as Annual Capacity Performance, MWs intend to offer as Summer-Period Capacity Performance, and MWs intend to offer as part of Aggregate Resource. Such classification is used to establish the maximum Existing/Planned Available ICAP that may be offered as Capacity Performance (annual) and maximum Existing/ Planned Available ICAP that may be offered as Seasonal Capacity Performance (summer).
- An EE Resource's Available ICAP to offer into a Base Residual Auction is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such Base Residual Auction and the provider's completion of the EE Setup process in the Capacity Exchange system prior to the Base Residual Auction. An EE Resource's Existing Available ICAP is determined based on Nominated EE Value approved by PJM in the most recent Post-Installation M&V Report and the EE Provider's completion of the EE Existing Setup process in the Capacity Exchange system. An Energy Efficiency Resource's Planned Available ICAP is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such Base Residual Auction and the provider's completion of the EE Planned Setup process for such Base Residual Auction in the Capacity Exchange system. An EE Resource's Available ICAP to offer into an RPM Auction is equal to the Existing Available ICAP and Planned Available ICAP. An Energy Efficiency Resource's Existing Available ICAP and Planned Available ICAP is further classified by the EE Resource Provider in the EE Existing/Planned Setup process as MWs intend to offer as Annual Capacity Performance, MWs intend to offer as Summer-Period Capacity Performance, and MWs intend to offer as part of an Aggregate Resource. Such classification is used to establish the maximum Existing/Planned Available ICAP that may be offered as Capacity Performance (annual) and maximum Existing/Planned Available ICAP that may be offered as Seasonal Capacity Performance (summer).
- Resources may be directly offered into the Base Residual Auction by specifying a MW quantity and sell offer price in the sell offer or may be self-scheduled into the Base

Residual Auction by enabling the self-schedule flag in the sell offer. See the Resource Specific Sell Offer Requirements Section for further details.

- The product offered in the Base Residual Auction must be resource-specific or apply to a Qualifying Transmission Upgrade.
- The smallest increment that may be offered into a Base Residual Auction is 0.1 MW.

### 5.7.2 Auction Clearing Mechanism – Base Residual Auction

The Base Residual Auction clearing software is an optimization algorithm. This algorithm has the objective of minimizing capacity procurement costs given the supply offers, Variable Resource Requirement Curve(s), and Locational Constraints, The algorithm will also enforce the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region. The supply curve formed by the Sell Offers submitted within a modeled LDA shall only consider the quantity of MWs from Summer-Period Capacity Performance Resources that are equally matched with Winter-Period Capacity Performance Resources within the LDA, such that only the equally matched quantity of opposite-season Sell Offers are considered in satisfying the modeled LDA's reliability requirement.

The Base Residual Auction clearing price for each LDA is determined by the optimization algorithm. The Resource Clearing Price within each LDA is the sum of:

- The marginal value of system capacity, and
- Locational Price Adder(s), if any, relevant to such LDA.

The marginal value of system capacity is the clearing price for Capacity Performance Resources in the unconstrained area of the PJM region.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying an LDA's Reliability Requirement. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDA and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest sell offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher constrained LDA, where they are considered in a similar manner for compensation.

In the event that the Sell Offers forming the supply curve do not result in an intersection with the Variable Resource Requirement Curve, the marginal value of system capacity will be set along

the Variable Resource Requirement Curve by extending the supply curve vertically from its end point until it intersects the Variable Resource Requirement Curve.

### 5.7.3 Resource Make-Whole Payments in the Base Residual Auction

A resource provider that offered and cleared fewer MWs than the minimum MW specification in the Base Residual Auction would receive a Resource Make-whole payment.

The Resource Make-whole Payment is equal to the product of the Capacity Resource Clearing Price and the quantity difference between the sell offer's minimum MW specification and the cleared MW quantity in the Base Residual Auction.

$$ResourceMakewholePayment = RCP * \left(SellOfferMinMW - ClearedMW_{BRA}\right)$$

A resource provider that offered and cleared a Seasonal Capacity Performance sell offer for which the sell offer price exceeded the clearing price determined for such resource as a result of the seasonal matching process in the post-processing of the auction results as described in Section 5.7.2 will receive a Resource Make-whole Payment. The Resource Make-whole Payment is equal to the difference between the sell offer price and clearing price for such resource determined as a result of the seasonal matching process, multiplied by the cleared MW quantity.

Make-whole payments required in the BRA will be charged to all LSEs in the LDA via the Final Zonal Capacity Price.

Only cleared Qualifying Transmission Upgrades, cleared resource-specific sell offers, and cleared flexible self-scheduled offers in excess of their self-scheduled quantity are eligible for make-whole payments in the BRA.

### 5.7.4 Posting of Base Residual Auction Results

Base Residual Auction results are posted to a participant's Capacity Exchange account and summary results are posted to a public portion of the PJM website. For any Base Residual Auction, clearing results will not be posted until after 4 p.m. EPT on Friday of Auction Clearing week.

Participants can view the resolution of their sell offer in the BRA through Capacity Exchange. The results of their sell offer will be categorized as cleared, uncleared, offered, unoffered, or make-whole.

Base Residual Auction sales are credited weekly during the Delivery Year as the unforced capacity is actually utilized.

## 5.8 Incremental Auctions

*The First, Second, and Third Incremental Auctions* are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments.

A *Conditional Incremental Auction* may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a Locational Deliverability Area to address the corresponding reliability problem.

### 5.8.1 Participation in the Incremental Auctions

Existing Generation Capacity Resources in a party's RPM Resource Portfolio that have no exception to the RPM must offer requirement and that have available capacity to offer and are not offered into an Incremental Auction for the Delivery Year shall be excluded from participation in any subsequent Incremental Auctions conducted for the Delivery Year. Generation is treated as existing when the generation is (a) in service at the commencement of the Incremental Auction or (b) not yet in service but has cleared an RPM Auction for any prior Delivery Year. These unoffered MWs from existing generation shall be ineligible to serve as capacity resources on behalf of any RPM or FRR Load Serving Entity for such Delivery Year, and are therefore prohibited from receiving any RPM capacity revenues for the Delivery Year and prohibited from being committed to an FRR Entity's Capacity Plan for the Delivery Year. To enforce this business rule, PJM will track Daily Unoffered ICAP amounts of generation resources.

Effective with the 2025/2026 Delivery Year, a Planned Generation Capacity Resource must satisfy the requirements of the binding notice of intent in section 4.2.3.1 in order for the Planned Generation Capacity Resource to be included in a Sell Offer for an RPM Auction.

Products that resource providers can offer into an Incremental Auction include:

- Existing Generation Capacity Resources that were offered and not cleared in a prior auction for the same Delivery Year
- Planned Generation Capacity Resources
- Existing Demand Resources or Energy Efficiency Resources that were offered and not cleared in a prior auction for the same Delivery Year
- Planned Demand Resources or Energy Efficiency Resources
- Transmission upgrades are not eligible to be offered into Incremental Auctions. (Transmission upgrades are only eligible to be offered into Base Residual Auction)

The following are business rules that apply to the Incremental Auctions:

- The product offered in the Incremental Auction must be resource-specific.
- The smallest increment that may be offered into an Incremental Auction is 0.1 MW.
- Planned Generation Capacity Resources, Planned Demand Resources, or Energy Efficiency Resources that were not eligible to participate at the time of the Base Residual

Auction or prior Incremental Auction, are eligible to participate in subsequent Incremental Auctions if the planned generation, Planned Demand Resource, or Energy Efficiency Resource meets the requirements specified in Section 4 of this manual.

- Existing Generation Capacity Resources and existing Demand Resources or Energy Efficiency Resources that have increases in Available ICAP after an Incremental Auction are eligible to offer the capacity increase into a subsequent Incremental Auction for the Delivery Year if the Available ICAP increase is approved prior to the opening of the subsequent Incremental Auction bidding window.
- For Incremental Auctions, a Current Available ICAP Position is calculated for generation resources. An Available ICAP Position is also determined for demand resources and energy efficiency resources that intend to offer into such Incremental Auction. These Available ICAP positions are determined for annual period and for summer/winter period if Seasonal Capacity Performance Resource.

A party's Current Available ICAP Position on a unit for an Incremental Auction is equal to the minimum Daily Available ICAP for such unit during the Delivery Year or during summer/winter season.

$$CurrentAvailableICAPPosition_{GEN} = Min\left(DailyAvailableICAP_{GEN}\right)$$

For a party, the Daily Available ICAP on a unit is equal to Daily ICAP Owned – Daily Unoffered ICAP – (Daily RPM Resource Commitments/(Accredited UCAP Factor)) – Daily FRR Capacity Plan Commitments.

$$DailyAvailICAP_{GEN} =$$

$$DailyICAPOwned - DailyUnofferICAP - \left(\frac{DailyRPMResourceCommitments}{Accredited\ \ UCAP\ \ Factor}\right)$$

$$- DailyFRRCommitments$$

A party's Daily Unoffered ICAP for a specific unit is calculated by adding the sum of any Daily Unoffered ICAP for such unit in prior RPM Auctions to Daily Unoffered ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases.

$$DailyUnofferICAP_{GEN}$$

$$= \sum \left(DailyUnofferICAP_{Prior\ RPMAuctions} + UnofferICAP_{BilateralSales\,/\,Purchases}\right)$$

For an Incremental Auction, a party's Daily Unoffered ICAP for generation resource is equal to the Current Available ICAP Position minus the Offered ICAP in the party's sell offer. A FRR Entity's Daily Unoffered ICAP for a generation resource is set equal to 0 MW.

$$DailyUnofferICAP_{GEN} = MinAvailableICAPPosition - OfferedICAP$$

A Demand Resource's Available ICAP to offer into an Incremental Auction is determined based on pre-registration confirmation process in the Capacity Exchange system for such Incremental Auction and PJM's approval of the Curtailment Service Provider's DR Sell Offer Plan for such

Incremental Auction. A Demand Resource's Existing Available ICAP is determined based on the CSP's completion of the pre-registration process and the DR Existing Setup process in the Capacity Exchange system. A Demand Resource's Planned Available ICAP is determined based on PJM's approval of planned MWs in the CSP's DR Sell Offer Plan and the CSP's completion of the DR Planned Setup process in the Capacity Exchange system. A Demand Resource's Available ICAP is equal to the Existing Available ICAP and Planned Available ICAP. A Demand Resource's Existing Available ICAP and Planned Available ICAP is further classified by the CSP in the DR Existing/Planned Setup process as MWs intend to offer as Annual Capacity Performance and MWs intend to offer as Summer-Period Capacity Performance. Such classification is used to establish the maximum Existing/Planned Available ICAP that may be offered as Capacity Performance (annual) and maximum Existing/Planned Available ICAP that may be offered as Seasonal Capacity Performance (summer).

An EE Resource's Available ICAP to offer into an Incremental Auction is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such Incremental Auction and the provider's completion of the EE Setup process in the Capacity Exchange system prior to the Incremental Auction. An EE Resource's Existing Available ICAP is determined based on Nominated EE Value approved by PJM in the most recent Post-Installation M&V Report and the EE Provider's completion of the EE Existing Setup process in the Capacity Exchange system. A Energy Efficiency Resource's Planned Available ICAP is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such Incremental Auction and the provider's completion of the EE Planned Setup process for such Incremental Auction in the Capacity Exchange system. An EE Resource's Available ICAP to offer into an RPM Auction is equal to the Existing Available ICAP and Planned Available ICAP. An Energy Efficiency Resource's Existing Available ICAP and Planned Available ICAP is further classified by the EE Resource Provider in the EE Existing/Planned Setup process as MWs intend to offer for Annual period and MWs intend to offer for Summer period. Such classification is used to establish the maximum Existing/ Planned Available ICAP that may be offered as Capacity Performance (annual) and maximum Existing/Planned Available ICAP that may be offered as Seasonal Capacity Performance (summer).

### 5.8.2 Timing of the Incremental Auctions

The First Incremental Auction is held during the month of September, twenty (20) months prior to the start of the Delivery Year.

The Second Incremental Auction is held during the month of July, ten (10) months prior to the start of the Delivery Year.

The Third Incremental Auction is held during the month of February, three (3) months prior to the start of the Delivery Year.

Incremental Auctions are conducted in accordance with the auction schedule posted on the PJM website.

### 5.8.3 Resource Make-Whole Payments in Incremental Auctions

A resource provider that offered and cleared fewer MWs than its minimum MW specification in an RPM Auction would receive a resource make-whole payment. This situation occurs because of the minimum MW specification in the sell offer data. This can occur at most for one resource in each LDA and for a one resource in the unconstrained market region.

The Resource Make-whole Payment is equal to the product of the Capacity Resource Clearing Price and the quantity difference between the sell offer's minimum MW specification and the cleared MW quantity in the Auction.

A resource provider that offered and cleared a Seasonal Capacity Performance sell offer for which the sell offer price exceeded the clearing price determined for such resource as a result of the seasonal matching process in the post-processing of the auction results as described in Section 5.8.5 will receive a Resource Make-whole Payment. The Resource Make-whole Payment is equal to the difference between the sell offer price and clearing price for such resource determined as a result of the seasonal matching process, multiplied by the cleared MW quantity.

Make-whole payments required in the Auction will be charged to all cleared participant and PJM buy bids on pro-rata basis based on the MWs cleared in such auction. Only cleared resource specific sell offers are eligible for make-whole payments in an Incremental Auction.

Make-whole charges assessed to buy bids cleared by PJM will be assessed to LSEs in the LDA via the Final Zonal Capacity Price.

### 5.8.4 Allocation of Costs in Incremental Auctions

The costs of the incremental commitments that are cleared in Incremental Auctions are allocated to resource providers that cleared Buy Bids in that Incremental Auction based on the cleared Buy Bid MW quantity and the clearing price and to LSEs by adjusting the Zonal Capacity Price.

### 5.8.5 Auction Clearing Mechanism – Incremental Auctions

The clearing of the Incremental Auctions is determined by the intersection of the supply curve and the demand curve. In the event the Sell Offers forming the supply curve do not intersect with the Buy Bids forming the demand curve, one of the following will occur:

1. The clearing will be set along the demand curve by extending the supply curve vertically upward from its end point unit it intersects the demand curve, or
2. The clearing will be set along the supply curve by extending the demand curve vertically downward from its end point until it intersects the supply curve, or

If no intersections occur as a result of the supply curve extension or the demand curve extension, no capacity will be cleared in the Incremental Auction. The Incremental Auction

clearing prices for each Buy Bid or Sell Offer cleared is determined by the same optimization algorithm used in the Base Residual Auction clearing.

The Resource Clearing Price within an LDA is equal to the sum of:

- The marginal value of system capacity and
- The Locational Price Adder(s), if any relevant for such LDA.

The marginal value of system capacity is the clearing price for Capacity Performance Resources in the unconstrained area of the PJM region.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying participant and PJM Buy Bids in an LDA. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDA and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest sell offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher constrained LDA, where they are considered in a similar manner for compensation.

The First, Second, and Third Incremental Auction clearing software is an optimization algorithm. The algorithm has the objective of minimizing the cost of committing capacity for the submitted Buy Bids given the Locational Constraints and submitted supply offers.

The algorithm will also enforce the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region. The supply curve formed by the Sell Offers submitted within a modeled LDA shall only consider the quantity of MWs from Summer-Period Capacity Performance Resources that are equally matched with Winter-Period Capacity Performance Resources within the LDA, such that only the equally matched quantity of opposite-season Sell Offers are considered in satisfying the participant and PJM Buy Bids in a modeled LDA.

### 5.8.6 Posting of Incremental Auction Results

The Incremental Auction results are posted to a participant's Capacity Exchange account and summary results are posted to a public portion of the PJM website. For any Incremental Auction, clearing results will not be posted until after 4 p.m. EPT on the fifth business day after the close of the RPM Auction offer window.

Participants may view the resolution of their sell offer in the Incremental Auction through Capacity Exchange. The results of their sell offer will be categorized as cleared, offered, unoffered, or make-whole.

Incremental Auction purchases/sales (i.e., Auction Charges/Auction Credits) are charged/credited weekly during the Delivery Year.

## 5.9 Auction Clearing Results

### 5.9.1 Zonal Capacity Prices

Zonal Capacity Prices for a Delivery Year are calculated following the Base Residual Auction for the Delivery Year and are adjusted following each Incremental Auction for the Delivery Year.

Preliminary Zonal Capacity Prices are calculated and posted following the Base Residual Auction for each Delivery Year. The Preliminary Zonal Capacity Price for each Zone is the sum of:

1. The marginal value of system capacity for the PJM Region;
2. The Locational Price Adder, if any, for such zones in a constrained Locational Deliverability Area (LDA); and
3. An adjustment in the Zone, if required, to account for any resource make-whole payments.

Make-whole payments are allocated to the entire obligation associated with the area in which the resource is cleared. If the resource clears in the unconstrained area, the make-whole payment is allocated to the entire RTO obligation. If the resource that is made whole clears in located in a constrained LDA, the make-whole payment is allocated to the entire obligation of the constrained LDA.

The following are business rules that apply to the Preliminary Zonal Capacity Prices:

- The Weighted Zonal Capacity Price for a Zone that includes multiple non-overlapping LDAs is the weighted average of the Zonal Capacity Prices for such LDAs, weighted by the Unforced Capacity of Resources Cleared (including Make whole MW) in each such LDA. If the Zone has a smaller LDA within a larger LDA then the Weighted Zonal Capacity Price is calculated using the smaller LDA and the remaining portion of the larger LDA.
- The Locational Price Adder is an addition to the marginal value of unforced capacity within an LDA as necessary to reflect the price of resources required to relieve the applicable binding locational constraints.
- A Locational Price Adder for an LDA shall not be a negative number.

**Note:**
***Preliminary Zonal Capacity Prices*** for the Delivery Year are posted by PJM at the end of the Base Residual Auction clearing process.

Zonal Capacity Prices for a Delivery Year are adjusted following each Incremental Auction for the Delivery Year. The Adjusted Zonal Capacity Prices for each Zone is the sum of:

1. The average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions conducted to date for the Delivery Year (excluding any Unforced Capacity cleared as replacement capacity);
2. The average Locational Price Adder, if any, weighted by the Unforced Capacity cleared in all auctions conducted to date for the Delivery Year (excluding any Unforced Capacity cleared as replacement capacity)[22]; and
3. An adjustment, if required, to account for any resource make-whole payments for all auctions conducted to date for the Delivery Year (excluding any resource make-whole payments to be charged to the buyers of replacement capacity).

**Note:**
***Adjusted Zonal Capacity Prices*** for the Delivery Year are posted following each Incremental Auction for that Delivery Year.

The Final Zonal Capacity Prices reflect the final price adjustments that are necessary to account for potential decreases in RPM Auction Credits to existing demand resources that were granted relief from Capacity Resource Deficiency Charges due to permanent departure of load . In addition, Final Zonal Capacity Prices reflect any price adjustments that are necessary to account for any transition provisions that are in effect for the Delivery Year (e.g., Prior CIL Exception External Resources that elected prior to the Delivery Year Third Incremental Auction to be relieved of their capacity obligation for such Delivery Year, or EE Resources electing prior to Delivery Year Third Incremental Auction to be relieved of their capacity obligation for such Delivery Year due to prohibition of EE participation by a Relevant Electric Retail Regulatory Authority.

The Final Zonal Capacity Prices are calculated such that the total amount of credit for CTR holders, Incremental CTR Holders, resources cleared for LSEs in all RPM Auctions for a given Delivery Year, Qualifying Transmission Upgrades cleared in the Base Residual Auction, and by LSEs serving load that is committed as price responsive demand for the Delivery Year equals to the total amount of Locational Reliability Charges assessed to loads. The Final Zonal Capacity Price is not net of the Final Zonal CTR Credit Rate.

**Note:**
The ***Final Zonal Capacity Prices*** for the Delivery Year are posted by PJM following the Third Incremental Auction for that Delivery Year.

[22] A weighted average Locational Price adder may be a negative number.

### 5.9.2 CTR Credit Rates

The Base Zonal CTR Credit Rate ($/MW-day) is equal to the Economic Value of CTRs allocated to LSEs in a zone as a result of the Base Residual Auction divided by the Base Zonal UCAP Obligation.

$$BaseZonalCTRCreditRate = \frac{BRAZonalEconomicValueofCTRs_{LSEs}}{BaseZonalUCAPOblig}$$

**Note:**
The ***Base Zonal CTR Credit Rate*** is posted with the Base Residual Auction results.

The Final Zonal CTR Credit Rate ($/MW-day) is equal to the Economic Value of CTRs allocated to LSEs in a zone as a result of all RPM Auctions for the Delivery Year divided by the Final Zonal UCAP Obligation.

$$FinalZonalCTRCreditRate = \frac{FinalZonalEconomicValueofCTRs_{LSEs}}{FinalZonalUCAPOblig}$$

**Note:**
The ***Final Zonal CTR Credit Rates*** are posted by PJM with the Third Incremental Auction clearing results.

### 5.9.3 CTR Settlement Rates

The CTR Settlement Rate ($/MW-day) is equal to the total Economic Value of CTRs ($/day) allocated to LSEs in a zone for all LDAs in which the zone resides as a result of all RPM Auctions for a Delivery Year divided by the maximum of the LDA CTR MWs allocated to LSEs in a zone.

$$FinalZonalCTRSettlementRate = \frac{FinalZonalEconomicValueofCTRs_{LSEs}}{ZonalMaxLDACTRMWs_{LSEs}}$$

**Note:**
The ***CTR Settlement Rates*** are posted by PJM with the Third Incremental Auction clearing results.

## 5.10 Reliability Backstop

The Reliability Backstop provides a mechanism to resolve reliability criteria violations caused by:

- Lack of sufficient capacity committed through the RPM Auctions or
- Near-term transmission deliverability violations identified after the Base Residual Auction is conducted

The purpose of the Reliability Backstop is to guarantee that sufficient generation, transmission and demand response solutions will be available to preserve system reliability. The Reliability Backstop mechanism is based on specific triggers that signal a need for a targeted solution to a reliability problem that was not resolved by the long-term commitment of Capacity Resources committed as a result of the RPM Auctions.

Details on the Reliability Backstop, including the triggering conditions and auction clearing procedures, can be found in ***Section 16 of Attachment DD of the Open Access Transmission Tariff.***

# Section 6: Capacity Transfer Rights

Welcome to the *Capacity Transfer Rights* section of the ***PJM Manual for the Capacity Market***. In this section, you will find the following information:

- The definition and purpose of Capacity Transfer Rights (see "Definition and Purpose of Capacity Transfer Rights")
- The business rules for determining Capacity Transfer Rights (see "Determination of Capacity Transfer Rights"
- The business rules for allocation of Capacity Transfer Rights (see "Allocation of Capacity Transfer Rights")
- The business rules for determining Capacity Transfer Right credits (see "Capacity Transfer Rights Credits")
- The business rules for transferring Capacity Transfer Rights (see "Capacity Transfer Rights Transfer")

## 6.1 Definition and Purpose of Capacity Transfer Rights

The purpose of Capacity Transfer Rights is to allocate the economic value of transmission import capability that exists into a constrained LDA to holders of Capacity Transfer Rights. Therefore, Capacity Transfer Rights serve to offset a portion of the Locational Price Adder charged to load in constrained LDAs.

As explained in Section 3, constrained Locational Deliverability Areas (LDAs) are modeled with their own VRR curves in the auction clearing process. The transmission import capability limit into a constrained LDA would require clearing resources with higher offer prices in the LDA (but at less than the prices on the LDA VRR Curve) to achieve the highest possible reliability in the LDA. This process would typically result in a price separation with LDA clearing price being higher than the unconstrained RTO clearing price. The Zonal Capacity Prices calculated in the constrained LDA would also be higher as they are a function of this higher clearing price. LSE Locational Reliability Charge in a zone is the LSE unforced capacity obligation multiplied by the Zonal Capacity Price. However, part of the LSE unforced capacity obligation is met by imported resources that receive auction credits at a lower price than the LDA clearing price. The credit to account for these lower-priced imported resources is achieved by allocating Capacity Transfer Rights (CTRs) to LSEs. CTRs would amount to dollar credits that would reduce the LSE load charges.

It is important to note that the LDA Reliability Requirement (based on the internal generation and CETO) used in the clearing process is typically higher than the unforced capacity obligation (based on coincident peak load) used for load charges and the CTR determination. Since the concept of CTRs is to provide credit towards the portion of the obligation met by imported resources, CTRs are calculated as the difference between the zonal (LDA) unforced capacity

obligation and the unforced capacity cleared in the zone (LDA). The total CTRs are typically lower than the LDA import capability (CETL) while the CETL is fully utilized in meeting the LDA Reliability Requirement and calculating the LDA clearing price. LSEs in the constrained LDA benefit when the CETL into the LDA is increased by transmission upgrades.

A transmission upgrade may be funded by a Project Developer, Eligible Customer, or Upgrade Customer (or, for facilities or upgrades in PJM queue prior to March 1, 2007 to an Interconnection customer) obligated to fund a transmission facility or upgrade through a rate or charge specific to such facility or upgrade. In this case, the customer is allocated Incremental CTRs (Participant-Funded Project ICTRs). Alternately, a transmission upgrade may be offered as a Qualified Transmission Upgrade (QTU) in the Base Residual Auction. A cleared QTU will receive auction credits.

Incremental Capacity Transfer Rights (ICTRs) associated with Regional Facilities and Necessary Lower Voltage Facilities that are Incremental Rights-Eligible Required Transmission Enhancements will be allocated to Responsible Customers to whom the costs of the Regional Facilities and Necessary Lower Voltage Facilities are assigned. ICTRs associated with Lower Voltage Facilities that are Incremental Rights-Eligible Required Transmission Enhancements are also allocated to Responsible Customers to whom the costs of the Lower Voltage Facilities are assigned. Incremental Rights-Eligible Required Transmission Enhancements are Regional Facilities and Necessary Lower Voltage Facilities or Lower Voltage Facilities (as defined in Scheduled 12 of the Tariff) and meet one of the following criteria: (1) cost responsibility assigned to non-contiguous Zones that are not directly electrically connected; or (2) cost responsibility is assigned to Merchant Transmission Providers that are Responsible Customers.

In these cases the total CTRs are reduced to provide credits to these parties before distributing the CTRs to LSEs.

### 6.1.1 Capacity Transfer Rights

The following are business rules that apply to Capacity Transfer Rights:

- Capacity Transfer Rights are applicable only for the Delivery Year for which they were defined.
- Capacity Transfer Rights are specified to the nearest 0.1 MW.
- The total amount of Capacity Transfer Rights that are allocated to LSEs in an LDA are equal to the amount of unforced capacity imported into such LDA based on the results of the Base Residual Auction and all Incremental Auctions for such Delivery Year less [the Participant-Funded ICTRs and Incremental Rights-Eligible Required Transmission Enhancements ICTRs that are allocated into the LDA for the Delivery Year less the amount of import capability increase into the LDA attributed to Qualifying Transmission Upgrades for the Delivery Year]. Capacity Transfer Rights (CTRs) for LSEs will be allocated in MWs for each modeled LDA in which the RPM Auctions for the Delivery Year resulted in a non-zero average weighted Locational Price Adder with respect to the immediate higher level LDA.

- The economic value (in $/day) of Capacity Transfer Rights in an LDA as a result of all RPM Auctions for the Delivery Year is equal to (i) the average weighted Locational Price Adder for such LDA determined with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year, multiplied by (ii) the MW quantity of CTRs allocated to LSEs in the LDA. The total economic value (in $/day) of Capacity Transfer Rights to LSEs in a zone is the sum of the economic values of Capacity Rights in an LDA for all LDAs in which such zone resides.

### 6.1.2 Participant-Funded Project Incremental Capacity Transfer Rights

Incremental Capacity Transfer Rights (ICTRs) are allocated to an Upgrade Customer (or, for facilities or upgrades in PJM queue prior to March 1, 2007 to an Interconnection customer) obligated to fund a transmission facility or upgrade through a rate or charge specific to such facility or upgrade, to the extent such upgrade or facility increases the import capability into an LDA. Such incremental Capacity Transfer Rights allocation is based on the incremental increase in import capability across a Locational Constraint that is caused by the transmission facility upgrade.

Incremental Capacity Transfer Rights will be effective for thirty years or the life of the facility or upgrade, whichever is less. Under conditions when the internal resources cleared in the LDA are high, the total amount of Capacity Transfer Rights is limited, which may reduce the Incremental Capacity Transfer Rights available to Participant-Funded Projects.

If a customer funds advancement of a network transmission upgrade, the customer will receive Incremental CTRs for the years the upgrade is advanced based on the incremental CETL into a constrained LDA as certified by PJM. The customer should request PJM to certify the Incremental CTRs due to an advancement of a network transmission upgrade at least 90 days prior to the Base Residual Auction.

Participants must request PJM to certify the Incremental CTRs into the constrained LDAs modeled in RPM at least 90 days prior to the Base Residual Auction. PJM will certify the Incremental CTRs into the constrained LDA at least 45 days prior to the Base Residual Auction.

For LDAs in which the RPM Auctions for such Delivery Year result in a positive average weighted Locational Price Adder with respect to the immediate higher level LDA, the holder of a Participant-Funded ICTR into such LDA shall receive a payment equal to (i) average weighted Locational Price Adder for the LDA into which the associated facility or upgrade increased import capability, multiplied by (ii) MW amount of ICTRs allocated to holder. No payment will be issued to the holder when a zero or negative average weighted Locational Price Adder with respected to the immediate higher level LDA is calculated as a result of the RPM Auctions for such Delivery Year.

Participant-Funded ICTRs may be traded similar to CTRs.

### 6.1.3 Incremental Capacity Transfer Rights Associated with Incremental Rights-Eligible Required Transmission Enhancements

Incremental Rights-Eligible Required Transmission Enhancements may include Regional Facilities and Necessary Lower Voltage Facilities, and Lower Voltage Facilities. Regional Facilities are Transmission Facilities as defined in section 1.27 of the Consolidated Transmission Owners Agreement (Rate Schedule FERC No. 42) that are included in Regional Transmission Expansion Plan (RTEP) and operate at or above 500 kV. Necessary Lower Voltage Facilities are Transmission Facilities that operate below 500 kV and must be constructed or strengthened to support new Regional Facilities. Lower Voltage Facilities are Transmission Facilities that operate below 500 kV which are included in RTEP to address one or more reliability violations or to address operational adequacy and performance issues and are not Necessary Lower Voltage Facilities. Responsible Customers, as defined in Schedule 12 of the Tariff, that are Network Customers, Transmission Customers with an agreement for Firm Point-to-Point Service, or Merchant Transmission Facility Owners, and that are assigned cost responsibility for an Incremental Rights-Eligible Required Transmission Enhancement shall be allocated a share of the ICTRs associated with such facility in accordance with the percentage cost responsibility assigned to Responsible Customers for such facility as set forth in Schedule 12-Appendix to the Tariff.

ICTRs associated with Regional Facilities and Necessary Lower Voltage Facilities are determined and allocated to Responsible Customers. ICTRs associated with Lower Voltage Facilities are also determined and allocated to Responsible Customers. The ICTRs (in MWs) associated with a given Incremental Rights-Eligible Required Transmission Enhancement are established by PJM prior to the conduct of the Base Residual Auction for the first Delivery Year for which such facility is to be in service. Once established, the ICTRs for such facility are available for allocation for 30 years or the life of the project, whichever is less.

PJM determines the increase in CETL into an applicable LDA as a result of an Incremental Rights-Eligible Transmission Enhancement planned for the Delivery Year. The increase in the CETL represents the ICTRs (in MWs) into the LDA provided by such planned facility. If such facility increases CETL into multiple LDAs, PJM will calculate ‘simultaneous’ increases in CETL into the LDAs and determine a separate ICTR MW amount for each LDA, equal to the respective increase in CETL into such LDA. .

The allocation (in MWs) of a Delivery Year’s ICTRs for the Incremental Rights-Eligible Required Transmission Enhancement to a Responsible Customer may change during the Delivery Year if the percentage cost responsibility assigned to the Responsible Customers for such facility as set forth in Schedule 12-Appendix to the Tariff changes during the Delivery Year.

During the Delivery Year, each Network Customer (LSE) within a zone will be allocated a share of the zone’s ICTRs associated with Incremental Rights-Eligible Required Transmission Enhancements for such Delivery Year in proportion to the customer’s share of the zonal NSPL. These allocations may change day to day as end-use customers change from LSE to LSE.

ICTRs associated with Incremental Rights-Eligible Required Transmission Enhancements may be traded similar to CTRs.

The economic value of Incremental Rights-Eligible Required Transmission Enhancement ICTRs may change from year to year and will become zero when a zero or negative average weighted Locational Price Adder with respect to the immediate higher level LDA is calculated as a result of RPM Auctions for such Delivery Year.

The economic value (in $/day) of Incremental Rights-Eligible Required Transmission Enhancement ICTRs in an LDA as a result of all RPM Auctions for the Delivery Year is equal to (i) the average weighted Locational Price Adder for such LDA determined with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year, multiplied by (ii) the MW quantity of Regional Project ICTRs in an LDA allocated to Responsible Customers.

## 6.2 Determination of Capacity Transfer Rights

For LDAs in which a positive average weighted Location Price Adder with respect to the immediate higher level LDA is calculated as a result of all RPM Auctions for the Delivery Year, the total amount of Capacity Transfer Rights in such LDA are equal to the Final Unforced Capacity Imported into such LDA as a result of all RPM Auctions for the Delivery Year. The Total CTRs into a constrained LDA are reduced by (1) an equivalent QTU import capability cleared, (2) Participant-Funded Project ICTRs, and (3) Incremental Rights-Eligible Required Transmission Enhancement ICTRs, and the remaining CTRs are allocated to the LSEs in the LDA (Zone). ICTRs may be reduced if the Total CTRs calculated for a constrained LDA are limited in any Delivery Year. If the Total CTRs are limited, CTRs will first be allocated to a cleared QTU. Any remaining CTRs will be allocated to ICTRs associated with Participant-Funded Projects and Incremental Rights-Eligible Required Transmission Enhancements pro rata based on their original ICTR certified amount. For LDAs in which the average Locational Price Adder with respect to the immediate higher level LDA is negative, the Total CTRs are allocated only to LSEs.

$$LDACTR_{LSEs} = FinalLDAUCAPImported - LDAQTUEquivalents - LDAICTRs$$

**Where:**

| | |
|---|---|
| **Final Unforced Capacity Imported into an LDA** | is equal to the Final Unforced Capacity Obligation for such LDA as a result of all RPM Auctions for such Delivery Year less the net participant buy bid/sell offers cleared in the LDA for all RPM Auctions for such Delivery Year. |
| **Final LDA Unforced Capacity Obligation** | is equal to the sum of the Final Zonal Unforced Capacity Obligations for the zones in the LDA. |
| **equivalent QTU import capability cleared into an LDA** | is determined as the QTU BRA Auction Credits ($/day) received by the cleared QTU into an LDA divided by the weighted locational price adder of such LDA with respect to the immediate higher level LDA. |

If the LDA into which the Incremental Capacity Transfer Rights are allocated or the import capability is increased by a Qualifying Transmission Upgrade is a part of a zone (e.g., DPL South or PS North), the calculations will be made based on the zone instead of the LDA using a Weighted Locational Price Adder for the zone with respect to the immediate higher level LDA to determine an equivalent Incremental Capacity Transfer Rights into the zone or an equivalent import capability into the zone in the case of a Qualifying Transmission Upgrade.

## 6.3 Allocation of Capacity Transfer Rights

The allocation of the total Capacity Transfer Rights in an LDA is performed on a pro-rata basis for each LSE based on the Daily Unforced Capacity Obligation that they serve in zones included in the constrained LDA. The allocated CTRs in an LDA will be reallocated to LSEs on a daily basis as load switches between retail suppliers within each zone.

When a Zone and its sub-zones are constrained LDAs, CTR calculations are performed on a Zonal basis.

When an LDA is entirely contained within another LDA (e.g., a Zone is a smaller LDA within a Group of Zones which is a larger LDA), a portion of the larger LDA Capacity Transfer Rights will be allocated to the smaller LDA, based on the smaller LDA’s proportion of the larger LDA’s unforced capacity obligation.

## 6.4 Capacity Transfer Rights Credits

LSEs that were allocated CTRs in a zone will receive a daily zonal CTR Credit as described in the Settlements section of this Manual.

Participants that were allocated Incremental CTRs into an LDA will receive a daily Incremental CTR Credit equal to the total Incremental CTRs allocated times the Final Incremental CTR Credit Rate for such LDA.

The Final Incremental CTR Credit Rate for an LDA is equal to the LDA's weighted Locational Price Adder with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year.

## 6.5 Capacity Transfer Rights Transfers

RPM Market Participants will have the ability to request CTR or ICTR Transfers by notifying PJM. The purpose of a CTR Transfer is to transfer the ownership of a specified amount of CTR MWs in a given zone from the Seller to the Buyer.

The following are business rules that apply to Capacity Transfer Rights Transfers:

- CTR Transfer requests must specify the buyer, seller, start and end dates of the transfer, the transfer amount (in MW), and the zone from which to transfer the CTRs.
- CTR Transfers will result in the "Buyer" receiving the credit that would have been due to the "Seller" of the CTRs.
- The smallest increment of CTRs that may be transferred is 0.1 MW.
- Both the Buyer and the Seller of a CTR Transfer Transaction must submit the CTR Transfer request to PJM before the following daily accounting deadlines (all times in Eastern Prevailing Time):
    - 1:00 PM (Tuesday – Friday) for transactions beginning on the previous day
    - 5:00 PM (Monday) for transactions beginning on Friday, Saturday, and Sunday
    - 5:00 PM (a day after the holiday) for transactions beginning on a holiday

# Section 7: Load Obligations

Welcome to the *Load Obligations* section of the ***PJM Manual for the PJM Capacity Market***. In this section, you will find the following information:

- An overview description of Load Obligations (see “Overview of Load Obligations”)
- The business rules for determining Unforced Capacity Obligations (see “Unforced Capacity Obligations”)
- The business rules for determining RPM Scaling Factors (see “RPM Scaling Factors”)
- The business rules for determining Obligation Peak Load values (see “Obligation Peak Load”)
- The process for determining load obligations (see “Process for Determining Load Obligations”)
- The business rules for the treatment of Non-Zone Load (see “Non-Zone Load)

## 7.1 Overview of Load Obligations

In the Reliability Pricing Model, Unforced Capacity is the basis for the market product that is cleared in each auction. Unforced Capacity (UCAP) is a) installed capacity rated at summer conditions that is not, on average, experiencing a forced outage or forced de-rating or b) Effective UCAP provided by ELCC Resources. While unforced capacity (UCAP) is the basis for the valuation of generating capacity, in RPM, this concept is also used to value load management (Demand Resources (DR) , Energy Efficiency, Reliability Requirements of RTO and LDAs, and to define load obligations of Load Serving Entities. Load obligations are obligations to serve load or obligations to reduce load during the Delivery Year valued as unforced capacity.

Load Obligations are based on the Unforced Capacity Obligation procured in Base Residual Auction and all the Incremental Auctions.

## 7.2 Unforced Capacity Obligations

### 7.2.1 Determination of Unforced Capacity Obligations

Unforced Capacity Obligations are obligations for load to be served during the delivery year in unforced capacity terms. However, since RPM auction participants are not bidding in the demand for UCAP in the RPM process, the reliability requirement is forecasted on an aggregate basis prior to the clearing of the RPM Auctions as an input into the clearing process.

In the Reliability Pricing Model, unforced capacity obligations are determined for the RTO and Zones as a result of the Base Residual Auction and all Incremental Auctions.

The following parameters, discussed in detail below, are values used in the determination of Unforced Capacity Obligations:

- Peak Load Forecasts
- Forecast Pool Requirement (FPR)

### 7.2.2 Base Unforced Capacity Obligations

A Base RTO Unforced Capacity Obligation is determined after the clearing of the Base Residual Auction and is posted with the Base Residual Auction results. The Base RTO Unforced Capacity Obligation is equal to the sum of the unforced capacity obligation satisfied through the Base Residual Auction.

$$BaseRTOUCAPOblig = UCAPOblig_{BRA}$$

RTO Unforced Capacity Obligation satisfied in Base Residual Auction is used to determine the Base Zonal RPM Scaling Factors for use in determining Base Zonal Unforced Capacity Obligation. See Section 7.3.2 for Base Zonal RPM Scaling Factor equation.

**Base Zonal Unforced Capacity Obligation**

Zonal Unforced Capacity Obligations are determined based on an allocation of the RTO Unforced Capacity Obligation based on zonal peak load forecasts. As a result of the RPM Auction clearing process, additional resources above those required to meet the IRM may be procured and allocated to the zones. Since resource requirements in the constrained zones may be higher than those required based on IRM (FPR) these requirements affect the clearing price in the zones but not the allocation of RTO obligations to zones.

A Base Zonal Unforced Capacity Obligation is determined for each zone and is equal to the (Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year* Base Zonal RPM Scaling Factor * the Forecast Pool Requirement).

$$BaseZonalUCAPOblig =$$

$$\left(ZWNSP_{DY-4} * BaseZonalRPMScalingFactor * FPR\right)$$

**Note:**
***Base Zonal Unforced Capacity Obligations*** are posted with the Base Residual Auction clearing results.

### 7.2.3 Final Zonal Unforced Capacity Obligations

The Final RTO Unforced Capacity Obligation is determined after the clearing of the final Incremental Auction for the Delivery Year. The Final RTO Unforced Capacity Obligation is equal to the RTO unforced capacity obligations satisfied through all RPM Auctions for the Delivery Year. The RTO unforced capacity obligation through all RPM Auctions is equal to the total MWs

cleared in PJM Buy Bids in RPM Auctions less the total MWs cleared in PJM Sell Offers in RPM Auctions.

$$FinalRTOUCapOblig = \sum PJMBuyBidMWsCleared - \sum PJMSellOfersCleared$$

The Final Zonal Unforced Capacity Obligation is determined for each zone and is equal to zonal allocation of the Final RTO Unforced Capacity Obligation. The Final RTO Unforced Capacity Obligation is allocated to the zones on a pro-rata basis based on the Final Zonal Peak Load Forecasts.

$$FinalZonalUCAPOblig = \left(\frac{ZonalFinalPeakLoadForecast}{RTOFinalPeakLoadForecast}\right) * FinalRTOUCAPOblig$$

**Note:**
The Final Zonal Unforced Capacity Obligations are posted after the clearing of the final Incremental Auction for the Delivery Year.

## 7.3 RPM Zonal Scaling Factors

RPM Zonal Scaling Factors are calculated as a result of RPM Auctions and are constant for the Delivery Year. The following RPM Zonal Scaling Factors are determined:

- Base Zonal Scaling Factors – determined for each zone after the clearing of the Base Residual Auction
- Final Zonal Scaling Factors –determined for each zone with the clearing of the final Incremental Auction.

These scaling factors account for (1) load growth from a prior-year summer to the Delivery Year; (2) any excess resources procured above those required to exactly meet the FPR requirements.

The following parameters are values used in the determination of RPM Zonal Scaling Factors:

- RTO Unforced Capacity Obligation (Base & Final)
- Zonal Peak Load Forecasts (ZPLF) (Preliminary & Final)
- Forecast Pool Requirement (FPR)
- Zonal Weather Normalized Summer Peaks (ZWNSP)

The purpose of RPM Zonal Scaling Factors is to determine the LSE Daily UCAP Obligations in the zones from the Daily Obligation Peak Loads.

### 7.3.1 Zonal Weather Normalized Summer Peaks

To account for the load growth from a prior-year summer to each Delivery Year, PJM determines Zonal Weather Normalized Summer Peaks by October 31 prior to the start of the

Delivery Year. The Zonal Weather Normalized Summer Peaks are calculated in accordance with the ***Load Forecasting & Analysis Manual (M-19)***.

The RTO Weather Normalized Summer Peak is the sum of the Zonal Weather Normalized Coincident Summer Peaks.

The Electric Distribution Company (EDC) is responsible for allocating the Zonal Weather Normalized Summer Peak for the summer prior to the Delivery Year and providing to PJM an Obligation Peak Load allocation for each Capacity Exchange defined "area" within their zone by December 31 prior to the start of the Delivery Year. See ***Reliability Assurance Agreement Schedule 8, Section A and Generator Operational Requirements Manual (14-D), Appendix A*** for the limitations in the netting of operating Non-Retail Behind the Meter Generation against wholesale area load.

### 7.3.2 Base Zonal RPM Scaling Factor

A Base Zonal RPM Scaling Factor is determined for each zone and is equal to the [(Preliminary Zonal Peak Load Forecast for the Delivery Year divided by the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year)* ((RTO Unforced Capacity Obligation Satisfied in Base Residual Auction divided by the (RTO Preliminary Peak Load Forecast * the Forecast Pool Requirement))]. Zonal peak load is adjusted for peak loads of zone/areas that elected FRR option.

$$BaseZonalRPMScalingFactor = \left(\frac{PrelimZPLF}{ZWNSP_{(DY-4)}}\right) * \left(\frac{RTOUCAPOblig_{BRA}}{RTOPrelimPeakLoadForecast * FPR}\right)$$

**Note:**
***Base Zonal RPM Scaling Factors*** are posted with the Base Residual Auction results.

### 7.3.3 Final Zonal RPM Scaling Factor

The Final Zonal RPM Scaling Factors are used in determining an LSE's Daily Unforced Capacity Obligation. A Final Zonal RPM Scaling Factor for a zone is equal to the Final Zonal Unforced Capacity Obligation divided by (FPR times the Zonal Weather Normalized Peak for the summer prior to the Delivery Year).

$$FinalZonalRPMScalingFactor = \frac{FinalZonalUCAPOblig}{FPR * ZWNSP_{DY-1}}$$

## 7.4 Obligation Peak Load

Obligation Peak Load is the peak load value on which LSEs' Unforced Capacity Obligations are based. Each PJM Electric Distribution Company (EDC) is responsible for allocating its

normalized previous summer's peak to each customer in the zone (both retail and wholesale). LSE Obligation Peak Load represents the summation of Peak Load Contributions for each of an LSE's customers.

The following business rules apply to Delivery Year Obligation Peak Load data for a zone/area:

- The Obligation Peak Load allocation for a zone/area is constant and effective for the entire Delivery Year.
- The EDC is also responsible for allocating the Obligation Peak Load for a zone/area among end-use customers by calculating Peak Load Contributions (i.e., "capacity tickets") for each end-use customer by December 31 prior to the start of the Delivery Year.
- The EDC must make Peak Load Contribution information available to LSEs by December 31 prior to the start of the Delivery Year.
- Non-dispatched charging energy for Energy Storage Model Participants and Open-Loop Hybrid Resources shall not be allocated a Peak Load Contribution value in accordance with Manual 27.

## 7.5 Daily Unforced Capacity Obligations

The following business rules apply to daily Obligation Peak Load data used in determining LSE Daily Unforced Capacity Obligations:

- The EDC is responsible for uploading Obligation Peak Load data into Capacity Exchange for every LSE serving load in their zone/area during the Delivery Year. The file upload must be performed in accordance with Capacity Exchange's file format specifications and by the file upload deadline (36 hours before the start of the operating day). Corrections to Obligation Peak Load data may be made up to 12:00 PM Eastern Prevailing Time of the next business day following the Operating Day.
- The daily sum of all the LSEs' Obligation Peak Load data in a zone/area must equal the EDC's Obligation Peak Load allocation to the zone/area.
- A Daily Obligation Peak Load Scaling Factor will be used to scale the uploaded LSE Obligation Peak Load values to the fixed Obligation Peak Load Allocation of the zone/area in the event that the Obligation Peak Load values uploaded by the EDC do not exactly sum to the Annual Obligation Peak Load Allocation for the zone/area.

$$DailyObligPeakLoadScalingFactor = \frac{AnnualZoneAreaObligPeakLoadAllocation}{\sum ZoneAreaObligPeakLoadUploads}$$

- The daily sum of the Obligation Peak Load data for all areas in a zone must equal the Zonal Weather Normalized Summer Peak for the summer prior to the Delivery Year.

The Daily Unforced Capacity Obligation of an LSE in a zone/area equals the LSE's Obligation Peak Load in the zone/area * the Final Zonal RPM Scaling Factor * the Forecast Pool Requirement.

*DailyUCAPOblig = ObligPeakLoad*FinalZonalPRMScalingFactor*FPR*

## 7.6 Process for Determining Load Obligations

The process that was described in the previous sections is illustrated below.

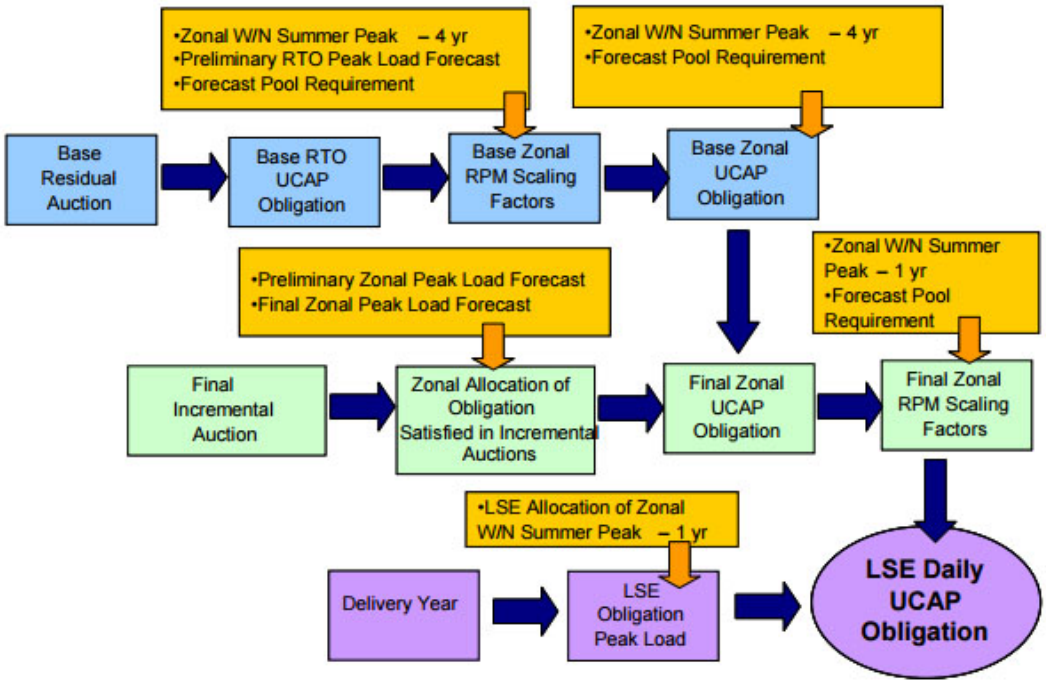



*Exhibit 3: Process for determining Load Obligations*

## 7.7 Treatment of Non-Zone Load

Non-Zone Load is the load that is located outside of the PJM Region served by a PJM Load Serving Entity using PJM internal resources. Non-Zone Load is included in the load of the Zone from which the load is served.

The following are business rules that apply to Treatment of Non-Zone Load:

- Non-Zone Load may be Non-Zone Network Load (Tariff 1.27B) that is charged a Network Integration Transmission Service (NITS) charge (Tariff Attachment H-A) or other load that may be ‘grandfathered’ from the NITS charge.
- PJM forecasts the Preliminary Non-Zone Load for the RPM Delivery Year and includes it in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load

of the Zone from which the Non-Zone Load is served, by February 1 prior to the Base Residual Auction.

- Non-Zone Load cannot be served in a Delivery Year using resources committed to RPM if it is not included in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load prior to the RPM Base Residual Auction for the Delivery Year.
- PJM forecasts the final Non-Zone Load for the RPM Delivery Year and includes it in the Final RTO Forecast Peak Load and the Final Zonal Forecast Peak Load that is posted by January prior to the Final Incremental Auction.
- EDC that is responsible to determine the Obligation Peak Loads for the Zone will also establish the Obligation Peak Load associated with the Non-Zone Load by December 31 prior to the start of the Delivery Year.
- Non-Zone load will be modeled as a defined “area” in the zone from which it is served in the Capacity Exchange system.

The LSE serving the Non-Zone Load will be assessed a Daily Unforced Capacity Obligation and will be responsible to pay an RPM Locational Reliability Charge.

# Section 8: Resource Performance Assessments

Welcome to the *Resource Performance Assessments* section of the ***PJM Manual for the PJM Capacity Market***. In this section, you will find the following information:

- An overview description of the resource performance assessments (see “Overview of Resource Performance Assessments”)
- The business rules for determining RPM commitment compliance (see “RPM Commitment Compliance”)
- The business rules for determining generating unit peak-hour availability (see “Generating Unit Peak-Hour Availability”)
- The business rules for determining Non-Performance Assessment (see “Non-Performance Assessment”)
- The business rules for assessing compliance with Summer/Winter capability testing (see “Summer/Winter Capability Testing”)
- The business rules for determining load management test compliance (see “Load Management Test Compliance”
- The business rules for replacement resources (“see “Replacement Resources”)

## 8.1 Overview of Resource Performance Assessments

The PJM Capacity Market is designed to ensure that capacity market prices are consistent with system reliability metrics. All LSEs must satisfy their capacity obligation either through the RPM or through the FRR Alternative. If a resource receives capacity payments, or in the case of FRR Alternative, is committed to directly satisfy load obligation requirements, there is an expectation that the resource will honor their commitments and provide reliability services when required. The following performance assessments provide the means to assess whether or not a resource honored their commitments and provided the expected reliability services during the Delivery Year.

- RPM Commitment Compliance
- Generation Operational Testing
- Summer/Winter Capacity Testing
- Non-Performance Assessment
- Load Management Test Compliance
- EE Measurement & Verification (M &V) Audit (see Manual 18-B)

Collectively, the performance assessments provide consumers, who have paid for a high level of reliability through their capacity market payments, with reasonable assurance that the resources committed to RPM or FRR Alternative will perform at adequate levels during the

Delivery Year. Since failure to perform in a performance assessment results in deficiency or penalty charges, resource providers are incented to ensure that their committed resources perform during the Delivery Year in order to limit their exposure to deficiency or penalty charges.

A resource will have an RPM Resource Commitment if the resource cleared or received make-whole payments through an RPM Auction or if the unit was specified as a replacement resource or as the source of a Locational UCAP transaction. A resource will have an FRR Capacity Plan commitment if the unit was included in an FRR Capacity Plan. Portions of the resource that do not have an RPM Resource Commitment or FRR Capacity Plan Commitment during the Delivery Year are not subject to resource performance assessments and the associated deficiency/penalty charges.

The performance assessments are not applicable to all types of resources committed to RPM or FRR Alternative. The following matrix provides an overview of the applicability of resource performance assessments.

| Assessment | Generation (except Variable Resources) | Variable Resources | DR | EE | QTU |
|---|---|---|---|---|---|
| RPM Commitment Compliance | X | X | X | X | X |
| Generation Operational Test | X | | | | |
| Summer/Winter Capability Testing | X | | | | |
| Load Management Test Compliance | | | X | | |
| M&V Audit | | | | X | |
| Non-Performance Assessment | X | X | X | X | X |

## 8.2 RPM Commitment Compliance

A resource committed to RPM is expected to be able to deliver unforced capacity during the Delivery Year that is equal to or greater than the unforced capacity committed through RPM Auctions or through the specification of replacement capacity. RPM Commitment Compliance is evaluated daily during the Delivery year on a resource-specific basis to determine if a party

satisfied their Daily RPM Resource Commitments on their generation resources, demand resources, and Qualifying Transmission Upgrades (QTUs).

A resource or portion of a resource committed to the FRR Alternative is not subject to RPM Commitment Compliance. Instead of unit-specific commitment compliance, FRR Entities are subject to daily unforced capacity obligation compliance.

### 8.2.1 Generation

A generation resource provider may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Unit cancellations and delays – A planned generation is cancelled or delayed and does not commence Interconnection Service prior to the start of the Delivery Year.
- Unit deratings and retirements – The generation resource is derated (through a Capacity Modification decrease) prior to or during the Delivery year. (Retirements result in derating the installed capacity value of a unit to zero MWs through a Capacity Modification decrease in the Capacity Exchange system).
- Accredited UCAP Factor decreases – The final Accredited UCAP Factor for a generation resource for the Delivery Year results in fewer UCAP MW on the resource than that cleared in RPM Auctions for the Delivery Year.

During the Delivery Year, failure to meet generation resource commitments will be determined by comparing a party's Daily RPM Generation Resource Position to their Daily RPM Resource Commitments for such resource. If a party's Daily RPM Generation Resource Position is less than their Daily RPM Resource Commitments for such resource on a delivery day, a Daily Capacity Resource Deficiency Charge will be assessed on the RPM Commitment Shortage.

A party's Daily RPM Generation Resource Position for a specific unit is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP)*(Accredited UCAP Factor).

$$DailyRPMPostion_{GEN}$$
$$= (DailyICAPOwned - DailyFRRCommitments - DailyUnofferICAP)$$
$$*(Accredited \quad UCAP \quad Factor)$$

A party's Daily RPM Resource Commitments for a specific generating unit are calculated by adding the sum of any UCAP Cleared plus UCAP Make-whole for such unit in RPM Auctions to decreases/increases of RPM Commitments due to approved unit-specific bilateral sales/ purchases of cleared capacity and the specification of replacement resources.

A party's Daily RPM Commitment Shortage for a specific unit is calculated as Daily RPM Resource Commitments minus Daily RPM Generation Resource Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$DailyRPMCommitmentShortage_{GEN} = DailyRPMCommitments - DailyRPMPosition_{GEN}$$

### 8.2.2 Demand Resources

A demand resource provider may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Load management program cancellation or delay– The load management program(s) associated with the planned demand resource is cancelled or delayed and is not installed prior to the start of the Delivery Year.
- Decrease in nominated value of demand resource – The final nominated value of the demand resource during the Delivery Year is less than the nominated value of the demand resource used in cleared offers in RPM Auctions for the Delivery Year due to a decrease in the peak load contributions (i.e., capacity tickets) of end-use customers providing the actual load response.
- Failure to have enough sites registered and approved in the DR Hub system prior to the start of the Delivery Year to support the nominated value of the demand resource committed for such Delivery Year. The sites registered and approved in the DR Hub system must be of the Capacity Performance product-type and sufficient to support the summer and non-summer commitments on the Demand Resource.
- Decrease in the Forecast Pool Requirement or ELCC Class Rating- The final UCAP value of the demand resource during the Delivery Year is determined based on the final FPR for the Delivery Year (prior to the 2025/2026 Delivery Year) or the final applicable ELCC Class Rating (starting with the 2025/2026 Delivery Year). Decreases in either of these factors can result in a final UCAP value being less than the UCAP MW cleared by the demand resource in RPM Auctions for the Delivery Year.
- During the Delivery Year, failure to meet demand resource commitments will be determined by comparing a party's Daily RPM Demand Resource Position to their Daily RPM Resource Commitments for such resource. If a party's Daily RPM Demand Resource Position is less than their Daily RPM Resource Commitments for such resource on a delivery day, a Daily Capacity Resource Deficiency Charge will be assessed on the RPM Commitment Shortage.

Through the 2024/2025 Delivery year, a party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) * Forecast Pool Requirement.

$$DailyRPMPosition_{DR} = (DailyICAPOwned - DailyFRRCommitments) * FPR$$

Starting with the 2025/2026 Delivery Year, a party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily ICAP Owned - Daily FRR Capacity Plan Commitments) * applicable ELCC Class Rating.

$$DailyRPMPosition_{DR} = (DailyICAPOwned - DailyFRRCommitments) * applicable\ \ ELCC\ \ Class\ \ Rating$$

A party's Daily ICAP Owned for a specific demand resource is equal to Daily Nominated DR Value adjusted for the ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such demand resource in effect for such day. The Daily Nominated Value of a Demand Resource for a Delivery Year is based on confirmed registrations in "completed" status linked to such Demand Resource in the DR Hub system. The Daily Nominated Value of a Demand Resource is determined for summer period of June through October and May of Delivery Year and non-summer period of November through April of Delivery Year based on information provided in the linked Capacity Performance registrations in the DR Hub system.

A party's Daily RPM Resource Commitments for a specific demand resource are calculated by adding the sum of any UCAP Cleared plus UCAP Make-whole for such demand resource in RPM Auctions to decreases/increase of RPM Resource Commitments due to the specification of replacement resources or use of such demand resource in a Locational UCAP transaction.

A party's Daily RPM Commitment Shortage for a specific demand resource is calculated as Daily RPM Resource Commitments minus Daily RPM Demand Resource Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$DailyRPMCommitmentShortage_{DR}$$

$$= DailyRPMCommitments - DailyRPMPosition_{DR}$$

Existing demand resources that offered and cleared in Base Residual Auction, First Incremental Auction, or Second Incremental Auction can receive relief from deficiency charges if they failed to meet their RPM Resource Commitments due to a decrease in Peak Load Contributions (i.e., "capacity ticket(s)") that were due to the permanent departure of load from the transmission system (e.g., plant closure, efficiency gains, or similar reasons) that was relied upon for load response. The resource provider of the existing Demand Resource must provide PJM with all information deemed necessary by PJM to assess the merits of the request for relief.

Request for relief from deficiency charges must be made no later than two weeks in advance of the opening of the Third Incremental Auction. Failure to maintain Demand Resources will not permit relief. If relief from deficiency charges is granted, the resource provider will receive a reduction in their RPM Auction Credits and a reduction in their RPM Resource Commitments. Any reduction in Auction Credits is factored into the calculation of the Final Zonal Capacity Price. There is no relief from deficiency charges for existing Demand Resources that offered and cleared in a Third Incremental Auction.

### 8.2.3 Energy Efficiency Resources:

An EE resource provider may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Energy efficiency installation cancellation or delay– The energy efficiency installation(s) associated with the planned EE Resource is cancelled or delayed and is not installed prior to the start of the Delivery Year.

- Decrease in Nominated EE value or Capacity Performance Value of EE Resource – The final nominated value or final Capacity Performance value of the energy efficiency resource for the Delivery Year is less than the Nominated value or Capacity Performance Value that was used as the basis of the energy efficiency resource cleared offers in RPM Auctions for the Delivery Year due to a change in number of planned installations associated with the planned EE Resource, change in EDC loss factor, or change due to post-installation measurement and verification activities, or reduction in nominated value due to failure to meet the precision standard requirement for measurement and verification activities in accordance with the PJM Manual for Energy Efficiency Measurement & Verification.

During the Delivery Year, failure to meet EE Resource commitments will be determined by comparing a party's Daily RPM EE Resource Position to their Daily RPM Resource Commitments for such resource. If a party's Daily RPM EE Resource Position is less than their Daily RPM Resource Commitments for such resource on a delivery day, a Daily Capacity Resource Deficiency Charge will be assessed on the RPM Commitment Shortage.

A party's Daily RPM EE Resource Position for a specific EE resource is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) * Forecast Pool Requirement).

$$DailyRPMPosition_{EE} = (DailyICAPOwned - DailyFRRCommitments) * FPR$$

A party's Daily ICAP Owned for a specific EE Resource is equal to the initial ICAP Owned set by PJM through "Approved" EE Modifications, adjusted for any ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such EE Resource in effect for such day.

A party's Daily RPM Resource Commitments for a specific EE resource are calculated by adding the sum of any UCAP Cleared plus UCAP Make-whole for such EE resource in RPM Auctions to decreases/increases of RPM Resource Commitments due to the specification of replacement resources or use of such EE resource in a Location UCAP transaction.

A party's Daily RPM Commitment Shortage for a specific EE resource is calculated as Daily RPM Resource Commitments minus Daily RPM EE Resource Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$DailyRPMCommitmentShortage_{EE} = DailyRPMCommitments - DailyRPMPosition_{EE}$$

### 8.2.4 Qualifying Transmission Upgrade (QTU):

A provider of a Qualifying Transmission Upgrade may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Upgrade cancellations and delays– A qualifying transmission upgrade is cancelled or delayed and does not commence Interconnection Service prior to the start of the Delivery Year.

During the Delivery Year, failure to meet qualifying transmission upgrade commitments will be determined by comparing a party's Daily RPM QTU Position to their Daily RPM Resource Commitments for such upgrade. If a party's Daily RPM QTU Position is less than their Daily RPM Resource Commitments for such upgrade on a delivery day, a Transmission Upgrade Delay Penalty will be assessed on the RPM Commitment Shortage.

A party's Daily RPM QTU Position for a Qualifying Transmission Upgrade is equal to the approved incremental import capability value into the Sink LDA from a Source LDA for such upgrade.

A party's Daily RPM Resource Commitments for a specific Qualifying Transmission Upgrade are calculated by adding the sum of any UCAP Cleared plus UCAP Make whole for such qualifying transmission upgrade in RPM Auctions to decreases of RPM Resource Commitments due to the specification of replacement resources.

A party's Daily RPM Commitment Shortage for a Qualifying Transmission Upgrade is calculated as Daily RPM Resource Commitments minus Daily RPM QTU Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$DailyRPMCommitmentShortage_{QTU} = DailyRPMCommitments - DailyRPMQTUPosition$$

## 8.3 Commitment Level Used in Summer/Winter Capability Tests (Through the 2024/2025 Delivery Year)

Since the RPM Resource Commitments or FRR Capacity Plan Commitments on a unit can vary daily during the delivery year, a Total Unit ICAP Commitment Amount (TUICA) is calculated for each unit and used as the basis for assessing the performance of a unit for summer/winter capability tests through the 2024/2025 Delivery Year.

Since replacement resources can be specified anytime during the Delivery Year, the Total Unit ICAP Commitment Amount is not finalized until after the conclusion of the Delivery Year.

The Total Unit ICAP Commitment Amount on a specific unit is equal to the lesser of (a) the Unit Average Daily ICAP Commitment Amount for the Delivery Year[23] or (b) maximum Summer Net Dependable Rating of the Unit during the Delivery Year.

$$TUICA = lesser\ of\ \left(UnitAvgDailyICAPCommitment_{GEN},\ Max\ DYSummerRating\right)$$

The Unit Average Daily ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the (sum of all Daily RPM Resource Commitments on such unit for the Delivery Year

[23] For days in which unit's Daily ICAP Commitment is greater than Daily ICAP Owned, Daily ICAP Owned is used in determining Unit Average Daily ICAP Commitment for DY.

divided by one minus the Effective EFORd plus the sum of all Daily FRR Capacity Plan Commitments on such unit for the Delivery Year) divided by 365 days (or 366 days).

$$UnitAvgDailyICAPCommitment_{GEN} =$$

$$\frac{\left(\frac{\sum DailyRPMCommitment}{1 - EffectiveEFORd}\right) + \sum DailyFRRCommitment}{365\ (or\ 366)\ days}$$

Since a single unit can have both RPM Commitments and FRR Capacity Plan Commitments during the Delivery Year, a Unit Average Daily FRR ICAP Commitment Amount and Unit Average Daily RPM ICAP Commitment Amount for the Delivery Year are calculated for each unit.

The Unit Average Daily FRR ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the sum of all Daily FRR Capacity Plan Commitments on such unit for the Delivery Year) divided by 365 days (or 366 days).

$$UnitAvgDailyFRRICAPCommitment = \frac{\sum DailyFRRCommitment}{365\ (or\ 366)\ days}$$

The Unit Average Daily RPM ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the Total Unit ICAP Commitment Amount less the Unit Average Daily FRR ICAP Commitment Amount.

$$UnitAvgDailyRPMICAPCommitment_{GEN} =$$

$$TUICA - UnitAvgDailyFRRICAPCommitment$$

Since a single unit can be committed by multiple parties, a Provider's Average Daily FRR ICAP Commitment Amount, Provider's Average Daily RPM ICAP Commitment Amount, and Provider's Share of Total Unit ICAP Commitment Amount for each unit is calculated in order for PJM to allocate any unit shortfalls calculated for, summer/winter capability testing.

A Provider's Average Daily FRR ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the sum of the Provider's Daily FRR Capacity Plan Commitments on such unit for the Delivery Year) divided by 365 (or 366 days).

$$ProviderAvgDailyFRRICAPCommitment_{GEN} =$$

$$\frac{\sum ProviderDailyFRRCommitment}{365\ (or\ 366)\ days}$$

A Provider's Average Daily RPM ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the sum of the Provider's Daily RPM Resource Commitments on such unit the Delivery Year divided by the sum of all Daily RPM Resource Commitments on such unit for the Delivery Year, multiplied by the Unit Average Daily RPM ICAP Commitment Amount.

$$Provider AvgDaily\ RPMICAPCommitment_{GEN} =$$

$$\frac{(\sum Provider DailyRPMCommitments}{\sum TotalDailyRPMCommitments)} * UnitAvgDailyRPMICAPCommitment_{GEN}$$

A Provider's Share of the Total Unit ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the Provider's Average Daily FRR ICAP Commitment Amount plus the Provider's Average Daily RPM ICAP Commitment Amount.

$$ProviderShareTUICA_{GEN} =$$

$$ProviderAvgDailyFRRICAPCommitment + ProviderAvgDailyRPMICAPCommitment$$

## 8.4 Deleted

## 8.4A Non-Performance Assessment

A Non-Performance Assessment[24] will assess performance of resources during emergency conditions. Non-Performance Assessment applies to Capacity Performance Resource commitments and Price Responsive Demand commitments. Capacity Performance Resource commitments and PRD commitments are exposed to Non-Performance Charges for under-performance during Emergency Actions throughout the entire Delivery Year. Resources that fail to perform are subject to Non-Performance Charge and resources that over-perform may be eligible for Bonus Performance Credit.

The Non-Performance Assessment will compare each Capacity Resource's Expected Performance against its Actual Performance for each Performance Assessment Interval. Performance Assessment Interval shall mean each Real-time Settlement Interval for which an Emergency Action as defined in the OATT has been declared by PJM. A Performance Assessment Interval is triggered based on either of the two conditions defined below and such condition must be in effect for the entire Real-time Settlement Interval.

- Condition 1 - A Primary Reserve Shortage is determined for the Reserve Zone or active Reserve Sub-zone and one of the following emergency procedures is issued that encompasses such Reserve Zone or active Reserve Sub-zone:
  - Voltage Reduction Warning and Reduction of Non-Critical Plant Load
  - Manual Load Dump Warning
  - Maximum Emergency Generation Action
  - Voltage Reduction Warning and Curtailment of Non-Essential Building Load

The following table illustrates which resources will be assessed for a PAI based on the location of the resource and the location of the above Emergency Procedure and location of the Primary Reserve Shortage

24 OATT, Attachment DD, Section 10A

| | | Primary Reserve Shortage | | | |
|---|---|---|---|---|---|
| Condition 1 Emergency Procedures | | Reserve Zone (RTO) | Reserve Subzone (MAD) | Reserve Zone and Reserve Subzone (RTO & MAD) | None |
| | Reserve Zone (RTO) | RTO | MAD | RTO | None |
| | Reserve Subzone (MAD) | None | MAD | MAD | None |
| | None | None | None | None | None |

- Condition 2 - One of the following emergency procedures is issued for the entire Reserve Zone or Sub-Zone:
  - Deploy All Resources Action
  - Voltage Reduction Action
  - Manual Load Dump Action
  - Load Shed Directive

See Manual 13 for details on the issuance of emergency procedures and Manual 11 for detail on Primary Reserve Shortage which is determined when the reserve MW assigned in the dispatch run is less than the Primary Reserve requirement for either the Reserve Zone or active Reserve Sub-zone.

When assessment is for the Reserve Sub-zone, the list of resources subject to assessment is determined based on the active subzone bus and resource list effective at the time of the PAI. The posting is found on the Ancillary Service page of PJM.com. DR/PRD dispatched and located in the Reserve Sub-zone will be included in the Reserve Sub-zone assessment.

If the Emergency Action area is for the Reserve Zone, Net Energy Imports are included in this assessment. External Generation Capacity Resources are included in the assessment if such external resource would have helped resolve the declared Emergency Action that was the subject of the assessment. At the start of the Delivery Year, PJM will inform the Capacity Market Seller of an external resource as to which Locational Deliverability Area it has been assigned for Non-Performance Assessment purposes. QTUs will be deemed to be located in the LDA into which such upgrade increased the CETL and the QTU will be included in the Non-Performance Assessment only if, and to the extent that, the declared Emergency Action encompasses only the LDA into which the upgrade increased the CETL.

For each Performance Assessment Interval, the Actual Performance and the Expected Performance is used to calculate a Performance Shortfall that determines both the Non-Performance Charge and Bonus Performance Credit applicability.

For each Performance Assessment Interval, the Actual Performance is equal to:

- for each generation resource (including External Generation Capacity Resources when applicable), the metered output of delivered energy plus the resource's real-time reserve or regulation assignment[25], if any; however, the resulting MW quantity is floored at 0 MW;
- for each Demand Resource, the demand response provided plus the resource's real-time reserve or regulation assignment, if any;
- for each Energy Efficiency Resource, the load reduction quantity approved by PJM subsequent to the pre-delivery year submittal of a post-installation M&V Report;
- for each entity providing Net Energy Imports during a PJM-wide event, the Net Energy Import quantity excluding any energy delivered from External Generation Capacity Resources ;
- for each Qualified Transmission Upgrade, the cleared MW quantity of the QTU if it is in-service prior to the start of the day of the Performance Assessment Interval, and zero if it is not in-service prior to the start of such day; and,
- For each PRD Provider, the Actual Performance is calculated in accordance with Section 3A.6.2A.

For each Performance Assessment Interval, the Expected Performance is equal to:

- for each generation resource (including External Generation Capacity Resources when applicable), the resource's committed Unforced Capacity times the ratio[26] of [(total amount of Actual Performance for all generation resources, plus net energy imports[27], plus total Demand Response Bonus Performance for that interval, plus total PRD Bonus Performance for that interval / (total amount of committed Unforced Capacity of all Generation Capacity Resources)];
- for each Demand Resource and Energy Efficiency Resource, the resources' committed capacity without making any adjustment for the Forecast Pool Requirement (i.e., the actual load reduction quantity the resource committed to provide);
- for each Qualified Transmission Upgrade, the committed MW quantity; and,
- for each PRD Provider, the Expected Performance is calculated in accordance with Section 3A.6.2A.

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[25] The metered output of jointly owned generation resources is allocated to each owner pro-rata with each owner's share of the total Installed Capacity of the resource.

[26] This ratio will be capped at 1.

[27] Net Energy Imports are only included in this formula for PJM-wide emergency events.

The Performance Shortfall for a resource or PRD Provider is calculated as Expected Performance minus the Actual Performance. If the Performance Shortfall for such resource or PRD Provider is a positive number, the under-performing resource or PRD Provider is subject to a Non-Performance Charge. If the Performance Shortfall is a negative number, the over-performing resource or PRD Provider may be eligible for Bonus Performance Credit.

For generation resources with a positive Performance Shortfall amount, the Performance Shortfall may be adjusted downward due to exempt MWs. Exempt MWs consist of the following:

- Unavailable MWs associated with a generator's approved planned or maintenance outage during the Performance Assessment Interval;
- MWs for which the resource was not scheduled to operate by PJM; or
- MWs for which the resource was on-line but was scheduled down by PJM based on the determination by PJM that such scheduling action was appropriate to the security constrained economic dispatch of the PJM Region[28].
- If such resource was needed by PJM and would otherwise have been scheduled by PJM to perform, but was not scheduled to operate, or was scheduled down solely due to (1) any operating parameter limitations submitted in the resource's offer or (2) submission of a market-based offer higher than its cost-based offer, then these MWs will not be considered exempted and will not result in a downward adjustment to the Performance Shortfall.
- For purposes of the Non-Performance Assessment for demand resources, compliance will be measured in accordance with Section 8.6 of this manual.
- During the Performance Shortfall calculation and the exempt MW determination, PJM will ensure that each energy offer complies with Manual 11, Section 2.3.7 and has the required associated information. If this information is not included, then no MWs will be exempt.

For purposes of calculating Bonus Performance quantity, the Actual Performance for a dispatchable resource shall not exceed the MW level at which such resource was scheduled and dispatched by PJM during the Performance Assessment Interval[29]. During the Bonus Performance quantity calculation, PJM will ensure that each energy offer complies with Manual 11, Section 2.3.7 and has the required associated information associated. If this information is not included, then the Bonus Performance quantity will be zero. For self-scheduled generation resources not dispatchable by PJM, the Actual Performance will not exceed the LMP Desired MW value as calculated by PJM based upon the higher of the cost or price schedules submitted for the resource, and will be zero if the LMP Desired MW is less than the lowest point on the higher of the cost or price schedules submitted for the resource.

[28] Scheduled MW appropriate to the security constrained economic is determined based on the results of the Dispatch Run described in Manual 11

[29] Scheduling and dispatch shall be determined based on the results of the Dispatch Run described in Manual 11

The interval Non-Performance Charge is calculated as Performance Shortfall multiplied by the Non-Performance Charge Rate. The Non-Performance Charge Rate for Capacity Performance commitments is equal to {[the modeled LDA through the 25/26 DY, otherwise the RTO Net CONE ($/MW-day in installed capacity terms) for which the resource resides times number of days in the Delivery Year] divided by 30} divided by the number of Real-Time Settlement Intervals in an hour. The modeled LDAs and their respective Net CONE are provided in the Delivery Year BRA Planning Parameters posted on the PJM website.

Through the 2024/2025 Delivery Year, for Capacity Performance Resources or PRD Providers, the maximum yearly Non-Performance Charge is 1.5 times the modeled LDA Net CONE ($/MW-day in installed capacity terms) in which the resource resides times number of days in Delivery Year times the maximum daily unforced capacity committed by the resource or PRD Provider during June 1 of the Delivery Year through the end of the billing month for which the Non-Performance Charge was assessed. For Seasonal Capacity Performance Resources, the maximum yearly Non-Performance Charge is based the number of days of the applicable season and the maximum daily unforced capacity committed by the resource for such season. The modeled LDAs and their respective Net CONE are provided in the Delivery Year BRA Planning Parameters posted on the PJM website.

Effective with the 2025/2026 Delivery Year for Capacity Performance Resources or PRD Providers, the maximum yearly Non-Performance Charge is 1.5 times the RPM Base Residual Auction clearing price applicable to the modeled LDA in which the resource resides times number of days in Delivery Year times the maximum daily unforced capacity committed by the resource or PRD Provider during June 1 of the Delivery Year through the end of the billing month for which the Non-Performance Charge was assessed. For Seasonal Capacity Performance Resources, the maximum yearly Non-Performance Charge is based on the number of days of the applicable season and the maximum daily unforced capacity committed by the resource for such season. The modeled LDAs and their respective clearing prices are provided in the Delivery Year BRA results posted on the PJM website

Revenue collected from payment of Non-Performance Charges will be distributed to resources (of any type, even if they are not Capacity Resources) and PRD Providers that perform above expectations. A resource or PRD Provider with Actual Performance above its Expected Performance is considered to have provided Bonus Performance, and will be assigned a share of the collected Non-Performance Charge revenues in the form of a Bonus Performance Credit. This credit is based on the ratio of its Bonus Performance quantity to the total Bonus Performance quantity (from all resources or PRD Providers) for the same Performance Assessment Interval.

The billing of any Non-Performance Charges incurred in any given month will be done within three calendar months after the calendar month that included such Performance Assessment Intervals and such billing of charges will be spread over the remaining months in the Delivery Year. Bonus Performance Credits will follow the same billing methodology as Non- Performance Charges.

For Public Distribution Microgrid Generators that are Generation Capacity Resources:

- If the Public Distribution Microgrid load is reported to PJM as wholesale load when the PDM is islanded, then any islanded generation MWh output that is settled through the PJM energy market counts towards Capacity Performance obligation as Actual Performance.
- If the Public Distribution Microgrid load is not reported to PJM as wholesale load when the PDM is islanded, then any islanded Public Distribution Microgrid Generators should not report their islanded output as PJM supply. In this case, the islanded Public Distribution Microgrid Generator is not available to supply PJM load, and their Actual Performance is zero for the intervals in which the Public Distribution Microgrid is islanded.
- Whether a Public Distribution Microgrid load is or is not reported to PJM as wholesale load when the PDM is islanded, the Expected Performance during a Performance Assessment Interval is what it would have been had the Public Distribution Microgrid Generator still been grid-connected.

Definitions and additional business rules for Public Distribution Microgrids can be found in PJM Manual 14D, Appendix B: Public Distribution Microgrid Business Rules and PJM Manual 14D, Appendix C: Voluntary Guideline on Public Distribution Microgrid Operations.

## 8.5 Summer/Winter Capability Testing

During the Delivery Year, generation owners are responsible to perform Summer/Winter Net Capability Verification (i.e., Capability Testing) in accordance with ***PJM's Rules and Procedures for Determination of Generating Capability (M-21)*** through the 2024/2025 Delivery Year and M-21B effective with the 2025/2026 Delivery Year and submit test results through the eGADS system. Variable Resources, and variable components of Hybrid Resources, are exempted from the summer/winter capability testing requirement and are not assessed Generation Resource Rating Test Failure Charges. The purpose of the summer/winter net capability verification is to demonstrate that the unit can achieve the claimed summer/winter net capabilityrating of the unit. PJM will use the results of the summer/winter net capability testing to assess whether a unit that was committed to RPM or FRR Alternative was able to achieve a Summer/Winter Net Corrected Test Capability value at least equal to the total daily ICAP commitment level on the unit, or non-variable components of a Hybrid Resource. The Summer/Winter Net Corrected Test Capability value of a Hybrid Resource with multiple non-variable resource components will be the sum of the Summer/Winter Net Corrected Test Capability values of the non-variable resource components. The total daily ICAP commitment level of the non-variable component(s) of a Hybrid Resource during the Jun-October and May of the Delivery Year equals the total daily ICAP commitment level of the Hybrid Resource minus the actual 95th percentile hourly summer net output between the hours ending 11AM and 10PM EPT for the variable component(s). The total daily ICAP commitment level of the non-variable component(s) of a Hybrid Resource during November through April of the Delivery Year equals the total daily commitment level of the Hybrid Resource minus the actual 95th percentile hourly winter net output in all hours except for hours beginning 9AM to 5PM EPT for the variable

component(s). Through the 2024/2025 Delivery Year, a unit's total daily ICAP commitment level is measured by the unit's Total Unit ICAP Commitment Amount ("TUICA") which is determined as described in section 8.3 of this manual. Effective with the 2025/2026 Delivery Year, a unit's total daily ICAP commitment level is determined each day of the delivery year and is calculated as the resource's total daily UCAP commitment level divided by the Accredited UCAP Factor of such resource.

In accordance with M-21 and 21B, a Net Capability Test must be performed during both the Summer and the Winter testing periods. The Summer test period begins the first day of June and ends the last day of August. The Winter test period begins the first day of December and ends on the last day of February. If the entire unit is on a forced or planned outage during the entire summer or winter testing period, the unit is expected to submit an out-of-period capability test when the outage ends.

An unlimited number of tests may be performed on the unit during each testing period. If none of the tests certify full delivery of the total daily ICAP commitment level, those parties with RPM Resource Commitments and FRR Capacity Plan Commitments from such unit may be subject to Generation Resource Rating Test Failure Charges.

The unit's installed capacity shortfall for the testing period is determined by the test that resulted in the highest installed capacity rating (i.e., the highest Summer/Winter Net Corrected Test Capability as described in ***PJM's Rules and Procedures for Determination of Generating Capability (M-21 and M-21B)***). Through the 2024/2025 Delivery Year, the Unit ICAP Shortfall is determined as described in Section 8.5.1. Effective with the 2025/2026 Delivery Year, the Unit ICAP Shortfall is determined as described in Section 8.5.2. A Unit ICAP Shortfall forms the basis for a Generation Resource Rating Test Failure Charge.

### 8.5.1 Determination of Unit ICAP Shortfall (through the 2024/2025 Delivery Year)

Through the 2024/2025 Delivery Year, the Unit ICAP Shortfall for the summer/winter testing period is equal to the Total Unit ICAP Commitment Amount minus the highest Summer/Winter Net Corrected Test Capability achieved in a summer/winter capability test.

A positive shortfall indicates a failure to certify the Total Unit ICAP Commitment Amount during the testing period. A negative shortfall indicates that the Total Unit ICAP Commitment Amount was exceeded during the testing period.

The following business rules apply in the determination of the Unit ICAP Shortfall:

- If a unit is on a partial outage during the test, the amount of the partial outage is added to the highest installed capacity rating in the test to determine the Unit ICAP Shortfall for the summer or winter test period.
- The Unit ICAP Shortfall for the summer testing period will be applied daily for the months of June through November of the Delivery Year. The Unit ICAP Shortfall for the winter testing period will be applied daily for the months of December through May of the Delivery

Year. If the Unit ICAP Shortfall as a result of the winter testing period is less than the Unit ICAP Shortfall as a result of the summer testing period, the Unit ICAP Shortfall as a result of the summer testing period will be applied daily for the months of December through May of the Delivery Year.

- If the entire unit is on a forced or planned outage from June 1 to December 1 of the Delivery Year, a Unit ICAP Shortfall for the summer testing period is not calculated.
- If the entire unit is on a forced or planned outage from December 1 – May 31 of the Delivery Year, the Unit ICAP Shortfall for the winter testing period is the calculated Unit ICAP Shortfall for the summer testing period.
- If the winter rating on a unit is less than the summer rating on the unit and the Total Unit ICAP Commitment Amount is greater than the winter rating, the Unit ICAP Shortfall for the winter testing period will be calculated as the winter rating of the unit (instead of the Total Unit ICAP Commitment Amount) minus the highest installed capacity rating achieved in a winter capability test.
- If a unit is exempt from the winter net capability verification requirement the Unit ICAP Shortfall that is calculated as a result of a summer capability test would also apply for the months of December through May of the Delivery Year.
- In the case of hydro generation, the Unit ICAP Shortfall that is calculated as a result of the single capability test submitted is applied for the entire Delivery Year.
- If a daily RPM commitment compliance shortage on a unit occurs due to a unit delay, derating, or retirement during the Delivery Year, the Daily Unit ICAP Shortfall will be reduced by the portion of the daily RPM commitment compliance shortage (in UCAP) due to the unit delay, derating, or retirement divided by one minus the unit's Effective EFORd for the Delivery Year. The Daily Unit ICAP Shortfall for the unit will not be reduced to a value less than zero.[30]

If portions of the unit were committed by multiple Resource Providers, the Daily Unit ICAP Shortfall is allocated to the Resource Providers based on the provider's pro-rata share of the unit's Total Unit ICAP Commitment Amount.

A Provider's Daily ICAP Shortfall for a unit is equal to the Daily Unit ICAP Shortfall times the Provider's Share of Total Unit ICAP Commitment Amount divided by Total Unit ICAP Commitment Amount.

$$Provider Daily ICAP Shortfall_{GEN} = \frac{Daily Unit ICAP Shortfall * Provider Share TUICA}{TUICA}$$

[30] This implicitly occurs through the calculation of the unit's Total Unit ICAP Amount. For days in which a unit's Daily ICAP Commitment is greater than Daily ICAP Owned, Daily ICAP Owned is used in determining Unit Average Daily ICAP Commitment for the Delivery Year.

If a Resource Provider has both RPM Resource Commitments and FRR Capacity Plan Commitments on the unit, the Provider's Daily ICAP Shortfall for such unit will be separated into a Daily ICAP Shortfall for RPM Resource Commitments and Daily ICAP Shortfall for FRR Capacity Plan Commitments.

A Resource Provider's Daily ICAP Shortfall for RPM Resource Commitments is equal to the Provider's Daily ICAP Shortfall times the Provider's Average Daily RPM ICAP Commitment Amount divided by the Provider's Share of the Total Unit ICAP Commitment Amount.

$$Provider Daily ICAP Shortfall_{RPM} = \frac{\text{Provider} Daily ICAP Shortfall_{GEN} * \text{Provider} Avg Daily RPM ICAP Commitment}{\text{Provider} Share TUICA}$$

A Resource Provider's Daily ICAP Shortfall for FRR Capacity Plan Commitments is equal to the Provider's Daily ICAP Shortfall times the Provider's Average Daily FRR ICAP Commitment Amount divided by the Provider's Share of the Total Unit ICAP Commitment Amount.

$$Provider Daily ICAP Shortfall_{FRR} = \frac{\text{Provider} Daily\ ICAP Shortfall_{GEN} * Provider Avg Daily FRR ICAP Commitment}{\text{Provider} Share TUICA}$$

A Resource Provider with a positive Daily ICAP Shortfall will be assessed The Generation Resource Rating Test Failure Charge.

### 8.5.2 Determination of Unit ICAP Shortfall (Effective with the 2025/2026 Delivery Year)

Effective with the 2025/2026 Delivery Year, the Unit ICAP Shortfall is determined for each Generation Capacity Resource (with the exception of Variable Resources) on a daily basis. Each day of the Delivery Year, the Daily Unit ICAP Shortfall is calculated as (i) the installed capacity committed for that day (adjusted for any replacement capacity), minus (ii) the highest Summer/Winter Net Corrected Test Capability determined for the resource in any test during the relevant testing period.

The summer period capability test result submitted in eGADS is used in this determination for each day in the months of June through October and the following May of each Delivery Year, and, winter period capability test result submitted in eGADS is used in this determination for each day in the months of November through April of each Delivery Year.

In the event a resource is eligible for an out of period capability test for the relevant season, as described in **PJM Rules and Procedures for Determination of Generating Capability Manual (M21B)** an updated Unit ICAP Shortfall would be determined based on the out of period test and the updated Unit ICAP Shortfall becomes effective on the date of the out of period test, and extends through the relevant seasonal period.

A positive Unit ICAP Shortfall in any day represents a failure to certify the total daily ICAP commitment amount on such resource through capability testing.

If portions of the unit were committed by multiple Resource Providers, the Daily Unit ICAP Shortfall is allocated to the Resource Providers based on each provider's pro-rata share of the total installed capacity commitment for that day (adjusted for any replacement capacity).

The daily installed capacity committed used for determining a resource's shortfall, or allocating a resource's shortfall to multiple providers, shall be capped at the ICAP Owned for such resource or provider to avoid double counting of shortfalls under the capability testing assessment and commitment compliance.

If a Resource Provider has both RPM Resource Commitments and FRR Capacity Plan Commitments on the unit, the Provider's Daily ICAP Shortfall for such unit will be separated into (i) a Daily ICAP Shortfall for RPM Resource Commitments based on the ratio of the Provider's installed capacity committed to RPM for the day divided by the Provider's total installed capacity committed for the day and (ii) a Daily ICAP Shortfall for FRR Capacity Plan Commitments based on the ratio of the Provider's installed capacity committed to FRR for the day divided by the Provider's total installed capacity committed for the day.

A Resource Provider with a positive Daily ICAP Shortfall will be assessed The Generation Resource Rating Test Failure Charge as described in Section 9.1.5.

### 8.5A Generation Operational Testing

Effective with the 2025/2026 Delivery Year, Generation Capacity Resources, with the exception of Variable Resources, that are committed to RPM or FRR shall be subject to operational testing initiated by the Office of the Interconnection up to two times in each of the summer and winter seasons during the relevant Delivery Year. The operational testing requirements, retest requirements, and determination of when a shortfall is assessed are found in **Generator Operational Requirements Manual (M14D)**.

When a unit fails a retest of the Generation Operational Test, a Generation Operational Test Failure Charge may be assessed. The Generation Operational Test Failure Charge shall equal the Daily Deficiency Rate multiplied by the applicable daily committed UCAP MW of such Generation Capacity Resource.

The applicable daily committed UCAP MW value subject to the Generation Operational Test Failure Charge will account for:

- any RPM and FRR commitments on the unit;
- any unit modeling differences that may exist between the energy market and capacity market; and
- any portions of the unit that were committed by multiple Capacity Market Sellers, provided, however, a Capacity Market Seller shall not be assessed a Generation Operational Test

Failure Charge to the extent (i.e., for the same megawatts and time period) that such seller is assessed a Capacity Resource Deficiency Charge for such resource.

The Daily Deficiency Rate shall equal the value defined in section 9.1.5A.

## 8.6 Measuring Compliance during Performance Assessment Interval for Demand Resources

A Capacity Performance Demand Resource is subject to Non-Performance Assessment during a Performance Assessment Interval that occurs during the Delivery Year during the availability window when linked registrations to such Capacity Performance Demand Resource are dispatched by PJM during such Performance Assessment Interval. A Summer-Period Capacity Performance Demand Resource is subject to Non-Performance Assessment during a Performance Assessment Interval that occurs during June through October and May of the Delivery year during the availability window when linked registrations to such Summer-Period Capacity Performance Demand Resource are dispatched by PJM during such Performance Assessment Interval.

Compliance is the process utilized to review Demand Resource performance during a Performance Assessment Interval and establishes a Performance Shortfall or Bonus Performance for such Demand Resource.

Compliance will be measured for each registration dispatched by PJM within the area defined by the Emergency Action for each Performance Assessment Interval. Compliance is measured for partial clock hour dispatch if dispatched for 30 minutes or more of the clock hour. Compliance is not measured if dispatched for less than 30 minutes of the clock hour.

DR Providers are responsible for submittal of compliance information to PJM through the DR Hub System within 45 days after the end of the month in which a Performance Assessment Interval occurred.

PJM verifies compliance on an end-use customer basis by reviewing the data submitted by the DR Provider through the DR Hub system. Load management compliance for non-interval metered residential customers may be verified using a statistical sample of end-use customers in accordance with ***PJM Manual 19: Load Forecasting & Analysis, Attachment D*** and subject to PJM approval.

DR Providers may use substitute registrations of a different resource product type to cover the commitment of non-performing registrations that cannot respond for the Performance Assessment Interval. The non-performing registration(s) and corresponding substitute registration(s) must be in the same geographic location defined by the PJM dispatch instruction with the same designated lead time. In addition, the total nominated value (summer or non-summer, as applicable) of the substitute registration(s) must be comparable (within either +/- 25% or +/- 0.5 MW) to the total nominated value (summer or non-summer, applicable) of the

corresponding non-performing registration(s). DR Providers that use substitute registrations must submit their list of nonperforming registrations and corresponding substitute registrations to PJM by 11:59 pm on the day of the Performance Assessment Interval in the appropriate PJM system. PJM may also request that resource providers submit evidence that notification to respond were sent to substitute registrations in advance or during the Performance Assessment Interval to verify that meter data was not used after the fact in finding the substitutes. Any registration used as a substitute must be included in the submittal of compliance information to the appropriate PJM system. The reduction value(s) of the substitute registration(s) will be used by PJM when measuring compliance during a Performance Assessment Interval for the corresponding non-performing registration(s). Non-performing registration(s) will be considered to have not performed. Registrations used as substitutes during an event will have the same obligation to respond to future event(s) as if it did not respond to such event. A registration may only be used as a substitute for a non-performing registration dispatched for a Performance Assessment Interval in the winter period if the registration provided winter data (Winter Peak Load, winter Firm Service Level, or winter Guaranteed Load Drop data) at the time of registration and meets the criteria outlined above.

For a Firm Service Level (FSL) customer on a registration, the actual load reduction provided for the hour ending that includes a Performance Assessment Interval(s) in the summer period (June through October and May of the Delivery Year) is calculated as the end-use customer's Peak Load Contribution minus (the hourly metered load multiplied by the loss factor). A load reduction will only be recognized if the hourly metered load multiplied by the loss factor is less than the Peak Load Contribution. For the non-summer period (November through April of the Delivery Year), the actual load reduction for a Performance Assessment Interval is calculated as (end-use customer's Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by loss factor) minus (the hourly metered load multiplied by the loss factor). A load reduction will only be recognized if the hourly metered load multiplied by the loss factor is less than the Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor.

For a Guaranteed Load Drop (GLD) customer on registration, the actual load reduction provided for the hour ending that includes a Performance Assessment Interval(s) in the summer period is calculated as the lesser of (a) the (comparison load minus the hourly metered load) multiplied by the loss factor or (b) end-use customer's Peak Load Contribution minus (hourly metered load multiplied by loss factor). A load reduction will only be recognized if the hourly metered load multiplied by the loss factor is less than the Peak Load Contribution. For the non-summer period (November through April of the Delivery Year), the actual load reduction for a Performance Assessment Hour is calculated as lesser of (a) (comparison load minus the hourly metered load) multiplied by the loss factor or (b) the end-use customer's Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by loss factor minus (the hourly metered load multiplied by the loss factor). A load reduction will only be recognized if the hourly metered load multiplied by loss factor is less than the Winter Peak Load multiplied by the Zonal Winter Weather Adjustment Factor multiplied by the loss factor.

DR Provider must submit 24 hours of actual load data for the day in which Performance Assessment Interval occurred and for all days required to determine comparison loads. Comparison loads must be developed in accordance with the guidelines included in ***PJM Manual M-19 Load Forecasting & Analysis, Attachment A: Load Drop Estimate Guidelines***, and note which method was employed.

A Load Management customer may not reduce their metered load below zero (i.e., export energy into the system). No compliance credit will be given for the incremental load drop below zero. Hourly load reduction for a registration is floored at 0 MW.

For a partial dispatch clock hour, the Expected Performance of a Demand Resource is not adjusted by the percentage of the hour dispatched. When five-minute revenue meter data is submitted to determine compliance for a Performance Assessment Interval, the actual load reduction for a Performance Assessment Interval is calculated using the five-minute metered load data for such Performance Assessment Interval as opposed to using hourly metered load data. When five- minute revenue meter data is not submitted to determine compliance of a Demand Resource for a Performance Assessment Interval, the actual hourly load reduction for the hour ending that includes a Performance Assessment Interval(s) is flat-profiled over the set of dispatch intervals in the hour. The actual load reduction for a Performance Assessment Interval is calculated as the actual hourly load reduction multiplied by (twelve divided by the number of five-minute intervals the Demand Resource was dispatched in the hour). The actual load reduction for a registration for a Performance Assessment Interval is capped at the Peak Load Contribution of the registration in the summer period and at the Winter Peak Load of the registration multiplied by Zonal Winter Weather Adjustment Factor in the winter period.

For each dispatched registration in the Emergency Action Area, the Actual Performance is equal to the actual load reduction plus any real-time reserve or regulation assignment for such registration for the Performance Assessment Interval. The Actual Performance for a Demand Resource for a Performance Assessment Interval is equal to the sum of the Actual Performance of the dispatched registrations linked to such Demand Resource. If a Demand Resource is owned by multiple parties, the Actual Performance of a Demand Resource shall be allocated to the owners of the Demand Resource based on ICAP ownership share to determine each Capacity Market Seller's Actual Performance for such Demand Resource.

The Expected Performance for the Performance Assessment Interval for a Capacity Market Seller's Demand Resource[31] is equal the Capacity Market Seller's committed capacity on the Demand Resource in installed capacity terms (i.e., the actual load reduction quantity the

[31] The Actual and Expected Performance of dispatched economic registrations are not considered in the performance of a committed Demand Resource. Actual Performance will be calculated for an economic registration in the same way it is calculated for a Pre-Emergency or Emergency registration and such registration may be eligible for Bonus Performance since its Expected Performance will be zero MW.

resource committed to provide), adjusted to account for any linked registrations that were not dispatched by PJM.

The Capacity Market Seller's Expected Performance minus the Actual Performance for a Demand Resource establishes the seller's initial Performance Shortfall for such Demand Resource. A positive initial Performance Shortfall indicates the seller's Demand Resource under-complied for the Performance Assessment Interval. A negative initial Performance Shortfall indicates the seller's Demand Resource over-complied for the Performance Assessment Interval. The Capacity Market Seller's initial Performance Shortfalls for Demand Resources in the Emergency Action Area (EAA) are netted to determine a net EAA Performance Shortfall for the Performance Assessment Interval. Any net positive EAA Performance Shortfall is allocated to the Capacity Market Seller's Demand Resources that under-complied within the EAA on a pro-rata basis based on the under-compliance MWs, and such seller's Demand Resources will be assessed a Performance Shortfall for the Performance Assessment Interval. Any net negative EAA Performance Shortfall is allocated to the Market Seller's Demand Resources that over-complied within the EAA on a pro-rata basis based on over-compliance MWs, and such Market Seller's Demand Resources will be assessed Bonus Performance.

## 8.7 Load Management Test Compliance

DR Resource providers are subject to Load Management Test Compliance.

For Demand Resources committed for the 2023/2024 Delivery Year and subsequent Delivery Years:

1. For Annual Demand Resources: if an Annual Demand Resource registration for the 2023/2024 Delivery Year is not dispatched by the Office of the Interconnection for a Load Management event in the Delivery Year or if an Annual Demand Resource registration for the 2024/2025 Delivery Year or subsequent Delivery Years is not dispatched by the Office of the Interconnection for a Load Management event in a Delivery Year and assessed for performance during Performance Assessment Intervals, then the registration committed by a Capacity Market Seller in a zone shall be tested as described in section (3) listed below, for a two-hour period between the hours of 11:00 EPT and 18:00 EPT of a non-NERC holiday weekday during June through October or November through March of the relevant Delivery Year, where date and time are selected by the Office of the Interconnection and notice is provided consistent with the procedure described in sections (4) and (5) listed below . If an Annual Demand Resource registration for the 2023/2024 Delivery Year is dispatched by the Office of the Interconnection for a Load Management event during the Delivery Year or if an Annual Demand Resource Registration for 2024/2025 Delivery Year or subsequent Delivery Years is dispatched by the Office of the Interconnection for a Load Management event in a Delivery Year and assessed for performance during Performance Assessment Intervals, then no test will be required.

   Subject to the conditions in this paragraph beginning in Delivery Year 2024/2025 and subsequent Delivery Years, CSPs may elect to use performance data from a Load Management event that was not subject to a Non-Performance Assessment (a non-PAI LM event) as performance data for a PJM zonal test event. Elections are made on or after June 1 and no later than July 14th after the Delivery Year in the DR Hub system. Data required for compliance evaluation must be submitted no later than July 14th after the Delivery Year. Only one event result (either test event or non-PAI LM event) for each end use customer site will be used in the zonal test evaluation:

   a. The duration of non-PAI LM event must be at least 30 minutes of a clock hour

   b. The election of non-PAI LM events to be used as zonal test performance will be done at the registration lead time interval.

   c. For purposes of this election, the calculated reduction value for a registration in the non-PAI LM event is the average of the registration's hourly reductions within the product period hourly window.

   d. CSP's Load Reduction Capability data submission(s) must account for registrations that will not participate in a PJM scheduled test.

      i. In accordance with the load reduction reporting requirements in section 4.3.9, any updates to the Load Reduction Capability data for non-participation in PJM scheduled test must be reported no later than 4 p.m. on the day prior to the PJM scheduled test.

   PJM will take into consideration non-PAI LM events when scheduling tests. This could result in test event postponements when non-PAI LM events occur within a scheduled test window.

2. For Summer-Period Demand Resources: if a Summer- Period Demand Resource registration for the 2023/2024 Delivery Year is not dispatched by the Office of the Interconnection for a Load Management event during June through October or the following May of the Delivery Year or if a Summer-Period Demand Resource registration for the 2024/2025 Delivery Year or subsequent Delivery Years is not dispatched by the Office of the Interconnection for a Load Management event during the June through October or the following May of the Delivery Year and assessed for performance during Performance Assessment Intervals, then the registration committed by a Capacity Market Seller must demonstrate that it was tested as described in section (3) listed below, for a two-hour period between the hours of 11:00 EPT and 18:00 EPT of a non-NERC holiday weekday, during June through October of the relevant Delivery Year, where date and time are selected by the Office of the Interconnection and notice is provided consistent with the procedure described below.

   Subject to the conditions in this paragraph beginning in Delivery Year 2024/2025 and subsequent Delivery Years, CSPs may elect to use performance data from a Load Management event that was not subject to a Non-Performance Assessment (a non-PAI LM event) as performance data for a PJM zonal test event. Elections are made on or after June 1 and no later than July 14th after the Delivery Year in the DR Hub system. Data required for compliance evaluation must be submitted no later than July 14th after the Delivery Year. Only one event result (either test event or non-PAI LM event) for each end-use customer site will be used in the zonal test evaluation:

   a. The duration of a non-PAI LM event must be at least 30 minutes of a clock hour

   b. The election of non-PAI LM events to be used as zonal test performance will be done at registration lead time level.

   c. The non-PAI LM event must have occurred in the summer.

   d. For purposes of this election, the calculated reduction value for a registration in the non-PAI LM event is the average of the registration's hourly reductions within the product period hourly window.

   e. CSP's Load Reduction Capability data submission(s) must account for registrations that will not participate in a PJM scheduled test.

      i. In accordance with the load reduction reporting requirements in section 4.3.9, any updates to Load Reduction Capability data non-participation in PJM scheduled test must be reported no later than 4 p.m. on the day prior to the PJM scheduled test.

   PJM will take into consideration non-PAI LM events when scheduling tests. This could result in test event postponements when non-PAI LM events occur within a scheduled test window.

3. All registrations in a zone will be tested simultaneously for two hours for each product. Registration performance will be calculated as the two hour average reduction. The Office of the Interconnection may, at its discretion, cancel a test and retest on an event day to ensure system reliability.
    a. If less than 25 percent (by megawatts) of a Curtailment Service Provider's total Demand Resources in a zone fail the test, the Curtailment Service Provider may conduct re-tests limited to all registrations that failed to meet their seasonal nominated ICAP in the prior test, provided that such re-test(s) must be during the same season period (except if test was conducted in March in which case retest can be conducted in May), at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registrations must test simultaneously, where affiliated means registrations that have any ability to shift load and are owned or controlled by the same entity. If less than 25 percent of resources fail the test and the Curtailment Service Provider chooses to conduct a retest, the Curtailment Service Provider may elect to maintain the performance compliance result for the registration(s) that achieved during the test if Curtailment Service Provider: (1) notifies the Office of the Interconnection 48 hours prior to the retest under this election; and (2) the Curtailment Service Provider retests affiliated registrations under this election as set forth in the PJM Manual.
    b. If 25 percent or more (by megawatts) of a Curtailment Service Provider's Demand Resources fail the test, the Curtailment Service Provider may request the Office of Interconnection to schedule a one-time retest limited to all registrations that failed to meet their seasonal nominated ICAP in the prior test, provided that all affiliated registrations must test simultaneously. Affiliated means registrations that have any ability to shift load and are owned or controlled by the same entity. The request must be made before the 46th day after the test. The Office of the Interconnection will select the date and time of the retest during the same season period (except if test was conducted in March in which case retest may be conducted in May) and notice is provided consistent with the procedure described below.
4. Notification of the initial Office of the Interconnection scheduled test will be provided based on the following procedure.
    a. The Office of Interconnection shall schedule, on an alternating basis, one test during June through October or November through March for each Delivery Year that a test is required. On the first business day of a week, PJM will provide notice of all zones to be tested during the following two week test window. The test window opens the first business day of the week following the notice. By 10:00 EPT the day before the test, the Office of the Interconnection will post on its website the test date and zones. The Office of the Interconnection will also notify the Curtailment Service Providers of the test date. On the test date, Curtailment Service Providers will be notified of start time of test through the same notification protocol used for an event and as described in the PJM Manuals.

5. Notification of any scheduled retest by the Office of the Interconnection will be provided based on the following procedure.
    a. By 10:00 EPT the day before the retest, the Office of the Interconnection will post the retest date on its website. PJM will also notify the Curtailment Service Providers the retest date. On the retest date, Curtailment Service Providers will be notified of start time of retest through the same notification protocol used for an event and as described in the PJM Manuals.

Load Management test compliance for a registration will be measured based on Performance Assessment Interval compliance for a registration; however, for purposes of Load Management test compliance the Resource Compliance Position for a registration considers the Summer Average RPM/FRR Commitment as opposed to the RPM/FRR Commitment on the day of the event or Performance Assessment Interval and performance will be aggregated to the zone and not Performance Assessment Area.

Resource Compliance Position for a registration for a test is determined as the Nominated Load Reduction Value reported in the DR Hub system minus the actual load reduction, where the Nominated Load Reduction Value is capped at the Summer Average RPM/FRR Commitment for such registration. The Nominated Load Reduction Value determined based on summer capability is used to test Capacity Performance DR product-type registrations.

Summer Average RPM/FRR Commitment for a Demand Resource is the daily average of the RPM/FRR resource commitments for such Demand Resource from June 1st through September 30th of the Delivery Year. If multiple registrations are linked to a committed Demand Resource in the Capacity Exchange system, the Summer Average RPM/FRR Commitment for such Demand Resource is allocated to the registrations pro-rata based on the nominated load reduction value of the registrations.

For any Load Management test, a provider's net testing shortfall in a zone for a product type is calculated by netting the Resource Compliance Positions of the product-type registrations tested in a zone. A resource provider with a positive net testing shortfall in a zone for a product type (i.e., under compliance MWs in zone for a product type) will be assessed a Zonal Load Management Test Failure Charge. A net testing shortfall in zone for Capacity Performance DR product-type (which may include Summer-Period DR) may be separated into net testing shortfall in zone due to annual commitments or summer-only commitments, as appropriate.

If a Demand Resource is committed by multiple parties, a portion of the provider's net testing shortfall in a zone for a product-type may be assessed to each party that has a commitment if tested registrations linked to such Demand Resource under-complied, based on the each party's commitment share of the Demand Resource.

## 8.8 Replacement Resources

Participants may specify replacement resources in order to avoid or reduce resource performance assessment shortfalls and the associated deficiency/penalty charges. Participants may not specify replacement resources in order to avoid or reduce performance assessment shortfalls and associated deficiency/penalty charges related to price responsive demand.

Replacement capacity for generation resources, Demand Resources, Energy Efficiency Resources, or Qualifying Transmission Upgrades committed to RPM may be specified via the Capacity Exchange system by entering a “Replacement Capacity” transaction before the start of the Delivery Day. However, upon a request to PJM made no later than three business days after a Delivery Day containing a Performance Assessment Interval, Replacement Capacity Transactions may be permitted retroactively effective with the Delivery Day provided such transaction meets the following criteria: (1) the replacement resource must have already been in the same sub-account as the resource being replaced on the Delivery Day, (2) the replacement resource must have been included in the same Performance Assessment Intervals as the resource being replaced, (3) the replacement resource must have the same or better temporal availability characteristics as the resource being replaced, (4) the replacement resource must be located in the same LDA (or a more constrained child LDA) as the resource being replaced, and (5) the resulting total Daily Resource Commitments (RPM and FRR) (in UCAP terms) on a generation resource used as a replacement resource cannot exceed such replacement resource’s Actual Performance during the Performance Assessment Intervals. Such requests must be submitted to rpm_hotline@pjm.com and include the start date and end date, resource being replaced, replacement resource, and the desired change in Daily RPM Commitments (in UCAP terms) for the resource being replaced and product type (Capacity Performance) of the commitment being replaced.

Through the “Replacement Capacity” transaction functionality in Capacity Exchange, PJM will provide participants with a list of the available capacity for each generation or demand resource in their portfolio as well as a list of cleared buy bids from any Incremental Auction via the Capacity Exchange system and a list of resources with RPM Resource Commitments. Participants will have the ability to match a generation, Demand Resource, Energy Efficiency Resource or Qualifying Transmission Upgrade resource committed to RPM that they would like to replace with available capacity from a generation resource, demand resource, cleared buy bids in an Incremental Auction, or from Locational UCAP transactions. Available capacity from an EE Resource may be utilized to replace the commitment of only another EE Resource because such commitments are accompanied by the adjustment that is required to avoid double-counting of energy efficiency measures as described in section 2.4.5 of this manual.

The following are business rules that apply to Replacement Resources for Resources Committed to RPM:

- The start date and end date of the replacement must be specified.

- The Delivery Year commitment of a Generation Capacity Resource may not be replaced until after the final Accredited UCAP Factor for the Delivery Year has been locked in the Capacity Exchange system. After the final Accredited UCAP Factor for the prior Delivery Year has been locked in and prior to the conduct of the Third Incremental Auction for the Delivery Year, the commitment of such a resource may be replaced but only up to the quantity of any commitment deficiency of the resource.
- Any or all of a Delivery Year commitment of a Generation Capacity Resource, Demand Resource, or Energy Efficiency Resource may be replaced any time prior to the conduct of the Third Incremental Auction for that Delivery Year when the owner of the replaced resource provides transparent and verifiable evidence to support the expected final physical position of the resource at the time of request. Such requests shall be submitted in writing simultaneously to PJM rpm_hotline@pjm.com and the Independent Market Monitor rpmacr@monitoringanalytics.com documenting the reason for the early replacement. PJM will approve or deny a request for early Replacement Capacity, based upon the below criteria, with input from the Market Monitor, within 15 days of receiving a completed early Replacement Capacity request.
    - Acceptable reasons for early replacement are:
        - Generator Deactivation (properly noticed to PJM and posted to the website)
        - A pending request to PJM for removal of Generation Capacity Resource status (in accordance with Manual 18, section 5.4.7, and subject to PJM approval)
        - Withdrawal of generation New Service Request/ cancellation of generation project (accompanied by written notification to PJM Interconnection Projects manager)
        - Generation delayed in-service date (accompanied by written notification to PJM Interconnection Projects manager)
        - Permanent departure of load used as a basis for an existing DR or EE resource at the time of commitment
        - A financially and physically firm commitment to an external sale of its capacity for the entire Delivery Year that is demonstrated with supporting evidence as specified in Tariff, Attachment DD, Section 6.6(g), for the 2023/24, 2024/25, 2025/26 Delivery Years where there is only one Incremental Auction
    - Generation replaced may not be recommitted for the Delivery Year. Therefore, the resource may not resell the replaced MW in a subsequent RPM auction for the applicable Delivery Year, and has no requirement to submit a Must-Offer Exception request for such auctions.
    - DR/EE sites replaced may not be registered or committed for the Delivery Year.
- A Replacement Resource used to reduce a Demand Resource commitment shall be specified for no less than the balance of the Delivery Year. An available Demand Resource may only be used as a Replacement Resource when the start date of the Replacement Capacity transaction is from June 1 through September 30th unless the Demand Resource

can demonstrate through the prior summer's event or test compliance data that the Demand Resource met both its Summer Average RPM Commitment and the new daily RPM commitment level that would result if the Replacement Capacity transaction was approved.

- The desired change in Daily RPM Resource Commitments (in UCAP terms) for the resource being replaced and the replacement resource must be specified. The change in Daily RPM Resource Commitments cannot result in a negative value for the Daily RPM Resource Commitments for the resource being replaced. The desired change in Daily RPM Resource Commitments (in UCAP terms) for the resource being replaced must also indicate the product type (Capacity Performance) of the commitment being replaced.
- The replacement resource must be located in the same sub-account as the resource that is being replaced.
- The replacement resource must be located in the same LDA as the resource that is being replaced or reside in the Sink LDA of the Qualifying Transmission Upgrade being replaced. However, if there is remaining import capability into the LDA after the Third Incremental Auction, a replacement resource may be located in a parent LDA, subject to the following restrictions. The ability to submit a replacement transaction from a parent LDA into a child LDA is limited by the import capability remaining into the LDA. After the Third Incremental Auction, the remaining import capability of each LDA is posted on the PJM website.
- Resources located in a constrained LDA can serve as replacement capacity for a generation resource located in a less constrained parent LDA.
- The replacement resource must have the same or better temporal availability characteristics as the resource that is being replaced.
- Capacity Performance Resource commitments can only be replaced by available capacity from a capacity resource that is eligible to be committed as CP, or by cleared Buy Bids or Locational UCAP of the Capacity Performance product type.
- Available capacity of a Capacity Resource with State Subsidy for which the Capacity Market Seller has not elected to forego receipt of any State Subsidy for the relevant Delivery Year and does not qualify for one of the categorical exemptions may not be used to replace the commitment of a Capacity Resource that (1) is not a Capacity Resource with State Subsidy or (2) is a Capacity Resource with State Subsidy for which the Capacity Market Seller elected the competitive exemption and reported that it will forego receipt of any State Subsidy for the relevant Delivery Year or (3) a Capacity Resource with State Subsidy that qualifies for one of the categorical exemptions.
- If a generation, demand, or EE resource is used as replacement capacity, a decrease in the Daily RPM Resource Commitments for the resource that is being replaced will result and a corresponding increase in the Daily RPM Resource Commitments for the replacement generation, demand, or EE resource will result during the time period specified for replacement. A change in the Daily RPM Resource Commitments for a generation resource will result in a change in the Total Unit ICAP Commitment Amount for the generation resource.

- If cleared buy bids from an Incremental Auction or Locational UCAP transactions are used as replacement capacity, a decrease in the Daily RPM Commitments for the resource that is being replaced will result during the time period specified for replacement. A change in the Daily RPM Commitments for a generation resource will result in a change in the Total Unit ICAP Commitment Amount for the generation resource.

Replacement resources for Generation Capacity Resources, QTU, Energy Efficiency Resources, or Demand Resources committed to FRR Capacity Plan are specified by an FRR Entity through the update of the FRR Entity's FRR Capacity Plan prior to the start of the Delivery Day. FRR Entities may update their FRR Capacity Plan to reduce the FRR Capacity Plan Commitment on the resource being replaced and increase the FRR Capacity Plan Commitment on a replacement resource. The change in the Daily FRR Capacity Plan Commitments for a generation resource will result in a change in the Total Unit ICAP Commitment Amount for the generation resource.

### 8.8.1 Excess Commitment Credits

LSEs may receive credits when Reliability Requirements decrease resulting in an excess capacity.

The Excess Capacity Credits will be the PJM Sell Offers in the Scheduled Incremental Auctions that do not clear less the PJM Buy Bids in Incremental Auctions that do not clear. The Excess Capacity Credits in PJM will be allocated to LDAs pro rata based on the reduction in LDA peak load forecast from BRA to the time of Third Incremental Auction, provided the amount allocated does not exceed the reduction in the corresponding LDA Reliability Requirement. There will not be an allocation to LDA with an increase in load forecast.

The amount allocated to LDA will be further allocated to LSEs that are charged a Locational Reliability Charge, based on the Daily Unforced Capacity Obligation of the LSEs as of June 1 of the Delivery Year, and the credits will be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

# Section 9: Settlements

Welcome to the *Settlements* section of the ***PJM Manual for the PJM Capacity Market***. In this section, you will find the following information:

- The business rules for the deficiency and penalty charges in RPM/FRR for committed supply resources (see “Deficiency and Penalty Charges”)
- The business rules for Locational Reliability Charges (see “Locational Reliability Charges”)
- The business rules for RPM auction credits and charges (see “Auction Credits and Charges”)
- The business rules for the penalty charges in RPM/FRR for non-performance of price responsive demand (see “Penalties for Non-Performance of Price Responsive Demand”)
- The business rules for the PRD Credits (see “PRD Credits”)

## 9.1 Deficiency and Penalty Charges

### 9.1.1 Deleted

### 9.1.2 Deleted

### 9.1.3 Capacity Resource Deficiency Charge

The Daily Capacity Resource Deficiency Charge is applicable to a capacity resource with a RPM commitment that does not have enough unforced capacity value on such resource to cover its RPM commitments. The Daily Capacity Resource Deficiency Charge is equal to the Daily Deficiency Rate times the Daily RPM Commitment Shortage for generation resource, Demand Resource, or Energy Efficiency Resource.

$$DailyCapResourceDeficiencyCharge = DDR * DailyRPMCommitmentShortage$$

The Daily Deficiency Rate ($/MW-day) applicable to a shortage is equal to the Party’s Weighted Average Resource Clearing Price for such resource plus the higher of 0.2*Party’s Weighted Average Resource Clearing Price for such resource or $20/MW-day. In the case where a Party’s Weighted Average Resource Clearing Price for such resource is equal to $0/MW-day because the committed resource did not clear in any RPM Auction (i.e., commitments were due to the resources being used as a source of a Locational UCAP transaction or as replacement capacity), a PJM Weighted Average Resource Clearing Price in an LDA will be used.

A party’s Weighted Average Resource Clearing Price for such resource’s commitments is determined by calculating the weighted average of segment-specific (i.e., annual, seasonal-summer, seasonal-winter) resource clearing prices received on the deficient day for such resource across all Delivery Year RPM Auctions, weighted by a party’s segment-specific

cleared and make-whole MWs for such resource. Segment-specific cleared MWs acquired or transferred through a Unit Specific Transaction for cleared capacity are accounted for in the calculation of a party's Weighted Average Resource Clearing Price.

The PJM Weighted Average Resource Clearing Price for commitments in an LDA is determined by calculating the c weighted average of segment-specific resource clearing prices applicable in the LDA across all Delivery Year RPM Auctions, weighted by the total segment-specific cleared and make-whole MWs in the LDA.

A resource that is also subject to a Non-Performance Charge during one or more Performance Assessment Intervals occurring during a continuous time period of Daily RPM Commitment Shortages associated with Capacity Performance commitments shall be assessed a charge equal to the greater of (a) the total Daily Capacity Resource Deficiency Charges calculated for shortages associated with Capacity Performance commitments for such continuous time period or (b) the total Non-Performance Charges calculated for the Performance Assessment Intervals occurring during such continuous time period. The sum of the Daily Capacity Resource Deficiency Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge.

**Note:**
Daily Capacity Resource Deficiency Charges are assessed daily and billed weekly.

### 9.1.4 Transmission Upgrade Delay Penalty Charge

The Daily Transmission Upgrade Delay Penalty Charge is equal to the QTU Delay Penalty Rate times the Daily RPM Commitment Shortage for the QTU.

$$DailyQTUDelayPenaltyCharge = QTUDelayPenaltyRate^{*} DailyRPMCommitmentShortage$$

The QTU Delay Penalty Rate is equal to the higher of (i)1.2 times the Capacity Resource Clearing Price of the LDA into which the QTU is cleared or (ii) the Net Cost of New Entry.

A QTU that is also subject to a Non-Performance Charge during one or more Performance Assessment Intervals occurring during a continuous time period of Daily RPM Commitment Shortages shall be assessed a charge equal to the greater of (a) the total Daily Transmission Upgrade Delay Penalty Charges calculated for such continuous time period or (b) the total Non-Performance Charges calculated for the Performance Assessment Intervals occurring during such continuous time period. The sum of the Daily Transmission Upgrade Delay Penalty Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge.

**Note:**
Transmission Upgrade Delay Penalty Charges are assessed daily and billed weekly.

### 9.1.5 Generation Resource Rating Test Failure Charge

The Daily Generation Resource Rating Test Failure Charge is applicable to all generation resources (with the exception of Variable Resources) committed to RPM or FRR that have a positive Daily Unit ICAP shortfall due to a rating test failure. The determination of the Daily Unit ICAP Shortfall for a generation resource and a Provider's Daily ICAP Shortfall is described in Section 8.5.1 for Delivery Years through the 2024/2025 Delivery Year and Section 8.5.2 for Delivery Years starting with the 2025/2026 Delivery Year.

For Delivery Years through the 2024/2025 Delivery Year, the Daily Generation Resource Rating Test Failure Charge shall be equal to the Daily Deficiency Rate times: a) for Combination Resources and Limited Duration Resources, the appropriate Accredited UCAP value that corresponds to the Provider's Daily ICAP Shortfall, or; b) for Unlimited Resources, the Provider's Daily ICAP Shortfall times (1 – Effective EFORd) for a generation resource.

Effective with the 2025/2026 Delivery Year, the Daily Generation Resource Rating Test Failure Charge shall be equal to the Daily Deficiency Rate times the Provider's Daily ICAP Shortfall of the resource converted to Unforced Capacity terms using the Generation Capacity Resource's final Accredited UCAP Factor for the Delivery Year.

*GenerationResourceRatingTestFailureCharge = DDR * DailyICAPShortfall * AUCAPFactor*

The Daily Deficiency Rate applied to a Daily ICAP Shortfall for RPM Resource Commitments is equal to the Party's Weighted Average Resource Clearing Price for such resource plus the higher of 0.2*Party's Weighted Average Resource Clearing Price for such resource or $20/MW-day. In the case where a Party's Weighted Average Resource Clearing Price for such resource is equal to $0/MW-day because the committed resource did not clear in any RPM Auction (i.e., commitments were due to the resources being used as a source of a Locational UCAP transaction or as replacement capacity), a PJM Weighted Average Resource Clearing Price in an LDA will be used.

The Daily Deficiency Rate applied to Daily ICAP Shortfall for FRR Resource Commitments is equal to 1.2 times the weighted average of the resource clearing prices across all Delivery Year RPM Auctions for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions.

A resource that is also subject a Non-Performance Charge during one or more Performance Assessment Intervals occurring during a continuous time period of Daily ICAP Shortfalls due to rating test failure shall be assessed a charge equal to the greater of (a) the total Daily Generation Resource Rating Test Failure Charges calculated for such continuous time period or (b) the total Non-Performance Charges for the Performance Assessment Intervals occurring during such continuous time. The sum of the Daily Generation Resource Rating Test Failure Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge. A resource that is subject to a Generation Operational Test Failure Charge shall not also be subject to a Generation Resource Rating Test Failure Charge for the same megawatts during overlapping time periods.

**Note:**
***Generation Resource Rating Test Failure Charges*** are assessed daily for the entire Delivery Year and are billed retroactively for the entire Delivery Year in the June monthly bill issued in July after the conclusion of the Delivery Year.

### 9.1.5A Generation Operational Test Failure Charge

The Generation Operational Test Failure Charge is applicable to all generation resources (with the exception of Variable Resources) committed to RPM or FRR that fail the Generation Operational retest in accordance with Manual 14D.

The Daily Generation Operational Test Failure Charge applicable to RPM commitments shall be equal to the Daily Deficiency Rate times the applicable daily RPM committed UCAP MW of that Generation Resource.

*RPM Daily Generation Operational Test Failure Charge = DDR × Applicable Daily RPM Committed UCAP MW*

The Daily Deficiency Rate applicable to RPM Resource Commitments is equal to the Party's Weighted Average Resource Clearing Price for such resource plus the higher of 0.2*Party's Weighted Average Resource Clearing Price for such resource or $20/MW-day. In the case where a Party's Weighted Average Resource Clearing Price for such resource is equal to $0/MW-day because the committed resource did not clear in any RPM Auction (i.e., commitments were due to the resources being used as a source of a Locational UCAP transaction or as replacement capacity), a PJM Weighted Average Resource Clearing Price for the corresponding LDA will be used.

The Daily Generation Operational Test Failure Charge applicable to FRR commitments shall be equal to the Daily Deficiency Rate times the applicable daily FRR committed UCAP MW of that Generation Resource).

*FRR Daily Generation Operational Test Failure Charge = DDR × Applicable Daily FRR Committed UCAP MW*

The Daily Deficiency Rate applicable to FRR Resource Commitments is equal to 1.2 times theweighted average of the resource clearing prices across all RPM Auctions for the relevant Delivery Year, for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions.

A resource that is also subject to a Non-Performance Charge during one or more Performance Assessment Intervals occurring during a continuous time period of a generation operational test failure shall be assessed a charge equal to the greater of (a) the total Daily Generation Operational Test Failure Charges calculated for such continuous time period or (b) the total Non-Performance Charges for the Performance Assessment Intervals occurring during such continuous time. The sum of the Daily Generation Operational Test Failure Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge.

### 9.1.6 Load Management Test Failure Charge

The Daily Load Management Test Failure Charge is equal to the net testing shortfall in zone (expressed in UCAP) times the LM Test Failure Charge Rate. A net testing shortfall in zone will be separated into net testing shortfall in zone due to annual commitments and summer-only commitments, as appropriate.

The Daily Load Management Test Failure Charge Rate for zonal net testing shortfall due to annual commitments is equal to the Provider's Weighted Daily Revenue Rate for annual commitments in such zone plus the greater of (0.20 times the Provider's Weighted Daily Revenue Rate for annual commitments in such zone, or $20/MW-day). In the case where a Provider's Weighted Daily Revenue Rate for annual commitments in zone is $0/MW-day because the underlying committed resource(s) did not clear in any RPM Auction (i.e., commitments were due to the resource(s) being used as a source of a Locational UCAP transaction or as replacement capacity or commitments due to FRR Alternative), a PJM Weighted Daily Revenue Rate for annual commitments in such zone will be used. A Daily Load Management Test Failure Charge, equal to the net testing shortfall in zone due to annual commitments times the Daily Load Management Test Failure Charge Rate, will apply for each day in the Delivery Year.

The Daily Load Management Test Failure Charge Rate for zonal net testing shortfall due to summer-only commitments is equal to the Provider's Weighted Daily Revenue Rate in such zone for summer-only commitments plus the greater of (0.20 times the Provider's Weighted Daily Revenue Rate in such zone for summer-only commitments, or $20/MW-day). In the case where a Provider's Weighted Daily Revenue Rate in such zone for summer-only commitments is $0/MW-day because the underlying committed resource(s) did not clear in any RPM Auction (i.e., commitments were due to the resource(s) being used as source of a Locational UCAP transaction or as replacement capacity or commitments due to FRR Alternative), a PJM Weighted Daily Revenue Rate in such zone for summer-only commitments will be used. A Daily Load Management Test Failure Charge, equal to net testing shortfall in zone due to summer-only commitments times the Daily Load Management Test Failure Charge Rate, will apply for June through October and May of the Delivery Year.

**Note:**
The Load Management Test Failure Charges will be assessed in August monthly bill issued in September after the conclusion of the Delivery Year.

### 9.1.7 Allocation of Deficiency and Penalty Charges

The Daily Capacity Resource Deficiency Charges, Daily Transmission Upgrade Delay Penalties, Daily Generation Resource Rating Test Failure Charges, Generation Operational Test Failure Charges, and Load Management Test Failure Charges are distributed on a pro-rata basis to

LSEs who were charged a Daily Locational Reliability Charge for the day in order to compensate for resource adequacy that was not delivered.

Daily Capacity Resource Deficiency Charges, Daily Transmission Upgrade Delay Penalties, Daily Generation Resource Rating Test Failure Charges, and Load Management Test Failure Charges are allocated on a pro-rata basis to LSEs based on their daily unforced capacity obligation.

### 9.1.8 Emergency Procedures Charges

The Emergency Procedures Charges outlined in ***Schedule 13 of the Reliability Assurance Agreement and section 13 of Attachment DD of OATT*** for refusal to comply or failure to employ all reasonable efforts to comply will remain in effect, and will be assessed in addition to any penalty described here.

### 9.1.9 Non-Performance Charge/Bonus Performance Credit

Non-Performance Charge will be assessed to a resource provider or PRD Provider that had a Performance Shortfall for a Performance Assessment Interval.

Non-Performance Charge is equal to the Performance Assessment Interval Performance Shortfall (MW) times Non-Performance Charge Rate ($/MWh).

The Non-Performance Charge Rate to be applied to shortfalls associated with Capacity Performance commitments or PRD commitments is equal to {[the modeled LDA Net CONE for which the resource resides ($/MW-day in installed capacity terms) times number of days in Delivery Year divided by 30} divided by the number of Real-Time Settlement Intervals in an hour.

Stop-loss provisions limit the total Non-Performance Charge that can be assessed on each Capacity Resource or to a PRD Provider. The stop-loss provision (i.e., the maximum year Non-Performance Charge) is covered in section 8.4A of this Manual.

Revenue collected from payment of Non-Performance Charges will be distributed to resources (of any type, even if they are not Capacity Resources) and PRD Provider that perform above expectations. A resource or PRD Provider with Actual Performance above its Expected Performance is considered to have provided Bonus Performance, and will be assigned a share of the collected Non-Performance Charge revenues in the form of a Bonus Performance Credit. This credit is based on the ratio of its Bonus Performance quantity to the total Bonus Performance quantity (from all resources and PRD Providers) for the same Performance Assessment Interval.

**Note:**
The billing of any Non-Performance Charges incurred in any given month will be done within three calendar months after the calendar month that included such Performance Assessment Intervals and such billing of charges will be spread over the remaining months in the Delivery Year. Bonus Performance Credits will follow the same billing methodology as Non-Performance Charges.

## 9.2 Locational Reliability Charges

### 9.2.1 Calculation of Locational Reliability Charges

All LSEs pay a Locational Reliability Charge equal to their Daily Unforced Capacity Obligation in a zone times the applicable Final Zonal Capacity Price.

$$LocationalReliabilityCharge = DailyUCAPOblig * FinalZonalCapacityPrice$$

Each LSE that serves load in a PJM Zone or load outside PJM using PJM resources (Non-Zone Network Load) during the Delivery Year is responsible for paying a Locational Reliability Charge equal to their Daily Unforced Capacity Obligation in a Zone times the applicable Final Zonal Capacity Price for that Delivery Year.

**Note:**
***Locational Reliability Charges*** are calculated daily and billed weekly during the Delivery Year.

## 9.3 Auction Credits and Charges

### 9.3.1 Calculation of Auction Credits

$$RPMAuctionCredits = MWCleared_{LDA} * RCP_{LDA}$$

Each generation, demand, energy efficiency, or QTU resource provider that clears Capacity Performance sell offer segments in an RPM Auction will receive a Daily Auction Credit equal to the total MW amount that cleared in Capacity Performance sell offer segments times the applicable LDA resource clearing price in such RPM Auction for the entire Delivery Year.

Each generation, demand, or energy efficiency resource provider that clears Seasonal Capacity Performance-Summer sell offer segments in an RPM Auction will receive a Daily Auction Credit equal to the total MW amount that cleared in Seasonal Capacity Performance-Summer sell offer segments times the resource clearing price applicable to the resource's Seasonal Capacity Performance-Summer sell offer segments in such RPM Auction. The Daily Auction Credit shall apply for June through October and May of the Delivery Year.

Each generation resource provider that clears Seasonal Capacity Performance-Winter sell offer segments in an RPM Auction will receive a Daily Auction Credit equal to the total MW amount that cleared in Seasonal Capacity Performance-Winter sell offer segments times the resource clearing price applicable to the resource's Seasonal Capacity Performance-Winter sell offer segments in such RPM Auction. The Daily Auction Credit shall apply for November through April of the Delivery Year.

The PJM Generation Deactivation Credits received by units with Reliability Must Run (RMR) contracts will be reduced by the Auction Credits received by the RMR unit in a RPM Auction.

**Note:**
***Auction Credits*** are calculated daily and billed weekly during the Delivery Year.

### 9.3.2 Calculation of Auction Charges

Each resource provider that clears a Buy Bid in an Incremental Auction will receive an Auction Charge (referred to as Resource Substitution Charge in OATT) equal to the MW amount that cleared in the LDA times the Resource Clearing Price in the LDA in the applicable Incremental Auction.

$$RPMAuctionCharges = MWCleared_{LDA} * RCP_{LDA}$$

**Note:**
***Auction Charges*** are calculated daily and billed weekly during the Delivery Year.

### 9.3.3 Resource Make-Whole Credit

A Resource Make-Whole Credit is paid to the marginal resource in an RPM auction as appropriate to ensure the seller is paid the sell offer MW times the sell offer price. Resource Make-Whole Credit is equal to the product of the Resource Clearing Price and the quantity difference between the sell offer's minimum MW specification and the cleared MW quantity in the RPM Auction. The difference between the minimum MW offered and the cleared MW quantities is equal to the Make-whole MWs.

$$ResourceMakeWholeCredit = \left(Min\ MWOffered - MWCleared\right) * RCP_{LDA}$$

A resource provider that offered and cleared a Seasonal Capacity Performance sell offer for which the sell offer price exceeded the clearing price determined for such resource as a result of the seasonal matching process in the post-processing of the auction results as described in Section 5.7.2 and 5.8.5 will receive a Resource Make-whole Credit. The Resource Make-whole Credit is equal to the difference between the sell offer price and clearing price for such resource determined as a result of the seasonal matching process times the cleared MWs.

The Resource Make-whole Credit to a Seasonal Capacity Performance sell offer is incorporated in the Daily Auction Credit to the Seasonal Capacity Performance Resource since the Resource Clearing Price applicable to the Seasonal Capacity Performance Resource will include a seasonal make-whole price, if applicable.

Resource Make-Whole Credits from the First, Second, or Third Incremental Auctions are charged to all cleared participant and PJM buy bids on a pro-rata basis based on the MWs cleared in such auction. Make-whole charges assessed to buy bids cleared by PJM will be assessed to LSEs in the LDA via the Final Zonal Capacity Price

### 9.3.4 Capacity Transfer Rights Credit

Each Zonal Capacity Transfer Rights (CTRs) owner will receive a daily Zonal CTR Credit equal to the Zonal CTRs owned multiplied by the Zonal CTR Settlement Rate. Zonal CTRs owned include the Zonal CTRs allocated to an LSE and the results of any CTR transfers. The Zonal CTR Settlement Rate is the Total Economic Value of CTRs in Zone ($/day) for all LDAs in which the zone resides as a result of all RPM Auctions for such Delivery Year divided by the maximum LDA CTRs (MWs) allocated to LSEs in a zone.

$$ZonalCTRCredit = ZonalCTRsOwned * ZonalCTRSettlementRate$$

Each Incremental CTR owner will receive a daily Incremental CTR Credit equal to the Incremental CTRs owned for the LDA multiplied by the LDA Incremental CTR Credit Rate. The LDA Incremental CTR Credit Rate is equal to the average weighted Locational Price Adder for such LDA determined with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year.

$$IncrementalCTRCredit = IncrementalCTRsOwned * LDAIncrementalCTRCreditRate$$

**Note:**
***CTR Credits*** will be calculated daily and billed weekly during the Delivery Year.

### 9.3.5 Auction Specific MW Transaction Credits and Charges

The Seller of an Auction Specific Capacity Transaction will receive a charge equal to the transaction amount (in MW) times the price associated with the transaction. The price associated with the transaction is a weighted average of the Resource Clearing Prices of the resource-specific, auction-specific, segment-specific Cleared MWs identified in the transaction.

$$SellerCharge = TransactionAmount * WeightedAvgRCP$$

The Buyer of an Auction Specific MW Transaction will receive a credit equal to the transaction amount (in MW) times the price associated with the transaction.

$$BuyerCredit = TransactionAmount * WeightedAvgRCP$$

**Note:**
***Charges and Credits for Auction Specific MW Transactions*** are calculated daily and billed weekly for the duration of the transaction during the Delivery Year.

### 9.3.6 Capacity Export Charges and Credits

Capacity Export Charge = Export Reserved Capacity * (Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported - Final Zonal Capacity Price for the Zone in which the resource designated for the export is located)

Where, Export Reserved Capacity = Reserved Capacity of Long-Term Firm Transmission Service used for the export.

Capacity Export Credit = Export Customer's Allocated Share * (Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported - the Final Zonal Capacity Price for the Zone in which the resource designated for the export is located)

Where,

Export Customer's Allocated Share = (Unforced Capacity imported) * [Export Reserved Capacity / (Export Reserved Capacity + Unforced Capacity Obligations of all LSEs in the Zone)]

Unforced Capacity imported = Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located =

[(Export Reserved Capacity + Unforced Capacity Obligations of all LSEs in the Zone) – (Unforced Capacity cleared in the Zone)] *

(Ratio, as determined by PJM, of the CETL from the Zone in which the resource designated for export is located to the total CETL into the export interface Zone).

The revenues collected from Capacity Export Charge less the credit provided will be distributed to the LSEs in the export-interface Zone that were assessed Locational Reliability Charge for the delivery year (RPM LSEs) based on their Daily Unforced Capacity Obligations.

## 9.4 Penalties for Non-Performance of Price Responsive Demand

### 9.4.1 PRD Commitment Compliance Penalty & Credits

A PRD Provider with a positive daily commitment compliance shortfall in a sub-zone/zone for RPM or FRR will be assessed a Daily PRD Commitment Compliance Penalty.

The Daily PRD Commitment Compliance Penalty is equal to the MW shortfall in the Sub-zone/ Zone * Delivery Year Forecast Pool Requirement * PRD Commitment Compliance Penalty Rate.

The MW Shortfall in Sub-zone/Zone for RPM is the Daily Nominal PRD Value committed in BRA and/or Third IA by the PRD Provider minus the Daily Nominal PRD Value for RPM determined from approved and effective PRD registrations for such PRD Provider.

The MW Shortfall in Sub-zone/Zone for FRR is the Daily Nominal PRD Value committed for FRR by the PRD Provider minus the Daily Nominal PRD Value for FRR determined from approved and effective PRD registrations for such PRD Provider.

The PRD Commitment Compliance Penalty Rate for a PRD Provider that committed PRD for RPM is equal to PRD Provider's Weighted Final Zonal Capacity Price in $/MW-Day + higher of [0.2 * PRD Provider's Weighted Final Zonal Capacity Price or $20/MW-day].

A PRD Provider's Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price due to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in Base Residual Auction and Third Incremental Auction.

The PRD Commitment Compliance Penalty Rate for a PRD Provider that committed PRD for FRR is 1.20 times the weighted-average Resource Clearing Price resulting from all RPM Auctions for the Delivery Year for the LDA where the FRR PRD commitment resides, weight-averaged for the Delivery year based on the prices established and quantities cleared in the RPM Auctions for such Delivery Year.

The revenue collected from assessment of the PRD Commitment Compliance Penalty shall be distributed on a pro-rata basis as Daily PRD Commitment Compliance Credit to all entities that committed Capacity Resources in the RPM Auctions for such Delivery Year, pro rata based on each such entity's daily revenues from Capacity Market Clearing Prices in such auctions, net of any daily compliance charges incurred by such entity.

### 9.4.2 Deleted

### 9.4.3 PRD Test Failure Charges & Credits

Each PRD Provider with a positive net testing shortfall in a zone will be assessed PRD Test Failure Charge.

The PRD Test Failure Charge is equal to the net testing shortfall in zone times * Delivery Year Forecast Pool Requirement * PRD Test Failure Charge Rate

The PRD Test Failure Charge Rate for RPM PRD is equal to the PRD Provider's Weighted Final Zonal Capacity Price in such Zone plus the greater of (0.20 times the PRD Provider's Weighted Final Zonal Capacity Price in such Zone or $20/MW-day) times the number of days in the Delivery Year.

A PRD Provider's Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price due to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in BRA and Third IA.

The PRD Test Failure Charge Rate for FRR PRD is 1.20 times the weighted-average Resource Clearing Price resulting from all RPM Auctions for the Delivery Year for the LDA where the FRR PRD commitment resides, weight-averaged for the Delivery year based on the prices established and quantities cleared in the RPM Auctions for such Delivery Year.

The PRD Test Failure Charge shall be assessed daily and billed retroactively in the August bill issued in September after the conclusion of the Delivery Year.

The revenue collected from assessment of the PRD Test Failure Charges shall be distributed on a pro-rata basis as Daily PRD Test Failure Credits to all entities that committed Capacity Resources in the RPM Auctions for such Delivery Year, pro rata based on each such entity's daily revenues from Capacity Market Clearing Prices in such auctions, net of any daily compliance charges incurred by such entity.

### 9.4.4 PRD Credit

The PRD Provider identified in the PRD registration will receive a Daily PRD Credit each day that the PRD registration is effective. The PRD Provider (FRR Entity) identified in the PRD registration will not receive a Daily PRD Credit.

PRD Credit = [(Share of Zonal Nominal PRD Value committed in Base Residual Auction * * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price) + (Share of Zonal Nominal PRD Value committed in Third Incremental Auction * * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price * Third Incremental Auction Component of Final Zonal Capacity Price stated as a Percentage)].

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Where:

Share of Zonal Nominal PRD Value Committed in Base Residual Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration * Zonal Nominal PRD Value committed in the Base Residual Auction by the PRD Provider of such registration.

Share of Zonal Nominal PRD Value Committed in Third Incremental Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration *Zonal Nominal PRD Value committed in the Third Incremental Auction by the PRD Provider of such registration.

When the PRD registration is associated with a sub-Zone, the Share of the Nominal PRD Value Committed in Base Residual Auction or Third Incremental Auction will be based on the Nominal PRD Values committed and registered in a sub-Zone.

A PRD Provider will receive a PRD Credit for each approved Price Responsive Demand registration that is effective and applicable to load served by such Load Serving Entity on a given day. The total daily credit to a PRD Provider in a Zone shall be the sum of the credits received as a result of all approved registrations in the Zone on a given day. The PRD Credit PRD Performance penalties are assessed to the PRD Provider in the registration.

# Section 10: Capacity Exchange

Welcome to the *Capacity Exchange* section of the ***PJM Manual for the PJM Capacity Market***. In this section, you will find the following information:

- A description of the PJM Capacity Exchange tool (see "PJM Capacity Exchange Overview").

## 10.1 Overview

PJM Capacity Exchange tool is an Internet application that allows Market Participants to participate in PJM's RPM Auctions, the FRR Alternative, and view load and obligation data.

The graphic below presents a conceptual view of the RPM auction subsystems.

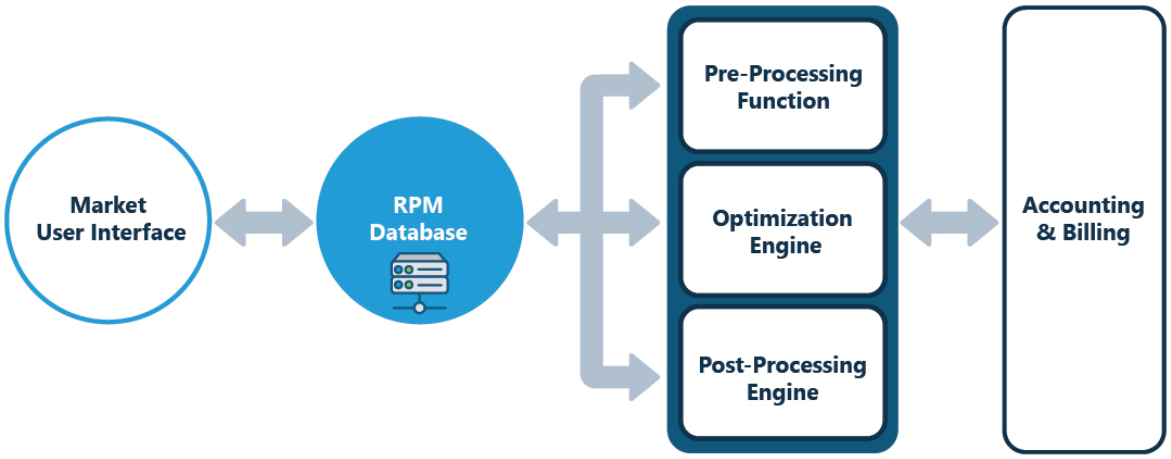



*Exhibit 4: RPM Auction Subsystems*

The Market User Interface (MUI) allows market participants to:

- Maintain their resource portfolio by increasing or decreasing their installed capacity values for generation via Capacity Modifications.
- View resource position
- Report Unit Specific Bilateral Transactions with a counterparty
- Report Auction Specific MW Transactions with a counterparty
- Report Locational UCAP Transactions
- Report Cleared Buy Bid Transactions
- Submit Resource Offers to sell capacity into an RPM auction

- Submit replacements for RPM Auction Commitments
- View Auction Results
- View load and obligation data
- Submit FRR Capacity Plan
- View deficiency data related to RPM/FRR Commitments

All data entered into the MUI is validated and entered into the RPM database by the MUI.

A ***Capacity Exchange User Guide*** is posted on the pjm website to help participants use the Capacity Exchange tool.

The RPM auction subsystem consists of the following three components:

- *Pre-processing Function* – performs all activities necessary to setup Auctions, including specifying the Planning Year Parameters as inputs into the solution and evaluating submitted resource offers.
- *Optimization Engine* – performs auction clearing process to ensure the most economical capacity threshold is met. Assigns unit commitments based on the entered offers, demand curves, and specific planning year parameters.
- *Post-processing Function* – ensures that the appropriate data items are transferred to the RPM auction database for posting on the MUI and ensures the results are transferred to the accounting and billing subsystems.

# Section 11: Fixed Resource Requirement Alternative

Welcome to the *Fixed Resource Requirement Alternative* section of the ***PJM Manual for the PJM Capacity Markets***. In this section, you will find the following information:

- An overview of the Fixed Resource Requirement Alternative (see "Overview of the Fixed Resource Requirement Alternative")
- The business rules for determining Load Obligations in FRR (see "Load Obligations")
- The business rules for creating the Capacity Plan in FRR (see "Capacity Plan")
- The business rules for supply resources in the FRR Alternative (see "Supply Resources in the FRR Alternative"
- The business rules for locational constraints in the FRR Alternative (see "Locational Constraints in the FRR Alternative")
- The conditions on sales by FRR Entities (see "Conditions on Sales by FRR Entities")
- The business rules for Delivery Year Activity (see "Deliver Year Activity")
- The business rules for the calculation of deficiency charges and penalties (see "Deficiency Charges and Penalties")
- The business rules for the allocation of deficiency charges (see "Allocation of Deficiency Charges")
- The business rules for Auction Specific MW Transactions (see "Auction Specific MW Transactions"

## 11.1 Overview

### 11.1.1 Definition and Purpose of Fixed Resource Requirement Alternative

The purpose of the Fixed Resource Requirement (FRR) Alternative is to provide a Load Serving Entity (LSE) with the option to submit a FRR Capacity Plan and meet a fixed capacity resource requirement as an alternative to the requirement to participate in the PJM Reliability Pricing Model (RPM), which includes a variable capacity resource requirement.

The FRR Alternative allows an LSE, subject to certain conditions, to avoid direct participation in the RPM Base Residual Auctions and the Incremental Auctions; however, such LSE is required to submit a FRR Capacity Plan to satisfy the unforced capacity obligation for all loads in an FRR Service Area, including all expected load growth in the FRR Service Area.

An LSE serving load in an FRR Service Area under the FRR Alternative does not pay an RPM Locational Reliability Charge. The portions of capacity resources included in an LSE's FRR Capacity Plan do not receive any RPM Resource Clearing Prices.

### 11.1.2 Implementation of the FRR Alternative

PJM's Planning Period is defined as an annual period from June 1 to May 31. The Delivery Year is the Planning Period for which resources are being committed and for which a constant load obligation for the entire PJM region exists. For example, the 2012/2013 Delivery Year corresponds to the June 1, 2012-May 31, 2013 Planning Period.

FRR Entities may commit Capacity Performance Resources and Seasonal Capacity Performance Resources to their FRR Capacity Plan.

### 11.1.3 Participation in the FRR Alternative

An LSE may participate in the Fixed Resource Requirement (FRR) Alternative and avoid participation in RPM, only if the LSE meets the eligibility requirements of the Fixed Resource Requirement (FRR) Alternative as defined in Schedule 8.1 of the Reliability Assurance Agreement (RAA).

To elect the FRR Alternative for the first time, an LSE must notify PJM of such election in writing at least four months before the conduct of the Base Residual Auction (BRA) for the first Delivery Year that such election is to be effective.

The election of the FRR Alternative shall be for a minimum term of five consecutive Delivery Years.

The written election notification must provide adequate information to demonstrate that the LSE meets the eligibility requirements of the FRR Alternative and that the FRR Service Area identified to be served by the LSE under the FRR Alternative complies with the meaning of an FRR Service Area as defined in the RAA. The written election must also indicate whether or not the LSE intends to sell capacity resources to a direct or indirect purchaser that may use such capacity resources in any RPM Auctions or as replacement resources in RPM or whether the LSE intends to serve load in another area under RPM.

Within ten business days of the receipt of the written election notification, PJM will validate that the LSE meets the eligibility requirements of the FRR Alternative. PJM will also request confirmation from the EDC that the identified FRR Service Area is metered and complies with the meaning of an FRR Service Area as defined in the RAA. PJM will (1) notify such LSE in writing that its election of the FRR Alternative is valid and the appropriate modifications to the Capacity Exchange database have been completed to allow the LSE to submit a FRR Capacity Plan through the Capacity Exchange system or (2) notify an LSE in writing that its election of the FRR Alternative is invalid since it did not meet the eligibility requirements of the FRR Alternative or that the identified FRR Service Area does not comply with the meaning of an FRR Service Area as defined in the RAA.

If PJM has provided written notice to an LSE that its election of the FRR Alternative is invalid, the LSE will be required to serve its load under the RPM for the Delivery Year such election was to be effective.

If PJM has provided written notice to an LSE that its election of the FRR Alternative is valid, an LSE must submit its initial FRR Capacity Plan through the Capacity Exchange system at least one month prior to the conduct of the Base Residual Auction for the first Delivery Year that such election is to be effective.

An LSE may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum term of five consecutive Delivery Years. An FRR Entity may terminate its election of the FRR Alternative prior to meeting its minimum five year commitment without penalty for any Delivery Year after the first Delivery Year of the FRR Entity's minimum five year commitment for which PJM will be required to establish a separate Variable Resource Requirement Curve, as described in Section 11.5 below. Written notice of such termination must be provided to PJM no later than two months prior to the Base Residual Auction (BRA) for such Delivery Year. In addition, an FRR Entity that elected the FRR Alternative for a Delivery Year prior to the 2025/2026 Delivery Year, may terminate its election of the FRR Alternative prior to meeting the minimum term of five years without penalty by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for a Delivery Year through and including the 2028/2029 Delivery Year.

An LSE that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.

In the event of a State Regulatory Structural Change as defined in the RAA, an LSE may elect or terminate its election of the FRR Alternative effective as to any Delivery Year by providing written notice to PJM of the election or termination of FRR Alternative. The written notice shall be provided in good faith as soon as the LSE becomes aware of such State Regulatory Change, but no later than two months prior to the BRA for such Delivery Year.

To facilitate the election and notices required by the FRR Alternative, except a new FRR Entity's initial election, the following information shall be posted by PJM with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website:

- Preliminary RTO and Zonal Peak Load Forecasts
- LDAs modeled in the Base Residual Auction
- Installed Reserve Margin (IRM)
- Pool-wide Average EFORd through 2024/2025 Delivery Year
- Pool-wide average Accredited UCAP Factor starting with the 2025/2026 Delivery Year
- Forecast Pool Requirement (FPR)
- Reliability Requirements of the PJM Region and each modeled LDA
- Variable Resource Requirement (VRR) Curves of the PJM Region and each modeled LDA
- CETO and CETL values for each modeled LDA

- Transmission Upgrades projected to be in service for the Delivery Year
- Cost of New Entry (CONE) for the PJM Region and each modeled LDA
- Net Energy and Ancillary Services Revenue Offset of the PJM Region and each modeled LDA
- Base Zonal FRR Scaling Factor
- Percentage of Internal Resources Required in an LDA
- Deadline for FRR Capacity Plan Submittal
- Auction Credit Rate

LSEs electing the FRR Alternative will be subject to the same credit requirements as suppliers of resources into the RPM auctions, to the extent that they submit as part of their FRR Capacity Plan any resources for which credit would be required if offered into an RPM auction. However, if an alternative retail LSE is providing capacity resources to the FRR Entity to satisfy the alternative retail LSE's capacity obligation in lieu of providing compensation to the FRR Entity in accordance with RAA Schedule 8.1D, section 9; the alternative retail LSE as opposed to the FRR Entity will be subject to any applicable credit requirements for capacity resources provided.

Any credit provided by an LSE to satisfy its credit requirements under the FRR Alternative must be established prior to the deadline for submitting the FRR Capacity Plan.

## 11.2 Load Obligations

Similar to RPM load obligations, FRR load obligations are calculated in two steps. First, prior to the RPM Base Residual Auction based on Preliminary Zonal Peak Load Forecast; then prior to the Third Incremental Auction based on the Final Zonal Peak Load Forecast. Base and Final Zonal FRR Scaling Factors and Forecast Pool Requirement are used in calculating the FRR Entity Unforced Capacity Obligations.

### 11.2.1 Preliminary Unforced Capacity Obligation

PJM will notify the Electric Distribution Company (EDC) that an election of the FRR Alternative was made by an LSE in their zone within two business days of the receipt of the written election notification.

An approved FRR Service Area will become a defined "area" within a zone in the Capacity Exchange system.

Only one LSE shall be responsible for serving the entire load in an FRR Service Area.

The Electric Distribution Company (EDC) is responsible for allocating the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year and providing to PJM a Base Obligation Peak Load allocation for the FRR Service Area(s) in their zone within five business days of the receipt of notice of an FRR Service Area within their zone.

The Preliminary Daily Unforced Capacity Obligation of an LSE serving load in an FRR Service Area in a zone equals the LSE's Base Obligation Peak Load in the zone/area * the Base Zonal FRR Scaling Factor * the Forecast Pool Requirement.

The Preliminary Daily Unforced Capacity Obligation of an LSE serving load in an FRR Service Area shall be reduced by the Nominal PRD Value associated with such load that was approved by PJM in advance of the BRA for such Delivery Year, multiplied by the BRA Forecast Pool Requirement.

The Preliminary Daily Unforced Capacity Obligation of an LSE serving load in an FRR Service Area shall be increased by the UCAP Value of any EE Resource that is used in the FRR Capacity Plan because energy efficiency measures are reflected in the peak load forecast that is used as the basis for determining the UCAP Obligation of the FRR Entity.

The Base Zonal FRR Scaling Factor is equal to Preliminary Zonal Peak Load Forecast divided by the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year. The Base Zonal FRR Scaling Factor is posted by February 1 three years prior to the Delivery Year.

The EDC is responsible for allocating the Zonal Weather Normalized Summer Peak for the summer one year prior to the Delivery Year and providing to PJM a Final Obligation Peak Load allocation for the FRR Service Area(s) in their zone by December 31 prior to the start of the Delivery Year.

The Final Zonal FRR Scaling Factor is equal to Final Zonal Peak Load Forecast divided by the Zonal Weather Normalized Summer Peak for the summer one year prior to the Delivery Year. The Final FRR Zonal Scaling Factor is determined by PJM and provided to the FRR Entity by February 1 prior to the Delivery Year.

The following parameters used in the determination of FRR load obligations are determined in accordance with Section 2 of this manual: Preliminary and Final Zonal Peak Load Forecasts, Zonal Weather Normalized Summer Peaks, Forecast Pool Requirement (FPR), Installed Reserve Margin (IRM), Pool-wide Average EFORd through the 2024/2025 Delivery Year, and the Pool-wide average Accredited UCAP Factor starting with the 2025/2026 Delivery Year.

### 11.2.2 Treatment of Non-Zone Load

Treatment of Non-Zone Load is similar to the treatment under RPM. The FRR Alternative is available to an LSE serving Non-Zone Load if the LSE meets the eligibility and election requirements of the FRR Alternative.

Non-Zone Load is the load that is located outside of the PJM Region served by a PJM Load Serving Entity using PJM internal resources. Non-Zone Load is included in the load of the Zone from which the load is served.

Non-Zone Load may be Non-Zone Network Load (Tariff 1.27B) that is charged a Network Integration Transmission Service (NITS) charge (Tariff Attachment H-A) or other load that may be 'grandfathered' from the NITS charge.

PJM forecasts the Preliminary Non-Zone Load for the RPM Delivery Year and includes it in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load of the Zone from which the Non-Zone Load is served, by February 1 prior to the Base Residual Auction.

To serve Non-Zone Load in a Delivery Year under the Fixed Resource Requirement Alternative, the Non-Zone Load should be included in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load prior to the RPM Base Residual Auction for the Delivery Year. In addition, the LSE must satisfy the eligibility and election requirements of the FRR Alternative.

PJM forecasts the final forecast of the Non-Zone Load and includes it in the Final RTO Forecast Peak Load and the Final Zonal Forecast Peak Load that is posted one month prior to the Third Incremental Auction.

EDC that is responsible to determine the Obligation Peak Loads for the Zone will also establish the Obligation Peak Load associated with the Non-Zone Load by December 31 prior to the start of the Delivery Year.

The LSE serving the Non-Zone Load under the FRR Alternative will be responsible to commit resources in their FRR Capacity Plan to cover the non-zone load.

### 11.2.3 Annexation & Switching of Load

The following business rules address the annexation of service territory by a Public Power Entity and load switching between FRR Entity and RPM LSEs. If an LSE that is a Public Power Entity annexes service territory to include new customers on sites where no load had previously existed, the incremental load will be treated as unanticipated load growth, and the LSE must commit additional resources to cover the additional load obligation associated with this annexed load.

If an LSE that is a Public Power Entity annexes service territory and the load was already included in the Base Residual Auction, the LSE cannot cover the incremental load obligation using the excess of resources from their FRR Capacity Plan. Instead, the LSE will pay the RPM Locational Reliability Charge for this incremental load obligation (including any additional demand curve obligation) since RPM process has already procured capacity resources to cover this load. The charges collected from the LSE will be used to pay capacity resources that that cleared in the Base Residual Auction for that LDA.

If an LSE that is a Public Power Entity annexes service territory and the Base Residual Auction was not held, the LSE must commit resources to cover this incremental load obligation in its FRR Capacity Plan.

If an LSE that has not elected the FRR Alternative acquires load from an FRR LSE after the Base Residual Auction, the shifted load will be considered as unanticipated load growth for purposes of determining RTO/LDA Reliability Requirements in all future Incremental Auctions for such Delivery Year, and such shifted load shall pay a Locational Reliability Charge for such Delivery Year. For the next Incremental Auction, the FRR Entity would have an RPM must offer requirement for a fixed amount of unforced capacity equal to the shifted load times the updated Forecast Pool Requirement applicable to the next Incremental Auction. The FRR Entity would continue to have an RPM must offer requirement for all future Incremental Auctions for such Delivery Year; however, the RPM must offer requirement would terminate once the FRR Entity cleared the required fixed amount of Unforced Capacity in Incremental Auction(s) for such Delivery Year.

If an LSE that has not elected the FRR Alternative acquires load from an FRR LSE and the Base Residual Auction has not been conducted for a Delivery Year, the FRR LSE should no longer commit capacity resources for the shifted load in its FRR Capacity Plan. PJM will include the shifted load in the future Base Residual Auctions.

## 11.3 Capacity Plan

The most important requirement in electing FRR Alternative is for the FRR Entity to commit Capacity Resources to meet their daily unforced capacity obligations, any applicable Percentage of Internal Resources Required in an LDA, plus any additional threshold if the FRR Entity plans to sell capacity. Failure to commit the required resources would result in FRR Commitment Insufficiency Charge and ineligibility to continue the FRR Alternative. An FRR Capacity Plan is the long-term plan for the commitment of Capacity Resources to satisfy the daily zonal unforced capacity obligations of an LSE that has elected the FRR Alternative in an FRR Service Area and any applicable Percentage of Internal Resources Required in a Locational Deliverability Area (LDA).

If the LSE intends to sell capacity resources to a direct or indirect purchaser that may use such a resource in any RPM Auctions or as a replacement resource in RPM, the LSE must also maintain a Threshold Quantity in its FRR Capacity Plan prior to the Delivery Year.

The Threshold Quantity is equal to the Preliminary Daily Unforced Capacity Obligation plus the lesser of (a) 0.03 * Preliminary Daily Unforced Capacity Obligation or (b) 450 MW.

An LSE must submit an initial FRR Capacity Plan at least one month prior to the conduct of the Base Residual Auction for the first Delivery Year by demonstrating that it has sufficient capacity resources in its FRR resource portfolio in Capacity Exchange to satisfy:

- LSE’s Preliminary Daily Unforced Capacity Obligations by zone for its FRR Service Area;

- any applicable Percentage of Internal Resources Required in LDA; and
- Threshold Quantity, if applicable.

If the initial FRR Capacity Plan does not satisfy the LSE's Preliminary Daily Zonal Unforced Capacity Obligations, any applicable Percentage of Internal Resources Required in LDA, and Threshold Quantity, if applicable, by the posted deadline for FRR Capacity Plan submittal, the LSE's election of the FRR Alternative will not be approved by PJM. The LSE will be required to serve its entire load in the FRR Service Area under the RPM for the Delivery Year such election was to be effective.

An LSE must annually demonstrate through the Capacity Exchange system no later than one month prior to the Base Residual Auction for each succeeding Delivery Year that it has extended the commitment of sufficient capacity resources to satisfy:

- LSE's Preliminary Daily Unforced Capacity Obligations by zone for its FRR Service Area;
- any applicable Percentage of Internal Resources Required in LDA; and
- Threshold Quantity, if applicable.

If the FRR Capacity Plan for a succeeding Delivery Year does not satisfy the LSE's Preliminary Daily Unforced Capacity Obligations, any applicable Percentage of Internal Resources Required in LDA, and Threshold Quantity, if applicable, by the posted deadline for FRR Capacity Plan submittal, the LSE will be assessed an FRR Commitment Insufficiency Charge for any shortage of unforced capacity in meeting the Percentages of Internal Resources Required in LDA or the Preliminary Daily Unforced Capacity Obligations (including any Threshold Quantity) for any remainder of the minimum term of the FRR election. The shortage is defined as the shortage in meeting the Percentage of Internal Resources Required in LDA plus any additional shortage in meeting the Preliminary Daily Unforced Capacity Obligation including any Threshold Quantity Requirement. The shortage amount identified in the first delivery year that this charge is to be assessed is to be applied in the remaining delivery years that the charge is to be assessed. Through the 2024/2025 Delivery Year, the FRR Commitment Insufficiency Charge in a zone is equal to two times the Cost of New Entry ($/MW-day) in the zone times the shortage amount. For Delivery Years between the 2025/2026 Delivery Year through the 2028/2029 Delivery Year, no FRR Commitment Insufficiency Charge shall be assessed. Effective with the 2029/2030 Delivery Year and subsequent Delivery Years, an FRR Commitment Insufficiency Charge is equal to the price level corresponding to point (1) of the Variable Resource Requirement curve for the relevant Locational Deliverability Area, in $/MW-day, times the shortage amount.

FRR Commitment Insufficiency Charges are allocated on a pro-rata basis to all other LSEs (including RPM LSEs) in the RTO based on their Daily Unforced Capacity obligations.

Existing generation, planned generation, bilateral contracts for unit-specific capacity resources, existing demand resources, planned demand resources, energy efficiency resources, Aggregate Resources , and Seasonal Capacity Performance Resources may be used in the FRR Capacity

Plan if these resources meet the requirements specified in the PJM Agreements and Business Rules.

Existing generation that is located outside of the PJM market footprint may be used in the FRR Capacity Plan if the external generation meets the requirements specified in PJM Agreements and Section 4 of this manual.

Capacity Performance Resources or Seasonal Capacity Performance Resources may be included in the FRR Capacity Plan.

Through the 2024/2025 Delivery Year, at the FRR Entity's election, the UCAP MW quantity of generation resources that are committed to the initial FRR Capacity Plan will be determined using the lower of the generation resources' EFORd calculated based on outage data for the 12 months ending September 30th prior to the Base Residual Auction or the 5 Year Average EFORd based on outage data for the 12 months ending September 30th prior to the Base residual Auction. The EFORd applied to the Final FRR Capacity Plan evaluated throughout the Delivery Year will be determined by PJM using the forced outage data for the 12 months ending September 30th prior to the Delivery Year. The final Accredited UCAP value of a resource will be applied to the Final FRR Capacity Plan evaluated throughout the Delivery Year.

Effective with the 2025/2026 Delivery Year, the UCAP MW quantity of generation resources that are committed to the initial FRR Capacity Plan will be based on the Accredited UCAP Factor determined for each generation resource prior to the Base Residual Auction, and the UCAP MW quantity of committed demand resources will be based on the applicable ELCC Class Rating determined prior to the Base Residual Auction. The final Accredited UCAP Factor of a generation resource and the final applicable ELCC Class Rating for a demand resource for the Delivery Year will be applied to the Final FRR Capacity Plan evaluated throughout the Delivery Year.

Qualifying Transmission Upgrades may be used to reduce the Percentage of Internal Resources Required in an LDA for the FRR LSE if the Qualifying Transmission Upgrade meets the requirements specified in the PJM Agreements and Section 4 of this manual.

A capacity resource used in an FRR Capacity Plan must be on a unit-specific basis, and may not include "slice of system" or similar agreements that are not unit-specific.

An LSE's FRR Capacity Plan for the Delivery Year shall not include any MWs committed to RPM for such Delivery Year.

Any capacity resource that was not offered by the FRR Entity or offered but did not clear by the FRR Entity in any RPM Auction for such Delivery Year may be included in an FRR Capacity Plan. Such MWs are classified as Available MWs and would be eligible to commit to an FRR Capacity Plan.

An LSE's FRR Capacity Plan for the Delivery Year may include resources that are committed for less than a full Delivery Year; however, the FRR Capacity Plan in aggregate must satisfy all obligations for the Delivery Year.

If an LSE has committed capacity to meet a Threshold Quantity, the LSE shall maintain such resources until the Delivery Year's Final Unforced Capacity Obligation and final requirements (Percentage of Internal Resources Required in LDA) are known. The LSE may use such resources during the Delivery Year to meet any increased capacity obligation resulting from an increase in Final Obligation Peak Load from Base Obligation Peak Load, or sell the resources to another FRR Entity in PJM or to an External Party.

All generation resources that have a FRR Capacity Plan Commitment must offer into PJM's Day Ahead Energy Market. Demand Resources that have an FRR Capacity Plan Commitment must be registered to participate in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Response Program and thus be available for dispatch during PJM-declared emergency event.

Prior to the start of each Delivery Year, the FRR entity must elect whether it seeks to be subject to the Non-Performance Charge or to physical non-performance assessments for such Delivery Year. An FRR Entity may not elect the physical non-performance assessment option if such FRR Entity will not be an FRR Entity for the following Delivery Year and will be serving load their under the RPM. If such FRR Entity opted to be subject to physical non-performance assessments, the FRR Entity will be required to update their FRR Capacity Plan for the following Delivery Year with additional MW of Capacity Performance Resources for each MW of FRR net Performance Shortfall for each Performance Assessment Interval in accordance with Section 11.8. Such FRR Entity shall not be eligible for, or subject to, Bonus Performance Credits.

## 11.4 Supply Resources in the FRR Alternative

The supply resources available and the qualification requirements for use in FRR Capacity Plans are very similar to RPM resources.

### 11.4.1 Resource Portfolio

An FRR Entity must specify through the Capacity Exchange system, before the FRR Capacity Plan submittal deadline, the amounts of installed capacity from resources in their Capacity Exchange resource portfolio that are being committed to their FRR Capacity Plan for the Delivery Year.

A party's Daily Generation Resource Position is calculated dynamically by the Capacity Exchange system for each unit and is equal to the Daily ICAP Owned on a unit multiplied by the unit's Accredited UCAP Factor

The Daily ICAP Owned on a unit is calculated by adding the ICAP Value of a unit as determined by a party's approved Capacity Modifications to ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases.

Through the 2024/2025 Delivery Year, the Accredited UCAP Factor shall mean one minus EFORd. The EFORd of a unit is based on forced outage data from an October through September period.

If a unit does not have a full one-year history of forced outage data, the EFORd will be calculated using class average EFORd and the available history as described in the Reliability Assurance Agreement, Schedule 5, Section B.

New units are initially assigned a class average EFORd.

The class average EFORds that are used by PJM to calculate a unit's EFORd are posted to the PJM website by November 30 prior to the Delivery Year.

The Effective EFORd is the EFORd that is effective for the delivery day in the Capacity Exchange system.

Prior to the Delivery Year, the Effective EFORd is the most recently calculated EFORd that has been bridged to the Capacity Exchange system.

During the Delivery Year, the Effective EFORd is based on forced outage data from the October through September period prior to the Delivery Year.

The EFORd that is effective for the Delivery Year is considered locked in the Capacity Exchange system by November 30 prior to the execution of the Third Incremental Auction.

Effective with the 2025/2026 Delivery Year, the Accredited UCAP Factor is the ratio of the Capacity Resource's Accredited UCAP as determined by ELCC analysis (see Section 4.2.7 Accredited UCAP for ELCC Resources) to the Capacity Resource's installed capacity.

A unit that is in a party's Generation Resource portfolio in Capacity Exchange may be committed to FRR Capacity Plan if the party has Daily Available ICAP to commit from the unit for the entire term of the commitment specified in the FRR Capacity Plan.[32] If the party's Daily Available ICAP for the unit varies for the term of the commitment specified in the FRR Capacity Plan, only the minimum Daily Available ICAP may be committed for the term of the commitment specified in the FRR Capacity Plan.

32 The term of the resource's commitment to the FRR Capacity Plan may be less than a Delivery Year.

For a party, the Daily Available ICAP to commit on a unit is equal to Daily ICAP Owned - (Daily RPM Resource Commitments/(Accredited UCAP Factor)) – Daily FRR Capacity Plan Commitments.

A party's Daily RPM Resource Commitments for a specific generating unit are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such unit in RPM Auctions to decreases/increases of RPM Resource Commitments due to approved unit-specific bilateral sales/purchases of cleared capacity, approved locational UCAP transactions, and the specification of replacement resources.

A party's Daily FRR Capacity Plan Commitments for a specific generating unit are equal to the total amount of installed capacity that was committed from the unit for the FRR Capacity Plan.

A party's Daily FRR Generation Resource Position for a specific unit is calculated by multiplying the Daily FRR Capacity Plan Commitments by (Accredited UCAP Factor).

An LSE's Daily Total FRR Generation Resource Position is calculated by summing the Daily FRR Generation Resource Positions of all units in their resource portfolio in Capacity Exchange.

An LSE's Daily LDA FRR Generation Resource Position is calculated by summing the Daily FRR Generation Resource Positions of all units in the LDA.

A party's Daily ICAP Owned for a specific demand resource is equal to the Daily Nominated DR Value adjusted for the ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such demand resource in effect for such day. Prior to the Delivery Year demand resource registration process in DR Hub system, the Daily Nominated DR Value for an FRR Entity's Demand Resource is established based on PJM's approval of the FRR Entity's DR Sell Offer Plan and PJM's submittal of a corresponding DR Modification into the Capacity Exchange system. After the Delivery Year demand resource registration process begins in DR Hub system, the Daily Nominated DR value for a Demand Resource for a Delivery Year is established based on confirmed Demand Resource Registrations in "completed" status linked to the DR Resource in the DR Hub system in accordance with Section 4.3.4 of Manual 18.

Through the 2024/2025 Delivery Year, a party's Daily Demand Resource Position for a Demand Resource is calculated dynamically by the Capacity Exchange system and is equal to the Daily ICAP Owned * Forecast Pool Requirement. Starting with the 2025/2026 Delivery Year, a party's Daily Demand Resource Position for a Demand Resource is calculated dynamically by the Capacity Exchange system and is equal to the Daily ICAP Owned * applicable ELC Class Rating. A Demand Resource that is in a party's Demand Resource portfolio may be committed to the FRR Capacity Plan, if there is Daily Available ICAP to commit from the Demand Resource for the entire term of the commitment specified in the FRR Capacity Plan.

Through the 2024/2025 Delivery Year, a party's, Daily Available ICAP for a specific demand resource is equal to the resource's Daily ICAP Owned- (Daily RPM Resource Commitments/

Forecast Pool Requirement) – Daily FRR Capacity Plan Commitments. Effective with the 2025/2026 Delivery Year, a party's Daily Available ICAP for a specific demand resource is equal to the resource's Daily ICAP Owned - (Daily RPM Resource Commitments/applicable ELCC Class Rating) - Daily FRR Capacity Plan Commitments.

A party's Daily RPM Resource Commitments for a specific demand resource are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such demand resource in RPM Auctions to decreases/increases of RPM Resource Commitments due to the specification of replacement resources, approved unit specific transactions for cleared capacity, and approved locational UCAP transactions.

A party's Daily FRR Capacity Plan Commitments for a specific demand resource are equal to the total amount of Nominated DR that was committed from the Demand Resource for the FRR Capacity Plan.

Through the 2024/2025 Delivery Year, a party's Daily FRR Demand Resource Position for a specific demand resource is equal to Daily FRR Capacity Plan Commitments* Forecast Pool Requirement. Effective with the 2025/2026 Delivery Year, a party's Daily LDA FRR Demand Resource Position is calculated by summing the Daily FRR Demand Resource Positions of all demand resources in the LDA.

A party's Daily FRR Capacity Plan Commitments for a specific EE Resource are equal to the total amount of Nominated EE that was committed from the EE Resource for the FRR Capacity Plan.

A party's Daily FRR EE Resource Position for a specific EE Resource is equal to Daily FRR Capacity Plan Commitments* Forecast Pool Requirement. A LSE's Daily Total FRR EE Resource Position is equal to the sum of the Daily FRR EE Resource Position of all EE resources in their resource portfolio in Capacity Exchange.

A LSE's Daily LDA FRR EE Resource Position is calculated by summing the Daily FRR EE Resource Positions of all EE resources in the LDA.

An LSE's Daily Total FRR Resource Position is calculated by summing the Daily FRR Generation Resource Positions, Daily FRR Demand Resource Positions, and Daily FRR EE Resource Positions of all resources in their Capacity Exchange resource portfolio. After the FRR Capacity Plan submittal deadline, an LSE's Daily Total FRR Resource Position is compared to their Daily Preliminary Unforced Capacity Obligation to determine if the LSE has satisfied their Preliminary Unforced Capacity Obligation for the entire Delivery Year.

After the FRR Capacity Plan submittal deadline, an LSE's Daily Total FRR Resource Position is compared to their Daily Threshold Quantity, if applicable, to determine if the LSE has satisfied their Daily Threshold Quantity for the entire Delivery Year.

During the Delivery Year, an LSE's Daily Total FRR Resource Position is compared to their Daily Final Unforced Capacity Obligation to determine if a Capacity Resource Deficiency Charge is to be assessed.

An LSE's Daily LDA FRR Resource Position is calculated by summing the Daily LDA FRR Generation Resource Positions, Daily LDA FRR Demand Resource Positions, and Daily LDA FRR EE Resource Positions of all resources in their FRR Capacity Plan.

After the FRR Capacity Plan submittal deadline, an LSE's Daily LDA FRR Resource Position is compared to Amount of Internal Resources Required in the LDA to determine if the LSE has satisfied the Percentage of Internal Resources Required in the LDA for the entire Delivery Year.

During the Delivery Year, an LSE's Daily LDA FRR Resource Position is compared to the Amount of Internal Resources Required in the LDA to determine if a Capacity Resource Deficiency Charge is to be assessed.

### 11.4.2 Existing Generation

Existing generation located within the PJM region or outside the PJM region is eligible to be committed to the FRR Capacity Plan if it meets the requirements set forth in Section 4 of this manual.

### 11.4.3 Planned Generation

Planned generation located within the PJM region or outside the PJM region is eligible to be committed to the FRR Capacity Plan if it meets the requirements set forth in Section 4 of this manual.

### 11.4.4 Capacity Modifications (Cap Mods)

RPM Business Rules regarding Capacity Modifications in Section 4 of this manual apply to the FRR Alternative.

CAP MODs with a start date that occurs on or before the start of the Delivery Year must be submitted and "Provisionally Approved" in the Capacity Exchange system in order for the CAP MODs to be considered in a party's Daily Generation Resource Position and the calculation of Available ICAP to commit to the FRR Capacity Plan.

If the status of a "Provisionally Approved" CAP Mod changes to "Denied" or "PJM Withdrawn" all bilateral transactions for the unit will be changed from "Approved" to "Denied". There will be no change to any party's RPM Resource Commitments; however, there may be a change to a party's FRR Capacity Commitments.

### 11.4.5 Bilateral Unit-Specific Transactions

RPM Business Rules regarding Bilateral Unit-Specific Transactions in Section 4 of this manual apply to the FRR Alternative.

Available installed capacity purchased through a bilateral unit-specific transaction that is reported via PJM's Capacity Exchange system may be committed to an FRR Capacity Plan.

All unit-specific bilateral transactions that are in the "Provisionally Approved" or "Approved" status in the Capacity Exchange system will be considered in a party's Daily Generation Resource Position and the calculation of Daily Available ICAP to commit.

The Capacity Export Charge and Credit described in Section 4: Supply Resources in the Reliability Pricing Model, under 4.6.3 Exporting a Generation Resource and in Section 9: Settlements are applicable to resources owned by FRR Entities also.

### 11.4.6 Qualified Transmission Upgrade

A Qualified Transmission Upgrade may be included in an LSE's FRR Capacity Plan. Such a transmission upgrade must be approved and assigned an incremental import capability value into the constrained LDA by the PJM Planning Department at least 45 days prior to deadline for submitting the initial FRR Capacity Plan for the Delivery Year.

An approved Qualified Transmission Upgrade may be used to reduce the Amount of Internal Capacity Required in the LDA for the FRR LSE.

The planned transmission upgrade in-service date must be on or before the start of the Delivery Year.

At a minimum, the Upgrade Customer must be in the Facilities Study phase for the proposed transmission upgrade, in order for approval to be granted and the transmission upgrade must conform to all applicable standards of the PJM Regional Transmission Expansion Planning Process.

If a Qualified Transmission Upgrade is not completed by the start of the Delivery Year, the LSE who included the upgrade as part of their FRR Capacity Plan for the Delivery Year shall provide a replacement in the form of an equivalent amount of capacity resource capability within the applicable LDA by the start of the delivery Year. If replacement capacity is not provided, a Capacity Resource Deficiency Charge may apply.

### 11.4.7 Load Management Products

A Load Management program (e.g., Firm Service Level or Guaranteed Load Drop program) is eligible to be committed as a Demand Resource (DR) to the FRR Capacity Plan, if the program meets the requirements specified in the ***Load Forecasting & Analysis Manual (M-19)*** and Section 4.3 of this manual.

In order to commit a Demand Resource to the initial FRR Capacity Plan for a Delivery Year, an FRR Entity must submit no later than 30 days prior to the initial FRR Capacity Plan submittal deadline a DR Sell Offer Plan as described in Attachment C of this Manual (i.e., a completed DR Plan template and DR Officer Certification Form). The completed DR Plan template must

clearly identify in the Summary section the Existing Nominated DR Value or Planned Nominated DR Value in ICAP MWs that the FRR Entity intends to commit to their initial FRR Capacity Plan. The FRR Entity must further classify the Existing/Planned Nominated DR Value as MWs intend to commit as Annual Capacity Performance for annual period and MWs intend to commit as Summer–Period Capacity Performance for summer period, and MWs intend to commit as part of an Aggregate Resource. Actual deadline date for the DR Plan template and DR Officer Certification is provided in the RPM Auction Schedule posted on the PJM website.

If an FRR Entity intends to commit demand resources located in a pre-identified zone/sub-zone, PJM will grant conditional approval of the total Nominated DR Value in such zone/sub-zone pending the PJM review of DR Sell Offer Plans for the Base Residual Auction for such Delivery Year.

An FRR Entity with PJM approved or conditionally approved Nominated DR Value(s) in zone/sub-zone(s) will be permitted to commit the associated Demand Resource(s) to the FRR Capacity Plan, provided credit has been posted with the PJM Treasury Department for any Planned Demand Resource(s).

If a review of the DR Sell Offer Plans for the Base Residual Auction for such Delivery Year reveals that any of the conditionally approved MWs in a pre-identified zone/sub-zone are ascribed to another CSP by a letter of support from an end-use customer, such MWs shall be uncommitted from the FRR Capacity Plan and additional capacity resources shall be committed by the FRR Entity to the FRR Capacity Plan to satisfy the FRR Entity's Preliminary Unforced Capacity Obligation.

The UCAP value of a Demand Resource committed to an FRR Capacity Plan is equal to the Nominated DR Value committed * Forecast Pool Requirement through the 2024/2025 Delivery Year, and starting with 2025/2026 Delivery Year is equal to the Nominated DR Value committed * the applicable ELCC Class Rating. The Nominated DR Values (summer, winter, or annual) for a load management program registration are determined in accordance with Section 4.3.7 of this manual and the Daily Nominated DR Value of a Demand Resource for a Delivery Year is established based on confirmed Demand Resource Registrations in "completed" status linked to such Demand Resource in DR Hub system in accordance with Sections 4.3.4 and 4.7.2 of this manual.

A resource provider who has FRR Capacity Plan Commitments for their demand resource must meet (or contract with another party to meet the requirements specified in Section 4.3.1 of this manual.

A resource provider who has FRR Capacity Plan Commitments for their demand resource will be subject to Non-Performance Assessment and Load Management Test Compliance in accordance with Section 8 of this manual.

### 11.4.8 Demand Resource Modifications (DR MODs)

RPM Business Rules for DR MODs in Section 4 of this manual apply to the FRR Alternative.

DR MODs are no longer submitted by participants. A DR Mod submitted by PJM based on FRR Entity's approved DR Sell Offer Plan must be in a "Provisionally Approved" or "Approved" status in order for the DR MOD to be considered in a party's Demand Resource Position and in the calculation of Available ICAP to commit to the FRR Capacity Plan. After the Delivery Year demand resource registration process begins in DR Hub system, the Daily Nominated DR value for a Demand Resource for a Delivery Year is established based on confirmed Demand Resource Registrations in "completed" status linked to the DR Resource in the DR Hub system in accordance with Sections 4.3.4 and 4.7.2 of this manual.

### 11.4.9 Energy Efficiency Resources

An EE Resource may commit to an FRR Capacity Plan for a maximum of up to four consecutive Delivery Years. The time period of an Energy Efficiency installation determines whether an installation is eligible to be a capacity resource for a Delivery Year. The time period of Energy Efficiency installations and their associated eligibility, in addition to the modeling of EE Resources in the PJM Capacity Market, is presented in ***PJM Manual 18B: Energy Efficiency Measurement &Verification.***

An EE Resource must meet the following minimum requirements:

- Submit Initial Measurement &Verification (M&V) Plan no later than 30 days prior to the FRR Capacity Plan submittal in which the EE Resource is initially committed
- Submit Updated M&V Plan no later than 30 days prior to next FRR Capacity Plan submittal in which EE Resource is subsequently committed
- Establish credit with PJM Credit Department prior to FRR Capacity Plan submittal (for planned EE Resources)
- Submit Energy Efficiency Resource Modification (EE MOD) in Capacity Exchange system (An EE MOD is submitted by PJM)
- Submit Initial Post-Installation M&V Report no later than 15 business days prior to first Delivery Year that the EE Resource is committed
- Submit Updated Post-Installation M&V Reports no later than business 15 days prior to each subsequent Delivery Year that the EE Resource is committed
- Permit Post- Installation M&V Audit(s) by PJM or Independent Third Party.

***PJM Manual 18B: Energy Efficiency Measurement & Verification*** establishes the requirements for the Initial M&V Plan, Updated M&V Plans, Initial Post-Installation M&V Report, Updated Post-Installation M&V Reports, and the M&V Audit.

### 11.4.10 Energy Efficiency Modifications (EE MODs)

RPM Business Rules for EE MODs in Section 4 of this manual apply to the FRR Alternative.

EE MODs submitted by PJM based on the FRR Entity's approved initial/updated M&V Plan must be in a "Provisionally Approved" or "Approved" status in order for the EE MOD to be considered in a party's EE Resource Position and in the calculation of Available ICAP to commit to the FRR Capacity Plan.

An EE MOD may be required prior to the Delivery Year to reflect the final Nominated EE Value or final Capacity Value of an EE Resource for the Delivery Year. An EE MOD decrease may result in the reduction of FRR Capacity Plan Commitments.

## 11.5 Locational Constraints in the FRR Alternative

As discussed in Section 2, locational constraints may require modeling constrained Locational Deliverability Areas (LDAs) separately. Locational Constraints are used to define the minimum Percentage of Internal Resources Required for a constrained LDA in the FRR Capacity Plan. For each LDA for which PJM is required to establish a separate Variable Resource Requirement Curve for the Delivery Year, a Percentage of Internal Resources Required for such LDA will be defined. PJM shall be deemed required to establish a separate Variable Resource Requirement Curve for an LDA if the LDA is Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), or Mid-Atlantic Region ("MAR"), or for other LDAs if separate modeling is required by Section 5.10(a)(ii)(A) or (B) of Attachment DD of the OATT.

The constrained Locational Deliverability Areas that will be modeled for a particular Delivery Year and Percentage of Internal Resources Required for such LDA (if applicable) will be posted on the PJM website by February 1 prior to the commencement of the Base Residual Auction for that Delivery Year.

An LDA has a limited import capability to import resources from outside the LDA. In RPM these imported resources are considered in clearing the auction in an LDA and the auction results would reflect the effect of the imports in reducing the LDA clearing price. Similar to RPM Entities, FRR Entities are provided the benefit of import capability by allowing them to include some resources from outside the LDA in their Capacity Plan**.** For each LDA that PJM is required to establish a separate Variable Resource Requirement Curve for the Delivery Year, the minimum Percentage of Internal Resources Required for such constrained LDA for the Delivery Year will be posted by February 1 prior to the commencement of the RPM Base Residual Auction for such Delivery Year. This Percentage of Internal Resources Required in an LDA is used to determine the Amount of Internal Resources Required (UCAP MWs) by the FRR LSE in the LDA. An approved Qualified Transmission Upgrade may be used to reduce the Amount of Internal Capacity Required in the LDA for the FRR LSE. An LSE must include enough capacity resource in its FRR Capacity Plan to satisfy the Amount of Internal Resources Required in the LDA. These capacity resources must be physically located in the LDA in which the FRR Service Area is located in order to satisfy this requirement.

The LDA Reliability Requirement is the projected internal capacity in the LDA plus the Capacity Emergency Transfer Objective (CETO) for the Delivery Year, as determined by the RTEP

process. The internal resource requirement in an LDA is the LDA Reliability Requirement less the Capacity Emergency Transfer Limit (CETL) for the Delivery Year, as determined by the RTEP process. This internal resource requirement is expressed as a percentage of the Unforced Capacity Obligation based on Preliminary LDA/Zonal Peak Load Forecast multiplied by FPR to determine the Amount of Internal Resources (UCAP MWs) Required by the FRR LSE in the LDA.

Capacity Transfer Rights (CTRs) are implicitly allocated to the FRR LSE in the determination of the Percentage of Internal Resources Required in an LDA. An FRR LSE will not be eligible for any explicit CTRs.

## 11.6 Conditions on Sales by FRR Entities

If an FRR LSE has not satisfied a Threshold Quantity, they may not offer to sell capacity in excess of the amount needed to satisfy Preliminary/Final Daily Unforced Capacity Obligation bilaterally into RPM or in RPM Auctions; however, they may offer to sell such excess capacity to an External Party (i.e., delist) or to an FRR Entity. If an FRR LSE has satisfied a Threshold Quantity, they may offer to sell capacity in excess of the amount needed to satisfy their Threshold Quantity bilaterally into RPM or in RPM Auctions up to a Sales Cap Amount. The Sales Cap and other rules related to sales by FRR Entities are shown below:

- The Sales Cap Amount is equal to the lesser of (a) 0.25 * Preliminary Unforced Capacity Obligation or (b) 1300 MW.
- If an FRR LSE has satisfied a Threshold Quantity, they may offer to sell capacity in excess of the Preliminary/Final Daily Unforced Capacity Obligation to an External Party (i.e., delist) or to another FRR Entity. In order for this type of sale to proceed, the Seller's FRR Capacity Commitments on the unit must be reduced.
- Sell offers in RPM Auctions and bilateral unit-specific transactions will be subject to offer and bilateral transaction checks to ensure that the seller does not violate any "Conditions on Sales by FRR Entities".
- A sell offer in an RPM Auction that violates any "Conditions on Sales by FRR Entities" will be rejected.

If an FRR LSE serves load under the FRR Alternative and additional load under the RPM, the LSE may self-supply capacity resources in RPM Auctions and avoid the requirement to satisfy a Threshold Quantity; however, the MW amount of their sell offer(s) may not exceed a Self-Supply Offer Cap Amount, where:

- The Self-Supply Offer Cap Amount is the lesser of (a) 0.25 * (FRR Preliminary Daily Unforced Capacity Obligation + RPM Expected UCAP Obligation) or (b) 200 MW.
- An LSE's RPM Expected UCAP Obligation in a Zone is equal to the LSE's allocation of the Zonal Weather Normalized Summer Peak for summer four years prior to the Delivery Year (i.e., an Obligation Peak Load) * (Preliminary Zonal Peak Load Forecast/Zonal Weather

Normalized Summer Peak for summer four years prior to Delivery Year) * Forecast Pool Requirement.

## 11.7 Delivery Year Activity

### 11.7.1 Final Daily Unforced Capacity Obligation

The Final Daily Unforced Capacity Obligation of an LSE in a zone equals the LSE's Final Obligation Peak Load in the zone * the Final Zonal FRR Scaling Factor * the Forecast Pool Requirement. The Forecast Pool Requirement updated for the RPM Third Incremental Auction will be used in determining the Final Daily Unforced Capacity Obligation.

The Final Daily Unforced Obligation shall be reduced by the committed Nominal PRD Value associated with such load that was approved by PJM in advance of the BRA and Third IA for such Delivery Year, multiplied by final Forecast Pool Requirement for the Delivery Year.

A reduction in the Daily Unforced Capacity Obligation is applicable in the case of annexation of service territory where the FRR load is acquired by a party that has not elected FRR alternative.

## 11.8 Deficiency Charges & Penalties

### 11.8.1 FRR Capacity Resource Deficiency Charges

An LSE participating in the FRR Capacity Plan Alternative will pay a FRR Capacity Resource Deficiency Charge in the delivery year for any shortage of resources to meet the Final Daily Unforced Capacity Obligation and the Amount of Internal Resources Required in an LDA.

A shortage/excess of resources to meet the Amount of Internal Resources Required in an LDA is calculated by comparing an LSE's Daily LDA FRR Resource Position to the Amount of Internal Resources Required in an LDA. If the Daily LDA FRR Resource Position is less than the Amount of Internal Resources Required in an LDA, a FRR Capacity Resource Deficiency Charge for this shortage will be assessed.

A shortage/excess of resources to meet the Final Daily Unforced Capacity Obligation is calculated by comparing an LSE's Daily Total FRR Resource Position to their Final Daily Unforced Capacity Obligation. If the Daily Total FRR Resource Position is less than Final Daily Unforced Capacity Obligation, a deficiency charge for this shortage less the shortage calculated for failure to satisfy the Amount of Internal Resources Required in the LDA will be assessed.

Through the 2024/2025 Delivery Year, the FRR Capacity Resource Deficiency Charge is equal to 1.2 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing such zone, weight-averaged for the Delivery Year based on the prices established and the quantities cleared in such auctions, multiplied by the shortage. The weighted average resource clearing price for the LDA will be calculated

considering all cleared MWs in RPM Auctions for the Delivery Year and such weighted average resource clearing price will apply to all shortages for the Delivery Year. Starting with the 2025/2026 Delivery Year, the FRR Capacity Resource Deficiency Charge is equal to the price level corresponding to Point (1) of the Variable Resource Requirement curve for the Locational Deliverability Area encompassing the Zone of the FRR Entity, multiplied by the shortage. FRR Capacity Resource Deficiency Charges are assessed daily and billed weekly.

### 11.8.2 Transmission Upgrade Delay

If a Qualifying Transmission Upgrade is not completed by the start of the Delivery Year and the upgrade was not replaced with an equivalent amount of Capacity Resources in the LDA into which the import capability was to be increased, then the Amount of Internal Capacity Resources Required in an LDA will be increased and the LSE may be assessed a FRR Capacity Resource Deficiency Charge.

### 11.8.3 Deleted

### 11.8.4 Generation Resource Rating Test Failure Charge

All generation resources that have FRR Capacity Plan Commitments are subject to Capacity Testing for both the Summer and Winter Periods.

RPM Business Rules regarding the Capacity Testing and Generation Resource Rating Test Failure Charges apply to the FRR Alternative.

### 11.8.5 Load Management Test Compliance

DR Resource providers are required to simultaneously test all of their non-dispatched registrations in a zone in the absence of being dispatched by PJM for an Emergency Action that triggers a Non-Performance Assessment during the Delivery Year.

Please see Section 8.7 of this manual for details on Load Management Test Compliance.

### 11.8.6 Non-Performance Charge/Bonus Performance Credit

An FRR Entity that elected to be subject to financial non-performance assessment as opposed to physical non-performance assessments will be subject to Non-Performance Assessment Charge for each resource committed to the FRR Capacity Plan or price responsive demand committed to reduce the FRR Entity's unforced capacity obligation that had a Performance Shortfall for a Performance Assessment Interval. If a resource committed to the FRR Capacity Plan or price responsive demand committed to reduce the FRR Entity's unforced capacity obligation had Bonus Performance for a Performance Assessment Interval, such resource or price responsive demand will be eligible for Bonus Performance Credits.

Please see Section 9.1.11 of this manual for details on Non-Performance Charge/Bonus Performance Credit.

### 11.8.7 Physical Non-Performance Assessment

An FRR Entity that elected to be subject to physical non-performance assessment for resources committed to the Delivery Year FRR Capacity Plan or price responsive demand committed to reduce the FRR Entity's unforced capacity obligation as opposed to financial non-performance assessment for such resources will be required to update the subsequent Delivery Year's FRR Capacity Plan and commit additional Capacity Performance Resources or Seasonal Capacity Performance Resources beyond the amount of Capacity Performance Resources required for the subsequent Delivery Year as a penalty for those resources committed to the FRR Capacity Plan that experienced Performance Shortfalls for Performance Assessment Interval during the relevant Delivery Year.

For each Performance Assessment Interval, the Actual Performance and Expected Performance of each resource contained in an FRR Entity' Capacity Plan will be determined according to the rules and formulas described in the Non-Performance Assessment section 8.4A,and for such interval, a net Performance Shortfall associated with FRR commitments [33]shall be determinedfor Capacity Performance Resources. . The net Performance Shortfall for Capacity Performance Resources shall also include the performance of Seasonal Capacity Performance Resources included in the FRR Capacity Plan and include the performance of price responsive demand committed to reduce the FRR Entity's unforced capacity obligation.

The FRR Entity's net Performance Shortfall among Capacity Performance Resources and price responsive demand , if any, for each Performance Assessment Interval shall by multiplied by a rate of 0.00139 MWs/Performance Assessment Interval [i.e., 0.5 MWs/30 PAHs/12 intervals per hour]] to establish the additional MW of Capacity Performance Resources that such FRR Entity must add to its FRR Capacity Plan for the following Delivery Year. The maximum additional MW required by the FRR Entity as a result of non-performance from the FRR Entity's Capacity Performance Resources during a Delivery Year shall not exceed 50% of the MW quantity of the Capacity Performance Resources committed in the FRR Capacity Plan for such Delivery Year and price responsive demand committed for such Delivery Year .

The additional MWs of Capacity Performance Resources required for Performance Assessment Intervals (PAIs) that occur during February through May of the Delivery Year shall be committed to the FRR Entity's FRR Capacity Plan for the remainder of the following Delivery Year by established deadlines below.

- February PAIs: by July 1 of the following Delivery Year
- March PAIs: by August 1 of the following Delivery Year
- April PAIs: by September 1 of the following Delivery Year

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[33] If a market participant has both RPM commitments and FRR commitments on a resource, the final Shortfall MW or Bonus MW on a resource will be allocated to RPM and FRR commitments on a pro-rata basis based on the amount of RPM and FRR CP commitments in unforced capacity terms.

- May PAIs: by October 1 of the following Delivery Year

## 11.9 Allocation of Deficiency Charges

The Daily FRR Capacity Resource Deficiency Charges, FRR Transmission Upgrade Delay Penalties, Generation Resource Rating Test Failure Charges, and Load Management Test Failure Charges are distributed on a pro-rata basis to the LSEs in the RTO that were charged an RPM Locational Reliability Charge.

Daily Capacity Resource Deficiency Charges, Transmission Upgrade Delay Penalties, Generation Resource Rating Test Failure Charges, and Load Management Test Failure Charges are allocated on a pro-rata basis to RPM LSEs based on their daily unforced capacity obligation.

## 11.10 Auction Specific MW Transactions

LSEs that elect the FRR Alternative may report Auction Specific MW Transactions if they have cleared capacity in RPM Auctions through the Capacity Exchange system.

The MWs associated with approved Auction Specific MW Transactions do not contribute to the Sales Cap Amount for RPM Auctions described in the FRR Business Rules.

# Attachment A: Glossary of Terms

Welcome to the *Glossary of Terms* section of the ***PJM Manual for the Capacity Market***. In this section, you will find the following information:

**Adjusted Zonal Capacity Prices** – are determined based on the results of RPM Incremental Auctions. Preliminary Zonal Capacity Prices that result from the Base Residual Auction are adjusted to account for the procurement in the RPM Incremental Auctions.

**Accredited UCAP** is defined in the RAA as the quantity of Unforced Capacity, as denominated in Effective UCAP, that an ELCC Resource is capable of providing in a given Delivery Year.

**Auction Specific MW Transactions** – are transactions reported to PJM via Capacity Exchange between a buyer and seller that report the transfer of physical MW between the buyer and seller using the Capacity Exchange system and PJM settlement process. Auction Specific MW Transactions are not eligible to be offered in an RPM auction. Auction Specific MW Transactions are settled at the weighted average Resource Clearing Price of the MW supplying the transaction.

**Available Transfer Capability** (ATC) – is the amount of energy above "base case" conditions that can be transferred reliably from one area to another over all transmission facilities without violating any pre- or post-contingency criteria for the facilities in the PJM Control Area under specified system conditions.

**Base LDA Unforced Capacity Obligation** – is equal to the sum of the Base Zonal Unforced Capacity Obligations for all the zones in an LDA and is the result of the clearing of the Base Residual Auction.

**Base Residual Auction (BRA)** – allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the LSEs through the Locational Reliability Charge.

**Base RTO Unforced Capacity Obligation** – determined after the clearing of the BRA and is posted with the BRA results. The Base RTO Unforced Capacity Obligation is equal to the sum of the unforced capacity obligation satisfied through the BRA.

**Base Unforced Capacity Imported into an LDA** – is equal to the Base LDA Unforced Capacity Obligation less the LDAs Unforced Capacity cleared in the Base Residual Auction. This value is used to determine the maximum total amount of Capacity Transfer Rights that are allocated into an LDA in the Base Residual Auction for the Delivery Year.

**Base Zonal RPM Scaling Factor** – is determined for each zone and is equal to the [(Preliminary Zonal Peak Load Forecast for the Delivery Year divided by the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Years) * ((RTO

Unforced Capacity Obligation Satisfied in Base Residual Auction divided by the (RTO Preliminary Peak Load Forecast * the Forecast Pool Requirement))]. Base Zonal RPM Scaling Factors are posted with the Base Residual Auction results.

**Base Zonal Unforced Capacity Obligation** – determined for each zone and is equal to the (Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year* Base Zonal RPM Scaling Factor * the Forecast Pool Requirement). Base Zonal Unforced Capacity Obligations are posted with the Base Residual Auction clearing results.

**Behind the Meter Generation** – a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of Interconnection. Behind the Meter Generation may not include at any time any portion of a generating unit's capacity that is designated as a Capacity Resource or any portion of the output of a generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market at any time.

**Bilateral Market** – provides LSEs the opportunity to hedge the Locational Reliability Charge determined through the RPM Auctions by purchasing available capacity in the bilateral market to offer into an RPM Auction. The bilateral market also provides resource providers an opportunity to cover any auction commitment shortages.

**Bilateral Unit-Specific Transaction** – transaction that enables reporting of the transfer of ownership of a specified amount of installed capacity from a specific unit from one party to another.

**Capacity Modification (Cap Mod)** – transaction that enables generation owners to request the addition of a new unit or the removal of an existing unit from their resource portfolio in Capacity Exchange, or to request an MW increase or decrease in the summer or winter installed capacity rating of an existing unit.

**Capacity Resources** – includes megawatts of (i) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources meeting the requirements of Schedules 9 and 10 of the RAA that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under the RAA, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in Schedules 9 and 10 of the RAA; and (iii) load reduction capability provided by Demand Resources or Energy Efficiency Resources that are accredited to the PJM Region pursuant to the procedures set forth in Schedule 6 of the RAA.

**Capacity Resource with State Subsidy** – (1) a Capacity Resource that is offered into an RPM Auction or otherwise assumes an RPM commitment for which the Capacity Market Seller

receives or is entitled to receive one or more State Subsidies for the applicable Delivery Year; (2) a Capacity Resource that has not cleared an RPM Auction for the Delivery Year for which the Capacity Market Seller last received a State Subsidy (or any subsequent Delivery Year) shall still be considered a Capacity Resource with State Subsidy upon the expiration of such State Subsidy until the resource clears an RPM Auction; (3) a Capacity Resource that is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) shall be deemed a Capacity Resource with State Subsidy to the extent an owner of the facility supporting the Capacity Resource is entitled to a State Subsidy associated with such facility even if the Capacity Market Seller is not entitled to a State Subsidy; and (4) any Jointly Owned Cross-Subsidized Capacity Resource.

**Capacity Emergency Transfer Limit (CETL)** – the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

**Capacity Emergency Transfer Objective (CETO)** – the amount of electric energy that a given area must be able to import in order to satisfy the locational reliability criteria established in the RAA, M20, and M20A.

**Capacity Only Option** - participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Attachment DD of the Tariff and as applicable, a capacity payment for load reductions during a pre-emergency or emergency event.

**Capacity Transfer Rights (CTR)** – rights used to allocate the economic value of transmission import capability that exists into a constrained LDA. Serve to offset a portion of the Locational Price Adder charged to load in constrained LDAs.

**Combination Resource** is defined in the RAA as a Generation Capacity Resource that has a component that has the characteristics of a Limited Duration Resource combined with (i) a component that has the characteristics of an Unlimited Resource or (ii) a component that has the characteristics of a Variable Resource.

**Control Area** – electric power system or combination of electric power systems bounded by interconnection metering and telemetering to which a common generation control scheme is applied in order to:

- Match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s) with the load within the electric power system(s)
- Maintain scheduled interchange with other Control Areas
- Maintain the frequency of the electric power system(s)
- Maintain power flows on transmission facilities within appropriate limits to preserve reliability
- Provide sufficient generating capacity to maintain operating reserves.

**Cost of New Entry (CONE)** – Levelized annual cost in ICAP $/MW-Day of a reference combustion turbine to be built in a specific location.

**CTR Settlement Rate** – The CTR Settlement Rate ($/MW-day) is equal to the Economic Value of CTRs allocated to LSEs in a zone as a result of the Base Residual Auction and RPM Incremental Auctions divided by the Total CTR MWs allocated to LSEs in the zone.

**Daily Unforced Capacity Obligation** - equals the LSE's Obligation Peak Load in the zone/area * the Final Zonal RPM Scaling Factor * the Forecast Pool Requirement for an LSE in a zone/ area.

**Daily Capacity Resource Deficiency Charge** – assessed to party when the Daily RPM Resource Position of its resource is less than the Daily RPM Resource Commitment for such resource on a delivery day. This charge is applicable to generation resource, Demand Resource, Energy Efficiency Resource, Aggregate Resource or Qualified Transmission Upgrade committed to RPM.

**Delivery Year** – Planning period for which resources are being committed and for which a constant load obligation for the entire PJM region exists. For example, the 2012/2013 Delivery Year corresponds to the June 1, 2012 – May 31, 2013 Planning Period.

**Demand Resource** – an Annual Demand Resource or Summer-Period Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of RAA, Schedule 6. A Demand Resource may be an existing or planned resource.

**Demand Resource Modification (DR Mods)** – transaction submitted by PJM to track an increase or decrease of the nominated value of the Demand Resource in a party's resource portfolio in Capacity Exchange.

**Demand Resource Registration -** a registration in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Resource Program in accordance with OATT, Attachment K-Appendix, Section 8. A Demand Resource Registration is linked to a Demand Resource.

**Effective UCAP** is defined in the RAA as a unit of measure that represents the capacity product transacted in the Reliability Pricing Model and included in FRR Capacity Plans. One megawatt of Effective UCAP has the same capacity value of one megawatt of Unforced Capacity.

**ELCC Resource** is defined in the RAA as a Generation Capacity Resource that is a Variable Resource, a Limited Duration Resource, or a Combination Resource (through the 2024/2025 Delivery Year). Effective with the 2025/2026 Delivery Year, an ELCC Resource is a Generation Capacity Resource or a Demand Resource.

**Electric Cooperative** – an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

**Electric Distribution Company (EDC)** – PJM Member that owns or leases with rights equivalent to ownership electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Control Area.

**Emergency** – an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scare fuel; or a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

**End Use Customer** – a member that is a retail end-user of electricity within the PJM region.

**Equivalent Demand Forced Outage Rate** (EFORd) – is a measure of the probability that generating unit will not be available due to a forced outages or forced deratings when there is a demand on the unit to generate. See Generator Resource Performance Indices Manual (M-22) for equation.

**Equivalent Demand Forced Outage Rate (EFORd-5)** (Prior to the 2025/2026 Delivery Year)– is EFORd determined based on five years of outage data through September 30 prior to the Delivery Year. This is an index similar to EFORd that is the basis for a unit's UCAP value for the Delivery Year, and it includes the events that are outside management control (OMC events).The index is calculated using Generator Availability Data System (GADS) data in PJM. If a generating unit does not have a full 5 years of history, the EFORd-5 will be calculated using class average EFORd and the available history as described in Reliability Assurance Agreement, Schedule 5, Section C. The class average EFORd will be used for a new generating unit. The class average EFORds that are used by PJM to calculate a unit's EFORd-5 are posted to the PJM website by November 30 prior to the Delivery Year.

**Effective EFORd** (Prior to the 2025/2026 Delivery Year)– the most recently calculated EFORd that has been bridged to the Capacity Exchange system. During the Delivery Year, the Effective EFORd is based on forced outage data from the October through September period prior to the Delivery Year. This is the basis for a unit's UCAP value, and it includes the events that are outside management control (OMC events..

**FERC** – Federal Energy Regulatory Commission or any successor federal agency, commission or department.

**Final RTO Unforced Capacity Obligation –**The Final RTO Unforced Capacity Obligation is equal to the RTO unforced capacity obligations satisfied through all RPM Auctions for the Delivery Year. The RTO unforced capacity obligation through all RPM Auctions is equal to the

total MWs cleared in PJM Buy Bids in RPM Auctions less the total MWs cleared in PJM Sell Offers in RPM Auctions.

**Final Zonal Capacity Prices** – are the capacity prices assessed to RPM Load Serving Entities through the RPM Locational Reliability Charge. The Final Zonal Capacity Prices are determined by PJM after the Third Incremental Auction. Final Zonal Capacity Prices reflect the final price adjustments that may be necessary to account for any granted requests for relief from Capacity Resource Deficiency Charges due to permanent departure of load or to account for Non-Viable MWs for any transition provisions that are in effect for the Delivery Year.

**Final Zonal RPM Scaling Factors** – used in determining an LSE's Daily Unforced Capacity Obligation. A Final Zonal RPM Scaling Factor for a zone is equal to the Final Zonal Unforced Capacity Obligation divided by (FPR times the Zonal Weather Normalized Peak for the summer prior to the Delivery Year). The Final Zonal RPM Scaling Factors are posted with the results of the final Incremental Auction.

**Final Zonal Unforced Capacity Obligation** – The Final Zonal Unforced Capacity Obligation is equal to the zonal allocation of the Final RTO Unforced Capacity Obligation and is allocated to the zones on a pro-rata basis based on the Final Zonal Peak Load Forecasts. The Final Zonal UCAP Obligations are determined after the clearing of the final Incremental Auction for the Delivery Year.

**Firm Transmission Service** – transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

**Fixed Resource Requirement (FRR)** – an alternative method for a Party to satisfy its obligation to provide Unforced Capacity. Allows an LSE to avoid direct participation in the RPM Auctions by meeting their fixed capacity resource requirement using internally owned capacity resources.

**Flexible Self-Scheduled Resources –** are resources specified by an LSE in the Base Residual Auction to provide a mechanism to manage quantity uncertainty related to the Variable Resource Requirement. For each resource-specific sell offer, the LSE must designate a flexible self-scheduling flag as well as an offer price that will be utilized in the market clearing in the event the resource is not needed to cover a specified percentage of the LSE's capacity obligation. Flexible self-scheduled resources will automatically clear the auction if they are needed to supply the LSE's resulting capacity obligation.

**Forecast Pool Requirement (FPR)** – the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region.

**FRR Capacity Plan** – a long-term plan for the commitment of Capacity Resources to satisfy the capacity obligations of a Party that has elected the FRR alternative.

**FRR Service Area** – the service territory of an IOU as recognized by state law, rule, or order; the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or a separately identifiable geographic area that is bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to and regularly reported to the Office of Interconnection or an EDC who agrees to aggregate the meters' load data for the FRR Service Area and regularly report the information to the Office of Interconnection or for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within the area excluding the load of Single-Customer LSEs that are FRR Entities. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Areas is defined as all customers physically connected to transmission or distribution facilities of the Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

**Full Requirements Service** – wholesale service to supply all of the power needs of a LSE to serve end-users within the PJM Region that are not satisfied by its own generation facilities.

**Full Program Option -** participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Attachment DD of the Tariff and as applicable, (i) an energy payment for load reductions during a pre-emergency or emergency event, and (ii) a capacity payment for load reductions during a pre-emergency or emergency event.

**Generation Capacity Resource** – A Generating Facility, or the contractual right to capacity from a specified Generating Facility, that meets the requirements of RAA, Schedule 9 and RAA, Schedule 10, and, for Generating Facilities that are committed to an FRR Capacity Plan, that meets the requirements of RAA, Schedule 8.1. A Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity Resource.

**Generation Owner** – a Member that owns or leases with rights equivalent to ownership facilities for the generation of electric energy that are located within the PJM Region. Purchasing all or a portion of the output of a generation facility is not sufficient to qualify a Member as a Generation Owner.

**Generator Forced Outage** – an immediate reduction in output or capacity or removal from service of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions does not constitute a Generator Forced Outage.

**Generation Interconnection Agreement** – an agreement among the Transmission Provider, a Project Developer, and applicable to a Generation Interconnection Request or Transmission Interconnect Request.

**Generator Maintenance Outage** – the scheduled removal from service of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage.

**Generator Planned Outage** – the scheduled removal from service of a generating unit for inspection, maintenance or repair with the approval of the office of the Interconnection.

**Incremental Auctions** – Allow for an incremental procurement/release of resource commitments to satisfy an increase/decrease in the RTO/LDA Reliability Requirements through PJM Buy Bids/Sell Offers. Allows a resource provider to submit a Sell Offer to procure replacement capacity to cover commitment shortfalls due to a generation resource cancellation, delay, derating, EFORd increase, Accredited UCAP Factor decrease, or decrease in the unforced capacity value of a Demand Resource or Energy Efficiency Resource.

**Incremental Capacity Transfer Rights** – allocated to transmission expansion projects associated with new generation interconnection that were required to meet PJM Deliverability requirements and to Merchant Transmission Expansion projects and are applicable to all such projects that have gone through the PJM interconnection process since the beginning of the PJM RTEPP in 1999. Such incremental Capacity Transfer Rights allocation is based on the incremental increase in import capability across a Locational Constraint that is caused by the transmission facility upgrade. Incremental capacity transfer rights associated with Incremental Rights-Eligible Required Transmission Enhancements are allocated. Incremental Rights-Eligible Required Transmission Enhancements may include Regional Facilities and Necessary Lower Voltage Facilities, and Lower Voltage Facilities.

**Installed Capacity (ICAP)** – value determined in accordance with PJM's Rules and Procedures of the Determination of Generating Capacity in M21, M21A, and M21B. For an ELCC Resource through the 2024/2025 Delivery Year, the term "ICAP" in this manual refers to the lesser of the Accredited UCAP or the resource's CIRs plus any awarded transitional MWs.

**Installed Reserve Margin (IRM)** – used to establish the level of installed capacity resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. The IRM is determined by PJM in accordance with the PJM Resource Adequacy Analysis Manual (M-20) and (M-20A). The IRM is approved and posted prior to its use in an RPM Auction for the Delivery Year.

**Investor Owned Utility** (IOU) – an entity with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

**Jointly Owned Cross-Subsidized Capacity Resource –** a Capacity Resource that is supported by a facility that is jointly owned, where at least one owner is entitled to or receives a State Subsidy associated with such Capacity Resource, and therefore shall be considered a Capacity Resource with State Subsidy; provided however, in the event that the material rights and obligations of such generating facility are in pari passu, meaning that such rights and

obligations are allocated among the owners pro rata based on ownership share, only Capacity Resources of those owners entitled to receive or receiving a State Subsidy shall have their share of such resource considered a Capacity Resource with a State Subsidy and Capacity Resources of owners not entitled to a State Subsidy shall not be considered a Capacity Resource with a State Subsidy. Each of these designations may be overcome by either Capacity Market Seller demonstrating to the Office of Interconnection, with advice and input from the Market Monitoring Unit, that there is no cross-subsidization or the Office of the Interconnection, with review and input from the Market Monitor, finds based on sufficient evidence, that there is cross-subsidization.

**Limited Duration Resource** is defined in the RAA as a Generation Capacity Resource that is not a Variable Resource, that is not a Combination Resource, and that is not capable of running continuously at Maximum Facility Output for 24 hours or longer. A Capacity Storage Resource is a Limited Duration Resource.

**Load Management** – is the ability to reduce metered load, either manually or automatically, by the customer, after a request from the resource provider which holds the Load management rights or its agent.

**Load Serving Entity (LSE)** – any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer that (a) serves end-users within the PJM Control Area, and (b) is granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Control Area.

**Locational Constraints** – localized capacity import capability limitations that are caused by transmission facility limitations, voltage limitations or stability limitations that are identified for a Delivery Year in the PJM Regional Transmission Expansion Planning Process (RTEPP) prior to each Base Residual Auction. Such Locational Constraints are included in the RPM to recognize and to quantify the locational value of capacity.

**Locational Deliverability Area (LDA)** – sub-regions used to evaluate locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

**Locational Price Adder** – an addition to the marginal value of unforced capacity within an LDA as necessary to reflect the price of resources required to relieve the applicable binding locational constraints.

**Locational Reliability Charge** – Fee applied to each LSE that serves load in PJM during the delivery year. Equal to the LSEs Daily Unforced Capacity Obligation multiplied by the applicable Final Zonal Capacity Price.

**Nested LDAs** – when an aggregate of Zones, a Zone and its sub-zones are constrained LDAs, the LDAs are referred to as “Nested”. When LDAs are nested, the Zonal CTR calculations include allocation of CTRs from RTO to aggregate of Zones as well as CTRs from aggregate of Zones to the Zone.

**Net Energy & Ancillary Services (E&AS) Offset** – is used to offset the value of Cost of New Entry (CONE) to determine the net value of CONE. This value is calculated using the historical averages of energy revenue data for a reference combustion turbine and an assumed value for ancillary services revenues as set forth in OATT. The energy revenues are calculated using a historical average of the three most recent calendar years preceding the Base Residual Auction.

**New Entry Pricing** – is an incentive provided to a Planned Generation Resource where the size of the new entry is significant relative to the size of the LDA and there is a potential for the clearing price to drop when all offer prices including that of the new entry are capped. This allows Planned Generation Resources to recover the amount of its cost of entry-based offer for up to two additional consecutive years, under certain conditions, and to set the clearing price of all resources within that LDA for all three years.

**New Service Request** – Interconnection Request.

**Nominated DR Value** – the nominated value of a Demand Resource is the value of the maximum load reduction and the process to determine this value is consistent with the process for the determination of the capacity obligation for the customer. Tthe maximum load reduction for Capacity Performance registration also takes into consideration the Winter Peak Load for the customer. The maximum load reduction for each resource is adjusted to include system losses.

**Non-Retail Behind the Meter Generation** – Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

**Non-Zone Load** – the load that is located outside of the PJM Region served by a PJM Load Serving Entity using PJM internal resources. Non-Zone Load is included in the load of the Zone from which the load is served.

**Obligation Peak Load** – the summation of the weather normalized coincident summer peaks for the previous summer of the end-users for which the Party was responsible on that billing day.

**Office of the Interconnection** – the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM board.

**Partial Requirements Service** – wholesale service to supply a specified portion, but not all, of the power needs of a LSE to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

**Percentage Internal Resources Required** – for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in that LDA.

**Planned Demand Resource** – a Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing a reduction or control on or before the start of the Delivery Year for which the resource is to be committed.

**Planned Generation Capacity Resource** – a Generation Capacity Resource participating in the generation interconnection process for which Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which the resource is to be committed. At a minimum, planned generation resources greater than 20 MW must be in the Phase III System Impact Study and planned generation resources less than or equal to 20 MW must be in the Phase II System Impact Study for the unit to participate in the Base Residual Auction. Generation Interconnection Agreement (GIA) or Wholesale Market Participant Agreement (WMPA) must be executed prior to any Incremental Auctions for the corresponding Delivery Year.

**Planning Year** – Annual period from June 1 to May 31 (also may be referred to as Planning Period).

**Pool-Wide Average EFORd** (Prior to the 2025/2026 Delivery Year)– average of the forced outage rates, weighted for unit capability and expected time in service, attributable to all units that are planned to be in service during the delivery year. Determined by PJM and is approved and posted by February 1 prior to its use in the Base Residual Auction for the Delivery Year. OMC events are considered in the EFORd values used to calculate Pool-Wide Average EFORd.

**Public Power Entity** – any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the above, that is engaged in the generation, transmission, and/or distribution of electric energy.

**Qualifying Transmission Upgrade (QTU)** – a proposed enhancement or addition to the Transmission System that will increase the Capacity Emergency Transfer Limit (CETL) into an LDA by a megawatt quantity certified by PJM. A Qualified Transmission Upgrade is scheduled to be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction. Prior to the conduct of the Base Residual Auction for such Delivery Year, at a minimum the Upgrade Customer must be in the Facilities Study phase for their proposed transmission upgrade.

**Regional Transmission Expansion Planning Process (RTEPP)** – is PJM's comprehensive annual process that examines the three interrelated components of electric power system reliability: load, generation, and transmission. The RTEP Process employs a range of planning study tools and methodologies to analyze and assess each component to ensure that reliability remains firm. The RTEP Process is designed to meet established reliability criteria, keep markets robust and competitive, and ensure stable operations.

**Regional Transmission Owner (RTO)** – Each entity that owns, leases, or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate

commerce or that provides Transmission that is a party to the PJM Transmission Owners Agreement and PJM Operating Agreement

**Reliability Pricing Model (RPM)** – is PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM adds stability and a locational nature to the pricing signal for capacity.

**Resource Clearing Price** – is the clearing price in the Base Residual Auction or Incremental Auctions as determined by optimization algorithm for each auction. The Resource Clearing Price within an LDA is equal to the sum of (1) the marginal value of system capacity; and (2) the Locational Price Adder, if any, for the LDA. The Resource Clearing Price for Capacity Performance Resources in the Unconstrained Market Area is the marginal value of system capacity. PJM posts the Resource Clearing Prices for all resources that clear in the Base Residual Auction and all Buy Bids and Sell Offers that clear in the Incremental Auctions.

**RPM Resource Commitment** – MWs committed from a Capacity Resource to RPM as a result of such Capacity Resource clearing or receiving make-whole MWs in a Delivery Year RPM Auction(s), being specified as a replacement resource in a Replacement Capacity transaction(s), or being specified as the source of a Locational UCAP transaction(s).

**RTO Unforced Capacity Obligation** – established in the BRA and is used to determine the Base Zonal RPM Scaling Factors to use in determining Base Zonal Unforced Capacity Obligation.

**RTO Weather Normalized Summer Peak** – the sum of the Zonal Weather Normalized Summer Coincident Peaks.

**Self-Scheduled Resources** – are resources specified by a resource provider in the Base Residual Auction to provide a mechanism to guarantee that the resource will clear in the Base Residual Auction. For each resource-specific sell offer, if a resource is designated as self-scheduled by the resource provider, the minimum and maximum MW amounts specified must be equal and the sell offer price will be set to zero. Self-Scheduled resources will be cleared first in the Base Residual Auction, and cannot set the clearing price as the marginal resource, since these resources lack flexibility.

**State Subsidy –** a direct or indirect payment, concession, rebate, subsidy, nonbypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that (1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or (2) will support the construction, development, or operation of a new or existing Capacity Resource; or (3) could have the effect of allowing the unit to clear in any PJM capacity auction. Notwithstanding the foregoing, State

Subsidy shall not include (a) payments, concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area or designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any revenues from the sale or allocation, either direct or indirect, to an Entity Providing Supply Services to Default Retail Service Provider where such entity's obligations was awarded through a state default procurement auction that was subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a non-discriminatory and competitive bidding process, subject to the below condition, and provided further that nothing herein would exempt a Capacity Resource that would otherwise be subject to the minimum offer price rule pursuant to this Tariff; (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm's length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction, development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

(i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);

(ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and

(iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

**Steady State Period** – period of time where the auction schedule follows the proposed three year forward planning dates. The steady-state condition of RPM begins with the 2011/12 Delivery Year.

**Transmission Facilities** – facilities within the PJM Region that have been approved by or meet the definition of transmission facilities established by FERC; or have been demonstrated to the satisfaction of the Office of Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

**Transmission Owner** – a Member that owns or leases, with rights equivalent to ownership, Transmission Facilities. Taking transmission service is not sufficient to qualify a Member as a Transmission Owner.

**Unforced Capacity (UCAP)** – prior to the 2025/2026 delivery year, the installed capacity rated at summer conditions that are not on average experiencing a forced outage or forced derating, calculated for each generation Capacity Resource based on EFORd data for the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit. For an ELCC Resource, the UCAP is the Accredited UCAP of the unit, not to exceed its Capacity Interconnection Rights plus any awarded transitional resource MWs. Effective with the 2025/2026 Delivery Year, for an ELCC Resource that is a Generation Capacity Resource, the UCAP is the Accredited UCAP of the unit, not to exceed its Capacity Interconnection Rights plus any awarded transitional resource MWs.

**Unlimited Resource** is defined in the RAA as a generating unit having the ability to maintain output at a stated capability continuously on a daily basis without interruption. Through the 2024/2025 Delivery Year, an Unlimited Resource is a Generation Capacity Resource that is not an ELCC Resource.

**Variable Resource** is defined in the RAA as a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power without storage, and landfill gas units without an alternate fuel source. All Intermittent Resources are Variable Resources, with the exception of Hydropower with Non-Pumped Storage.

**Variable Resource Requirement Curve (VRR)** – defines the maximum price for a given level of Capacity Resource commitment relative to the applicable reliability requirement. VRR Curves are defined for the PJM Region and each of the constrained LDAs within the PJM region.

**Weighted Average Resource Clearing Price** – the average of the segment-specific Resource Clearing Prices that result in all the auctions for a party's specific Capacity Resource, weighted

by the segment-specific Unforced Capacity cleared for that particular resource. This value is used to determine a party's Daily Deficiency Rate for an individual resource.

**Zonal Capacity Price** – the price of UCAP in a Zone that an LSE that has not elected the FRR Alternative is obligated to pay for a Delivery Year. Zonal capacity prices are calculated as a result of the clearing of all RPM Auctions for the Delivery Year. A zonal capacity price consists of the following price components: (1) the marginal value of system capacity for the PJM Region; (2) the Locational Price Adder, if any, for such zones in a constrained Locational Deliverability Area (LDA); and (3) an adjustment in the Zone, if required, to account for any resource make-whole payments. *Preliminary Zonal Capacity Prices* are the result of the clearing of the Base Residual Auction. *Adjusted Zonal Capacity Prices* are the result of the clearing of the Base Residual Auction and any Incremental Auction(s). *Final Zonal Capacity Prices* are determined after the Final Incremental Auction for the Delivery Year.

**Zonal CTR Credit Rate (Base and Final)** – the rate calculated as a ratio of economic value of CTRs to zonal unforced capacity obligation. These rates are calculated as the Base Zonal CTR Credit Rate after the Base Residual Auction and as the Final CTR Credit Rate adjusted for the results of all RPM Auctions. Zonal CTR Credit Rate is subtracted from Zonal Capacity Price to estimate Net Load Price.

**Zonal CTR Settlement Rate** – a rate calculated as a ratio of economic value of CTRs to total CTRs allocated to LSEs in a zone. This rate is used to settle CTRs by calculating credit for CTRs owned.

**Zone** – an area within the PJM Region or such areas that may be combined as a result of mergers and acquisitions; or added as a result of the expansion of the boundaries of the PJM Region. A Zone will include any Non-Zone Network Load located outside the PJM Region that is served from inside a particular Zone.

# Attachment B: Authorization to Self-Schedule Capacity

**Authorization to Self-Schedule Capacity**

This Authorization to Self-Schedule Capacity ("Authorization") of _____ ("Owner"), effective this ___ day of ____, 20___, hereby authorizes PJM Interconnection, L.L.C. ("PJM") to self-schedule on its behalf as ("Product type"), the capacity associated with a specific generating unit _____ ("Unit"), which it will own or control for a portion of the delivery year from June 1 to May 31, 20___ to 20___ ("Delivery Year"), with the following other party or parties owning or controlling the Unit for the balance of such delivery year (if known): _____ ("Other Owners"). Owner states that it will own or control the Unit during the period(s) within the Delivery Year from ___/___/___ to ___/___/___ and any additional periods listed hereafter: _____.

**Recitals:**

WHEREAS, PJM Interconnection, L.L.C. ("PJM") is a Regional Transmission Organization ("RTO") that administers the Reliability Pricing Model ("RPM"), a centralized market for obtaining the electric capacity resources necessary to ensure resource adequacy in its control area;

WHEREAS, a capacity resource must remain available for the entire delivery year in order to be eligible to offer its capacity in RPM auctions;

WHEREAS, an owner may seek to sell capacity in an RPM auction associated with a generating unit that such owner owns or controls for only a portion of the delivery year as result of a transaction specific to such unit commencing or terminating within a delivery year;

WHEREAS, PJM, in order to facilitate participation in its auctions of all capacity resources potentially available, permits owners collectively to authorize PJM to self-schedule the Unit on their behalf capacity owned or controlled by such owner for a portion of the delivery year,

**Authorization**

NOW, THEREFORE, Owner authorizes PJM to self-schedule its Unit during the years during which it will own or control the Unit for only a portion of the identified delivery year(s), and

acknowledges that it understands and accepts the following terms and conditions of this authorization:

1. Each Owner and Other Owner (i) must submit to the PJM-designated electronic mail address a fully prepared and executed Authorization from the Owner and each Other Owner at least 5 business days prior to the opening of the bidding window of an RPM auction and (ii) must submit as the "seller" into the Capacity Exchange electronic interface system a new unit-specific transaction(s) indicating "Self Scheduling Coordinator (SELFSC)" as the "buyer" prior to the opening of the auction bidding window. Owner understands that failure of any Other Owner to satisfy both of these requirements shall preclude a Unit from participation in an RPM auction even where Owner otherwise has otherwise fully complied.
2. Because PJM will use the Unit's current Accredited UCAP Factor in the self-schedule, Owner recognizes that, consequently, the Unit's unforced capacity value may change between the time the Unit is offered into the RPM Auction and the delivery year for which the Unit was self-scheduled.
3. Because PJM will self-schedule the Unit, Owner recognizes that the Unit's offer will always clear an auction and that Owner must accept the applicable clearing price.
4. PJM automatically will transfer to Owner (and each Other Owner) the cleared capacity of the Unit for the portion of the Delivery Year during which it owns or controls the Unit, and that, as the "buyer" in this unit specific transaction, the Owner will for the duration of this period be responsible for any Capacity Resources Deficiency Charges and Non-Performance Assessment Charges that may be assessed (including those resulting from a reduced Accredited UCAP), and, for the duration of the delivery year, its proportional share of any Generation Test Resource Rating Test Failure Charges, or that may be assessed under RPM rules.

The undersigned, having been granted Capacity Exchange Read/Write Access by Owner and duly authorized to act on Owner's behalf, declares to PJM the authority described here above and intends that PJM may rely upon such declaration even to Owner's detriment.

Signed this ____th day of _____, 20____

_____

Signed by:_____Title:_____

# Attachment C: Demand Resource Sell Offer Plan

The Demand Resource Sell Offer Plan (DR Sell Offer Plan) is a PJM template document, requiring the information set forth below, together with an accompanying signed PJM Demand Resource Officer Certification Form (DR Officer Certification Form). A completed DR Sell Offer Plan (including a signed DR Officer Certification Form) must be submitted to PJM no later than 15 business days prior to the relevant RPM Auction by Curtailment Service Providers (CSPs) that intend to offer Demand Resources (DR) in RPM Auctions. The DR Sell Offer Plan must provide information that supports the CSP's intended DR Sell Offers and demonstrates that the DR is being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource Registrations for the relevant Delivery Year.

The DR Sell Offer Plan encompasses both existing DR and Planned DR. Existing DR is identified as end-use customer sites that the CSP has under contract for the current Delivery Year (i.e. end-use customer sites registered in the PJM DR Hub system for the current Delivery Year)[34] and that the CSP intends to have under contract for the auction Delivery Year. Planned DR is that quantity of the CSP's intended total DR Sell Offer in excess of the CSP's existing DR and is subject to an RPM Credit Requirement. The CSP shall not include Critical Natural Gas Infrastructure in their Plan.

Both the signed DR Officer Certification Form and the completed DR Sell Offer template must be submitted to PJM via email to rpm_hotline@pjm.com no later than 15 business days prior to the relevant RPM auction. PJM will review the DR Sell Offer Plan and notify the CSP via email no later than 10 business days prior to the RPM Auction if another CSP has identified the same end-use customer site(s) in their DR Sell Offer Plan and request supporting documentation, such as a letter of support from the end-use customer indicating that the end-use customer and CSP are likely to execute a contract for the auction Delivery Year. Supporting documentation must be submitted via email to the rpm_hotline@pjm.com no later than 7 business days prior to the RPM Auction. PJM will notify all CSPs via the Capacity Exchange system of the approved DR MW quantity by zone/sub-zone that the CSP is permitted to offer into the RPM Auction no later than 5 business days prior to the RPM Auction.

**I. PJM Demand Resource Officer Certification Form**

[34] For a Base Residual Auction and a Third Incremental Auction, end-use customer sites registered in the PJM DR Hub system for the subsequent Delivery Year may also be considered as existing DR provided the Demand Resource Registrations are in "Confirmed" status by specified deadlines established by PJM and communicated to CSPs in advance of the DR Sell Offer Plan submittal deadline.

A DR Officer Certification Form is located in Attachment D of Manual 18 and is posted on the PJM web site. A signed DR Officer Certification Form must accompany the DR Sell Offer Plan. The DR Officer Certification Form specifies that the signing officer has reviewed the DR Sell Offer Plan, that the information provided therein is true and correct, and that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource Registrations for the relevant Delivery Year.

**II. DR Sell Offer Plan Template**

A DR Sell Offer Plan template (in Excel format) is provided on the PJM web site, and consists of the following three sections:

A. DR Sell Offer Plan Summary

B. Planned DR Details

C. Schedule

**A. DR Sell Offer Plan Summary**

The DR Sell Offer Plan requires the following information to be provided:

- Company name
- Contact information (name, phone number and email address of submitter)
- Existing Nominated DR Value in ICAP MWs by zone/subzone that CSP intends to offer
- Planned Nominated DR Value in ICAP MWs by zone/subzone that CSP intends to offer

Existing DR is identified by the CSP as end-use customer sites that the CSP has under contract and registered in the PJM eLRS/DR Hub System for the current Delivery Year and that the CSP also intends to have under contract for the auction Delivery Year. Planned DR is identified by the CSP as described in the Planned DR Details section of the DR Sell Offer Plan template. Based on the information provided above, a total Nominated DR Value in MWs will be calculated for each zone/sub-zone as the addition of the Nominated DR Value of existing DR plus the Nominated DR Value of Planned DR. The total Nominated DR Value represents the maximum MW amount that the CSP intends to offer for the zone/sub-zone. Effective with the 2020/2021 Delivery Year, a CSP must apportion the total Nominated DR Value for the zone/sub-zone into the quantity that the CSP intends to offer into the auction as Annual Capacity Performance , the quantity that the CSP intends to offer into the auction as Summer-Period Capacity Performance, and the quantity that the CSP intends to offer into the auction as part of an Aggregate Resource, such that, the sum of such quantities must equal the total Nominated DR Value The actual MW value(s) submitted by a CSP in their Sell Offer(s) for a zone/sub-zone during the auction bidding window may be less than the total Nominated DR Value in their DR Sell Offer Plan Summary.

Certain zones/sub-zones will be pre-identified by PJM as zones for which DR Sell Offers may require additional information to support the plan. Additional information may be required to support DR Sell Offer Plans for zones/sub-zones for which the quantity of cleared zonal/sub-zonal DR from the last BRA exceeds a threshold determined for the applicable LDA group (EMAAC, SWMAAC, Rest of MAAC, or Rest of RTO) as the higher of the maximum DR/ILR quantity registered in eLRS/DR Hub over the past three Delivery Years for the zones in the LDA group or the zonal DR potential quantity for the zones in the LDA group estimated based on a June 2009 FERC Staff Report on "A National Assessment of Demand Response Potential", where DR quantities are expressed in all cases as a percent of the forecasted zonal peak load. This determination of the identified zones is made each year prior to each BRA and is applicable to all auctions conducted for that Delivery Year. Zones or sub-zones remain on the identified list unless the threshold is not exceeded for three consecutive years. Identified zones for a Delivery Year will be posted by PJM to the pjm website no later than December 1 prior to the Base Residual Auction for such Delivery Year. Updates, if any, made to the 2009 FERC Staff Report will be subject to stakeholder review and considered for use in the establishment of thresholds in the future.

For these pre-identified zones/sub-zones, a CSP sell offer threshold is determined for each CSP; and DR sell offer quantities in excess of the CSP sell offer threshold will require site-specific information, as this quantity in excess of the CSP sell offer threshold should reflect Planned DR associated with end-use customer sites that the CSP has a high degree of certainty that it will physically deliver for the Delivery Year. The CSP sell offer threshold is determined as the higher of [(the CSP's maximum DR quantity registered in eLRS/DR Hub for that zone/sub-zone over the past three Delivery Years) or (the CSP's maximum cleared DR quantity for the past three BRAs for that zone/sub-zone) or (10 MW)].

**B. Planned DR Details**

The Planned DR Details section describes the program or strategy for procuring end-use customers and provides the details and key assumptions behind the development of the Planned DR quantities contained in the CSP's DR Sell Offer Plan. The Planned DR Details section is comprised of three sub-sections.

**1. Description and Key Assumptions of Planned DR**

The CSP must describe the program(s) that the CSP plans to employ to achieve the Planned Nominated DR Value indicated on the DR Sell Offer Plan Summary. This section must describe key program attributes and assumptions used to develop the Planned Nominated DR Value. This section must include, but is not limited to, discussion of:

- Method(s) of achieving load reduction at customer site(s)
- Equipment to be controlled or installed at customer site(s), if any
- Plan and ability to acquire customers
- Types of customer targeted

- Support of market potential and market share for the target customer base, with adjustments for existing DR customers within this market and the potential for other CSPs targeting the same customers
- Assumptions regarding regulatory approval of program(s), if applicable

**2. Planned Nominated DR Value by Customer Segment**

For those Planned Nominated DR Values for which an end-use customer site is not identified in section 3 of the Planned DR Details, the CSP must identify the Planned Nominated DR values by zone/sub-zone and by end-use customer segment. End-use customer segments include residential, commercial, small industrial (less than 3 MW), medium industrial (between 3 MW and 10 MW) and large industrial (greater than 10 MW). If known, the CSP may identify more specific customer segments within the commercial and industrial category.

By zone/sub-zone and by end-use customer segment, the CSP must provide estimates of the following information regarding the Planned DR component of the DR Sell Offer Plan:

- Number of end-use customers to be registered for auction Delivery Year
- Average Peak Load Contribution (PLC) per end-use customer in kW
- Average Nominated DR Value per customer in kW

Based on the above provided information, a total Planned Nominated DR Value in MW will be calculated for each end-use customer segment and for each zone/sub-zone. The total Planned Nominated DR values identified by customer segment and aggregated for each zone/sub-zone in Section 2 of the Planned DR Details plus the total Planned Nominated DR Values identified by end-use customer site(s) and aggregated for each zone/sub-zone in Section 3 of the Planned DR Details must equal the total Planned Nominated DR Value for each zone-sub-zone as identified in the DR Sell Offer Plan Summary.

**3. Planned Nominated DR Value by End-Use Customer Site**

This section must be completed by the CSP when the end-use customer is known at the time of the submittal of the DR Sell Offer Plan. This section must also be completed for DR Sell Offer quantities identified in the DR Sell Offer Plan Summary as requiring site-specific information, since this identified quantity should reflect Planned DR associated with specific end-use customer sites for which the CSP has a high degree of certainty that it will physically deliver for the relevant Delivery Year.

The CSP must provide the following information:

- Customer EDC account number (if known)
- Customer name
- Customer premise address
- Zone/Sub-zone

- Customer segment
- Actual value (if known) or estimate of current PLC and estimate of expected auction Delivery Year PLC in kW
- Estimated Nominated DR Value in kW

In the event that multiple CSPs identify the same end-use customer site, the MWs associated with such site will not be approved for offering into the RPM auction by any of the CSPs, unless it can be supported by evidence, such as a letter of support from the end-use customer indicating that they have been in contact with the CSP and are likely to execute a contract with that CSP for the relevant Delivery Year. In the event that multiple letters of support indicating different CSPs are provided from the end use customer, the MWs associated with the end-use customer site will not be approved for offering into the RPM auction by any of the CSPs.

**C. Schedule**

The CSP must provide an approximate timeline for procuring end-use customer sites in order to physically deliver the total Nominated DR Value (existing and Planned DR) by zone/sub-zone in the DR Sell Offer Summary. For each zone/sub-zone and for each customer segment, the CSP must specify the cumulative number of customers and the cumulative Nominated DR Value associated with that group of customers that the CSP expects to have under contract by the beginning of each of the full Delivery Years occurring between the time of the auction and the auction Delivery Year.

# Attachment D: Demand Resource Officer Certification Form

**PJM DEMAND RESOURCE SELL OFFER PLAN OFFICER CERTIFICATION FORM**

Market Participant Name: _____ (“Participant”)

I, _____, a duly authorized officer of Participant, understanding that PJM Interconnection, L.L.C. (“PJM”) and PJM Settlement, Inc. (“PJM Settlement”) are relying on this certification as evidence that Participant meets all requirements for participating in PJM’s Reliability Pricing Model (“RPM”) auctions, as set forth in the PJM Open Access Transmission Tariff (“PJM Tariff”), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (“Operating Agreement"), the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region (“RAA”), and in the PJM Manuals, hereby certify that, as of the date of this certification, to my knowledge and belief:

1. I have reviewed Participant’s Demand Resource Sell Offer Plan (the “Plan”) and the information supplied to PJM in support of the Plan is true and correct as of the date of this certification.
2. The Participant is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of this certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.
3. This certification does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Participant’s rights and obligations thereunder, including Participant’s ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

Date: _____ By: _____

(Signature)

Print Name:_____ Title:_____

## Revision History

**Revision 60 (06/01/2025):**

- Conforming changes were made to the following sections to incorporate provisions of FERC's CIFP-RA order (ER24-99)
- 8.1 - Overview of Resource Performance Assessments
- 8.3 - Commitment Level Used in Summer/Winter Capability Tests (through the 2024/2025 Delivery Year)
- 8.5 - Summer/Winter Capability Testing
- 8.5.1 - Determination of Unit ICAP Shortfall (through the 2024/2025 Delivery Year)
- 8.5.2 - Determination of Unit ICAP Shortfall (effective with the 2025/2026 Delivery Year)
- 8.5A - Generation Operational Testing
- 9.1.5 - Generation Resource Rating Test Failure Charge
- 9.1.5A - Generation Operational Test Failure Charge
- 9.1.7 - Allocation of Deficiency and Penalty Charges
- Update 5.2 to include preliminary ELCC Class Rating and Accredited UCAP Factors on the auction timeline as approved by the 5/21/25 MRC.

**Administrative Change (Pete Langbein approved 02/26/2025):**

- Added missing content in Section 8.7.1

**Revision 59 (06/27/2024):**

- Conforming changes were made to the following sections to incorporate provisions of FERC's CIFP-RA order (ER24-99) and CONE Area 5 order (ER24-462):
- 1.2.2 Participation of Resource Providers
- 2.1.1 Installed Reserve Margin
- 2.1.2 Peak Load Forecasts
- 2.1.3.1 Pool-wide Average EFORd (Through 2024/2025 Delivery Year)
- 2.1.3.2 Pool-wide average Accredited UCAP Factor (Starting with 2025/2026 Delivery Year)
- 2.1.4 Forecast Pool Requirement
- 2.1.5 Effective Load Carrying Capability and ELCC Resources in Capacity Exchange
- 2.2 Role of Load Deliverability in the Reliability Pricing Model
- 2.3 Locational Constraints in the Reliability Pricing Model
- 2.3.1 Locational Constraints in the Reliability Pricing Model
- 2.4 Reliability Requirements

- 3.3 Parameters of the Variable Resource Requirement
- 3.3.1 Cost of New Entry
- 3.4 Plotting the Variable Resource Requirement Curve
- 4.2.1 Existing Generation Capacity Resource – Internal
- 4.2.2 Existing Generation Capacity Resources – External
- 4.2.3 Planned Generation Capacity Resources – Internal
- 4.2.3.1 Binding Notice of Intent to Offer (Effective with the 2025/2026 Delivery Year)
- 4.2.4 Planned Generation Capacity Resources – External
- 4.2.5 Equivalent Demand Forced Outage Rate
- 4.2.7 Accredited UCAP for ELCC Resources
- 4.3.1 Requirements of Load Management Products in RPM
- 4.3.8 Determination of the UCAP Value of Load Management
- 4.4 Energy Efficiency Resources
- 4.6.2 Entering Unit-Specific Bilateral Transactions
- 4.6.3 Exporting a Generation Resource
- 4.6.5 Treatment of Unit-Specific Capacity Transactions that Start/End Mid-Delivery Year
- 4.6.8 Locational Unforced Capacity (UCAP) Transactions
- 4.7.1 Resource Position for Generation Capacity Resources
- 4.7.2 Resource Position for Demand Resources
- 5.2 RPM Auction Timeline
- 5.3. RPM Auction Parameters
- 5.4.1 Resource-Specific Sell Offer Requirements
- 5.4.3 New Entry Pricing Adjustment
- 5.4.4 Sell Offer Caps
- 5.4.8.4 Default MOPR Floor Offer Prices
- 5.7.1 Participation in the Base Residual Auction
- 5.8.1 Participation in the Incremental Auctions
- 8.1 Overview of Resource Performance Assessments
- 8.2.1 Generation (RPM Commitment Compliance)
- 8.2.2 Demand Resources (RPM Commitment Compliance)
- 8.4A Non-Performance Assessment
- 8.7 Load Management Test Compliance
- 8.8 Replacement Resources
- 9.1.9 Non-Performance Charge/Bonus Performance Credit

- 11.1.3 Participation in the FRR Alternative
- 11.2.1 Preliminary Unforced Capacity Obligation
- 11.3 Capacity Plan
- 11.4.1 Resource Portfolio
- 11.4.7 Load Management Products
- 11.8.1 FRR Capacity Resource Deficiency Charges

**Revision 58 (11/15/2023):**

- Conforming changes for interconnection process (ER22-2110)
- Section 4.7.1, 4.2.6, 4.2.7: RAA updated for Transitional MW (Docket No. ER23-1067-000)
- Section 7.4: Conforming language for Order 841 and Hybrid Order (ER22-1420)
- Section 8.2.2: Remove reference to DR Factor
- Section 3.3 and 3.4: Conforming to approved quad review filing (ER22-2984-000)
- Section 8.4A: Change to PAI Trigger (ER23-1996-000)
- Section 5.4.8.4: Updated Default Gross CONE and Gross ACR for MOPR (ER23-1700)

**Revision 57 (07/26/2023):**

- Interconnection Process Reform Taskforce nomenclature updates
  - Section 4.2.3: Updated terminology for IPRTF updates
  - Section 4.2.4: Updated terminology for IPRTF updates
  - Section 4.5: Updated terminology for IPRTF updates
  - Section 4.8.2: Updated terminology for IPRTF updates
  - Section 4.8.5: Updated terminology for IPRTF updates
  - Section 4.10: Updated terminology for IPRTF updates
  - Section 5.4.7: Updated terminology for IPRTF updates
  - Section 6.1: Updated terminology for IPRTF updates
  - Section 6.1.2: Updated terminology for IPRTF updates
  - Section 8.8: Updated terminology for IPRTF updates
  - Section 11.4.6: Updated terminology for IPRTF updates
  - Glossary A: Updated terminology for IPRTF updates

**Administrative Change (Approved by Peter Langbein 04/28/2023):**

- Removed reference to Manual 10 Section 6 in Section 8.5. Justification for this change is due to the decision for Section 6's removal stated in M10 "based on RFC Standard MOD-024-RFC-01, which permits verification of winter gross Real Power capability by adjusting the summer verification, eliminating the need for exemption program. Revisions approved by stakeholders at MRC on November 30, 2009"

**Revision 56 (02/09/2023):**

- Change to Section 8.8 to allow early replacement actions for export under specific conditions as approved at 11/16/22 MRC.

**Revision 55 (02/09/2023):**

- Updated section 3A.3 and Attachment C to prohibit Critical Natural Gas Infrastructure

**Administrative Change (Approved by Peter Langbein 01/05/2023):**

- Section 5.4.8.3: Updated binary pronoun usage (e.g., “his/her” to a gender-neutral equivalent (e.g., “their,” etc.) in order to support PJM’s diversity, equity and inclusion efforts.

**Revision 54 (09/21/2022):**

- Periodic Review updates include:
  - Deletion of outdated information in the following sections:
    - Section 1.5
    - Sections 2.1.3, 2.2, 2.3, 2.3.4, 2.4.3, 2.4.3A, 2.4.4, & 2.4.5
    - Sections 3.3.1, 3.3.2, 3.4, 3.5, 3A.1, 3A.2, 3A.3, 3A.4.1, 3A.4.2, 3A.5, 3A.6, 3A.6.2, & 3A.6.2A
    - Sections 4.1, 4.2.2, 4.2.4, 4.2.5, 4.2.6, 4.3.1, 4.3.3, 4.3.4, 4.3.5, 4.3.7, 4.3.8, 4.3.10, 4.4, 4.4.1, 4.4.2, 4.4.3, 4.5, 4.6.2, 4.6.4, 4.6.5, 4.6.6, 4.6.7, 4.6.8, 4.7.1, 4.7.2, 4.7.2, 4.7.3, 4.8.3, 4.8.4, 4.8.5, 4.9, & 4.10
    - Sections 5.3, 5.4.1, 5.4.4, 5.4.5, 5.4.8, 5.5, 5.7.1, 5.7.2, 5.7.3, 5.8.1, 5.8.3, 5.8.5, & 5.9.1
    - Section 6.1.3
    - Section 7.2.2
    - Sections 8.1, 8.2.1, 8.2.2, 8.2.3, 8.3, 8.4, 8.4A, 8.5, 8.6, 8.7, 8.8
    - Sections 9.1.1, 9.1.2, 9.1.3, 9.1.5, 9.1.6, 9.1.9, 9.3.1, 9.3.3, 9.4.2, 9.4.4
    - Sections 11.1.2, 11.3, 11.4.1, 11.4.7, 11.4.8, 11.8.1, 11.8.3, 11.8.5, 11.8.6, & 11.8.7
    - Attachment A: Glossary of Terms
  - Added reference to Section 3.4 for development of VRR Curves (Sections 2.4.4 & 2.4.5)
  - Added missing OVEC zone to CONE Area (Section 3.3.1)
  - Added footnote to clarify the Reliability Requirement used in UCAP quantity equation for points (a), (b), and (c) of VRR Curve excludes any adjustment for PRD or EE (Section 3.4)
  - Clarified VRR Curve is adjusted rightward for EE addback (Section 3.4)

- Clarified information to be verified in Resource Confirmation process to reflect current practice in Capacity Exchange system (Section 4.1)
- Clarified generation resource committed to FRR Capacity Plan must satisfy same qualification requirements as resource offering into RPM Auction (Section 4.2)
- Moved Prior CIL Exception Resource definition from Section 2.3 to this section (Section 4.2.2)
- Clarified load management programs and EE installations are eligible to be committed to FRR Capacity Plan (Section 4.3 & Section.4.4)
- Updated DR Plan deadline from 15 business prior to 30 days prior (Sections 4.3.1, 5.2, 11.4.7, & Attachment C: DR Sell Offer Plan)
- Replaced "annual" product availability with "Capacity Performance" (Section 4.3.10)
- Added Nominated EE Value Template requirement to reflect current practice (Section 4.4)
- Updated EE Modification process to reflect current practice (Section 4.4.3)
- Clarified UCAP Value of CP EE Resource and Summer Period EE Resource (Section 4.4.2)
- Added Generation Resource Rating Test Failure Charge to list of charges applicable to Seller of Auction Specific MW Transaction (Section 4.6.6)
- Added footnote to reference RPM Auction schedule on website for DYs FERC approved a compressed auction schedule (Section 5.2)
- Added Capacity Performance value when missing (Section 8.2.3)
- Clarified party/PJM Weighted Average Resource Clearing Price to consider segment-specific RCPs (Section 9.1.3)
- Clarified LDA Incremental CTR Credit Rate (Section 9.3.4)
- Changed “product-specific” to “segment-specific” in description of price applicable to Auction Specific MW transaction (Section 9.3.5)
- Clarified Capacity Exchange tool functionality (Section 10.1)
- Clarified alternative retail LSE is subject to credit requirement as opposed to FRR Entity for alternative retail LSE’s Planned Resources (Section 11.1.3)
- Corrected the treatment of switched load between FRR Entity and RPM LSEs to be in compliance with RAA (Section 11.2.3)
- Clarified EE Modification submittal process (Section 11.4.9)
- Clarified the requirement to perform Load Management test (Section 11.8.5)
- Added footnote to clarify final Shortfall or Bonus MW will be allocated to RPM and FRR if have both RPM and FRR commitments on resource (Section 11.8.7)
- Clarified definition of DR Mod, EFORd, Effective EFORd, Nominated DR Value, Pool-wide average EFORd, Resource Clearing Price, Weighted Average Resource Clearing Price, and Zonal Capacity Price (Attachment A: Glossary of Terms)

    - Administrative updates throughout manual
        - Corrected manual or agreement references
        - Consolidated information
        - Deleted duplicative information
        - Updated tool name to Capacity Exchange
        - Corrected grammar and formatting
- Update the process for Capacity Market Seller to demonstrate written commitment to must-offer requirement for an External Resource via Officer Certification Form as opposed to External Resource Must Offer Agreement (Section 4.2.2)
- Updates to include certain Hybrid Resources in the exemption to the RPM must offer requirement (Sections 4.7.1, 5.4.1, 5.7.1, and 5.8.1)
-

**Revision 53 (07/27/2022):**

- Conforming revisions for FERC Order ER20-1590-000 issued on September 3, 2020 approving changes to Load Management and Price Responsive Demand testing requirements to make testing more closely simulate actual emergency events. This includes details on scheduling tests, notification of tests, duration of tests and retesting provisions.
    - Section 3A.6.3A establishes the testing requirements for PRD effective with 2023/2024 Delivery Year.
    - Section 8.7 modified for Load management testing requirements effective with 2023/2024 Delivery Year.

**Revision 52 (02/24/2022):**

- Update to section 3.3.2 to reflect that Net EAS of the Reference Resource CT is calculated using the forward-looking methodology with application of the 10% adder for only the 2022/2023 Delivery Year. The Net EAS is determined using the historical approach and without application of the 10% adder for all other delivery years.
- Update to section 5.4.1 to reflect that sell offers of existing generation capacity resources above $0/MW-Day must seek unit-specific exception or elect to use MSOC based on gross ACR of applicable resource type, if available, effective 9/2/2021. Added language specifying that sellers may elect to use a default offer cap of 1.1 times the BRA RCP for any 3$^{rd}$ IA.
- Updated section 5.4.4 to reflect that the Net EAS of units seeking a net ACR-based exception is calculated using the forward-looking methodology for only the 2022/2023 Delivery Year. The Net EAS is determined by historical net revenues for all other delivery years.
- Updated section 5.4.5 to make clear that this section and its sub-sections which describe the MOPR provisions of Sections 5.14(h) and 5.14(h-1) of Attachment DD of the PJM

OATT are not applicable after the 2022/2023 Delivery Year. Deleted language in section 5.4.5.2 describing consequences of accepting State Subsidy after electing competitive exemption or certifying that resource is not state subsidized.

- Added new section 5.4.8 to describe the MOPR provisions of Section 5.14(h-2) of Attachment DD of the PJM OATT which are effective with the 2023/2023 Delivery Year.

**Revision 51 (10/20/2021):**

- Updates to Section 2.4.5 to reflect new EE Addback methodology to be used in all RPM Auctions conducted for the 2023/2024 Delivery Year and all subsequent delivery years.

**Revision 50 (09/01/2021):**

Revision includes:

• Updates to Section 8.4A to clarify Scheduled MW used for Excusal and Bonus purposes in Performance Assessment Interval settlement is calculated using Dispatch Run LMP due to Fast Start Pricing implementation on 9/1/2021.

**Revision 49 (08/01/2021):**

Revised the following sections to make confirming changes to implement Effective Load Carrying Capability to calculate the capacity value of renewables and storage. Unless otherwise noted, section changes were made to update and clarify terminology usage related to ICAP, UCAP, and EFORd, and replacing the terms “wind” and “solar” with “Variable Resources”:

- New Section 2.1.5 – provides a summary description of ELCC and describes the use of the terms “ICAP” and “UCAP” for ELCC Resources in the context of Manual 18
- 4.2.5 and 4.2.6
- New Section 4.2.7 – provides a summary description of ELCC and describes the use of the terms “ICAP” and “UCAP” for ELCC Resources in the context of Manual 18
- 4.7.1 – clarifies that ELCC Resources may not offer or otherwise provide UCAP MW quantities above their Capacity Interconnection Rights.
- 5.4.1 and 5.4.5.6
- 7.1
- 8.1 – revised the table of generator assessments to reflect rules for Variable Resources
- 8.4
- 8.5
- 8.8 – reflects application of commitment deficiency rules given the Accredited UCAP values of ELCC Resources
- 9.1.1
- 9.1.5 – reflects application of the Daily Generation Resource Rating Test Failure Charge given the Accredited UCAP value of ELCC Resources

- 11.3
- 11.4.1
- Attachment A – added the RAA definitions for several new ELCC-related terms, such as Accredited UCAP, Combination Resource, Variable Resource, ELCC Resource, etc.

**Revision 48 (05/26/2021):**

- New paragraph in Section 8.4A to clarify treatment of Public Distribution Microgrid Generators that are Generation Capacity Resources for Non-Performance Assessment.
- PRD – Approved as per Docket Nos. ER21-1243--0000 and ER21-1243-001 on 4/28/2021, effective on 06/01/2021:
  - Removed reference to LSE from PRD Provider description (Section 1.2.3)
  - Revised PRD Provider description, changed PRD Credit recipient from LSE to PRD Provider (Section 3A.1)
  - Removed LSE-specific requirements for PRD (Section 3A.4.2)
  - Removed section 3A.4.2.1 - Verification of Retail Rate Structure with LSE
  - Removed reference to LSE (Section 3A.4.2.2)
  - Removed identification of LSE from registration requirement (Section 3A.5)
  - Changed PRD Credit recipient from LSE to PRD Provider (Section 9.4.4)

**Revision 47 (01/27/2020):**

- Conforming changes were made to the following sections to incorporate provisions of FERC's expanded MOPR order (EL16-49, EL18-178, ER18-1314) and Forward Net EAS order (EL19-58):
  - Section 3.3.2 Demand in RPM
  - Section 5.4.4 Sell Offer Caps
  - Section 5.4.5 Minimum Offer Price Rule (MOPR)
  - Section 8.8 Replacement Resources
  - Attachment A Glossary of Terms

**Revision 46 (11/19/2020):**

- Section 8.4A – Corrected effective date from 2021/2022 to 2020/2021 Delivery Year for when External Generation Capacity Resources that would have helped resolve the declared Emergency Action are included in a performance assessment in order to conform with the effective date in the OATT.

**Administrative Change (06/23/2020):**

- Updated manual ownership to Peter Langbein

**Revision 45 (05/28/2020):**

- Conforming revisions for FERC Order ER20-271-001 issued on February 28, 2020 to clarify that Price Responsive Demand (PRD) registration will not be considered in the calculation of a performance shortfall or bonus performance for a Performance Assessment Interval (PAI) when the PRD Curve associated with registration indicates a price point where no demand reduction is expected at the real-time LMP recorded during the PAI. (Section 3A.6.2A)
- Conforming revisions for FERC Order ER20-217-000 issued on December 30, 2019 to update certain rules and requirements for PRD to conform to rules and requirements for Capacity Performance resources.
  - Added prior to 2022/2023 Delivery Year, PRD Provider is subject to performance compliance during Maximum Emergency Events. Added effective with 2022/2023 Delivery Year, PRD Provider is subject to Non-Performance Assessment during the Delivery Year (Sections 3A.1, 3A.3, 3A.6, 3A.6.2, 8.4A, 9.1.9, and 9.4.2)
  - Deleted outdated provisions related to the Transition Period for PRD (Section 3A.2)
  - Added footnote that any PRD Plan submitted and approved for 2022/2023 Delivery Year BRA may be withdrawn or modified no later than 30 days prior to the commencement of the 2022/2023 Delivery Year BRA. (Section 3A.4.1)
  - Added that Zonal Scaling Factors for use in preparation of PRD Plans will be posted by PJM prior to the 2022/2023 Delivery Year. (Section 3A.4.1)
  - Added effective with 2022/203 Delivery Year, the PRD Value for Zone/LDA provided in a PRD Plan is based on a Zonal/LDA Peak Load Contribution (PLC) value minus (the Zonal/LDA Firm Service Level (FSL) quantity times the loss factor). (Section 3A.4.2)
  - Added Expected Peak Load Value of PRD is submitted prior to 2022/2023 Delivery Year and Peak Load Contribution value of PRD is submitted effective with 2022/2023 Delivery Year. (Section 3A.4.2)

**Revision 44 (12/05/2019):**

- Conforming revisions for FERC Order ER19-2417 issued on September 16, 2019 that (1) enable Capacity Market Sellers to request removal of the Generation Capacity Resource Status and (2) require Capacity Market Sellers seeking an exception to the RPM must offer requirement on the basis that an existing Generation Capacity Resource is physically unable to satisfy the requirements of Capacity Performance (CP) to include a documented plan to become capable of participating in RPM.
  - Updated RPM Auction Timeline to include activities associated with removal of a resource from Capacity Resource status (Section 5.2)
  - Included the requirement to submit a documented plan showing steps that intend to pursue for a resource to become physically capable of satisfying the requirements of a CP Resource, and provide periodic updates on progress of such plan, effective with must-offer exception requests for the 2023/2024 Delivery Year (Section 5.4.1)

- Added new section “Removal of Generation Capacity Resource Status” to document the process to voluntarily request removal of a Capacity Resource from Generation Capacity Resource status (Section 5.4.7)

- Clarification updates to RPM must-offer exception process:
  - Clarified that timing is an acceptable reason for must-offer exception request (Section 5.4.1)
  - Clarified that sellers may specify multiple auctions in a written must-offer exception request (Section 5.4.1)
  - Added that a pending request to PJM for removal of Generation Capacity Resource status is an acceptable reason for early replacement (Section 8.8)

**Revision 43 (12/03/2019):**

- Conforming revision for FERC Order 841: Electric Storage participation (ER19-462) in Section 7.4 to address Energy Storage Resources not being allocated a Peak Load Contribution.

**Revision 42 (07/25/2019):**

- Periodic Review updated to address:
  - Corrections/Clarifications of Existing Provisions
    - Clarify Delivery Year applicability of Limited Resource Constraint, Sub-Annual Resource Constraint, Base Capacity Demand Resource Constraint, and Base Capacity Resource Constraint for FRR Alternative in Sections 2.4.3A, 2.4.3B and 5.3
    - Clarify treatment of Qualifying Transmission Upgrade once in service in Section 4.5
    - Clarify Behind the Meter Generation provisions in Sections 4.3.3 and 7.3.1
    - Correct Non-Performance Charge Rate in Sections 8.4A, 9.1.11 and 11.8.8
    - Clarify replacement capacity rules when remaining import capability into an LDA in Section 8.9
    - Add Aggregate Resource to list of capacity resources in Sections 4.1, 5.7.1 and Glossary
    - Clarify charges applicable to Owner in Authorization to Self-Schedule Capacity in Attachment B
  - Deletion of Outdated Provisions
    - Capacity Performance Transition IAs in Sections 1.5, 4.6.2, 4.6.6, 5.1, 5.8 and 5.9
    - Minimum Annual and Extended Summer Requirements in Sections 2.4.3, 2.4.4, 2.4.5, 3.5, 5.3, 5.7.2, 5.8.5, 5.9, 11.1.3, 11.3 and 11.8
    - EE adjustments for 2016/17 – 2018/2019 Delivery Years in Section 2.4.5

        - Short-term Resource Procurement Target in Sections 3.3, 3.5, 5.1, 5.4.3, 5.8, 6.1, 7.2.2, 11.1.3 and Glossary
        - Demand Response Legacy Direct Load Control Transition Provision in Sections 3.5 and 5.9
        - Limited Resource Constraint and Sub-Annual Resource Constraint (when it relates to RPM Auctions) in Sections 3.5, 5.7.2, 5.8.5, and 5.9
        - Product types (Limited DR, Extended Summer, and Annual) for RPM Auctions in Sections 4.1, 4.5, 4.6.2, 4.6.7, 4.6.8, 4.8.3, 5.5, 8.2.2, and 8.9
        - Out-dated qualification requirements for generation resource prior to 2019/2020 Delivery Year in Section 4.2.3
        - Legacy Direct Load Control Programs in Section 4.3.1
        - Credit-Limited Offers in Section 4.8.4
        - Coupled Sell Offers in Section 5.4
        - Peak Season Maintenance Compliance in Sections 8.1, 8.6, 9.1.6, 9.1.8 and 11.8.5
        - Load Management Event Compliance in Sections 8.1, 8.7, 9.1.9 and 11.8.6
        - Non-Performance Assessment provisions for 2016/2017 – 2017/2018 Delivery Years in Sections 8.4A, 9.1.4 and 9.1.11
    - Conforming Revisions for FERC Orders
        - OVEC Integration (ER18-459, ER18-460) in Section 2.3.1
        - Periodic Review of Variable Requirement Curve Shape and Key Parameters (Quadrennial Review) (ER19-105-001,002) in Sections 3.3 and 3.4
        - Energy Efficiency Resources Compliance with Authorized Relevant Electric Retail Regulatory Authority (RERRA) Rules to Opt-Out or Restrict Sales of EE Resources (ER18-870) in Sections 3.5, 4.4 and 5.9
        - Minimum Offer Price Rule Remand (ER13-535-005, 006) in Sections 5.2 and 5.4.5
        - FERC Order 841: Electric Storage Participation (ER19-462) in Section 5.4.1

**Revision 41 (01/01/2019):**

- Revisions for FERC Order ER19-244, accepted on December 31, 2018 and effective January 1, 2019, to amend Demand Resource registration rules and define a summer period and winter period nominated value for a Capacity Performance registration and to change the methodology used to determine the daily nominated capacity values for Capacity Performance Demand Resources.
- Revisions for FERC Order ER19-142, accepted on December 17, 2018 and effective December 17, 2018, to modify the definition of Winter Peak Load to exclude atypically low usage winter peak days from the calculation of Winter Peak Load.

**Revision 40 (02/22/2018):**

- Conforming revisions for FERC Order ER17-1138, accepted on November 17, 2017 and effective May 9, 2017 to implement enhancements to the rules for external capacity resources.

**Revision 39 (12/22/2017)**

- Revisions to Sections 4.3 (4.3.1, 4.3.5, & 4.3.10), 4.6 (4.6.6), 4.9, 4.10, 8.4, 8.4A, 8.7A, 8.8, 8.9, 9.1 (9.1.3, 9.1.4, 9.1.5, & 9.1.11), 11.3, and 11.8 (11.8.8 &11.8.9) to accommodate sub-hourly settlements (FERC Order 825).

**Revision 38 (07/27/2017)**

- Revisions to Section 8.4A to describe that if energy offer does not comply with Manual 11, Section 2.3.7, then no MWs from generation resource will be exempt or considered for bonus performance during the Performance Assessment Hour.

**Revision 37 (4/27/2017)**

- Conforming revisions for FERC Order ER17-367 issued on March 21, 2017, to enhance aggregation rules, implement Seasonal Capacity Performance Resources, provide opportunity for Intermittent and Environmentally Limited Resources to request additional Capacity Interconnection Rights in winter, and modify measurement and verification rules for Demand Resources.

**Revision 36 (12/22/2016)**

- Revisions to include restrictions on early replacement of RPM capacity commitments as endorsed by MRC on 12/22/2016 (Section 8.9)

**Revision 35 (11/17/2016)**

- Revisions to remove the restrictions on early replacement of RPM capacity commitments as endorsed by MRC on 11/17/2016 (Section 8.9).

**Revision 34 (07/28/2016)**

- Revisions to clarifying the details of Auction Specific MW bilateral transactions (Section 4.6.6)

**Revision 33 (06/30/2016)**

- Revisions needed as a result of a Cover to Cover Periodic Review
- Revisions needed to clarify the implementation details of Capacity Performance

**Revision 32 (04/01/2016)**

- Conforming revisions for FERC Order ER16-873-000, accepted on 4/1/2016 and effective 4/1/2016 to eliminate the RRMSE requirement for Load Management registrations that will use a customer baseline to measure capacity compliance in non-summer periods.

**Revision 31 (02/25/2016)**

- Conforming revisions for FERC Order ER16-333, accepted on 12/22/2015 and effective 01/16/2016 to change (1) instances in which FRR Entities would not be required to meet the Percentage of Internal Resource Requirement, (2) circumstances in which an FRR Entity can terminate its five-year minimum commitment period, and (3) the FRR Alternative election dates for new FRR Entities (Sections 11.1.3 & 11.6).

**Revision 30 (12/17/2015)**

- Revisions to accommodate EE Resource participation in the PJM capacity market when the peak load forecast reflects energy efficiency measures (sections 2.4.5, 4.4, 8.7 & 11.2.1).

**Revision 29 (10/16/2015)**

- Revisions to Section 8.7, endorsed at the July 23, 2015 MRC meeting, to add provisions for replacement capacity transactions earlier than November 30th prior to start of Delivery Year when the owner of the replaced resource provides transparent and verifiable evidence to support the expected final physical position of resource at the time of the request.

**Revision 28 (08/03/2015)**

- Conforming revisions for FERC Order ER15-623 (i.e., Capacity Performance filing), accepted on 06/09/2015 and effective April 1, 2015 to better ensure that committed resources will perform when called upon to meet the reliability needs of the PJM Region.
- Conforming revisions for FERC Order ER15-1849, accepted on 7/23/15 and effective 8/3/15, to improve measurement and verification procedures for CSPs with Residential Demand Response Customers. Direct Load Control is re-defined as Legacy Direct Load Control and is only effective through May 31, 2016. Statistical sampling may be used instead of customer-specific compliance and verification information for residential customers without interval metering.

**Revision 27 (01/22/2015)**

- Conforming revisions for FERC Order ER14-2940, accepted on 11/28/2014 and effective 12/01/2014, to revise the shape of Variable Resource Requirement Curve, the gross Cost of New Entry values, and the methodology to determine Net Energy and Ancillary Services Revenue Offset and Net Cost of New Entry. (Sections 3.3.1, 3.3.2, 3.3.3, 3.4, & 3.4.1)

**Revision 26 (01/01/2015)**

- Conforming revisions for FERC Order ER15-134-000, accepted on 12/01/2014 and effective 01/01/2015, to allow Electric Distribution Companies to correct the Obligation Peak Load data up to 12 noon on the next business day after the Operating Day.

**Revision 25 (10/30/2014)**

- Conforming revisions for FERC Order ER11-2288-000, accepted on 01/31/2011 and effective 02/1/2011, to clarify the Annual DR Maintenance Outage process.

**Revision 24 (07/31/2014)**

- Revision to allow Auction Specific MW Transactions for a Delivery Year to be submitted following the completion of the RPM auction to which the transaction applies (Section 4.6.6).

**Revision 23 (06/01/2014)**

- Conforming revisions for FERC Order ER14-822, accepted on 05/09/2014, and effective on 06/01/2014 for various DR operational changes including: (i) requiring all Demand Resources participating in PJM's capacity market to serve as Pre-Emergency Load Response, unless the resource utilizes behind-the-meter generation that is subject to an environmental restriction; (ii) requiring, on a phased-in basis, that all Demand Resources reduce load reductions within 30 minutes of notification from PJM to the CSP, unless PJM has granted an exemption for a Demand Resource; (iii) limiting the duration of the required minimum load response reduction period from two hours to one hour; (iv) modifying measurement and verification for capacity compliance for all hours where PJM has dispatched the resource for at least 30 minutes of the wall clock hour; (v) modifying measurement and verification to allow aggregation of compliance results by compliance aggregation areas and provide further clarification on definition of "Load Management Event'; and (vi) CSP expected load reductions must be reported at more granular basis to include these changes. (Sections 4.3.1, 4.3.2, 4.3.4, 4.3.5, 4.3.6, 4.3.7, 4.3.9, 8.5, 8.5.1, and 8.5.2)
- Revision to include the ability to request an adjustment to the Nominated DR Value (in MWs) associated with an end-use customer site and used in the determination of a CSP's Existing MWs if certain criteria are satisfied. (Section 4.3.3)

**Revision 22 (04/24/2014)**

- Conforming revisions for FERC Order ER14-504, accepted on 01/30/2014, and effective on 01/21/2014 to retire the Minimum Annual Resource Requirements and Minimum Extended Summer Resource Requirements and implement Limited Resource Constraints and Sub-Annual Resource Constraints effective with the 2017/2018 Delivery Year. (Sections 2.4.3, 2.4.3A, 2.4.4, 3.5, 5.3, 5.6.2, 5.7.5, 5.8.1, 11.1.3, 11.3, 11.4.1, & 11.9.1)
- Confirming revisions for FERC Order ER14-503 to employ Capacity Import Limits for RPM Auctions effective with the 2017/2018 Delivery Year. (Sections 2.1.2, 2.2, 2.3, 2.3.4, & 5.8.1)
- Conforming revisions for hydro and pumped storage units to perform rating tests during summer verification window in accordance with PJM Manual 21, Rules and Procedures for Determination of Generating Capability, Revision 11, effective 03/05/2014. (Section 8.4.6)

- Clarifications to deficiency/penalty charge rates when committed capacity resources did not clear in any RPM Auctions (Sections 9.1.1, 9.1.3, 9.1.5, 9.1.6, 9.1.7, & 9.1.9)
- Revisions to permit the maximum credit requirement specified in a credit-limited sell offer to exceed the RPM Credit Limit of a resource when the RPM Credit Adjustment Factor of the resource is less than one (Section 4.8.4).

**Revision 21 (01/30/2014)**

- Revisions to include demand resource product substitution rules for a load management event (Section 8.5).

**Revision 20 (11/21/2013)**

- Conforming revisions for FERC Order ER12-513, accepted on 01/31/2013 and effective 01/31/2013, to update Gross CONE values for CONE areas, region-wide Gross CONE value, and Benchmark CONE values. (Section 3.3.1)
- Conforming revisions for FERC Order ER12-513, accepted on 01/30/2012 and effective 01/31/2012, to revise definition of peak-hour dispatch to provide for day-ahead energy market revenues to be considered in the determination of Energy & Ancillary Services revenues. (Section 3.3.2)
- Conforming revisions for FERC Order ER13-535, accepted on 05/02/2013 and effective 02/05/2013, to revise the Minimum Offer Price Rule. (Section 5.2 and 5.3.5)
- Conforming revisions for FERC Order ER13-2140, accepted on 10/10/2013 and effective 10/15/2013, to change the deadline for submission of must-offer exemption requests for resources that are expected to be deactivated prior to or during the relevant Delivery Year. (Section 5.2)
- Conforming revisions for FERC Order ER13-1023, accepted on 04/30/2013 and effective 05/01/2013, to correct the NEPA qualification calculation and allow NEPA contingent sell offers in Base Residual Auction. (Section 5.3.3)
- Revision to correct LSE's options to hedge Locational Reliability charges by offering and clearing resources in Base Residual Auction and Incremental Auctions. (Section 1.2.1)
- Removal of obsolete reference to information on Transition Period. (Section 1.4)
- Revisions to correct number of LDAs and RECO's relationship to parent LDA. (Section 2.3.1)
- Revisions to correct terminology from "Capacity Injection Rights" to "Capacity Interconnection Rights, the defined term in OATT. (Section 4.2.6)
- Revisions to correct indemnification provision for Unit-specific transactions for Cleared MWs to conform with current tariff language. (Section 4.6.2)
- Revisions to correct business rules regarding start and end dates of Auction Specific MW transactions to conform with current tariff language. (Section 4.6.6)
- Removal of obsolete ILR references (Sections 4.6, 7.1, 8.5, & Attachment A).

- Revisions to clarify bill timing for Peak Hour Period Availability Charges/Credits, Generation Resource Rating Test Failure Charges/Credits, and PSM Compliance Charges/Credits (Sections 9.1.2, 9.1.5, and 9.1.6)
- Revisions to clarify that factor for On-Peak Load Management Compliance Penalty Rate is based on number of on-peak events.(Section 9.1.9)

**Revision 19 (06/01/2013)**

- Revisions for EKPC integration (Section 2.3.1)
- Revisions for Load Reduction Reporting for Emergency Demand Response capacity resources (Section 4.3.9)

**Revision 18 (3/18/2013)**

- Proposed revisions for Demand Resource Sell Offer Plan Enhancements (Sections 4.3.1, 4.3.3, 4.3.6, and 11.4.7, Attachments C and D)

**Revision17 (12/20/2012)**

- Conforming revisions in Docket ER13-305-000 to add a Cleveland LDA (Section 2.3.1)
- Conforming revisions in Docket ER13-149-000 to incorporate task oriented deadlines to ensure timely submission of offer data, exception requests and unit-specific requests by market participants as well as timely responses thereto by PJM and the IMM
- Removal of language restricting replacement transactions on EE Resources with non-EE Resources (Section 8.7)
- Removal of ILR related content
- Removal of Transition Period (2007/08 – 2010/11 Delivery Year) related content
- Removal of pre-2012/13 Delivery Year-specific content
- Glossary updates

**Revision 16 (09/27/2012)**

- Conforming revisions for FERC Order ER11-4628 accepted on 12/14/2011 and effective 05/15/2012 to integrate Price Responsive Demand (PRD) in PJM Capacity Market.

**Revision 15 (06/28/2012)**

- Conforming revisions for FERC Order ER12-1372 accepted on 05/31/2012 and effective 06/01/2012, to clarify load management event and test compliance requirements related to sub-zonal and product-specific dispatch (Sections 4.3.1, 8.5, 8.5.2, 8.6, 9.1.7, and 9.1.9).
- Conforming revisions for FERC Order ER11-3322 conditionally accepted on 02/24/2012 and effective June 1, 2012, to implement a Demand Response Transition Provision (DR Capacity Transition Credit and Alternate DR Transition Credit) for the 2012/2013 through 2014/2015 Delivery Years (Sections 8.8 and 9.4).

- Conforming revisions for FERC Order ER12-513, accepted on 01/30/2012 and effective 01/31/2012, to revise point (a) on the VRR Curve (Section 3.4) and clarify New Entry Pricing provision (Section 5.3.3).
- Conforming revisions for FERC Order ER12-636, accepted on 02/16/2012, and effective 02/18/2012, to make corrections, clarifications identified as a result of the Quality Project Initiative including revisions for CTRs and ICTRs (Sections 5.8.3, 5.8.4, 6.1.1, 6.1.2, 6.1.3, 6.2, 6.3, 6.4, and 9.3.4) and removal of obsolete provisions for Single Customer LSE electing the FRR Alternative and the Unauthorized Load Transfer Charge (Section 11.2.3).
- Revisions to correct bill timing from monthly to weekly for Capacity Resource Deficiency Charges (Section 9.1.3), Locational Reliability Charges (Section 9.2.1), Auction Charges/ Credits (Sections 9.3.1 and 9.3.2), CTR and ICTR Credits (Section 9.3.4), Auction Specific MW Transaction Credits (Section 9.3.5), and ILR Credits (Section 9.3.6).

**Revision 14 (02/23/2012)**

- Conforming Revisions for FERC Order ER11-2287, accepted on 01/31/2011, and effective 01/31/2011 to revise the definition of an Existing Generation Resource for the purposes of must-offer and mitigation provisions (Section 1.2, 5.6.1, 5.7.1).
- Conforming Revisions needed to include updates to Installed Reserve Margin, Pool-wide average EFORd, Forecast Pool Requirement, CETO, and CETLs prior to Incremental Auctions and conform to Attachment DD of Open Access Transmission Tariff. (Sections 2.1.1, 2.1.3, 2.1.4, and 2.3)
- Conforming Revisions for FERC Order ER11-2287, accepted on 01/31/2011 and effective 02/01/2011 to establish three product alternatives (limited, extended summer, and annual) for demand resources seeking to participate in PJM's capacity market. (Sections 2.4.3, 4.3, 4.3.1, 4.3.2, 4.3.7, 5.3, 5.3.1, 5.4, 5.6.2, 5.7.5, 5.8.1, 8.2.2, 8.5, 8.5.1, 8.5.2, 8.6, 8.7, 9.1.7, 9.1.9, 11.1.3, 11.3, 11.9.1)
- Conforming Revisions for FERC Order ER11-3365, accepted on 6/6/2011 and effective 06/ 17/2011, to refine the calculations of the amount of capacity commitments that PJM seeks to procure or release in Incremental Auctions and the amount of Excess Committed Credits commencing with the 2012/2013 Delivery Year (Sections 3.5 and 8.7.2 )
- Conforming Revisions for FERC Order ER05-1410-015, et al., accepted on 05/20/2010 to implement the use of an Updated VRR Curve Increment/Decrement in developing PJM Buy Bids/Sell Offers in Incremental Auctions (Section 3.5).
- Conforming Revisions for FERC Order ER12-125 accepted on 12/02/2011 and effective 12/19/2011 to clarify that PJM Emergency Load Response Registrations must be submitted to PJM no later than one day before the tenth business day preceding the relevant Delivery year, and must be approved on or before May 31st preceding the relevant Delivery Year (Section 4.3.7)
- Conforming Revisions for FERC Order ER10-1003, accepted on 05/05/2010, and effective 06/01/2010 to revise PJM's credit risk management rules for certain bilateral transactions

(unit-specific transactions for cleared capacity, Auction Specific MW transactions, and Locational UCAP transactions) (Sections 4.6.2, 4.6.6, and 4.6.7).

- Conforming Revisions needed to clarify the Auction Credit Rate and conform to Attachment Q of Open Access Transmission Tariff. (Section 4.8.3)
- Conforming Revisions for FERC Order ER11-2913, accepted on 4/13/2011and effective 04/20/2011, to allow Credit-Limited Offers in RPM Auctions for planned resources (whether generation, demand resources, or energy efficiency) (Section 4.8.4).
- Conforming Revisions for FERC Order ER11-4143, accepted on 09/12/2011 and effective 06/01/2007, to correct time periods for critical peak periods for the assessment of Peak Hour Period Availability from eastern prevailing time (EPT) to local prevailing time (LPT) (Section 8.4).
- Conforming Revisions for FERC Order ER09-412, accepted on 03/26/2009, and effective 06/01/2009 to allow excess available capacity that satisfies all capacity resource obligations of a committed resource to serve as replacement capacity to offset potential peak hour period availability penalties. (Sections 8.4.5 and 8.4.5.1)
- Conforming Revisions for FERC Order ER10-2917, accepted on 10/29/2010, and effective 11/23/2010 to further clarify that PJM considers committed capacity first in determining net peak hour period capacity shortfalls in an LDA and then considers uncommitted, available capacity to adjust the net peak hour period capacity shortfall in an LDA only to extent necessary to mitigate or eliminate any availability shortfalls for committed capacity (Sections 8.4.5 and 8.4.5.1).
- Conforming Revisions for FERC Order ER12-271, accepted on 12/27/2011 and effective 12/30/2011, to modify the bill timing of the Demand Resource and ILR Compliance Penalty Charge such that charges are assessed and billed in two phases. (Section 9.1.9)
- Conforming Revisions needed to clarify Fixed Resource Requirement Alternative business rules in Section 11.3 and conform to Schedule 8.1 of the Reliability Assurance Agreement.
- Conforming Revisions for FERC Order ER11-2875 regarding MOPR (Section 5.3.5)

**Revision 13 (11/17/2011)**

- Revisions for DEOK integration (Sections 2.3.1, 2.3.4, 3.3.1, and Attachment B)

**Revision 12 (05/25/2011)**

- Confirming Revisions for FERC Order ER11-2898, accepted on 04/04/2011 and effective 04/18/2011, to include changes for:
  - Requirement to provide meter data on a 24-hour basis during the day on which a Load Management event or performance test occurs and for all hours during any other days as required by PJM to calculate load reduction
  - Avoiding double assessment of a penalty (penalty for both RPM Commitment Compliance and Load Management Event or Test Compliance) for a Demand Resource

  - Modification to the load management retest rules
  - Modification and clarification of the rules for use of Demand Resources as replacement capacity
- Confirming Revisions for FERC Order ER11-1909, accepted on 12/20/2010 and effective on 12/27/2010, to include a change to clarify the definition of an EE Resource to reflect that a project qualifying as an EE Resource is one installed at an end-use customer's retail site.
- Revisions to EFORd used for a generation resource in the initial evaluation of a FRR Entity's FRR Capacity Plan for a Delivery Year as approved by stakeholders at the MRC on August 5, 2010.

**Revision 11 (04/28/2011)**

- Revisions for ATSI integration (Sections 2.3.1, 2.3.4, 3.3.1, and Attachment B)

**Revision 10 (06/01/2010)**

- Revisions made to rules for Non Unit-specific Capacity Transactions to clarify that PJM will be the counterparty to all transactions, unless market participants expressly and mutually contract between themselves (or self schedule to themselves). Revisions have been approved at the Markets and Reliability Committee on April 21, 2010 and by FERC (Order ER10-1003 issued on May 5, 2010)
- (Reference: FERC Order ER10-1003)

**Revision 9 (03/01/2010)**

- Clarifying Revisions
- Conforming Revisions for FERC Order ER10-15, accepted on 11/13/09 and effective 12/01/09, to include changes to Credit Rate Change
- Conforming Revisions for FERC Order ER09-1679 accepted on October 29, 2009 and effective November 1, 2009 to include changes for:
- New Entry Pricing Adjustment
- Removal of Existing EE and DR offer caps
- Allocation of LM Test Failure Charges
- Planned DR Deadline - change to 15 business days
- Excess Commitment Credit for LSEs if cannot sell excess in IA
- Reduction in FRR Obligation when Load Forecast is reduced
- Conforming Revisions for FERC Order ER05-1410 accepted on October 30, 2009 and effective 11/1/09 to include changes to Incremental Auctions design
- Conforming Revisions for FERC Order ER09-412 accepted on November 5, 2009 and effective November 13, 2009, to include changes to the trigger for a Conditional IA only for delay of Backbone Transmission Upgrade

- Conforming Revisions for ER09-1679 to include changes to Revisions for the automated adjustment to Net CONE
- Conforming Revisions for FERC Order ER10-366 accepted on January 22, 2010 and effective January 31, 2010, to include changes
- evaluate the method for creation of additional CONE regions
- Revisions to allow Energy Efficiency Resources to participate in Earlier Deliver Years
- RPM Incremental Auction Times

**Revision 8 (01/01/10)**

- Revisions approved by stakeholders at MRC on November 11, 2009
- One CSP Rule (Section 4, p 33)
- Permanent Load Departure (Section 8, p 98)
- Tracking Existing DR (Section 4, pp 30-31)
- Revisions approved by stakeholders at MRC on November 30, 2009 (awaiting FERC approval by February 1, 2010)
- Winter Capacity Test Exemption (Sections 4 & 8, pp 24, 27, 104-105)

**Revision 7 (08/18/2009)**

- Revision to Section 4 to modify business rules to state that RPM suppliers must confirm the modeling of each of their capacity resources (Zone, LDA, Unit Type, State Location) prior to any RPM auction.
- Revision to Section 5 to modify business rules to state that RPM Auction Results will not be posted until 4pm or later on Friday of Auction Clearing week.

**Revision 06 (06/18/2009)**

- Revisions to include business rules for Cleared Buy Bid and Locational UCAP transactions.
- Revisions required as a result of the March 26, 2009 FERC Order regarding Reliability Pricing Model

**Revision 05 (10/03/2008)**

- Revisions regarding Transmission Service for External Resources offering into RPM.

**Revision 04 (06/08/2008)**

- Incorporate Rules for Capacity Export Charge per FERC Order ER07-1050 (Effective May 30, 2008)

**Revision 03 (04/01/2008)**

- Established a Min and Max capacity value for Wind Resources offering into an RPM Auction.

**Revision 02 (02/21/2008)**

- Correct an error in the original posting of this Manual. Remove the word “not” in the End-Use Customer Aggregation section of Section 4 to reflect the fact that aggregation of Interruptible for Load (ILR) Resources is allowed.

**Revision 01 (02/03/2008)**

- Revisions made for the following changes:
  - Current, Minimum, Maximum Available Capacity Position Definitions.
  - Change Final Zonal RPM Scaling Factors posting date from October 31st to January 5th.
  - Allow for Combined Demand Resources and ILR Resources at the same location.

**Revision 00 (06/01/07)**

- Manual Created for the Implementation of the Reliability Pricing Model, and the Fixed Resource Requirement Alternative.

# EXHIBIT 40

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) Emergency Order: PJM Interconnection And Constellation Energy | ) ) ) ) ) | Order No. 202-25-4 |

Motion to Intervene and Request for Rehearing of
Natural Resources Defense Council, Citizens for Pennsylvania's Future,
Environmental Defense Fund, Sierra Club and Public Citizen


**I. INTRODUCTION ..... 4**

**II. STATEMENT OF ISSUES AND SPECIFICATION OF ERROR ..... 7**

**III. INTERVENORS' INTERESTS ..... 9**

A. NATURAL RESOURCES DEFENSE COUNCIL ..... 10

B. CITIZENS FOR PENNSYLVANIA'S FUTURE ..... 11

C. ENVIRONMENTAL DEFENSE FUND ..... 12

D. SIERRA CLUB ..... 13

E. PUBLIC CITIZEN ..... 13

**IV. BACKGROUND ..... 14**

A. CONSTELLATION ENERGY GROUP AND THE EDDYSTONE PLANT ..... 14

B. HOW PJM ENSURES RESOURCE ADEQUACY AND RELIABILITY ..... 17

C. DOE'S MAY 30, 2025 202(C) ORDER AND PJM'S JUNE 13 LETTER ..... 25

**V. REQUEST FOR REHEARING ..... 28**

A. THE ORDER EXCEEDS THE DEPARTMENT'S AUTHORITY BECAUSE IT HAS NOT, AND CANNOT, DEMONSTRATE AN UNEXPECTED EMERGENCY UNDER SECTION 202(C) NECESSITATING CONTINUED OPERATION OF EDDYSTONE. ... 28

B. SECTION 202(C) ONLY AUTHORIZES THE DEPARTMENT TO RESPOND TO SPECIFIC, IMMINENT, UNEXPECTED, AND TEMPORARY EVENTS, NOT TO MANDATE GENERATION BASED ON LONGER-TERM RELIABILITY CONCERNS. ..... 30

1. Section 202's Text and Structure Establish that Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response. ..... 30

2. Congress' Enactment of a Specific, Cabined Scheme to Address Reliability Concerns Confirms that Section 202(c) Cannot be Expanded to Impose Requirements Related to Long-Term Reliability. ..... 34

3. Regulations Similarly Establish that Section 202(c) Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response. ..... 36

4. Courts Have Uniformly Held that Section 202(c) Can Be Invoked Only in Immediate Crises. ..... 38

5. The Department's Prior Orders Recognize that Section 202(c) Does Not Confer Plenary Authority Over Long-Term Resource Adequacy. ..... 40

C. THERE IS NO FACTUAL BASIS SUPPORTING THE DEPARTMENT'S ORDER. ..... 42

1. The Energy Emergency Executive Order does not provide a valid basis under Section 202(c). ..... 43

2. The Department Failed to Produce Evidence of an Emergency. ..... 45

3. PJM Has Sufficient Capacity Resources for Summer 2025 Without Eddystone. ..... 56

4. The Order Is Based on a False Premise and Violates the Department's Duties Under the Administrative Procedure Act. ..... 61

D. THE ORDER WILL UNDERMINE COMPETITIVE MARKETS TO THE DETRIMENT OF CONSUMERS AND RELIABILITY. ..... 63

1. Competitive Markets Have a Long History of Success. ..... 63

2. Command and Control Orders Run Counter to Federal Power Act Requirements and Fundamental Market Principles. ..... 66

E. EVEN IF THERE WERE A SHORT-TERM NEED—THERE IS NOT—THE ORDER DOES NOT COMPLY WITH THE STATUTORY COMMAND TO SET TERMS THAT BEST MEET THE EMERGENCY AND SERVE THE PUBLIC INTEREST. ..... 71

1. Section 202(c)(1) Only Authorizes the Department to Require Generation that Best Meets the Emergency and Serves the Public Interest. ..... 71

2. The Order Does not Contain a Reasoned Basis that Eddystone Best Meets the Claimed Emergency and Serves the Public Interest. ..... 74

F. BECAUSE THE ORDER IS AMBIGUOUS, IT FAILS TO PROVIDE FAIR NOTICE TO THE PUBLIC AND REGULATED ENTITIES AND CONFLICTS WITH LIMITATIONS ON THE DEPARTMENT'S AUTHORITY ..... 76

G. THE ORDER FAILS TO PROVIDE THE CONDITIONS NECESSARY TO OVERRIDE ENVIRONMENTAL STANDARDS UNDER SECTION 202(C)(2). ..... 79

H. THE ORDER AND THE DEPARTMENT'S CONTINUED CONDUCT ARE INCONSISTENT WITH DEPARTMENTAL PROCEDURE, DEPRIVING THE PUBLIC AND THE PUBLIC INTEREST ORGANIZATIONS OF FAIR NOTICE AND AN ADEQUATE RECORD. ..... 84

**VI. REQUEST FOR STAY ..... 85**

A. INTERVENORS ARE IRREPARABLY HARMED BY THE ORDER... 87

B. A STAY WOULD NOT RESULT IN HARM TO ANY OTHER INTERESTED PARTIES. ..... 88

C. A STAY IS IN THE PUBLIC INTEREST ..... 89

**VII. CONCLUSION ..... 89**

## I. INTRODUCTION

Pursuant to section 313 of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, Natural Resources Defense Council, Citizens for Pennsylvania's Future, Environmental Defense Fund, Sierra Club, and Public Citizen (together "Public Interest Organizations") request that the Department of Energy ("Department" or "DOE") grant rehearing of Order No. 202-25-4 (May 30, 2025) (the "Order").[1] Acting on its own motion and without providing notice, the Department issued the Order on May 30, 2025, pursuant to its emergency authority under section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c) ("Section 202(c)"), to instruct PJM Interconnection, LLC ("PJM") and Constellation Energy Corporation ("Constellation") to "take all measures necessary to ensure that" Units 3 and 4 of the Eddystone Generating Station, in Eddystone, Pennsylvania, ("Eddystone" or the "Eddystone Units"), remain "available to operate" until August 28, 2025, and further directed PJM to "take every step to employ economic dispatch" during that time period. Ex. 1 at 3. Prior to the Department's eleventh-hour intrusion, Constellation was preparing to retire these two oil- and gas-burning units on May 31, 2025, with PJM's approval.

The Department should grant rehearing and rescind this costly, harmful, unnecessary, and unlawful order. There is no energy emergency in the PJM region as defined by Section 202(c). The Eddystone Units were scheduled to deactivate only following analysis showing that this would not cause any transmission

[1] A copy of the Order is attached as Exhibit 1.

instability and that replacement economic capacity resources were available. The result of the Department's overreach will be unnecessary costs imposed on already-overburdened ratepayers, needless pollution emitted into Pennsylvania and neighboring states, and unprecedented interference with regulation of grid resource adequacy, an area Congress reserved for other authorities. 16 U.S.C. § 824(b)(1).

The Order's emergency declaration cannot withstand even the mildest scrutiny. On its face, the Order fails to identify conditions necessary to invoke Section 202(c)'s extraordinary powers, which are reserved for sudden, imminent, and unexpected energy shortages.[2] The Order offers only selective quotes from PJM documents about potential future risks of shortages well outside the 90-day period covered by the Order. In fact, the cited documents refute the Department's conclusory assertions. Nor does the Order's reference to the "declared state of national energy emergency" cure the defect. Ex. 1 at 2. The vague, unsupported assertions in Executive Order ("EO") 14,156 *Declaring a National Energy Emergency* ("Energy Emergency EO")—belied by the U.S. Energy Information Administration's current data[3]—do not override Section 202(c), nor do they supply

[2] As the Department's own regulations emphasize, an "emergency," arises when there is an "unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities," due to weather, acts of God, "sudden" increases in demand, inability to obtain fuel, or a regulatory action prohibiting the use of certain facilities. 10 C.F.R. § 205.371. The Department makes no pretense of identifying these conditions as the bases for the Order.

[3] Indeed, U.S. energy production and exports are currently at an all-time high: Energy Info. Admin., U.S. primary energy production, consumption, and exports increased in 2024 (June 20, 2025), https://www.eia.gov/todayinenergy/detail.php?id=65524.

the specific information needed to support issuance of this Order or any other Section 202(c) order. The Order also refers to EO 14,262 (*Strengthening the Reliability and Security of the United States Electric Grid*) ("Grid EO"), but that order merely directs the Department to develop an as-yet unpublished methodology to analyze grid reliability to support future 202(c) orders, and can't be bootstrapped to supply a *post hoc* basis for this Order.

Even assuming there is an emergency under Section 202(c), the Order also fails to demonstrate that continued operation of the Eddystone Units is the action that "best meet[s] the emergency and serve[s] the public interest." 16 U.S.C. § 824a(c). The Order completely fails to address alternatives to continued operation of the Eddystone Units, including PJM's contracted demand reserve programs,[4] which ensure grid reliability at a lower cost even in the event of historically high demand peaks. Nor does the Order provide sufficiently clear instructions for Constellation and PJM, both as to plant operations and economic dispatch. And compounding these failures, the Order makes no effort to limit the environmental and public health harms that Eddystone imposes on the surrounding communities, despite explicit instruction from Congress to do so.

In short, the Order is an unlawful abuse of the Department's emergency authority and should be rescinded. The statutory bases for issuing an order under

[4] *See* PJM Interconnection, PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk, Inside Lines (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/ (hereinafter "Summer Outlook 2025").

Section 202(c) are not present; and even if they were, the Order would still be unlawful because it fails to comply with the substantive requirements of Section 202(c), resulting in a twofold blow to PJM ratepayers: higher rates and more pollution with no net benefit received. The Department is authorized only to use Section 202(c) for real emergencies, not to usurp authority for grid reliability planning and to prop up fossil fuel businesses.

## II. STATEMENT OF ISSUES AND SPECIFICATION OF ERROR

The undersigned Public Interest Organizations move to intervene and request rehearing and a stay pursuant to section 313(a) of the Federal Power Act, 16 U.S.C. § 825*l*(a), and the applicable rules of practice and procedure,[5] based upon the following errors and issues:

- The order exceeds the Department's authority because it has not, and cannot, demonstrate an unexpected emergency under Section 202(c) necessitating continued operation of Eddystone. 16 U.S.C. § 824a(c).

- Section 202(c) only authorizes the Department to respond to specific, imminent, unexpected, and temporary events, not to mandate generation based on longer-term reliability concerns. 16 U.S.C. § 824a(c); H.R. Rep. No. 114-357 § 61002 (2015); *Jarecki v. G.D. Searle & Co.*, 367 U.S. 303 (1961); *Richmond Power & Light of City of Richmond, Ind. v. FERC*, 574 F.2d 610

[5] U.S. Dep't of Energy, DOE 202(c) Order Rehearing Procedures, https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (last visited June 18, 2025) (attached as Ex. 2) (hereinafter "DOE Rehearing Procedures"). This website was altered after June 18, 2025, and the procedures were removed. *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website. *See also* Ex. 3 (Email from Lot Cooke, U.S. Dep't of Energy to Linda Alle-Murphy Re: Rehearing procedures for DOE Order No. 202-05-3 (December 28, 2005)) (recommending that "a party seeking rehearing can look for procedural guidance to [Federal Energy Regulatory Commission's ("FERC")] Rules of Practice and Procedure, 18 CFR Part 385.").

(D.C. Cir. 1978); S. Rep. No. 74-621 (1935); 16 U.S.C. § 824a(a) & (b); *Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232 (8th Cir. 1970); 16 U.S.C. § 824o; 70 Fed. Reg. 53,117; S. Rep. No. 109-78 (2005); *Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); 16 U.S.C. § 824o(c)-(d); 16 U.S.C. § 824o(a)(3); 16 U.S.C. § 824o(d)(2)-(4); 16 U.S.C. § 824o(e); 16 U.S.C. § 824o(i)-(j); *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120 (2000); *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395 (D.C. Cir. 2004); 10 C.F.R. § 205.371; 10 C.F.R. § 205.375; 46 Fed. Reg. 39,984; *FTC v. Bunte Brothers, Inc.*, 312 U.S. 349 (1941).

- There is no factual basis supporting the Department's Order. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371; *Biden v. Nebraska*, 600 U.S. 477 (2023); S. Rep. No. 94-1168 (1976); 1976 U.S.C.C.A.N. 2288; 16 U.S.C. § 824o-1; 16 U.S.C. § 809; 16 U.S.C. § 824a; 50 U.S.C. § 1631; Executive Order 14,156, Declaring a National Energy Emergency, 90 Fed. Reg. 8,433 (Jan, 20, 2025); 42 U.S.C. § 7172; 5 U.S.C. § 706(2)(A); 10 C.F.R. 205.375; *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260 (2016); *Dep't of Homeland Sec. v. Regents of the Univ. of California,* 140 S. Ct. 1891 (2020); Order Accepting Tariff Revisions Subject to Condition, 190 FERC ¶ 61,088 (2025); *Youngstown Sheet & Tube Co. v. Sawyer*, 343 U.S. 579 (1952); *Dept. of Com. v. New York*, 588 U.S. 752 (2019); *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983); *Amerijet Int'l, Inc. v. Pistole*, 753 F.3d 1343 (D.C. Cir. 2014); *D.C. Fed'n of Civic Ass'ns v. Volpe*, 459 F.2d 1231 (1971).

- The Order will undermine competitive markets to the detriment of consumers and reliability. Executive Order 14,156, Declaring a National Energy Emergency, 90 Fed. Reg. 8,433 (Jan, 20, 2025); 16 U.S.C. § 824a(c); 16 U.S.C. § 824d; Order Terminating Rulemaking Proceeding, Initiating New Proceeding, And Establishing Additional Procedures, 162 FERC ¶ 61,012 (2018); Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996); Order No. 888-A, FERC Stats. & Regs. ¶ 31,048; Order No. 888-B, 81 FERC ¶ 61,248 (1997); Order No. 888-C, 82 FERC ¶ 61,046 (1998); *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000); *New York v. FERC*, 535 U.S. 1 (2002); Order No. 890, FERC Stats. & Regs. ¶ 31,241 (1997); Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999); Order 787, 145 FERC ¶ 61,134 (2013); Order 809, 151 FERC ¶ 61,049 (2015); Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, 149 FERC ¶ 61,145 (2014); Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1, 182 FERC ¶ 61094 (2023); Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification, 187 FERC ¶ 61,204 (2024); Order Accepting Tariff Revisions Subject to Condition, 186 FERC ¶ 61,080 (2024).

- Even if there were a short-term need—there is not—the Order does not comply with the statutory command to set terms that best meet the emergency and serve the public interest. 16 U.S.C. § 824a(c)(1); *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208 (2009); *Sierra Club v. Env't. Prot. Agency*, 353 F.3d 976 (D.C. Cir. 2004); *Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1 (2020); *Motor Vehicle Mfrs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983); *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200 (D.C. Cir. 2013); *Chamber of Com. of the U.S. v. Secs. & Exch. Comm'n*, 412 F.3d 133 (D.C. Cir. 2005); 10 C.F.R. § 205.370; 16 U.S.C. § 824a(c); 10 C.F.R. § 205.373; *Wabash Valley Power Ass'n*, 268 F.3d 1105 (D.C. Cir. 2001); *Gulf States Utils. Co. v. Fed. Power Comm'n*, 411 U.S. 747 (1973); *California v. Fed. Power Comm'n*, 369 U.S. 482, 484–86 (1962); *NAACP v. Fed. Power Comm'n*, 425 U.S. 662 (1976); *Otter Tail Power Co. v. United States*, 410 U.S. 366 (1973); *Pa. Water & Power Co. v. Fed. Power Comm'n*, 343 U.S. 414 (1952); 46 Fed. Reg. 39,985.

- Because the order is ambiguous, it fails to provide fair notice to the public and regulated entities and conflicts with limitations on the Department's authority. *Fed. Commc'ns Comm'n v. Fox Telev. Stations, Inc.*, 567 U.S. 239 (2012); *Grayned v. City of Rockford*, 408 U.S. 104 (1972); 16 U.S.C. § 824a(c); *Allentown Mack Sales & Serv., Inc. v. N.L.R.B.*, 522 U.S. 359 (1998).

- The Order fails to provide the conditions necessary to override environmental standards under Section 202(c)(2). 16 U.S.C § 824a(c)(2); *City of New Orleans v. FERC*, 67 F.3d 947 (D.C. Cir. 1995); *Fla. Power & Light Co. v. FERC*, 88 F.3d 1239 (D.C. Cir. 1996); 68 Fed. Reg. 1660.

- The Order and the Department's continued conduct are inconsistent with departmental procedure, depriving the public and the Public Interest Organizations of fair Notice and an adequate record. *Morton v. Ruiz*, 415 U.S. 199 (1974); *Mine Reclamation Corp. v. FERC*, 30 F.3d 1519 (D.C. Cir. 1994); *United States v. Nova Scotia Food Prods. Corp.*, 568 F.2d 240 (2d Cir. 1977).

## III. INTERVENORS' INTERESTS

As further discussed below, each of the Public Interest Organizations has interests that may be directly and substantially affected by the outcome of this proceeding. Each party may therefore intervene in this proceeding. DOE Rehearing Procedures; *see also* 18 C.F.R. § 385.214.

Each of the Public Interest Organizations also demonstrate a concrete injury arising from the Order that is redressable by a favorable outcome. Each organization is therefore aggrieved by the Order and may properly apply for rehearing. *See* 16 U.S.C. § 825*l*(a); *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105, 1112-13 (D.C. Cir. 2001); *NextEra Energy Res. v. ISO New Eng., Inc.*, 157 FERC ¶ 61,059, at P 5 (2016).

### A. Natural Resources Defense Council

Natural Resources Defense Council ("NRDC") is a national non-profit membership organization whose mission includes ensuring the rights of all people to clean air, clean water, and healthy communities. NRDC has a longstanding organizational commitment to protect the interests of its members and to reducing pollution caused by fossil fuel fired power plants such as Eddystone. NRDC works to achieve clean energy solutions that will lower consumer energy bills, meet greenhouse gas emission reduction goals, accelerate the use of energy efficiency and renewable energy, and ensure that clean energy is affordable and accessible to all.

NRDC and its members are aggrieved by the Order. Over 19,800 NRDC members reside in Pennsylvania, over 1,500 NRDC members reside in Delaware, over 9,600 NRDC members reside in Maryland, and 12,600 NRDC members reside in New Jersey. Of these, approximately 1,300 members reside within ten miles of the Eddystone Units. These NRDC members are harmed by the order to operate Eddystone beyond its planned retirement date because continued operation will subject NRDC members to air and water pollution in the areas where they live, work, and recreate. NRDC members are also exposed to the noise and visual

impacts of the plant's operation. The impact of the Order on the health, aesthetic, and recreational interests of NRDC members is compounded by the Order's failure to address the Federal Power Act's requirements for environmental protection that apply even in true emergencies (discussed in section V.G. below). In addition, NRDC members are ratepayers in the PJM region who will be subject to higher electric bills as a result of the Order. NRDC also operates an office in Washington D.C., which is in the PJM region. NRDC pays for the electricity used by its Washington D.C. office and will be subject to higher electric bills as a result of the Order. Moreover, NRDC has a sustainable operations plan with a goal of reducing net creation of greenhouse gas emissions derived from building operational activity to zero. NRDC and its members therefore have a strong interest in promoting actions that displace less cost-effective fossil generation with more cost-effective clean energy.

### B. Citizens for Pennsylvania's Future

Citizens for Pennsylvania's Future ("PennFuture") is a Pennsylvania-based statewide environmental organization dedicated to leading the transition to a clean energy economy in Pennsylvania and beyond. PennFuture has approximately 1,000 members across the state. PennFuture's mission is to protect our air, water, and land, and to empower citizens to build sustainable communities for future generations. One focus of PennFuture's work is to address the climate-warming pollution from Pennsylvania's power fleet. PennFuture also works to advance understanding and recognition of Pennsylvania's Environmental Rights Amendment, contained in Article 1, Section 27 of Pennsylvania's Constitution and

to ensure that Commonwealth entities meet their obligations under the Amendment as trustees of Pennsylvania's public natural resources. To promote affordable and clean energy, PennFuture advocates before government entities, including local, state, and federal agencies such as FERC, on issues related to electricity markets, policies affecting the clean energy transition, and just and reasonable rates. This proceeding raises issues which are important to the environmental, public health, and affordability interests that PennFuture seeks to advance.

### C. Environmental Defense Fund

The Environmental Defense Fund ("EDF") is a nonprofit membership organization with hundreds of thousands of members nationwide, including more than thirteen thousand members in Pennsylvania, whose mission is to build a vital Earth for everyone by preserving the natural systems on which all life depends. Guided by expertise in science, economics, law, and business partnerships, EDF seeks practical and lasting solutions to address environmental problems and protect human health, including in particular by addressing pollution from the power sector. On behalf of its members, EDF works with partners across the private and public sectors to engage in utility regulatory forums at the federal level and throughout the United States to advocate for policies that will create an affordable, reliable, and low pollution energy system. The Order harms EDF members because it will result in increased pollution that will impact the health of people and nature and because it will increase energy costs for EDF members throughout the PJM region.

### D. Sierra Club

Sierra Club and its members are aggrieved by the Order. Over 55,000 Sierra Club members reside in Pennsylvania and New Jersey; and over 4,000 of those members reside in one of the four counties most likely to be impacted by pollution from Eddystone. Sierra Club members are harmed by pollution produced by operating the Eddystone Units. The Order to operate the plant beyond its planned retirement date will subject Sierra Club members to additional air pollution in the areas where they live and recreate. The Order's impact on the health, aesthetic, and recreational interests of Sierra Club members is heightened by the Order's failure to address the Federal Power Act's requirements for environmental protection that apply even in true emergencies. In addition, Sierra Club operates multiple offices in the PJM region, and has well over 100,000 members living in the PJM region, all of whom will be subject to higher electric bills as a result of the Department's Order.

### E. Public Citizen

Established in 1971, Public Citizen is a national, not-for-profit, non-partisan, research and advocacy organization representing the interests of household consumers. Public Citizen has over 500,000 members and supporters across the United States, including in PJM and Pennsylvania. Public Citizen is active before FERC promoting just and reasonable rates, and supporting efforts for utilities to be accountable to the public interest. Public Citizen's interests in this proceeding are unique, and cannot be represented by any other party.

## IV. BACKGROUND

### A. Constellation Energy Group and the Eddystone Plant

The Eddystone Generating Station is owned and operated by Constellation. It is a six-unit, 820 megawatt ("MW") power plant located along the banks of the Delaware River in Eddystone, Pennsylvania, just south of Philadelphia and in the PJM regional transmission organization ("RTO").[6] Units 3 and 4 are both 380 MW capacity steam boiler-turbine generator units that can run on either natural gas or distillate fuel oil. These units were installed between 1967 and 1970 and are "peakers," i.e., units that run only during periods of high demand. The plant also includes two smaller pairs of oil fueled peaking units—Units 10, 20, 30, and 40—which have a total combined capacity of 60 MW that were also installed between 1967 and 1970. Eddystone Units 1 and 2, which operated on coal, were both closed over ten years ago. As shown in Table 1 below, Eddystone Units 3 and 4 have each operated less than 1% of the time during the last four years. In Pennsylvania's restructured utility market, generation units like Eddystone are not committed to serve customers of a particular utility; rather, Constellation submitted offers into regional markets for services that Eddystone was eligible to provide and generated energy or provided other services when those offers were selected by the market mechanism.

[6] Constellation, Eddystone Generating Station, https://www.constellationenergy.com/our-company/locations/location-sites/eddystone-generating-station.html (last visited June 20, 2025).

| Table 1 | | | | | | |
|---|---|---|---|---|---|---|
| Capacity Factor | 2020 | 2021 | 2022 | 2023 | 2024 | Average |
| *Capacity Factor* | 0.18% | 0.25% | 0.27% | 0.40% | 0.92% | **0.40%** |

Sources: EIA, *Form EIA-923: Power Plant Operations Report, Net Generation Data for Eddystone Generating Station*, 2020–2023, https://www.eia.gov/electricity/data/eia923/ (accessed June 20, 2025); EPA, *CEMS Gross Load Data for Eddystone Generating Station*, 2020–2023, CAMPD, https://campd.epa.gov/ (accessed June 20, 2025) (2024 capacity factor estimated using average gross-to-net ratio from 2020–2023).

The Eddystone Units are located just outside of Chester, Pennsylvania, a community that faces one of the nation's worst cases of environmental racism.[7] Whenever it is operating, Eddystone contributes to the pollution impacting this community. On a yearly basis, Eddystone emits thousands of tons of criteria air pollutants, *see* Table 2, and large amounts of water pollutants.[8] And when Eddystone operates on oil rather than natural gas, it emits higher levels of both criteria pollutants and hazardous air pollutants.[9] These air pollutants are linked to

[7] *See* Chester Residents Concerned for Quality Living, https://chesterpaej.org/ (last visited June 26, 2025); University of Pennsylvania, Perelman School of Medicine, Center of Excellence in Environmental Toxicology, *Chester*, http://ceet.upenn.edu/community/target-communities/chester/ (last visited June 26, 2025).

[8] EPA, Pollutant Loading Report, https://echo.epa.gov/trends/loading-tool/reports/dmr-pollutant-loading?permit_id=PA0013714&year=2024 (last visited June 26, 2025) (including over 2 million pounds of total suspended solids, and over 25,000 pounds of ammonia, as well as 1,617 pounds of copper and 564 pounds of lead, in 2024 alone).

[9] Ex. 4 (Eddystone Title V Permit) at 28, 50 (noting sulfur content of oil and higher NOx emissions from oil-fired generation); 68 Fed. Reg. 1660,1678 (Jan. 13, 2003) (noting that switching from oil to natural gas "would reduce mercury, metallic [toxics], and inorganic" hazardous air pollutant emissions).

respiratory symptoms like asthma,[10] cancer, reproductive difficulties, and other health problems.[11]

| Table 2 | | | | | | |
|---|---|---|---|---|---|---|
| **Annual Emissions** | **2020** | **2021** | **2022** | **2023** | **2024** | **Cumulative Emissions** |
| *CO2 (tons)* | 11,167 | 14,943 | 18,636 | 28,332 | 58,566 | **131,644** |
| *NOx (lbs)* | 11,918 | 15,488 | 20,506 | 29,606 | 59,232 | **136,750** |
| *SO2 (lbs)* | 128 | 176 | 234 | 322 | 704 | **1,564** |
| Source: EPA, *Annual Emissions Data for Eddystone Generating Station*, 2020–2024, available at CAMPD, https://campd.epa.gov/ (accessed June 20, 2025). | | | | | | |

On December 1, 2023, Constellation notified PJM of its intent to deactivate Eddystone Units 3 and 4 effective May 31, 2025.[12] In that letter, Constellation explained that it was "retiring Eddystone Units 3 and 4 because continued operation of these units is expected to be uneconomic."[13] Such a notice triggers PJM's process under Section 113.2 of its Open Access Transmission Tariff to study whether the deactivation will cause any reliability violations. In February 2024, PJM sent a letter to Constellation indicating that it had completed its study and no

[10] EPA, Effects of NO2, Health Effects, https://www.epa.gov/no2-pollution/basic-information-about-no2#:~:text=Health%20effects,more%20about%20Visibility%20and%20Haze; https://www.epa.gov/so2-pollution/sulfur-dioxide-basics (last visited June 26, 2025).

[11] EPA, Health and Environmental Effects of Hazardous Air Pollutants, https://www.epa.gov/haps/health-and-environmental-effects-hazardous-air-pollutants (last visited June 26, 2025).

[12] Letter from Bryan Hanson, Constellation, to Michael Bryson, PJM (Dec. 1, 2023), https://www.pjm.com/-/media/DotCom/planning/gen-retire/deactivation-notices/eddystone-deactivation-letter.pdf.

[13] *Id.*

reliability violations had been identified; PJM granted permission to deactivate "on May 31, 2025, or sooner if desired."[14]

### B. How PJM Ensures Resource Adequacy and Reliability

PJM serves as the grid operator for a region that spans all or part of 13 states and the District of Columbia.[15] PJM has established rules and processes for maintaining grid reliability that meet both industry standards and the requirements of the FERC certified Electric Reliability Organization—the North American Electric Reliability Corporation ("NERC")—including through ensuring resource adequacy. Electric utilities and other load-serving entities that have joined PJM comply with those rules and participate in those processes to maintain regional reliability. Many of the utilities in PJM own few or no generation assets and therefore rely substantially on PJM-run markets to procure both energy and other services that support the reliable operation of the grid.

PJM's primary tool to maintain resource adequacy throughout the region, including the state of Pennsylvania, is its Reliability Pricing Model ("RPM"), commonly known as its capacity market, which is designed to ensure there is enough energy supply on the system to meet demand, especially during high-risk

[14] Letter from Paul McGlynn, PJM, to Bryan Hanson, Constellation (Feb. 27, 2024), https://www.pjm.com/-/media/DotCom/planning/gen-retire/deactivation-notices/pjm-response-letter-eddystone.pdf.

[15] PJM, About PJM, https://www.pjm.com/about-pjm (last visited June 20, 2025).

periods.[16] The capacity market does not pay for energy itself but pays resources for the promise to make a given quantity of energy available for sale at any time over the course of one year (the contracted "delivery year") upon demand of the grid operator.[17] For each "delivery year," which begins June 1, PJM determines the region's "Reliability Requirement" and sub-regional reliability requirements for any "locational deliverability areas" that are transmission-constrained.[18] PJM determines the Reliability Requirement based on a granular risk model of the system that reflects variability in consumer demand as well as the performance of all the supply resources on its system. The determination of the Reliability Requirement includes a forecast of the peak load and the addition of a reserve margin to account for uncertainties, in order to meet the reliability standard set out in PJM's Reliability Assurance Agreement—i.e., a loss of load expectation ("LOLE")

[16] High risk periods are generally winter storms and hot summer days. *See Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656, 659-61 (D.C. Cir. 2017); *see also* PJM, PJM Capacity Market: Promoting Future Reliability, https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/pjm-capacity-market-promoting-future-reliability-fact-sheet.pdf (Jan. 25, 2025).

[17] *See* PJM, Capacity Market (RPM) https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets.aspx (last visited June 26, 2025); FERC, An Introductory Guide to Electricity Markets Regulated by the Federal Energy Regulatory Commission, https://www.ferc.gov/introductory-guide-electricity-markets-regulated-federal-energy-regulatory-commission#_ednref2 (last visited June 26, 2025).

[18] PJM, Manual 18: PJM Capacity Market, Revision 57, at 26 (July 26, 2023), https://www.pjm.com/-/media/DotCom/documents/manuals/archive/m18/m18v57-capacity-market-07-26-2023.pdf.

no greater than one occurrence in ten years.[19] The systemwide Reliability Requirement is the number of megawatts of capacity needed to ensure adequate reserve margins during high-risk periods; Local Reliability Requirements for constrained locational deliverability areas reflect the local capacity needed to ensure adequate reserve margins during high risk periods, when accounting for transmission constraints applicable to that area. Using the same granular risk model, PJM determines the capacity accreditation values for each supply resource on its system—these values represent the amount of capacity, in "unforced capacity" or "UCAP" terms that a resource may offer into the capacity market. Since 2024, PJM has determined these accreditation values using a marginal effective load carrying capability ("ELCC") methodology, that assesses how much adding one additional megawatt of a particular generation type to the system increases the system's ability to serve consumer demand.[20] A generator or demand response resource's marginal ELCC value is expressed as a percentage—the unit can sell capacity equivalent to its nameplate capacity times that percentage. When PJM applied ELCC to oil and gas resources, the capacity accreditation values for these sources decreased from prior values, due to their historically poor performance

[19] *See* PJM Interconnection LLC, 186 FERC ¶ 61,080, at P 2 (2024) (citing PJM Resource Adequacy Planning, 2022 PJM Reserve Requirement Study (Oct. 4, 2022).

[20] *PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,080 (2024) (approving PJM's proposal to adopt use of ELCC methodology for capacity accreditation).

during extreme winter weather.[21] In other words, PJM concluded that oil and gas resources such as Eddystone should be deemed to contribute less to capacity requirements than it previously had assumed.

For each delivery year, PJM conducts a series of auctions to procure commitments from supply resources to provide capacity—to be available to generate power (or curtail power in the case of demand response) when needed by PJM as the system operator. The primary event is the Base Residual Auction, typically held three years in advance of the delivery year. In this auction, supply resources submit offers for the price at which they are willing to sell the quantity of capacity that reflects their ELCC. Demand in the auction is represented by the Variable Resource Requirement Curve, which reflects the administratively determined price that, in PJM's judgment, consumers should be willing to pay to attract sufficient supply to the auction. PJM constructs a supply curve from the sellers' offers. Where this supply curve crosses the demand curve determines the quantity of capacity that will be obligated for the delivery year, as well as the clearing price that will be paid to all sellers that submitted offers at or below that price level. Between the Base Residual Auction and the delivery year, PJM will conduct one or

[21] Ex. 5, Affidavit of Adam Keech on Behalf of PJM Interconnection LLC in *PJM Interconnection, L.L.C.*, FERC Accession No. 20231013-5157 (Oct. 13, 2023) (PJM's filing in the above docket) ¶ 9: "Winter Storm Elliott represents the fifth event where, 'cold weather-related generation outages jeopardized bulk power system reliability,'" (citing FERC, NERC, and Regional Entity Joint Staff Inquiry, December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations, Federal Energy Regulatory Commission, 3 (Sept. 21, 2023), https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott.)

more incremental auctions that allow additional capacity to be procured, or released if the load forecast declines relative to the three-year ahead forecast, and for suppliers to be relieved of their obligations or take on new ones.

In addition to these market mechanisms, RPM also includes a reliability backstop mechanism.[22] As PJM's Senior VP of Markets recently described it, this mechanism exists in part "to resolve reliability criteria violations caused by . . . lack of sufficient capacity committed through the Reliability Pricing Model auctions" and is "intended to guarantee that sufficient generation, transmission and demand response solutions will be available to preserve system reliability."[23]

Load-serving entities in PJM are utilities or competitive retail suppliers that have obligations to serve retail electricity consumers. PJM requires these load-serving entities to purchase an amount of capacity for each delivery year that corresponds to their peak-load contribution—the amount of electricity they serve consumers (the load) during specific times when demand is highest on PJM's system.[24] Load-serving entities have two options for demonstrating compliance—they can either have capacity purchased on their behalf through the auction, or opt out of participation in the auction by meeting 100% of their obligations through a

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[22] *See* PJM Open Access Transmission Tariff, Att. DD, section 16 (Reliability Backstop), https://agreements.pjm.com/oatt/5130.

[23] Prefiled Statement of Adam Keech on Behalf of PJM Interconnection, L.L.C., FERC Docket No. AD25-7, at p. 6 n.7 (June 4, 2025), https://www.ferc.gov/media/adam-keech-pjm-vice-president-market-design-and-economics.

[24] PJM Reliability Assurance Agreement, Rate Schedule FERC No. 44, https://www.pjm.com/pjmfiles/directory/merged-tariffs/raa.pdf.

"Fixed Resource Requirement" plan. Most load-serving entities in PJM, including those that serve load in Pennsylvania, choose the prior option.

PJM is responsible for aspects of reliability beyond resource adequacy. For example, PJM maintains operational reliability of the system on a minute-to-minute basis through its use of security-constrained economic dispatch of generators and energy storage resources on its system.[25] In addition to paying generators for their actual production of electricity in response to PJM's dispatch instructions, PJM also pays generators and storage providers for ancillary services. These services include operating reserves that remain available on short notice to respond to disturbances on the system, such as other generators unexpectedly dropping offline. Market participants utilize PJM's Markets Gateway software system to submit information and otherwise participate in PJM's energy and ancillary service markets.[26]

Another tool that PJM has to maintain reliability and reduce energy costs for consumers is interregional transmission with its neighboring grid regions. As PJM's President recently explained, PJM's "strong interconnected ties with our neighbors have allowed us to facilitate exports to our neighbors in MISO

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[25] PJM, Manual 11: Energy & Ancillary Services Market Operations, Revision 120, at 54 (2022), https://www.pjm.com/-/media/DotCom/documents/manuals/archive/m11/m11v120-energy-and-ancillary-services-market-operations-05-25-2022.pdf. *See* PJM, Understanding the Differences Among PJM's Markets (2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/understanding-the-difference-among-pjms-markets.pdf.

[26] *See* PJM, Markets Gateway, https://www.pjm.com/markets-and-operations/etools/markets-gateway.aspx (last visited June 26, 2025).

[Midcontinent Independent System Operator], TVA [Tennessee Valley Authority], Duke Energy-Carolinas and the Southwest Power Pool (SPP) during tight conditions" and "also enables us to import energy from our neighbors when our system is stressed."[27] PJM incorporates some benefits from these interregional ties into its resource adequacy planning, which reduces the amount of capacity it must procure internally and thus lowers costs for consumers.[28]

Moreover, to ensure the stability of the transmission system when generators deactivate, PJM requires generators to provide advance notice of such deactivations so that PJM can study the impacts and determine whether any system upgrades are needed to maintain the stability of the system upon deactivation. In some cases, these upgrades won't be operational until after the generator's planned deactivation date, in which case PJM will seek to retain the generator to operate under specific conditions through a Part V agreement, commonly known as a reliability-must-run agreement ("RMR"). The Eddystone units were studied under those provisions, and in February 2024, PJM reported that it "did not identify any reliability violations resulting from the proposed deactivation of the Eddystone Generating Units #3&4" and stated that "[b]ecause there are no reliability

[27] Testimony of Manu Asthana, President and CEO, PJM Interconnection, Before the Subcomm. on Energy of the H. Comm. on Energy & Com. 3 (Mar. 25, 2025), https://docs.house.gov/meetings/IF/IF03/20250325/118040/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.

[28] Adria Brooks, et al., Resource Adequacy Value of Interregional Transmission at 49-50 (June 2025), https://cleanenergygrid.org/wp-content/uploads/2025/06/250610_RAValueInterregionalTx_Corrections.pdf.

violations associated with the deactivation of this generator…the generating unit may deactivate on May 31, 2025, or sooner if desired."[29]

PJM states retain authority that strongly influences resource adequacy, including authority to approve and site new generation and energy storage projects, and to incentivize the development and utilization of particular types of resources.[30] While some PJM states have retained traditional vertically integrated utilities, others—such as Pennsylvania—have restructured their utilities so that they no longer own generation facilities, and have introduced retail choice to permit end use consumers to purchase power from a load-serving entity other than their utility.[31] Pennsylvania state utility regulators expressly rely on PJM's markets to ensure resource adequacy,[32] while also actively shaping those markets to prioritize

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[29] Letter from PJM to Bryan C. Hanson, Constellation Re: Deactivation Notice for Eddystone Generation Units #3&4 at 1 (Feb. 27, 2024), https://www.pjm.com/-/media/DotCom/planning/gen-retire/deactivation-notices/pjm-response-letter-eddystone.pdf.

[30] *See* 16 U.S.C. § 824(b)(1) (reserving authority over generation facilities to the states); *see also Devon Power LLC et al.,* 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").

[31] Electricity Generation Customer Choice and Competition Act, Pa. Code Ch. 28. *See also*, Electric Choice, The Ultimate Guide to Pennsylvania Electricity Deregulation, https://www.electricchoice.com/blog/guide-deregulation-pennsylvania/#:~:text=Pennsylvania%20decided%20in%20favor%20of,save%20$2.5%20billion%20every%20year (last visited June 27, 2025).

[32] *See, e.g.,* Letter from Pennsylvania PUC to PJM Board of Managers 1, (July 7, 2021), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/20210706-pa-puc-letter-regarding-minimum-offer-price-rule.pdf ("Pennsylvania was one of the first restructured states in PJM that embraced the

affordability.[33] Through a combination of market signals and state policies, Pennsylvania has added nearly 3.5 gigawatt ("GW") UCAP of capacity, net of retirements, since 2015—the most of any state in PJM.[34]

### C. The Department's May 30, 2025 202(c) Order and PJM's June 13 Letter

On May 30, 2025, the Department issued the Order based on its "determin[ation] that an emergency exists in portions of the electricity grid operated by PJM due to a shortage of facilities for the generation of electric energy, resource adequacy concerns, and other causes." Ex. 1 at 1. The Order provides a brief, general description of the "Emergency Situation" based primarily on PJM public statements and regulatory filings referring to a "growing resource adequacy concern" that PJM asserts will arise by the end of the decade due to exceptional load growth and a rate of new entry that is inadequate to replace resource

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promise of competition in the wholesale generation market and then spent considerable time and effort developing a burgeoning retail electricity market built on the expectations and benefits of a properly functioning wholesale market."); *see also* Comments of the Pennsylvania Public Utility Commission, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, AD13-7-000 (Jan. 8, 2014), https://www.puc.pa.gov/General/pdf/FERC/DN_AD13-7-000.pdf.

[33] *See, e.g.*, Pa. PUC Dkt. No. M-2024-3051988 (hosting a technical conference and collecting extensive public comments regarding steps the PUC can take to ensure resource adequacy for retail customers), https://www.puc.pa.gov/filing-resources/issues-laws-regulations/technical-conference-on-resource-adequacy/; Pa. PUC, Technical Conference on Resource Adequacy, https://www.puc.pa.gov/filing-resources/issues-laws-regulations/technical-conference-on-resource-adequacy/ (last visited June 26, 2025).

[34] Prefiled Statement of Manu Asthana on Behalf of PJM Interconnection, L.L.C., at 9, Table 2, Meeting the Resource Adequacy Challenge in RTOs/ISOs, FERC Dkt. No. AD25-7 (May 20, 2025) (Acc. No. 20250520-5173).

retirements. *Id.* The "declared state of national energy emergency" is also cited as a basis for the Department's determination of an emergency. The Department asserts that the retirement of the Eddystone Units would "further decrease available dispatchable generation within PJM's service territory" and therefore exacerbate these general issues. *Id.* at 2. The Order was effective immediately, expiring at 5:03 pm ET on August 28, 2025. *Id.* at 3.

Based on this determination, the Department orders Constellation to take all measures necessary to ensure that the Eddystone Units are available to operate and orders PJM to take steps to employ economic dispatch for the Units. *Id.* The Order includes various reporting requirements and instructs PJM and Constellation to file tariff revisions or waivers necessary to effectuate the order. *Id.*

The Order also requires PJM, by June 15, 2025, to provide the Department "with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with the public interest." *Id.* PJM published the letter it provided to the Department on June 13, 2025.[35] That letter indicates that PJM has worked with Constellation to develop an Operations Memorandum setting out the circumstances in which Eddystone can be committed to run. In a summary of that Memorandum, PJM states that Constellation "will maintain active cost offers in Markets Gateway that

[35] Letter from Michael Bryson, PJM, to Secretary of Energy Christopher Wright, PJM Report in Compliance with Ordering Paragraph D of the Department of Energy's May 30, 2025 Order No. 202-25-4 (June 13, 2025), https://www.pjm.com/-/media/DotCom/documents/other-fed-state/20250613-doe-pjm-report-on-compliance-with-Eddystone-order-202-25-4.pdf.

reflects the prevailing costs . . . to operate on gas or oil for both Eddystone 3 and 4, unless either fuel is unavailable or if the units are on a Planned, Maintenance or Forced outage," but that "[t]he units will be shown as 'unavailable' until PJM operators direct the units" to operate "for reliability purposes."[36] Those purposes include: (1) supporting the PJM system operation within established thermal, voltage, and stability limits, when these needs "cannot otherwise be met with available economically dispatched generating resources;" (2) system restoration needs; and (3) a Capacity Emergency, during which "PJM determines that the resources scheduled for an operating day are not sufficient to maintain the appropriate reserve levels for PJM."[37]

PJM's June 13 letter to the Department expresses PJM's "understanding that the Eddystone Units have been available to operate, consistent with the DOE Order, since the order's issuance on May 30, 2025."[38] It also states that "PJM and [Constellation] have coordinated, pursuant to existing generation outage coordination practices and procedures, outages needed by the Eddystone Units to ensure their operational availability consistent with the public interest."[39] A Constellation's spokesperson has publicly stated that, "we are working quickly to

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[36] PJM, Eddystone 3 and 4 Unit Reporting and Commitment Process (June 12, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/postings/20250612-eddystone-3-and-4-unit-reporting-and-commitment-process.pdf.

[37] *Id.*

[38] *Id.*

[39] *Id.* at 3.

retain necessary staff and perform necessary maintenance to allow for safe and reliable operations this summer and beyond."[40]

## V. REQUEST FOR REHEARING

### A. The Order Exceeds the Department's Authority Because It Has Not, and Cannot, Demonstrate an Unexpected Emergency Under Section 202(c) Necessitating Continued Operation of Eddystone.

Section 202(c) confers an extraordinary power; it permits the Department to command action from market participants and to do so freed from core procedural safeguards, jurisdictional boundaries, and substantive limitations that undergird the rest of the Federal Power Act. *See* 16 U.S.C. § 824a(c). It comes as no surprise, then, that when Congress granted this power, Congress narrowly tailored its use to extraordinary circumstances. Simply, the Order here exceeds the Department's authority because this is not one of those extraordinary circumstances. There is no emergency within the meaning of Section 202(c).

The Order fails to meet the standards of Section 202(c) both because the Department does not demonstrate that any emergency currently exists and because the resource adequacy concerns it does describe are long-term concerns, that no one has even alleged, much less provided a credible projection, will ripen into actual supply shortages within the ninety-day term of the Order. As detailed *infra*, Section V.B, Section 202(c) provides the Department with a limited authority to

[40] Jon Hurdle, Aging Pennsylvania Power Plant to Keep Running after Trump Order on Eve of Shutdown, Pennsylvania Capital-Star (June 9, 2025), https://penncapital-star.com/energy-environment/aging-pennsylvania-power-plant-to-keep-running-after-trump-order-on-eve-of-shutdown/.

address immediate electric supply shortages to meet emergency conditions; it does not authorize the Department to address long-term energy system shifts by appointing itself the central planner and supplanting the decisions of participants in an organized electric market. Yet here, even though the Department claims that the "Order is limited in duration to align with the anticipated emergency circumstances," Ex. 1 at 2, the Department offers no evidence of an emergency in the specified period. The Order speaks only of "growing resource adequacy *concern*," resource adequacy constraints that "*could* exist," and the "increasing risk of reliability risk in *the coming years*." Ex. 1 at 1 (emphasis added).

In fact, the results of the 2025-2026 Base Residual Auction demonstrate that the PJM grid has more than enough committed capacity to offer reliable service throughout Summer 2025 without the need for the Eddystone Units, and even if there were to be supply shortages, PJM has mechanisms to handle them.[41] Furthermore, PJM has rules and processes in place to ensure long-term reliability even as shifts occur in electric demand and resource availability, and has access to a number of both short-term and long-term tools that are better suited to address long-term resource adequacy concerns than an unlawful Section 202(c) Order.[42]

[41] Summer Outlook 2025, *supra* n. 4.

[42] PJM Interconnection, LLC, PJM Capacity Market: Promoting Future Reliability (2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/pjm-capacity-market-promoting-future-reliability-fact-sheet.pdf.

### B. Section 202(c) Only Authorizes the Department to Respond to Specific, Imminent, Unexpected, and Temporary Events, Not to Mandate Generation Based on Longer-Term Reliability Concerns.

The plain language and structure of Section 202(c), the legislative history for the provision, the Federal Power Act overall, as well as case law interpreting Section 202(c), the Department's regulations, and its historic use of Section 202(c) all establish that an "emergency" under Section 202(c) must be sudden, unexpected, imminent, and specific.

#### 1. Section 202's Text and Structure Establish that Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response.

Section 202(c)'s text and context confirm that it provides only authority to address imminent, near-term, and exigent electricity supply shortfalls requiring immediate response; it does not permit the Department to act based merely on concerns over long-term reliability. Had Congress intended to vest regulatory authority over long-term reliability in Section 202(c), it would have stated so clearly. But it did not.[43]

The statute's text empowers the Department to act only upon "emergency." 16 U.S.C. § 824a(c). The statute itself does not define "emergency." At the time Congress enacted Section 202(c), Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "*sudden* or *unexpected*

[43] Congress amended Section 202(c) in 2015, but it did not alter the description of conditions that trigger the Department's grant of authority to issue emergency orders; it only addressed occasions on which a Department order might produce a conflict with other laws. *See* H.R. Rep. No. 114-357 § 61002 (2015).

appearance or occurrence… An *unforeseen* occurrence or combination of circumstances which calls for *immediate* action or remedy; *pressing* necessity; exigency." (emphasis added).[44] Contemporary dictionaries similarly define "emergency" as demanding imminence: an emergency is "an *unforeseen* combination of circumstances or the resulting state that calls for *immediate* action."[45]

The remainder of Section 202(c) underscores the exigency inherent in the governing term "emergency": the authority granted by Section 202(c) is, in the first instance, a wartime power. 16 U.S.C. § 824a(c) (beginning with "[d]uring the continuance of any war in which the United States is engaged"); *see Jarecki v. G.D. Searle & Co.*, 367 U.S. 303, 307 (1961) (noting that statutory terms should be interpreted in the context of nearby parallel terms "in order to avoid the giving of unintended breadth to the Acts of Congress"). An "emergency" under the statute is limited to circumstances of similar urgency: "a *sudden* increase in the demand for electric energy," for example. 16 U.S.C. § 824a(c) (emphasis added); *see Richmond Power & Light of City of Richmond, Ind. v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978) (holding that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances"); S. Rep. No. 74-621, at 49 (1935) (explaining that Section

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[44] *See also* 3 Oxford English Dictionary 119 (1st ed. 1913) (defining emergency similarly as "a state of things unexpectedly arising, and urgently demanding immediate action" (emphasis added).

[45] *Emergency*, Merriam-Webster Dictionary, https://www.merriam-webster.com/dictionary/emergency (last visited June 27, 2025) (emphasis added)); *See also* Benjamin Rolsma, The New Reliability Override, 57 Conn. L. Rev. 789, 812 n.147 (2025) (noting that dictionaries have given the term "emergency" the "same meaning for many years").

202(c) provides "temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose").

The text's use of the present tense also underscores that focus on imminent and certain shortfalls: it empowers the Department to act only where "an emergency *exists*." 16 U.S.C. § 824a(c) (emphasis added). That near-term focus, along with the statute's strictly "temporary" authority, 16 U.S.C. § 824a(c), precludes use of Section 202(c) to pursue long-term policy goals, such as a preference for a particular fuel source. *Richmond Power & Light*, 574 at 615 (Section 202(c) "is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").

Section 202's overall structure further highlights Section 202(c)'s emphasis on imminent, near-term concerns. The preceding subsections 202(a) and (b) together define and limit the tools by which the federal government may pursue "abundant" energy supplies in the normal course. 16 U.S.C. § 824a(a) (seeking "abundant supply of electric energy" by directing the federal government to "divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy") & § 824a(b) (allowing the federal government to order "physical connection . . . to sell energy or to exchange energy" upon application, and after an opportunity for hearing). The resulting statutory "machinery for the promotion of the coordination of electric facilities" comprises the following: in subsection (a), an

instruction to establish a general framework meant to facilitate "coordination by voluntary action;" in subsection (b), "limited authority to compel interstate utilities to connect their lines and sell or exchange energy," subject to defined procedural and substantive requirements, when "interconnection cannot be secured by voluntary action;" and in subsection (c), "much broader" but "temporary" authority "to compel the connection of facilities and the generation, delivery, or interchange of energy during times of war or other emergency." S. Rep. No. 74-621 at 49 (1935).

That tiered structure—relying on voluntary action for quotidian energy planning, specifying limited authority where that voluntary system fails, and allowing for "temporary" central command-and-control only in case of "emergency"—requires that Section 202(c) remain narrowly bounded to instances of an immediate and unavoidable "break-down in electric supply," *id.*, rather than mere want of more abundant supply in the future, *cf.* Ex. 1 at 2 (imposing responsibility on PJM "to ensure maximum reliability on its system"). Interpreting Section 202(c)'s "emergency" powers to encompass longer-term concerns—e.g., potential shortfalls years into the future—would unwind the careful balance of voluntary, market-driven action and federal power set out in subsections 202(a) and 202(b). *See infra*, Section V.D. Such an interpretation cannot be squared with the statutory text and structure. *See Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232, 233-34 (8th Cir. 1970) (holding that Section 202(c) "enables the Commission to react to a war or national disaster," while Section 202(b) "applies to a crisis which is likely to develop in the foreseeable future").

2. Congress' Enactment of a Specific, Cabined Scheme to Address Reliability Concerns Confirms that Section 202(c) Cannot be Expanded to Impose Requirements Related to Long-Term Reliability.

That Section 202(c) cannot be used to enforce the Department's view of long-term reliability needs is confirmed by Section 215 of the Federal Power Act—which specifically and directly delineates the scope of federal power to enforce mandatory long-term reliability requirements. 16 U.S.C. § 824o ("Section 215"). Congress added Section 215 to the Federal Power Act in 2005 precisely because the Act as it then existed—including Section 202(c)—did not provide the federal government with the power to enforce measures designed to ensure broad, long-term reliability. *See* 70 Fed. Reg. 53,117, 53,118 ("In 2001, President Bush proposed making electric Reliability Standards mandatory and enforceable," leading to enactment of Section 215 in 2005); Report of the National Energy Policy Development Group (May 2001) at p. 7-6[46] (noting that "[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country" and that "[o]ne factor limiting reliability is the lack of enforceable reliability standards" because "the reliability of the U.S. transmission grid has depended entirely on *voluntary* compliance," and then recommending "legislation providing for enforcement" of reliability standards) (emphasis added); S. Rep. No. 109-78 at 48 (2005) (Section 215 "changes our current voluntary rules system to a mandatory rules system" for long-term reliability). *See Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005,

[46] https://www.nrc.gov/docs/ml0428/ml042800056.pdf.

"the reliability of the nation's bulk-power system depended on participants' voluntary compliance with industry standards").

By enacting Section 215, Congress provided a comprehensive and carefully circumscribed scheme to empower the federal government to enforce long-term reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent "of the users and owners and operators of the bulk-power system" but with "fair stakeholder representation." 16 U.S.C. § 824o(c)-(d). *See also id.* 824o(a)(3) (defining reliability standards as "a requirement … to provide for reliable operation of the bulk-power system"). FERC may approve or remand those standards (but not replace them with its own) and is required to "give due weight" to NERC's "technical expertise" while independently assessing effects on "competition." *Id.* § 824o(d)(2)-(4). Section 215 provides specified enforcement mechanisms and procedures for reliability standards. *Id.* § 824o(e). And it carefully preserves state authority over "the construction of additional generation" and in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards. *Id.* § 824o(i)-(j).

Interpreting Section 202(c) to permit the Department to mandate generation based on its declaration that non-imminent reliability concerns create an "emergency" would effectively allow the Department to bypass Section 215's procedural safeguards, constraints on federal authority, and protection of state

power. Such a bypass would impermissibly "contradict Congress' clear intent as expressed in its more recent," reliability-specific "legislation," enacted "with the clear understanding" that the Department had "no authority" to address long-term reliability through Section 202(c). *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 142 & 149 (2000); s*ee also Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401–02 (D.C. Cir. 2004) ("Congress's specific and limited enumeration of [agency] power" over a particular matter in one section of the Federal Power Act "is strong evidence that [a separate section] confers no such authority on [agency]."). Congress has, in Section 215, directly established the mechanisms (and limitations) by which the federal government may compel action to ensure long-term electric-system reliability. In so doing, it has confirmed that the word "emergency," in Section 202(c), does not extend to long-term reliability concerns.

3. Regulations Similarly Establish that Section 202(c) Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response.

The Department's regulations demonstrate its own long-standing understanding that Section 202(c)'s authority is confined to imminent and unavoidable resource shortages, rather than long-term reliability concerns. The regulations define an emergency as "an *unexpected* inadequate supply of electric energy which may result from the *unexpected* outage or breakdown" of generating or transmission facilities—not a means of planning against distant expectations or risks. 10 C.F.R. § 205.371 (emphasis added). Emergencies "may result" from a number of events. *Id.* ("may result from the unexpected outage," "may be the result of weather conditions," "can result from a sudden increase in customer demand").

The use of the verb "result," defined as "arise as a consequence, effect, or conclusion,[47] suggests that the event triggering the emergency has already happened rather than that there is a speculation that it could occur. Moreover, the events are characterized by those produced by "weather conditions, acts of God, or *unforeseen* occurrences not reasonably within the power of the affected 'entity' to prevent," *id.* (emphasis added), not an event that can be planned for because there is a forecasted risk. Where the culprit is increased demand, it must be "a *sudden* increase in customer demand" producing a "*specific* inadequate power supply situation," *id.* (emphasis added), rather than long-term demand projections producing general reliability concerns. The need for both specificity and certainty is repeated in the Department's regulations defining an inadequate energy supply: "A system may be considered to have" inadequate supply when "the projected energy deficiency... *will* cause the applicant [for a 202(c) Order] to be unable to meet its normal peak load requirements based upon use of all of its otherwise available resources so that it *is* unable to supply adequate electric service to its customers." 10 C.F.R. § 205.375 (emphasis added).

And while the regulations suggest that "inadequate planning or the failure to construct necessary facilities *can result* in an emergency," they recognize that the Department may not utilize a "continuing emergency order" to mandate long-term system planning. 10 C.F.R. § 205.371 (also recognizing that "where a shortage of

[47] *Result*, Merriam-Webster Dictionary, https://www.merriam-webster.com/dictionary/result (last visited June 27, 2025).

electricity is projected due solely to the failure of parties to agree to terms, conditions, or other economic factors" there is no emergency "unless the inability to supply electric service is *imminent*") (emphasis added). An emergency may exist where past planning failures produce an immediate, present-tense shortfall (that is where, a shortfall *results* from insufficient planning); the Department has no authority to commandeer long-term planning merely because it deems current plans inadequate to meet far-distant needs. *See* 10 C.F.R. § 205.375 (requiring present inability to meet demand to demonstrate inadequate energy supply). As the Department stated when it promulgated those regulations, the statute allows the Department to provide "assistance [to a utility] during a period of unexpected inadequate supply of electricity," but does not empower it to "solve long-term problems." 46 Fed. Reg. 39,984, 39,985–86 (Aug. 6, 1981).

4. Courts Have Uniformly Held that Section 202(c) Can Be Invoked Only in Immediate Crises.

Two courts have addressed the scope of authority under Section 202(c), and both determined that this Section applies only when there is a sudden, unexpected, imminent, and specific emergency.

*Richmond Power and Light of City of Richmond, Indiana v. FERC*, 574 F.2d 610 (D.C. Cir. 1978) arose out of the 1973 oil embargo. The Federal Power Commission ("Commission") needed to decide how to respond to oil shortages, and decided to call for the voluntary transfer of electricity from non-oil power plants to areas of the country that relied heavily on oil, such as New England. *Id.* at 613. The New England Power Pool was not convinced that the voluntary program would

work and petitioned the Commission for a 202(c) order. *Id.* The Commission instead facilitated an agreement between state commissions and supplying utilities, which satisfied the New England Power Pool and it withdrew its petition. *Id.* A dissatisfied utility sought judicial review of the Commission's decision to allow the withdrawal of the Section 202(c) petition. *Id.* at 614.

The court easily upheld the Commission's decision not to invoke Section 202(c). *Id.* Though the oil embargo had ended, the utility argued that the "high cost and uncertain supply of imported oil" justified an emergency order. *Id.* The Commission countered that the voluntary program had worked, the New England Power Pool never interrupted service, and there was no need for a Section 202(c) order. *Id.* at 615. The court agreed with the Commission. *Id.*

Trying another tactic, the utility argued that "dependence on imported oil leaves this country with a *continuing* emergency." *Id.* (emphasis added). The court observed that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances." *Id.* Interpreting this statutory language, the court upheld the Commission's view that Section 202(c) cannot be used when "supply is adequate but a means of fueling its production is in disfavor." *Id.* Section 202(c) is not an appropriate means to implement long-term national policy to switch fuels. It is only a temporary fix for a temporary problem.

The Eighth Circuit has similarly held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970), a utility insisted that the only way for the Commission

to properly order the utility to connect to a municipal power provider was to issue a Section 202(c) order. Demand for electricity in the city had increased, and the peak load of the municipal power provider was getting to be so high that both of its two generators would likely need to be used simultaneously in the near future, "causing a possible loss of service should one malfunction during a peak period." *Id.* at 233-34. To avoid this possible loss of service, the Commission issued a Section 202(b) order, requiring the utility to connect the municipal power provider. *Id.* at 234. The utility argued that the Commission used the wrong section and should have used Section 202(c) instead. *Id.*

The court explained that Section 202(c) "enables the Commission to react to a war or national disaster" by ordering "immediate" interconnection during an "emergency." *Id.* (citing 16 U.S.C. § 824a(c)). For non-emergency situations, "[o]n the other hand, § 202(b) applies," including when there is a "crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission." *Id.* The court upheld the Commission's use of Section 202(b) instead of Section 202(c) because there was no immediate emergency.

The case law uniformly supports the interpretation that Section 202(c) can only be used in acute, short-term, urgent emergencies.

5. The Department's Prior Orders Recognize that Section 202(c) Does Not Confer Plenary Authority Over Long-Term Resource Adequacy.

The Department's consistent application of Section 202(c) further corroborates the urgency of the conditions necessary to invoke the provision. *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established

practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred."). The Department has only ever used Section 202(c) to address specific, imminent, and unexpected shortages—never to address longer-term reliability concerns or demand forecasts. *See, e.g.,* Ex. 6, Department of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between December 23 and December 26); Ex. 7, Department of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires); *see also* Rolsma, 57 Conn. L. Rev. at 803-4 (describing "sparing[]" use of Section 202(c) outside of wartime shortages during the twentieth century). The Department has also narrowly tailored the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, to limit the order to the minimum period necessary, and to mitigate violations of environmental requirements and impacts to the environment. *See, e.g.*, Ex. 6, Department of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex. 7, Department of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to

exhaust all available resources beforehand, requiring detailed environmental reporting).

Public Interest Organizations are not aware of any instance in which the Department has utilized Section 202(c) to mandate generation the Department views as necessary to ensure long-term resource sufficiency, or to retain fuel sources that the Department believes beneficial, *Richmond Power and Light,* 574 F.2d at 616—and for good reason.

### C. There Is No Factual Basis Supporting the Department's Order.

The Department asserts that the Order is justified by "the declared state of national energy emergency" and "resource adequacy concerns." Ex. 1 at 2. However, the Department fails to demonstrate that either of these factors constitutes an emergency under Section 202(c). 16 U.S.C. § 824a(c). No agency can lean exclusively on a Presidential declaration of an emergency; emergency authority is circumscribed by the authority granted by Congress. Further, a broad, generic declaration of a national emergency is not sufficient on its own to justify the use of emergency powers under a statute with specific requirements. And the Department fails to provide evidence that there are such imminent resource adequacy shortfalls that an emergency exists pursuant to Section 202(c). The Department's suggestion that there is an emergency due to resource inadequacy is also belied by the robust portfolio of capacity resources available this summer.

1. The Energy Emergency Executive Order does not provide a valid basis under Section 202(c).

The Order generally states that the availability of Eddystone is necessary considering "the declared state of national energy emergency," but fails to explain what state of emergency it refers to or cite any evidence supporting this claim. Without more, this statement of a national emergency is not specific enough to provide evidence of an emergency for purposes of Section 202(c). *See* 10 C.F.R. § 205.371 (defining emergency as a "*specific* inadequate power supply situation") (emphasis added). Even assuming the Order refers to the Energy Emergency EO, that Executive Order also does not provide a valid basis for an emergency under Section 202(c). To the extent that the Order is a stopgap to maintain Eddystone until the Department can produce its national methodology meant to address the alleged national energy emergency, that too is beyond the authority of Section 202(c). *See infra,* Section V.C.2.

If the Department's reference to a national energy emergency is meant to serve as evidence of an emergency as defined under Section 202(c), it is insufficient. An emergency under Section 202(c) must be "a *specific* inadequate power supply situation," 10 C.F.R. 205.371 (emphasis added), but the Energy Emergency EO only generically claims "[t]he energy … generation capacity of the United States [is] far too inadequate to meet our Nation's needs." The EO provides no evidence of inadequate generation nationwide, let alone in Pennsylvania specifically.[48] An

[48] Indeed, U.S. energy production and exports are currently at an all-time high. U.S. Energy Information Administration, U.S. primary energy production,

emergency under Section 202(c) also must be imminent. *See supra*, Section V.B. But the EO only generically claims that "this situation will dramatically deteriorate in *the near future*." As we demonstrate *infra*, Section V.C.3, there is sufficient generation for the claimed "emergency" period in Pennsylvania.

Indeed, unlike in previous 202(c) orders, the Department does not even claim there is an emergency specifically in Pennsylvania. Rather, in addition to citing the "national" emergency, the Order appears to describe resource concerns throughout PJM. But nowhere does the Department explain why a power plant retirement in a single state—Pennsylvania—supports the existence of an emergency in the whole region, let alone the whole country. We further demonstrate *infra*, Section V.C.3, that there is no 202(c) "emergency," and, in fact, sufficient generation in PJM.

Even if the declared national energy emergency were legitimate, a presidential declaration of an emergency does not unlock unlimited powers. *See Biden v. Nebraska*, 600 U.S. 477, 500-01 (2023) (presidential declaration of national emergency does not change the limitations on agency's emergency authority as written into statute). President Trump issued the Energy Emergency EO pursuant to authority from the National Emergencies Act.[49] Congress explained that the

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consumption, and exports increased in 2024 (Jun. 20, 2025), https://www.eia.gov/todayinenergy/detail.php?id=65524.

[49] Under the National Emergencies Act, no emergency powers unlocked by a Presidential declaration of a national emergency "shall be exercised unless and until the President *specifies the provisions of law* under which he proposes that he, or other officers will act." 50 U.S.C. § 1631 (emphasis added). The Energy Emergency EO does not adhere to this requirement. EO 14,156 (Jan. 20, 2025) (generically directing agencies to "identify and exercise any lawful emergency

National Emergencies Act "is not intended to enlarge or add to Executive power. Rather, the statute is an effort by Congress to establish clear procedures and safeguards for the exercise by the President of emergency powers *conferred on him by other statutes*." S. Rep. No. 94-1168, 3 (1976), (emphasis added). Congress sometimes ties emergency authority to a president's declaration of a national emergency and sometimes to a determination by the head of an agency. The Federal Power Act contains both types of emergency authority: two provisions of the Federal Power Act provide the President with emergency authority (section 215A, 16 U.S.C. § 824o-1, and 16 U.S.C. § 809), but Section 202(c) requires that "the *Commission* determine[] that an emergency exists." 16 U.S.C. § 824a (emphasis added).[50] Thus, the burden is on the Department to demonstrate that there is an emergency pursuant to the narrow language of Section 202(c); simply pointing to the Energy Emergency EO without determining for itself that an emergency exists results in an arbitrary and capricious order.

2. The Department Failed to Produce Evidence of an Emergency.

None of the sources that the Department relies on in the Order provides evidence that a 202(c) emergency exists. The Order relies on four sources of evidence for its emergency declaration: (1) a March 2025 testimony of the President and CEO of PJM, (2) the FERC order accepting PJM's Reliability Resource

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authorities available to them, as well as all other lawful authorities they may possess, to facilitate the … generation of domestic energy resources.").

[50] The Department has exercised certain powers under Section 202(c) since the DOE Organization Act of 1977. 42 U.S.C. § 7172.

Initiative, (3) PJM's 2023 report *Energy Transition in PJM,* and (4) PJM's 2025 Summer Outlook. Ex. 1 at 1. The Department misconstrues these sources and consequently its reliance on them is not reasoned decision-making. *See* 5 U.S.C. § 706(2)(A) (agency actions that are "arbitrary" or "capricious" are to be "set aside"). Even if there were longer-term risks of an energy supply shortage some number of years in the future, that would not constitute a legal basis for invoking Section 202(c).

First, the Department notes that "PJM has recently stated its system faces 'growing resource adequacy concern' due to load growth, the retirement of dispatchable resources, and other factors," citing testimony from PJM's current President, Manu Asthana, to the U.S. House of Representatives Committee on Energy and Commerce, and contends that retirement of the Eddystone Units will "exacerbate" these issues.[51] While President Asthana's testimony indeed describes an emerging—but not present—resource adequacy concern, the primary focus of his testimony was on how PJM is preparing to meet resource adequacy challenges that PJM forecasts may emerge later in the decade as a result of potential data center growth in the region.[52] According to President Asthana, PJM has instituted reforms to PJM's interconnection process that will permit new resources to come

[51] Ex. 1 at 1 (citing Testimony of Manu Asthana, President and CEO, PJM Interconnection, to the U.S. House of Representatives, Committee on Energy and Commerce, Subcommittee on Energy (Mar. 25, 2025), https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf.).

[52] Testimony of Manu Asthana, at 1, 4.

online in the PJM region much more quickly than they have in recent years (though not as quickly as FERC Order 2023 would require), thus responding to capacity market price signals that incentivize that new entry.[53] As President Asthana notes, these reforms include not only changes to PJM's interconnection tools and processes it employs, but also the introduction of an interconnection fast track for resources that PJM concludes will substantially contribute to resource adequacy (the Reliability Resource Initiative), and two pathways for new generation to be added at existing points of interconnection (capacity interconnection rights transfer and surplus interconnection service).[54] He also describes changes that PJM has made to its capacity market to ensure that market prices accurately reflect available supply, concluding that "[c]ollectively, the various proposals and reforms that PJM have pursued are making a difference as they are rolled out and implemented."[55] Specifically, he notes that "since the beginning of last year, 1,100 MW of existing generation chose to remain as supply resources in PJM after previously submitting a notice to retire," and expresses optimism that this process will continue given market reforms.[56]

A full review of President Asthana's testimony demonstrates the inappropriateness of 202(c) emergency action based on resource adequacy shortfalls that may arise in future years. PJM has already identified actions it is taking

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[53] *Id.* at 8.

[54] *Id.*

[55] *Id.* at 8-9.

[56] *Id.* at 11.

through its rates and practices overseen by FERC to address the same long-term resource adequacy concerns relied upon in the Order, and the Department neither suggests nor demonstrates that PJM's long-term market mechanisms will not be successful in addressing resource adequacy needs.

Indeed, Constellation itself takes a bullish view on the state of reliability in Pennsylvania as a result of PJM's markets:[57]

> Notably, investment in new generation resources is currently being proposed in Pennsylvania. Constellation has announced the relaunch of the renamed Crane Clean Energy Center ("CCEC") in Dauphin County, which will add approximately 835 MWs of carbon-free baseload generation to the grid. Likewise, just last month, Homer City Generation Station, the largest coal-burning facility in Pennsylvania before it was closed in 2023, announced plans to restart and increase its generating capacity through burning natural gas. In addition, 31,608 MW of new generation is proposed to be built in Pennsylvania, according to the PJM generation interconnection queue. In short, the PJM markets are working to ensure resource adequacy in Pennsylvania.

Second, the Order cites FERC's approval of the Reliability Resource Initiative filed by PJM to alleviate "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry"[58]—a possibility that would only come to pass well after the 90-day period relevant to the Order. Curiously, the Order fails to discuss the results of the Reliability Resource Initiative published in May, which PJM intends will expedite interconnection for 9.3 GW of capacity, most of it thermal resources, by 2031—the vast majority of it by

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[57] Comments of Constellation at 2, Pennsylvania Public Utility Commission Docket No. Docket No. M-2024-3051988, https://www.puc.pa.gov/pcdocs/1861961.pdf.

[58] Ex. 1 at 1 (citing PJM Interconnection LLC, 190 FERC ¶ 61,084 (Feb. 11, 2025)).

2030.[59] On the time scale relevant to PJM's expressed concerns about a growing resource adequacy problem, the existence of the Reliability Resource Initiative demonstrates the effectiveness of existing tools to avoid an emergency arising. Suffice it to say, the Department's citation of an approved solution to a problem that would otherwise arise in several years does not constitute evidence of an emergency in the next 90 days as required for a Section 202(c) order.

Third, the Order cites PJM's February 2023 assessment, "Energy Transition in PJM: Resource Retirements, Replacements & Risks," commonly known as the "R4" report, in which "PJM highlights the increasing risk of reliability risk in the coming years due to the 'potential timing mismatch between resource retirements, load growth and the pace of new generation entry' under 'low new entry' scenarios for renewable generation." Ex. 1 at 1.[60] The problems with the Order's reliance on this 2023 assessment are manifold.

As the Department's statement makes plain, the February 2023 R4 Report describes only "increasing risk of reliability risk," *id.*, over a period of seven years, which falls far short of an emergency within the meaning of Section 202(c), which must be imminent and certain. *See supra*, Section V.B., 10 C.F.R. 205.375, 205.371.

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[59] Donnie Bielak, Reliability Resource Initiative Results Summary (May 6, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250506/20250506-item-06---reliability-resource-initiative---summary-results.pdf.

[60] Citing PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks (Feb. 24, 2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

The potential risk of a risk of inadequacy does not meet these standards. Furthermore, the February 2023 R4 Report's assessment of increasing risk is flawed on its own terms. The most fundamental problem is that PJM failed to account for the operation of its own capacity market in ensuring resource adequacy, by assuming that capacity prices would remain at their then-recent low levels even as reserve margins shrunk. As economist James F. Wilson explained in a critique published in May 2023, this ignores that the sloped demand curve utilized in the capacity auction prevents this very result—as supply becomes more scarce, prices increase dramatically, thus incentivizing more new entry and retention of existing generators.[61] Additional flaws with PJM's R4 Report that undermine its validity as a basis for the Order include:

- Ignoring reliability safety valve mechanisms in state policies to which PJM attributes anticipated retirements, which allow for delays in retirements in the case of reliability issues.[62]

- Overstating retirements that would result from certain U.S. Environmental Protection Agency rules affecting the power sector, by assuming that all facilities subject to these rules would retire rather than retrofit.[63]

- Presenting a low new entry scenario based on historic rates of new entry that occurred during a time period when the PJM capacity market was oversupplied and prices were low.[64]

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[61] Ex. 8 James F. Wilson, Maintaining the PJM Region's Robust Reserve Margins A Critique of the PJM Report: Energy Transition in PJM: Resource Retirements, Replacements and Risks, 8 (May 2023)

[62] *Id.* at 10 fn. 36.

[63] *Id.*

[64] *Id.* at 12.

- Assuming without explanation that only one-third of the natural gas generation with a signed interconnection agreement would enter service, even while assuming that large numbers of existing thermal units would retire.[65]

- Assuming no increase in demand response resources, despite the increased capacity prices that would accompany declining reserve margins.[66]

- Overstating retirements that will result from state policies.[67]

The February 2023 R4 Report is also stale. As the PJM region now sees a level of supply that balances current demand, PJM capacity prices have skyrocketed substantially compared to the prices assumed in the R4 Report, which reflected the market's then-state of oversupply.[68] Specific unit retirements that PJM accounted for in the R4 analysis, such as those of Talen Energy's Brandon Shores and Wagner facilities in Maryland, have not occurred. These particular facilities, representing

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[65] *Id.* at 12. *See also* PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks (Feb. 24, 2023) at 3, 10, https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

[66] *Id.*

[67] *See* Statement of President Christine Guhl-Sadovy of the New Jersey Board of Public Utilities, at 8-9, FERC Docket No. AD 25-7, (describing how PJM's R4 report overstated retirements in 2027 associated with New Jersey's greenhouse gas regulations and failed to correct this once it was pointed out by the New Jersey Board of Public Utilities).

[68] *Compare* PJM, 2023/2024 RPM Base Residual Auction Results, https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-base-residual-auction-report.pdf *with* PJM 2025/2026 Base Residual Auction Results (Aug. 21, 2024), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20240821/20240821-item-08---2025-2026-base-residual-auction---presentation.pdf. *See also*, PJM, 2025/2026 Base Residual Auction Report (July 30, 2024), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf.

about 1.5 GW of capacity, will continue operating under RMR agreements through the end of the decade.[69] And as noted above, PJM has taken steps intended to improve its processes to enable new resources to come online, which in combination with the higher prices, are already bearing fruit. None of these changes are reflected in the low new entry scenario described in the R4 Report and upon which the Order relies.

In addition to relying on stale evidence of low new entry, all of PJM's assessments of possible resource adequacy shortfalls later this decade depend on whether forecasted data center load growth materializes at the scale, and in the locations, that PJM currently anticipates.[70] As PJM's Vice President of Market Design and Economics recently explained, "any technology that is early in its development cycle is uncertain. Data centers are still relatively new, and there's uncertainty on how big their demand might be, and there's added uncertainty as to where they might ultimately be developed."[71] PJM is evaluating ways to facilitate developers of data centers bringing their own supply to the market, incentivizing

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[69] Talen Energy, FERC Approves Reliability Must Run Settlement Agreement for Units at Talen Energy's Brandon Shores and H.A. Wagner Power Plants (May 1, 2025), https://ir.talenenergy.com/news-releases/news-release-details/ferc-approves-reliability-must-run-settlement-agreement-units. *See generally* FERC Docket No. ER24-1790 (Brandon Shores LLC submits tariff filing: RMR Arrangement).

[70] *See, e.g.,* Joe Bowring, Pre-Technical Conference Comments of the Independent Market Monitor for PJM at 3, FERC Docket No. AD25-7 (May 27 2025), https://www.ferc.gov/media/joe-bowring-monitoring-analytics-president-and-independent-market-monitor.

[71] Adam Keech, Prefiled Statement on Behalf of PJM Interconnection, L.L.C. at 7, FERC Docket No. AD25-7.

higher degrees of data center participation as a demand response resource, or allowing for lower-cost, faster interconnection by data centers that are willing to have their usage curtailed.[72] A recent study showed that even a very small degree of data center load flexibility enables large amounts of data centers—18 GW in PJM—to be added to the system without increasing the system peak that is a major input to the resource adequacy analysis.[73] Meanwhile, utilities and states are taking significant steps to require deposits and other commitments from large loads, such as data centers, to ensure that the load forecasts driving pessimism about PJM's long-term resource adequacy don't include speculative or duplicative projects.[74]

Fourth, the Department offers a single piece of evidence relating to near-term conditions—a PJM newsletter summarizing its outlook for the summer. But it too does not demonstrate an emergency. According to the Department, "PJM indicates that resource constraints could exist within the service territory under peak load conditions, stating that 'available generation capacity may fall short of required

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[72] Tim Horger, Senior Director, Forward Market Operations & Performance Compliance, "Large Load Additions Workshop," PJM (May 9, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/workshops/llaw/2025/20250509/20250509-item-02---large-load-additions-workshop---presentation.pdf.

[73] Tyler H. Norris et al., Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems 20, 22 (Duke Univ. Nicholas Inst. for Energy, Env't & Sustainability ed. 2025), https://nicholasinstitute.duke.edu/publications/rethinking-load-growth.

[74] Adam Keech, Prefiled Statement on Behalf of PJM Interconnection, L.L.C. at 7-8, FERC Docket No. AD25-7.

reserves in an extreme planning scenario.'"[75] As PJM further explains: "Demand response programs pay customers who have opted in to reduce their electricity use in times of system emergencies."[76] The Department's brief quotation of this summer outlook article omits a key point that is prominent in PJM's article—that "[u]nder such circumstances, PJM would call on contracted demand response programs to meet its required reserve needs."[77] PJM's plan to call on demand response is also noted in the article's subheading and first paragraph—it is not a subtle point.

The possibility that PJM might ask demand response resources to activate is not an "emergency" within the meaning of Section 202(c). That is exactly the point of such resources— they offer to curtail their use of power on demand in exchange for hefty payments.[78] Instead of an emergency, it is indicative of routine analysis and planning to rely upon the most cost-effective resources available to the grid operator. *See infra*, Section V.C.3. As PJM's Vice President of Markets, Adam Keech, explains, demand response is important to "maintaining resource adequacy

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[75] Order at 1 (quoting Summer Outlook 2025, *supra* n. 4).

[76] Summer Outlook 2025, *supra* n. 4.

[77] *Id.*

[78] *See, e.g.*, *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 269 (2016), *as revised* (Jan. 28, 2016) (explaining that market operators like PJM devised wholesale demand response programs, which "induce consumers to refrain from using … electricity during peak periods" for situations whenever "doing that costs less than adding more power" in order to "bring electricity supply and demand into balance at a lower price … [and] ease pressure on the grid, thus protecting against system failures").

both currently and in the future."[79] He notes that "demand response accounted for approximately 4.5% of capacity that cleared" in the 2025/26 Base Residual Auction, and that "[i]f generation resources are unable to be developed economically to meet anticipated load growth in PJM, it will be critical to have flexible demand that is willing to curtail in order to maintain reliability."[80] The Department's own regulations explicitly acknowledge that inadequate energy is an emergency only if the grid operator is unable to meet "normal peak load requirements based upon use of all of its otherwise available resources." 10 C.F.R. 205.375. Thus, the Order arbitrarily ignores PJM's plan to rely upon demand response in the event that its generation resources are inadequate to maintain the required operating reserves during extreme load conditions this summer.

Finally, the Order mentions in the description of the emergency situation the Department's intent to consider Eddystone in the as-yet unpublished resource adequacy methodology the Department is developing pursuant to the Grid EO. Ex. 1 at 2. This context cannot be evidence of an emergency under Section 202(c) for the simple reason that the methodology does not yet exist. And any reliance on the methodology, once it is published, as evidence to support the issuance of the Order will be impermissible *post hoc* rationale. *Dep't of Homeland Sec. v. Regents of the Univ. of California,* 140 S. Ct. 1891, 1907 (2020) ("'foundational principle of administrative law' that judicial review of agency action is limited to 'the grounds

[79] Adam Keech, Prefiled Statement on Behalf of PJM Interconnection, L.L.C. at 5, FERC Docket No. AD25-7.

[80] *Id.* at 5-6.

that the agency invoked when it took the action.'"). Further, this context suggests that the Order in reality is merely a preliminary step in the long-term strategy to preserve fossil fuel generation under the guise of grid reliability concerns. As discussed *infra*, Section V.C.4., regardless of this Administration's policy goals, the Department's actions must adhere to the Administrative Procedure Act's requirement of reasoned decision making as well as remain within the statutory limits Congress wrote into the Federal Power Act.

The Department's claims represent a blinkered and incorrect review of the evidence: while there is the possibility for energy demand growth over the coming years, and there has been an increase in generator retirements, PJM is equipped with the tools to address those system changes in a way that maintains resource adequacy and reliability, and indeed is already doing so. Rather than recognizing this broader picture, the Department points to cherry-picked statements by PJM that if certain conditions arise—such as particular levels of load growth and low new entry of capacity resources—then, in several years' time, the PJM region would have reserve margins below its target if appropriate action were not taken to address those conditions. The Department takes PJM's warnings of future risk that might arise out of context and ignores other mechanisms at work to address the longer-term risk and thereby prevent any energy shortfall from arising.

3. PJM Has Sufficient Capacity Resources for Summer 2025 Without Eddystone.

The Base Residual Auction for the delivery year encompassing the period of emergency that the Department identifies in the Order—Delivery Year 2025-2026—

cleared more capacity than the Reliability Requirement.[81] Specifically, the auction cleared 135,684 MW of unforced capacity, representing a 18.6% reserve margin—0.8 percentage points higher than the target reserve margin of 17.8%.[82] Constellation did not offer the Eddystone Units into the auction, considering its June 1, 2025 deactivation date was accepted by PJM, and Constellation's 2023 notice that it would seek removal of its capacity resource status.[83] Thus, the auction cleared more than sufficient resources for the 2025-2026 delivery year without Eddystone's capacity being included or otherwise counted on. Clearing an amount of capacity close to, and indeed above, the Reliability Requirement is consistent with the capacity market's design objectives.[84]

Indeed, the auction-clearing results *understate* the quantity of resources available in the PJM region for at least two reasons. The supply curve did not

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[81] PJM, 2025/2026 Base Residual Auction Report 3 (July 30, 2024), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf.

[82] *Id.* Two transmission-constrained areas that must import capacity cleared at the price cap for those areas, indicating that they had insufficient internal capacity to meet their internal demand for the delivery year. These two areas–Baltimore Gas & Electric and Dominion–are in Maryland and Virginia, respectively, and would not be able to import any additional capacity even if it were available elsewhere in the region, due to the transmission constraints.

[83] *See supra*, Section IV.A. Constellation is contemporaneously submitting a written request to PJM and the IMM for removal of capacity resource status beginning with the 2025/26 delivery year.

[84] *See* Kathleen Spees et al., Sixth Review of PJM's Variable Resource Requirement Curve for Planning Years 2028/29 through 2031/32, at 19 (Apr. 9, 2025), https://www.brattle.com/wp-content/uploads/2025/04/Sixth-Review-of-PJMs-Variable-Resource-Requirement-Curve.pdf ("By design, RPM aims to support long-term reliability by targeting a cleared volume of capacity resources consistent with the reliability requirement, the 1-in-10 reliability standard.").

include nearly 1.5 GW of capacity available in the Baltimore Gas & Electric zone that are committed to operate under RMR agreements during the 2025-2026 delivery year.[85] FERC has since approved tariff revisions filed by PJM that will, in future auctions, account for the capacity value of RMR units with obligations to perform during capacity emergencies, like the units in the Baltimore Gas & Electric zone.[86] In addition, approximately 1.6 GW of accredited wind, solar, and storage capacity did not offer into the auction for the 2025-2026 delivery year; these resources have capacity interconnection rights and will be available to provide energy, including during many of PJM's riskiest hours of this delivery year.[87]

NERC's 2025 Summer Reliability Assessment, published in May 2025, indicates that PJM has adequate anticipated resources for both normal and extreme summer load conditions, and that PJM anticipates calling upon demand response resources during any extreme high temperatures.[88] It further notes that "PJM is forecasting 27% installed reserves (including expected committed demand

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[85] *See* Maryland Office of People's Counsel, Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland 6 (Aug. 2024), https://opc.maryland.gov/Portals/0/Files/Publications/RMR%20Bill%20and%20Rates%20Impact%20Report_2024-08-13%20Final%20corrected%208-29-24.pdf?ver=fHKa18_idtwi4Rm4OeK-7A%3d%3d.

[86] *See Order Accepting Tariff Revisions Subject to Condition*, *PJM Interconnection, L.L.C.*,190 FERC ¶ 61,088, at P 1 (2025).

[87] *See Extending the Capacity Must-Offer Requirement to All Generation Capacity Resources, PJM Interconnection, L.L.C.*, FERC Docket No. ER25-785-000 (2024), at P 7.

[88] NERC, 2025 Summer Reliability Assessment 5, 25 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion."[89]

The heat wave that occurred June 23-26, 2025, and PJM's response thereto, demonstrate that the PJM system is working as it should to maintain grid reliability—and it would have worked as planned even without the Eddystone Units running. On June 22, 2025, PJM projected that its forecasted load across PJM from June 23 through 26 would range from 148,500 to 161,000 MW.[90] While these load forecasts are higher than PJM's summer forecast peak, they are lower than PJM's extreme planning scenario of more than 166,000 MW and lower than the 187,100 MW of total generation capacity and demand response that PJM has available this summer.[91] Thus, PJM called on ordinary economic resources to respond to this event, but also had additional typical resources it could call on to address the peak forecasts, and still would have even without Eddystone operating. PJM reached the last step before an emergency[92]—Pre-emergency Load Management Reduction, in other words, demand response.[93] Ultimately, PJM hit a peak load of approximately

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[89] *Id.* at 25.

[90] *June 23 Update: Maximum Generation Alert Issued for June 24*, PJM Inside Lines (June 19, 2025), https://insidelines.pjm.com/pjm-issues-hot-weather-alert-for-expected-heat-wave-june-22-25/.

[91] Summer Outlook 2025, *supra* n. 4.

[92] PJM, PJM Manual 13: Emergency Operations 20-21 (Feb. 20, 2025), https://www.pjm.com/-/media/DotCom/documents/manuals/m13.pdf.

[93] While this is an action under PJM's Capacity Emergency, *id.*, PJM's Operating Agreement explains that "[a] pre-emergency event is implemented when economic resources are not adequate to serve load and maintain reserves or maintain system reliability, and *prior to proceeding into emergency procedures*."

160,000 MW on June 23 and 158,000 on June 24[94] and still had additional demand response available (at least 3,640 MW) that it could have relied on rather than running Eddystone's 820 maximum MW.[95]

This event was not an emergency as defined by Section 202(c) because it did not produce a "specific inadequate power supply situation," 10 C.F.R. § 205.371. And Department regulations define an inadequate energy supply as when "the projected energy deficiency... will cause the [utility] to be unable to meet its *normal peak load* requirements based upon *use of all of its otherwise available resources*." 10 C.F.R. § 205.375 (emphasis added). For this event, PJM kept net load below its summer seasonal peak load through relying on only some of its otherwise available resources. The June 23-26 event demonstrates that PJM has sufficient capacity resources for summer 2025.

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PJM, 8.5 Pre-Emergency Operations, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. 516, https://www.pjm.com/library/governing-documents (emphasis added). In fact, the purpose of pre-emergency Load Management Reduction is to "potentially avoid, or at least reduce the duration and breadth of, a system emergency." PJM tariff filing, Revisions to the PJM OATT, OA & RAA, FERC Accession # 20131224-5000, at 8 (Dec. 24, 2013).

[94] https://www.gridstatus.io/live/pjm?date=2025-06-23to2025-06-25.

[95] PJM only issued a Pre-Emergency Load Management Reduction Action calling on only some of the available short and long capacity performance demand response (https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf#). But PJM also has 3640 MW of quick demand response. James McAnany, PJM, 2025 Demand Response Operations Markets Activity Report (June 10, 2025), https://www.pjm.com/-/media/DotCom/markets-ops/dsr/2025-demand-response-activity-report.pdf (45.5% of total 25/26 demand response is quick).

4. The Order Is Based on a False Premise and Violates the Department's Duties Under the Administrative Procedure Act.

On its face, the Department's decision to require Eddystone to recommence and continue operations over the next 90 days is completely untethered from the statutory and regulatory requirements of Section 202(c). Given the incongruity of the record and the result, the Department's decision to require Eddystone to return to service shows itself to be nothing more than a brazen effort to prop up fossil fuel generation– to the detriment of PJM ratepayers and the surrounding community– by manufacturing an "emergency" and illegally abusing an important statutory safeguard. *See, e.g. Youngstown Sheet & Tube Co. v. Sawyer*, 343 U.S. 579, 649-54, (1952) (Jackson, J., concurring) ("[Our founding fathers] knew what emergencies were, knew the pressures they engender for authoritative action, knew, too, how they afford a ready pretext for usurpation. We may also suspect that they suspected that emergency powers would tend to kindle emergencies.")[96]

[96] Administrative review does not require "exhibit[ing] a naiveté from which ordinary citizens are free," *Dep't of Com. v. New York*, 588 U.S. 752, 785 (2019). That the Department's action is intended to support the White House's stated goals of keeping fossil fuel plants from retiring is evidenced by a wealth of publicly available information surrounding the Administration's policies and stated intent. *See, e.g., Agenda47: America Must Have the #1 Lowest Cost Energy and Electricity on Earth*, Trump-Vance 2025 (Sept. 7, 2023), https://www.donaldjtrump.com/agenda47/agenda47-america-must-have-the-1-lowest-cost-energy-and-electricity-on-earth; Jill Colvin & Bill Barrow, *Trump's Vow to Only be a Dictator on 'Day One' Follows Growing Worry over his Authoritarian Rhetoric*, Associated Press (Dec. 7, 2023, 4:58 PM), https://apnews.com/article/trump-hannity-dictator-authoritarian-presidential-election-f27e7e9d7c13fabbe3ae7dd7f1235c72 (President Trump indicated he was not concerned about statutory compliance when he stated repeatedly that he would "be a dictator" on Day One in order to "drill, drill, drill.").

Whatever the political aspirations of the Executive may be or its demands of its agency leaders, actions by the Department are still governed by the Administrative Procedure Act, which requires that a court "hold unlawful and set aside agency action, findings, and conclusions found to be arbitrary, capricious, [or] an abuse of discretion." 5 U.S.C. § 706(2)(A). The Administrative Procedure Act requires agencies to make a reasoned explanation for their actions by examining the relevant data and providing a rational connection between the facts found and the choice made. *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). And because an agency's authority rests squarely within the four corners of Congress' delegation, agencies are not permitted to make decisions based on factors which Congress has not intended it to consider. *Id.*; *see also Amerijet Int', Inc. v. Pistole*, 753 F.3d 1343, 1350 (D.C. Cir. 2014).

The Department's use of Section 202(c) is thus arbitrary and capricious because it is not tied to the requirements of the statute and is instead a product of impermissible political influence beyond those requirements. *D.C. Fed'n of Civic Ass'ns v. Volpe*, 459 F.2d 1231, 1248 (1971). As explained by the Supreme Court:

> The reasoned explanation requirement of administrative law, after all, is meant to ensure that agencies offer genuine justifications for important decisions, reasons that can be scrutinized by courts and the interested public. Accepting contrived reasons would defeat the purpose of the enterprise. If judicial review is to be more than an empty ritual, it must demand something better … [and] agencies must pursue their goals reasonably.

*Dep't of Com.*, 588 U.S. at 785.

### D. The Order Will Undermine Competitive Markets to the Detriment of Consumers and Reliability.

When viewed together with the Energy Emergency EO,[97] Grid EO, and the Department's nearly identical 202(c) order regarding the Campbell coal plant,[98] the Department advances an illegal command-and-control energy policy that effectively overrides the capacity and energy markets to force a private entity to continue operating an uneconomic unit they wished to decommission and for ratepayers to pick up the tab. Congress delegated to FERC the authority to regulate wholesale energy markets and interstate transmission and granted the Department only a narrow, backstop authority through Section 202(c). 16 U.S.C. § 824a(c). If left to stand, the Department's overbroad Order will forebode a fundamental undermining of competitive markets for energy, leading to a system that will deliver less reliability to consumers at greater cost.

1. Competitive Markets Have a Long History of Success.

For nearly a century, FERC's core responsibility under the Federal Power Act has been to ensure that rates, terms, and conditions employed by utilities for wholesale energy sales and transmission are just, reasonable, and not unduly discriminatory. 16 U.S.C. § 824d ("Section 205"). While the initial utility structure was vertically integrated such that generation, transmission, and distribution resources were all held by the same entity, advances in technology and statutory

[97] Exec. Order No. 14,156 Declaring a National Energy Emergency, 90 Fed. Reg. 8,433 (Jan, 20, 2025).

[98] Ex. 9 at 1-2, DOE Order No. 202-25-3 (May 23, 2025) (directing dispatch of the Campbell plant, which was scheduled to cease operations the following week).

changes led to the development of energy markets and merchant generation.[99] Further regulation by FERC in the 1990s with Order Nos. 888, 890, and 2000 fostered the establishment of several independently operated RTOs, which set up competitive markets that determine the prices for energy, capacity, and ancillary services based on procurement and dispatch of least-cost resources.[100] As RTO markets expanded, many states deregulated their utility monopolies and required them to join RTOs. Generating resources in competitive RTOs are built and retired by private investors in response to market price signals designed to encourage new investment when supply is tight and to encourage the retirement of facilities that are no longer competitive when capacity is plentiful. RTOs now account for approximately 2/3 of all electricity sales in the U.S. and have saved consumers billions of dollars, increased reliability, and reduced environmental harm.[101]

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[99] *See, e.g.*, *Order Terminating Rulemaking Proceeding, Initiating New Proceeding, And Establishing Additional Procedures*, 162 FERC ¶ 61,012, PP 7-11 (2018); *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,639-31,645 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[100] Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 638-41 (1996), Order No. 890, FERC Stats. & Regs. ¶ 31,241, at 124-352 (1997), Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 99-130 (1999).

[101] *See, e.g.*, Judy Chang et al., The Brattle Group, Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers, 1, 3-7 (April 2019), https://www.brattle.com/wp-

As explained by FERC, its "support of competitive wholesale electricity markets has been grounded in the substantial and well-documented economic benefits that these markets provide to consumers."[102] In addition to billions of dollars of consumer savings, FERC found that competitive markets protect consumers by "providing more supply options, encouraging new entry and innovation, spurring deployment of new technologies, promoting demand response and energy efficiency, improving operating performance, exerting downward pressure on costs, and shifting risk away from consumers."[103]

As part of its role in regulating markets, FERC has implemented Congressional mandates to ensure system reliability, including working with NERC to set industry standards for grid reliability;[104] coordination requirements for the

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content/uploads/2021/05/16092_nc_wholesale_power_market_whitepaper_april_2019_final.pdf (discussing billions of dollars in estimated cost saving); Jennifer Chen & Devin Hartman, *Why wholesale market benefits are not always apparent in customer bills*, R Street (Nov. 10, 2021), https://www.rstreet.org/commentary/why-wholesale-market-benefits-are-not-always-apparent-in-customer-bills/ (same); Jeff St. John, *A Western US energy market would boost clean energy. Will it happen?*, Canary Media (Jun. 10, 2024), https://www.canarymedia.com/articles/utilities/a-western-us-energy-market-would-boost-clean-energy.-will-it-happen; John Tsoukalis et al., Assessment of Potential Market Reforms for South Carolina's Electricity Sector, at 6, 46, 77-78 (Apr. 27, 2019), https://www.scstatehouse.gov/CommitteeInfo/ElectricityMarketReformMeasuresStudyCommittee/2022-04-27%20-%20SC%20Electricity%20Market%20Reform_Brattle%20Report.pdf (discussing cost savings across regional wholesale markets).

[102] Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 FERC ¶ 61,012, P 11 (2018).

[103] *Id.* (citation omitted).

[104] PJM, NERC and Reliability (Jan. 5, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/nerc-and-reliability-fact-sheet.pdf.

natural gas and electricity market scheduling;[105] investigation and improvements required in light of the grid's response to extreme weather events;[106] and reviewing capacity accreditation processes to ensure that capacity markets generate reliable results.[107]

2. Command and Control Orders Run Counter to Federal Power Act Requirements and Fundamental Market Principles.

Despite the decades of evidence that competitive energy markets deliver reliable energy at least cost to consumers, as well as the extensive and constant oversight of these markets by FERC, the Order operates under the implicit

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*See also* PJM, PJM Ensures a Reliable Grid (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/reliability-fact-sheet.pdf.

[105] PJM, PJM Promotes Gas/Electricity Industry Coordination (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/gas-electric-coordination-fact-sheet.pdf. *See also*, Order 787, 145 FERC ¶ 61,134 (2013); Order 809, 151 FERC ¶ 61,049 (2015).

[106] *See, e.g., Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators*, 149 FERC ¶ 61,145 (2014) (order addressing technical conferences on, among other things, the 2014 Polar Vortex); *Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1*, 182 FERC ¶ 61094 (2023);*Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification*, 187 FERC ¶ 61,204 (2024). *See also,* FERC, NERC and Regional Staff, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott (Oct. 2023), https://www.ferc.gov/sites/default/files/2023-11/24_Winter-Storm_Elliot_1107_1300.pdf; FERC, NERC and Regional Staff, The February 2021 Cold Weather Outages in Texas and the South Central United States (Nov. 2021), https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/FERC%20Presentation-Phase%202.pdf; PJM, Winter Storm Elliott Event Analysis and Recommendation Report (2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf?ref=blog.gridstatus.io.

[107] *Id.*; *see also* Order Accepting Tariff Revisions Subject to Condition, 186 FERC ¶ 61,080 (2024).

assumption that capacity market results are not reliable, and that market-driven generator retirement is cause for alarm. This is not the first time this President has sought to require preferential treatment for retiring resources he preferred for grid reliability.[108] When the Department proposed to have a rule that would require tariff provisions designed to prevent the retirement of preferred resources, FERC rejected the proposal unanimously.[109] FERC found that the allegations that potential retirements of particular resources would lead to grid reliability problems did not demonstrate that existing rules were unjust and unreasonable.[110] Nor was there evidence from the RTOs that any particular generator retirement would be a threat to grid resilience.[111] Moreover, FERC found that the proposal to pay cost-of-service rates for only certain types of resources "regardless of need or cost to the system" would not be just, reasonable, or unduly discriminatory.[112]

Similar to this prior effort, the Order proposes to force the Eddystone Units to run regardless of need or cost to the system. The Order demands that PJM "take every step to employ economic dispatch," which it fails to define. Ex. 1 at 3. As discussed above in section IV., PJM dispatches generators based on the lowest

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[108] *See, e.g.*, Casey Roberts, *FERC Rejects DOE's Dangerous Proposal to Shield Coal and Nuclear From Clean Energy Competition*, Sierra Club (Jan. 9, 2018), https://www.sierraclub.org/compass/2018/01/ferc-doe-coal-nukes-perry-subsidies

[109] Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 FERC ¶ 61,012 (2018).

[110] *Id.* at PP 15-16.

[111] *Id.*

[112] *Id.* at P 16.

marginal price. The low historic utilization of Eddystone reflects that its costs to operate are so much higher than alternative resources that it isn't being dispatched enough of the time—even during times of peak load—to warrant keeping the unit online. *See supra*, Section IV.B. Constellation was well aware of PJM's load forecasts and the related high capacity prices when it opted to retire the Eddystone Units. This indicates that Constellation either didn't see Eddystone becoming economic even in future scenarios and/or that it felt it could make more money by retiring the Eddystone Units and investing in other options that offered the ability to dispatch more frequently and earn a greater return on investment. By forcing Eddystone to stay on the system despite this, the Department will raise prices for consumers by forcing them to pay for a resource that is unnecessary to meet PJM's Reliability Requirement for the current delivery year. Keeping Eddystone online also forces Constellation to continue to invest its money in an aging and expensive unit instead of investing in newer, more profitable units.

Should the Order be extended, as the Department suggests it will be, the consequences will become further reaching. Mandating that Eddystone remain online over a longer timeline forces PJM and Constellation to tie up the transmission capacity rights owned by the Eddystone Units that could otherwise be repurposed by Constellation for a new unit at the Eddystone site or put back into the system for allotment to new, more efficient resources waiting in PJM's

infamously years-delayed interconnection queue.[113] In other words, the Order forces Constellation to tie up an incredibly valuable transmission resource by maintaining that transmission headroom for a resource that is no longer useful and is unlikely to actually need to be used. As such, this decision is the very opposite of the bedrock principle of utility law that asset expenditures must be used and useful.[114] Moreover, it defeats the Administration's alleged concern that there are more retirements than new resources coming on the system. Ex. 1 at 1. As mentioned above, PJM has instituted new procedures for allowing resources needed for reliability to advance to the front of the interconnection queue. By tying up unused transmission capacity at the Eddystone Units, it also prevents new, more affordable and reliable resources already waiting to replace it from doing so. While extensions of the Order beyond the initial 90-days would almost certainly be unlawful and unreasonable, the Department appears to be contemplating

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[113] Joseph Rand et. al., Queued Up: 2024 Edition, *Lawrence Berkeley National Laboratory* (April 2024) at 35,https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf (showing that PJM has the longest queue processing timelines in the U.S.); Synapse Energy Economics, Inc., Sabine Chavin et al., Tackling the PJM Electricity Cost Crisis (Apr. 2025), https://www.synapse-energy.com/sites/default/files/Evergreen%20PJM%20Queue%20Report%204.10.25_%20final%2024-145.pdf; Grid Strategies, Generator Interconnection Scorecard (Feb. 2024) https://gridstrategiesllc.com/wp-content/uploads/2024/03/AEI-2024-Generation-Interconnection-Scorecard.pdf (scoring PJM's overall interconnection a D-).

[114] *See* FERC, Energy Primer, at 55 (2024), https://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf; Jim Lazar, Electricity Regulation in the US: A Guide, Second Edition, at 91 (2016), https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-electricity-regulation-US-june-2016.pd.

extensions given the statement that "DOE plans to use [the Grid EO] methodology to further evaluate Eddystone Units 3 and 4." Ex. 1 at 2.

Finally, the longer-term impacts of the Department's strategy send signals that will disrupt market stability. Markets ultimately still depend on private investors, who will be less likely to invest billions of dollars in an energy system run according to personal whim rather than on market forces. The need for market stability across administrations and department heads is why Congress deliberately placed the authority for utility regulation—a matter so fundamentally central to the entire economy and well-being of the nation—in the hands of independent regulators with specialized expertise and only allowed the Department to intervene in true emergencies.[115] In usurping the role of FERC and RTO markets to regulate the energy markets so that the Department can prioritize resources it favors and thwart the development of those it dislikes, the ultimate message is for private investors not to invest. As noted by former FERC Commissioner Brownell, to do otherwise "will have a chilling effect on markets because investors will be unlikely to risk hundreds of billions of dollars on investments regulated by politically influenced non-transparent decisions."[116]

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[115] *See generally*, Patrick M. Corrigan & Richard L. Revesz, *The Genesis of Independent Agencies*, 92 N.Y.U. L. Rev. 637 (2017).

[116] Herman K. Trabish, *Trump executive order threatens transmission, interconnection initiatives: former FERC commissioners*, Utility Dive (Mar. 26, 2025), https://www.utilitydive.com/news/trump-executive-order-agency-independence-ferc-transmission-interconnection-initiatives/742356/. *See also* Oskar Dye-Furstenberg, *The Hollow Energy Agenda of Trump's First Four Months*, Roosevelt Institute (May 29, 2025), https://rooseveltinstitute.org/blog/the-hollow-energy-agenda-of-trump/.

### E. Even If There Were a Short-Term Need—There Is Not—the Order Does Not Comply with the Statutory Command to Set Terms That Best Meet the Emergency and Serve the Public Interest.

#### 1. Section 202(c)(1) Only Authorizes the Department to Require Generation that Best Meets the Emergency and Serves the Public Interest.

Even if there were a Section 202(c) emergency, which as shown above there is not, Section 202(c)(1) requires the Department only impose requirements that (i) "best" (ii) "meet the emergency and" (iii) "serve the public interest." 16 U.S.C. § 824a(c)(1). The Department therefore must consider alternatives and choose the alternative that is most advantageous to meeting the emergency and serving the public interest as defined by the Federal Power Act.

The term "best" demands a comparative judgment that there are no better alternatives. The word "best" is inherently a comparative term and means "that which is 'most advantageous.'" *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 218 (2009) (quoting Webster's New International Dictionary 258 (2d ed.1953)); *cf. Sierra Club v. Env't. Prot. Agency*, 353 F.3d 976, 980, 983–84 (D.C. Cir. 2004) (explaining that statutory "best available control technology" requirement demands sources in a category clean up emissions to the level that peers have shown can be achieved). Consequently, the Department must, at minimum, consider alternatives and evaluate whether and to what extent a given alternative addresses the alleged emergency and serves the public interest, including deficiencies associated with each option.

Moreover, the Department must consider alternatives as part of exercising reasoned decision-making. It need not consider every conceivable alternative, but it

must consider alternatives within the ambit of the existing policy as well as alternatives which are significant and viable or obvious. *See Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1, 30 (2020) (failure to consider alternative was arbitrary and capricious); *Motor Vehicle Mfrs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 51 (1983) (must consider alternatives "within the ambit of the existing standard"); *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 215 (D.C. Cir. 2013) ("agency must consider and explain its rejection of reasonably obvious alternatives" (cleaned up)). Intervenors and the public may also introduce information that requires the Department to evaluate alternatives and reconsider its decision to impose or maintain a requirement. *See, e.g.*, *Chamber of Com. of the U.S. v. Secs. & Exch. Comm'n*, 412 F.3d 133, 144 (D.C. Cir. 2005) (holding that agency's failure to consider the disclosure alternative raised by dissenting Commissioners and introduced by commenters violated the Administrative Procedure Act); *cf.* 10 C.F.R. § 205.370 (stating the Department's right "to cancel, modify, or otherwise change" an order). To be sure, the nature and extent to which the Department must consider alternatives depends on the emergency. An emergency that truly requires the Department to act within hours, for instance, would permit a more abbreviated consideration than an emergency for which the Department has days to decide. 16 U.S.C. § 824a(c) (directing the Department to exercise its judgment).

The Department's regulations and practice suggest relevant alternatives for its consideration. The regulations specify information the Department shall

consider in deciding to issue an order under Section 202(c), and require an applicant for a 202(c) order to provide the information. 10 C.F.R. § 205.373. The specified information includes "conservation or load reduction actions," "efforts . . . to obtain additional power through voluntary means," 10 C.F.R. § 205.373(g)–(h), and "available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions." Ex. 6 at 4-5 (DOE Order No. 202-22-4).

The statutory command to take only measures that serve the public interest further constrains the Department's authority. The public interest element demands that the Department advance, or at least consider, the various policies of the Federal Power Act. *Cf. Wabash Valley Power Ass'n*, 268 F.3d at 1115 (interpreting the "consistent with the public interest" standard in Section 203 of the Federal Power Act); *see Gulf States Utils. Co. v. Fed. Power Comm'n*, 411 U.S. 747, 759 (1973) (discussing "public interest" standard in other provisions); *California v. Fed. Power Comm'n*, 369 U.S. 482, 484–86, 488 (1962). Primary policies of the Federal Power Act include protecting consumers against excessive prices; maintaining competition to the maximum extent possible consistent with the public interest; and encouraging the orderly development of plentiful supplies of electricity at reasonable prices. *NAACP v. Fed. Power Comm'n*, 425 U.S. 662, 670 (1976) (orderly development); *Otter Tail Power Co. v. United States*, 410 U.S. 366, 374 (1973) (maintaining competition); *Pa. Water & Power Co. v. Fed. Power Comm'n*, 343 U.S. 414, 418 (1952) (excessive prices). And because Section 202(c) expressly

protects environmental considerations, these are part of the public interest element too. *See NAACP*, 425 U.S. at 669 ("[T]he words 'public interest' . . . . take meaning from the purposes of the regulatory legislation.").

2. The Order Does Not Contain a Reasoned Basis that Eddystone Best Meets the Claimed Emergency and Serves the Public Interest.

Even if the scenario the Order lays out were an emergency pursuant to Section 202(c), the Department has not explained why ordering Eddystone to be available to operate is the best means to meet that scenario. Ex. 1 at 1 & n.2

The operational status of Eddystone suggests that it may be unable to meet purported emergencies. Although a spokesperson for Constellation indicated recently that the units were in "ready" status, that statement also indicated a need to take steps to "retain necessary staff and perform necessary maintenance to allow for safe and reliable operations."[117] And while the Eddystone Units did run during the June 23-26 heatwave, Unit 4 "went offline."[118] These old, ready-to-retire Units are themselves likely to be unreliable.

Moreover, the Order also does not address readily available and obvious alternatives which, in point of fact, would better compensate for the supposed "resource adequacy issues" asserted (inaccurately) by the Order. Ex. 1 at 1. PJM's

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[117] Jon Hurdle, *Aging Pennsylvania power plant to keep running after Trump order on eve of shutdown*, Pennsylvania Capital-Star (June 9, 2025), https://penncapital-star.com/energy-environment/aging-pennsylvania-power-plant-to-keep-running-after-trump-order-on-eve-of-shutdown/.

[118] PJM Interconnection, LLC, Compliance Report (June 24, 2025), https://www.pjm.com/-/media/DotCom/documents/other-fed-state/20250624-doe-compliance-report-for-eddystone-units-3-and-4.pdf.

own summer outlook predicts that even in the case of an all-time peak load, PJM would be able to meet its required reserve needs through its existing programs.[119] PJM has already contracted demand response programs—a lower cost means to address grid reliability concerns—that can meet even a record-high summer demand peak this year and will continue to be available, and even expanded, in the coming years.[120] Additionally, Public Interest Organizations have highlighted above the robust transmission connectivity between PJM and neighboring regions, which PJM has accessed on a regular basis to support the stability of its grid. *See supra*, Section IV.B. This is consistent with the Department's long-standing recognition that power pools and utility coordination "are a basic element in resolving electric energy shortages." 46 Fed. Reg. at 39,985–86. The Department offers no reasonable basis to question the availability of resources from neighboring regions. But even if there were some barrier to transmission from those regions, the Department has not (and likely could not) explain why the Order provides a better means of ensuring resource sufficiency than addressing those barriers directly through its power to require "interchange" and "transmission" of electric energy from those neighboring regions. 16 U.S.C. § 824a(c)(1). Finally, even if

[119] *See* Summer Outlook 2025, *supra* n. 4.

[120] *Id.* Commissioner Chang commended PJM's use of demand response in the June 23-26 heatwave. ("In particular, I do want to highlight the PJM's use of nearly 4,000 MW of demand response to reduce the peak load, their peak load, on Tuesday from what would have been the third highest peak load experienced on the PJM system. I see load flexibility as a key tool for grid operators to meet the challenges that we face and I commend PJM for the successful use of demand response during the system strain.") FERC Commission Meeting, June 2025 Open Meeting, https://youtu.be/eAHyYMKI_Yg.

preventing the retirement of existing facilities was the best means of addressing the alleged emergency, the Order does not address why maintaining the Eddystone Units over other retiring units is the best means. Buchannan Units 1 and 2 are set to retire by July 1, 2025.[121] These more modern combustion turbines, with a combined name plate generation of 88 MW, were constructed in 2002. Not only are these units newer than Eddystone, but their recent annual generation has been at least six times as much GWh and the plant has run almost twice as efficiently.[122]

The Orders failure to include any consideration of these other alternatives. And the Order contains no reasoning demonstrating why Eddystone is the best alternative, or a better alternative than other options. As such, the Order is unlawful.

### F. Because the Order Is Ambiguous, It Fails to Provide Fair Notice to the Public and Regulated Entities and Conflicts with Limitations on the Department's Authority.

The Order requires PJM and Constellation to "take all measures necessary to ensure that Eddystone Units are available to operate." Ex. 1 at 3. The Order further requires PJM to "take every step to employ economic dispatch of the units to minimize cost to ratepayers." *Id.* Those directions are so vague that neither the public nor the regulated entities have fair notice of the Department's actions, and so

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[121] Letter from Jason P. Connel, VP Planning, PJM to Nathan Dixon, VP Buchanan Generation, LLC, *Deactivation Notice for Buchanan Unit 1 & Unit 2* (May 30, 2025) https://www.pjm.com/-/media/DotCom/planning/gen-retire/deactivation-notices/buchanan-unit-1-unit-2-pjm-response.pdf.

[122] *See* U.S. Energy Information Administration., Form EIA-923: Power Plant Operations Report (2023), https://www.eia.gov/electricity/data/eia923/.

imprecise as to conflict with the limitations on the Department's authority under Section 202(c).

The Department's direction to "ensure that Eddystone Units are available to operate" is impermissibly ambiguous and vague. Ex. 1 at 3. The Order does not explain, for instance, whether it requires (a) only that PJM and Constellation take measures so they are ready to send, receive, and respond to dispatch instructions to the extent capable with no other actions, or (b) that PJM and Constellation take additional measures that enlarge their capabilities to operate (like capital investments). It is also unclear whether PJM and Constellation are required to take measures to ensure that each of the units is equally "available to operate." *Id.* at 3.

Additionally, the Order's reference to "ratepayers" is impermissibly ambiguous and vague. *Id.* For instance, does the Order refer to ratepayers in the PJM wholesale energy markets, the PJM capacity market and ancillary services markets, bilateral markets, retail ratepayers, some combination of these ratepayers, or some other set of ratepayers? The Order also contains no geographic limit on the referenced ratepayers, such that it is not clear whether PJM is directed to minimize costs to ratepayers in Pennsylvania, across PJM, or some other area. It further contains no temporal limit, such that it is unclear whether PJM is directed to minimize cost to current ratepayers, future ratepayers, or both. Moreover, the Order contains no standards or guidance on how PJM is to reconcile or balance countervailing tensions, like minimization of costs to current and future ratepayers.

The ambiguities also make unclear the scope of activities and omissions coming within the effect of Section 202(c)(3), leaving the public and Public Interest Organizations in the dark as to what pollution is and is not allowed.

The above defects are fatal to the Order's validity. The Order does not give PJM and Constellation reasonably clear direction. And a reasonably prudent person—regardless of whether such person is familiar with the electric industry—cannot ascertain the Order's meaning. As such, the Order does not give fair notice of conduct that is forbidden or required, and it is therefore unlawful. *Fed. Commc'ns Comm'n v. Fox Telev. Stations, Inc.*, 567 U.S. 239, 253 (2012) ("A fundamental principle in our legal system is that laws which regulate persons or entities must give fair notice of conduct that is forbidden or required"); *Grayned v. City of Rockford*, 408 U.S. 104, 108–09 (1972) ("an enactment is void for vagueness if its prohibitions are not clearly defined").

In addition, the ambiguities of the Order permit such a wide variety of actions and interpretations by PJM and Constellation that the Department has not met the statutory requirement to select only the activity that "*best* meet[s] the emergency and serves the public interest." 16 U.S.C. § 824a(c) (emphasis added). There can only be one "best" in the Department's judgment. Given the vagaries of the Order, many potential activities could be allowed, and the Department has not specified which activity is "best," much less explained why. As such, the Department fails to comply with Section 202(c)(1) and the Order is consequently arbitrary and capricious, an abuse of discretion, not in accordance with law, and

beyond the Department's statutory authority. *Cf. Allentown Mack Sales & Serv., Inc. v. NLRB,* 522 U.S. 359, 375 (1998).

### G. The Department's Order Fails to Provide the Conditions Necessary to Override Environmental Standards Under Section 202(c)(2).

The Order purports to authorize operations that may "conflict with environmental standards and requirements." Ex. 1 at 2. Where an order may produce such a conflict, Section 202(c)(2) requires the Department to "ensure:" (1) that it compels "generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest;" (2) that operations are "to the maximum extent practicable . . . consistent with any applicable Federal, State or local environmental law[s];" and (3) that it minimizes any adverse environmental impact, regardless of the facility's compliance (or non-compliance) with environmental standards. 16 U.S.C § 824a(c)(2). The Order here violates all three of those statutory obligations—a failure with especially severe consequences given the pollution produced by the Eddystone Units.

First, the Order directly contradicts the Department's obligation to require generation "only during hours necessary to meet the emergency." *Id.* The Order instead states: "For the duration of this order, PJM is directed to take every step to employ *economic dispatch* of the units to *minimize cost* to ratepayers." Ex. 1 at 3 (emphasis added). *See also* Ex. 10[123] (PJM stating that "Constellation will maintain active cost offers" on Markets Gateway to "operate on gas or oil for both

[123] Ex. 10 (PJM Reporting and Commitment Process).

Eddystone 3 and 4, unless either fuel is unavailable or if the units are on a Planned, Maintenance or Forced outage"). The "emergency" nominally described by the Order is "the potential loss of power to homes and local businesses in the areas that may be affected by curtailments," during the Order's 90-day span. Ex. 1 at 2. Even if the Department had substantiated that emergency (which it has not) the Federal Power Act would allow the Department to compel generation only when such losses would occur absent operation of the Eddystone Units. 16 U.S.C. 824a(c)(2); *see, e.g.*, Ex. 11 at 9 (DOE Order No. 202-17-4 Summary of Findings) ("authorizing operation of" units subject to emergency order "only when called upon . . . for reliability purposes," according to "dispatch methodology" approved by Department). "Economic dispatch," in sharp contrast, requires "the lowest-cost resources [to] run first," in pursuit of "the lowest-cost energy available." *City of New Orleans v. FERC,* 67 F.3d 947, 948-49 (D.C. Cir. 1995)*; see also Fla. Power & Light Co. v. FERC,* 88 F.3d 1239, 1241 (D.C. Cir. 1996) (noting distinction between economic dispatch and reserve capacity rules). PJM has, for the time being, accepted that it may only dispatch the units to address immediate reliability and capacity needs.[124] But even that has proven not precise enough; on June 23 and 24, 2025, PJM allowed Eddystone to run[125] before relying on all of its demand response

[124] *Id.*

[125] *See* Compliance Report, *supra* n. 118; PJM Interconnection, LLC, Compliance Report (June 25, 2025), https://www.pjm.com/-/media/DotCom/documents/other-fed-state/20250625-pjm-report-in-compliance-w-ordering-paragraph-b-of-the-doe-20250530-order-no-202-25-4.pdf. In fact, on June 24 Eddystone Unit 3 ran for 24 hours and Eddystone 4 ran for 20. This appears to be beyond even the vague requirements of the Order.

resources.[126] The fact that PJM had additional demand response resources available to more than cover the day-ahead load forecast and in reality did have excess demand response resources means that the emergency claimed by the Order—"the potential loss of power to homes and local businesses"—was not in play and therefore Eddystone should not have been run. Moreover, any assurance by PJM does not alter the Order's unlawful terms. By directing PJM to dispatch the plant along cost-based principles, rather than "only during hours necessary to meet the emergency," the Department has violated Section 202(c)(2). 16 U.S.C. § 824a(c)(2).

Second, the Order fails to ensure that Eddystone operates, "to the maximum extent practicable," in conformity with applicable environmental rules. *Id.* The Order paraphrases the statutory text—that "operation of the Eddystone Units must comply with applicable environmental requirements . . . to the maximum extent feasible," but fails to specify *who* bears that responsibility or *what* such operation entails. Ex. 1 at 3. It imposes no further conditions beyond requiring Constellation to "pay fees or purchase offsets or allowances for emissions." *Id.* The direction to "comply . . . to the maximum extent feasible" is, as a result, potentially unenforceable; the Order provides no basis for the Department, or anyone else, to determine whether the plant is in fact complying or who might face the consequences of any failure to do so. *See* Ex. 6 at 5–7 (DOE Order No. 202-22-4)

[126] *See* PJM Emergency Procedures, Postings, Effective from 06/23/2025 to 06/26/2025, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (calling on some but not all demand response).

(requiring, *inter alia,* reporting of "number and actual hours each day" of operation "in excess of permit limits or conditions," and information describing how generators met their requirement to comply with environmental requirements to the maximum extent feasible). As such, the Order does not meet the Department's statutory obligation to "*ensure*" the maximum feasible compliance with applicable environmental standards. 16 U.S.C. § 824a(c)(2) (emphasis added).

Third, the Order fails to provide any conditions at all to "minimize[] any adverse environmental impacts." 16 U.S.C. § 824a(c)(2). That mandate is textually and substantively distinct from the Department's (also unfulfilled) obligation to ensure maximum practicable compliance with environmental standards. *Id.* The Order fails, most importantly, to include measures, such as utilization of demand response resources, that would mitigate impacts when compliance with environmental standards proves impracticable. Past orders have routinely included such measures. *See, e.g.*, Ex. 11 at 2 (DOE Order No. 202-17-4 Summary of Findings) (permitting non-compliant operation only during specified hours, and requiring exhaustion of "all reasonably and practicably available resources," including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions); Ex. 6 at 7 (DOE Order No. 202-22-4) (requiring "reasonable measures to inform affected communities" of non-compliant operations). At a minimum the statute requires the Department to include sufficiently detailed reporting obligations to ascertain what impacts result from emergency operations; without such reporting, the Department

has no ability to "ensure" that adverse impacts are minimized. *See, e.g.*, Ex. 12 Department of Energy, Order No. 202-24-1, at 5 (Oct. 9, 2024) (requiring detailed data on emissions of pollutants). The Order here instead gestures towards "such additional information" as the Department may (or may not) "request[] . . . from time to time." Order at 3. That possibility of future, unspecified inquiry cannot satisfy the statute's demand that the Department "ensure" that its Order minimizes environmental impacts. 16 U.S.C. § 824a(c)(2).

Failure to meet those conditions is especially critical because the Eddystone Units can be operated on either gas or oil. PJM and Constellation have both indicated that the units intend to use fuel oil, rather than gas, when economically favorable. Ex. 10 (PJM Reporting and Commitment Process). Allowing the units to utilize oil based solely on cost—especially absent a requirement to exhaust demand-response and other available resources prior to dispatching the units at all—does not minimize environmental impacts "to the maximum extent practicable." 16 U.S.C. 824a(c)(2). *See* Ex. 13 (stating that Eddystone Units may alter fuels based on "pricing changes).[127] Oil-fired generation results in higher emissions of both criteria pollutants and hazardous air pollutants. Ex. 4 (Eddystone Title V Permit) at 28, 50 (noting sulfur content of oil and higher NOx emissions from oil-fired generation); 68 Fed. Reg. 1660, 1678 (Jan. 13, 2003) (noting that switching from oil to natural gas "would reduce mercury, metallic [toxics], and inorganic" hazardous

[127] Constellation Energy, *Eddystone Generating Station*, https://www.constellationenergy.com/our-company/locations/location-sites/eddystone-generating-station.html (last visited June 27, 2025).

air pollutant emissions). The months during which the Order operates do not pose a risk that natural gas will be unavailable, so even if an emergency requiring generation from the Eddystone Units existed—which it does not—gas-fired generation would be entirely practicable. Ex. 14 (Natural gas may not be available to Eddystone Units "[w]hen there's a cold snap" or during "a polar vortex").[128] The Order's failure to at least ensure that the Eddystone Units operate only on the least-polluting fuel available to them, even as it authorizes violation of governing environmental standards, violates the law. 16 USC § 824a(c)(2). At a minimum, the Department should impose tighter limits on the dispatch of Eddystone.

### H. The Order and the Department's Continued Conduct Are Inconsistent with Departmental Procedure, Depriving the Public and the Public Interest Organizations of Fair Notice and an Adequate Record.

According to the Department's procedures, the agency will use "best efforts" to post filings on a specified website within 24 hours of receipt.[129] The Department has received, and is supposed to receive, materials related to this proceeding that it has not posted. On June 13, 2025, the Department received a letter from PJM reporting on its compliance with the 202(c) Order.[130] The Public Interest

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[128] Constellation Energy, *Natural Gas and Oil,* https://www.constellationenergy.com/our-work/what-we-do/generation/natural-gas-and-oil.html (last visited June 27, 2025).

[129] Ex. 2 DOE Rehearing Procedures, *supra* n. 5.

[130] Letter from Michael Bryson, PJM, to Secretary of Energy Christopher Wright, *PJM Report in Compliance with Ordering Paragraph D of the Department of Energy's May 30, 2025 Order No. 202-25-4* (June 13, 2025), https://www.pjm.com/-/media/DotCom/documents/other-fed-state/20250613-doe-pjm-report-on-compliance-with-Eddystone-order-202-25-4.pdf.

Organizations have been able to access this letter because PJM published the letter to its website. The Department still has not met its obligation to publish this letter to its website. The Department may have received additional materials. The Order requires daily notifications on operations, p. 3 ¶ B, and such additional information regarding environmental impacts as the Department requests, p. 3 ¶ D. None of those materials are posted on the Department's 202(c) website.[131]

The Department must follow its own procedures. *See Morton v. Ruiz*, 415 U.S. 199, 235 (1974); *Mine Reclamation Corp. v. FERC*, 30 F.3d 1519, 1524 (D.C. Cir. 1994). The Department's failure to follow its procedures deprives the public and Public Interest Organizations of fair notice and an adequate record. *See United States v. Nova Scotia Food Prods. Corp.*, 568 F.2d 240, 249 (2d Cir. 1977).

## VI. REQUEST FOR STAY

Public Interest Organizations further move the Department for a stay of the Order until the conclusion of judicial review. 18 C.F.R. § 385.212.[132] The Department has the authority to issue such a stay under the Administrative Procedure Act and should do so where "justice so requires." 5 U.S.C. § 705. In

[131] The Department still has not posted filings for other recent 202(c) orders, either. *See e.g.*, U.S. Dep't of Energy, *Federal Power Act Section 202(c) Midcontinent Independent System Operator (MISO)*, https://www.energy.gov/ceser/federal-power-act-section-202c-midcontinent-independent-system-operator-miso (last visited June 27, 2025) (the Department received at least two requests for rehearing of the Campbell 202(c) order that it has not posted).

[132] Pursuant to FPA Section 313 and Rule 713(e) of the applicable rules, the filing of a request for rehearing does not automatically stay a Department Order. 16 U.S.C. § 825*l*(c), 18 C.F.R. § 385.713(e).

deciding whether to grant a request for stay, agencies consider: (1) whether the party requesting the stay will suffer irreparable injury without a stay; (2) whether issuing a stay may substantially harm other parties; and (3) whether a stay is in the public interest. *See Nken v. Holder*, 556 U.S. 418, 434, 436 (2009); *Ohio v. EPA*, 603 U.S. 279, 291 (2024); *see, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,020, at P 41 (2023); *ISO New Eng. Inc.*, 178 FERC ¶ 61,063, at P 13 (2022), *rev'd on other grounds sub nom. In re NTE Conn., LLC*, 26 F.4th 980, 987-88 (D.C. Cir. 2022).

Injuries under this standard must be actual, certain, imminent, and beyond remediation. *Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 555 (D.C. Cir. 2015); *Wis. Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985); *ANR Pipeline Co.*, 91 FERC ¶ 61,252, at p. 61,887 (2000); *City of Tacoma*, 89 FERC ¶ 61,273, at p. 61,795 (1999) (recognizing that, absent a stay, options for "meaningful judicial review would be effectively foreclosed"). Financial injury is only irreparable where no "adequate compensatory or other corrective relief will be available at a later date, in the ordinary course of litigation." *Wis. Gas Co.*, 758 F.2d at 674 (quoting *Va. Petroleum Jobbers Ass'n v. Fed. Power Comm'n*, 259 F.2d 921, 925 (D.C. Cir. 1958)); *see also In re NTE Conn., LLC*, 26 F.4th at 990-91. Environmental injury, however, "can seldom be adequately remedied by money damages and is often permanent or at least of long duration, *i.e.*, irreparable. If such injury is sufficiently likely, therefore, the balance of harms will usually favor the issuance of an

injunction to protect the environment." *Amoco Prod. Co. v. Vill. of Gambell*, 480 U.S. 531, 545 (1987).

### A. Intervenors Are Irreparably Harmed by the Order.

Here, a stay is necessary to ensure that Eddystone does not continue with activities that are already causing irreparable harm to Public Interest Organizations, their members, and the public as a result of the Order.[133]

Operating the Eddystone Units, which burn oil and natural gas, results in emissions of dangerous air pollutants, including sulfur dioxide ("SO2"), nitrogen oxides ("NOX"), particulate matter ("PM"), and carbon dioxide ("CO2") that would not otherwise have occurred but for the Order blocking the deactivation of the Eddystone Units.[134] These pollutants cause and exacerbate respiratory problems, cardiovascular issues, and other health conditions. These impacts are accentuated by Eddystone's location in an area already disproportionately overburdened by heavily polluting industrial sources and toxic waste sites.[135]

The Order also causes irreparable harm by imposing costs on PJM ratepayers that would not otherwise be borne and will not be recoverable through litigation. Constellation is complying with the Order and is seeking cost recovery through

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[133] The Eddystone Units have in fact operated as a result of the Order. *See, e.g.,* Compliance Report, *supra* n. 118.

[134] *Id.*

[135] *See supra*, Section IV.A.

FERC.[136] If that request is granted, costs will be borne by PJM ratepayers, and the Department does not identify any clear recourse for a refund in the event the Order is declared unlawful. In forcing ratepayers to reopen and operate an uneconomic, unreliable, and obsolete resource that was already approved for closure, the Order also jeopardizes the diversification of generating resources the Department itself has said increases grid reliability and will inherently and unjustifiably add to ratepayer costs.[137] As there is no clear recourse to recovering these costs from the Department should Public Interest Organizations prevail in their challenge, a stay pending judicial review is necessary to protect ratepayers from unwarranted energy cost increases-especially at a time when energy prices are already on the rise.[138]

**B. A Stay Would Not Result in Harm to Any Other Interested Parties.**

No other interested parties would be harmed by a stay. The issuance of a stay would not harm end-use electricity consumers because the lack of an actual emergency means that a stay would not disrupt the provision of electricity. *See supra*, Section V.C.3. Furthermore, because Constellation and PJM had both already planned for the closure of the Eddystone Units, a stay would only have the

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[136] *See* Letter from David E. Mills, Chair, PJM Board, to PJM Members and Stakeholders (June 26, 2025), 20250626-pjm-board-letter-re-results-of-the-cifp-process-for-doe-202-c-order-for-eddystone-units-3-and-4.pdf.

[137] *See* U.S. Dep't of Energy, Energy Reliability and Resilience, https://www.energy.gov/eere/energy-reliability-and-resilience (last visited June 26, 2025).

[138] *See* Mitchell Terpstra, *2024 News Release: PJM Capacity Auction Prices Skyrocket*, Energy Choice Blog (Oct. 2, 2024), https://electricityrates.com/resources/pjm-capacity-auction-spike/.

effect of relieving them of the administrative, compliance, and planning burdens imposed by the Order. *See, e.g.,* Ex. 1 at 2-3. On the balancing of equities, there is therefore no meaningful countervailing harm that would follow from a stay.

### C. A Stay is in the Public Interest.

There is no public interest served by the Order, and a stay will only benefit the public. First, the Order exceeds the Department's authority; it has provided no reasonable grounds to substantiate any near-term or imminent shortfall in electricity supply that would justify the Eddystone Units' continued operation. *See League of Women Voters v. Newby*, 838 F.3d 1, 12 (D.C. Cir. 2016) (noting that "there is a substantial public interest 'in having governmental agencies abide by the federal laws that govern their existence and operations'") (quoting *Washington v. Reno*, 35 F.3d 1093, 1103 (6th Cir. 1994)). Second, a stay would protect the broader public—beyond Public Interest Organizations and their members—from the costs and additional pollution produced by unnecessary operation of the Eddystone Units.

## VII. CONCLUSION

For the reasons set forth above, the undersigned Public Interest Organizations respectfully request that the Department grant intervention; grant rehearing and rescind the Order (and any renewals of the Order); and stay the Order.

*/s/ Caroline Reiser*
Caroline Reiser
Simi Bhat
Gavin McCabe
Natural Resources Defense Council
1152 15th Street NW, Suite 300

Washington, DC 20005
creiser@nrdc.org
sbhat@nrdc.org
gmccabe@nrdc.org
(202) 717-8341

*/s/ Ted Kelly*
Ted Kelly
Tomás Carbonell
Environmental Defense Fund
555 12th St. NW, #400
Washington, DC 20004
tekelly@edf.org
tcarbonell@edf.org
(202) 387-3500

Jessica O'Neill
PennFuture
1429 Walnut Street, Suite 701
Philadelphia, PA 19102
oneill@pennfuture.org

*/s/ Francis W. Sturges, Jr.*
Francis W. Sturges, Jr.
Danielle Fidler
Clean Air Task Force
114 State St., 6th Floor
Boston, MA 02109
fsturges@catf.us
dfidler@catf.us
(617) 624-0234
*Counsel for Citizens for Pennsylvania's Future*

*/s/ Tyson Slocum*
Tyson Slocum
Public Citizen, Inc.
215 Pennsylvania Ave SE
Washington, DC 20003
(202) 454-5191
tslocum@citizen.org

*/s/ Gregory E. Wannier*
Gregory E. Wannier

Sanjay Narayan
Sierra Club Environmental Law Program
2101 Webster St., Ste 1300
Oakland, CA 94612
greg.wannier@sierraclub.org
sanjay.narayan@sierraclub.org
(415) 977-5646

# EXHIBIT 41

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order TransAlta<br>Centralia Generation | Order No. 202-25-11 |

**DECLARATION OF CALLAHAN MORIYASU IN SUPPORT OF MOTION TO INTERVENE, REQUEST FOR REHEARING, AND MOTION TO STAY BY STATE OF WASHINGTON**

**Background and Qualifications**

1. I am currently employed as a Regulatory Analyst with the Public Counsel Unit of the Washington State Office of the Attorney General. In this role, I serve as an in-house expert on utility regulation. I have submitted testimony and written formal comments in several cases related to energy and electricity. I have a Master of Public Policy degree from the University of Southern California, as well as a Bachelor of Arts in Economics and History from Northwestern University. In addition to my formal education, I have completed several utility ratemaking courses, including New Mexico State University's Electricity Regulatory Training Course, Michigan State University's Power Grid School, and the National Association of Regulatory Utility Commissioners' (NARUC) Rate School and Fundamentals of Electricity Course.

**Purpose of This Affidavit**

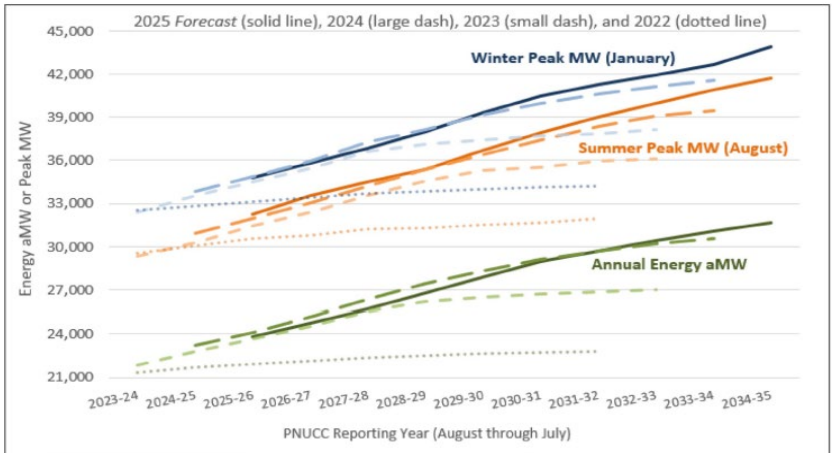
2. This affidavit addresses the reliability impacts of delaying the transition of the TransAlta Centralia Plant from coal to natural gas fuel. I also discuss the impact on ratepayers of keeping Centralia open as a coal plant longer than planned for.


ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

**The Conversion of the TransAlta Centralia Plant from Coal to Natural Gas on its planned timeline is Better for Long-Term Reliability**

3. Any potential energy shortage or emergency would likely not occur in the next few months, but several years from now. Delaying conversion exacerbates future reliability in 2028-2029, when the need for additional resources is projected to increase.

4. Long-term reliability assessments show that reliability issues are more significant in later years. For example, projections show that the 2025-26 winter peak is expected to be around 34,500 MW, while in 2028–29 it is expected to be over 36,000 MW. Ex. 3 at 7 (Energy + Environmental Economics, *Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results*, Power Point (September 22, 2025)). Note that the E3's full and final report has not yet been published as of this filing. The report is expected in late January or early February 2026. Therefore, additional energy will be needed in the 2028-29 winter season, rather than the upcoming 2025-26 winter season.




Growth Rates

| Energy | 10 year |
|---|---|
| 2025 Forecast | 3.2% |
| 2024 Forecast | 3.1% |
| 2023 Forecast | 2.4% |
| 2022 Forecast | 0.9% |

| Summer Peak | 10 year |
|---|---|
| 2025 Forecast | 2.9% |
| 2024 Forecast | 2.7% |
| 2023 Forecast | 2.3% |
| 2022 Forecast | 1.0% |

| Winter Peak | 10 year |
|---|---|
| 2025 Forecast | 2.6% |
| 2024 Forecast | 2.3% |
| 2023 Forecast | 1.8% |
| 2022 Forecast | 0.7% |

5. Furthermore, estimates of the reliability shortfall in 2026 (-1,321 MW) is significantly lower than in 2028 (-5,046 MW), which is when the Centralia natural gas conversion would come online as it would have without Energy's Order. Ex. 3 at 10.

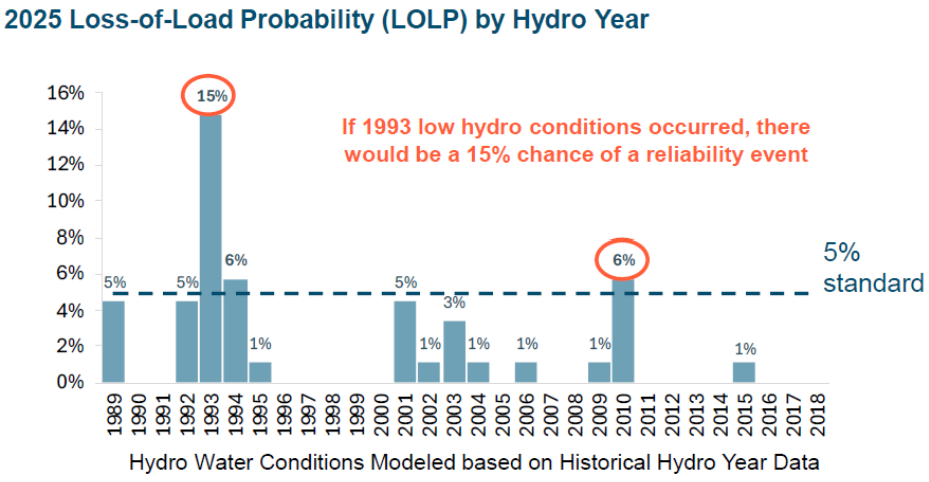
| System Needs (MW) | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| Total Resource Need* | 49,245 | 50,737 | 52,499 | 54,184 | 55,879 | 57,195 |
| Existing Portfolio w/ Retirements | 46,716 | 45,666 | 45,395 | 45,388 | 45,098 | 44,757 |
| Firm Imports | 3,750 | 3,750 | 3,750 | 3,750 | 3,750 | 3,750 |
| **Reliability Position Surplus (+) / Shortfall (-)** | **+1,221** | **-1,321** | **-3,354** | **-5,046** | **-7,031** | **-8,689** |
| ELCC from "In-Development" Firm Resources | - | 296 | 407 | 580 | 770 | 1,114 |
| ELCC from "In-Development" Wind, Solar and Battery projects | - | 645 | 1,015 | 1,316 | 1,508 | 1,934 |

6. Centralia's natural gas plant was set to come online in late 2028, in time for the 2028-2029 winter season. Ex. 20 (TransAlta News Release, "TransAlta Signs Long-Term agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion," Dec. 9, 2025). If Centralia is required to operate or even be prepared to operate as a coal plant for the 2025-2026 winter season, it will likely delay the retrofits necessary to transition to a natural gas plant. Holding current timelines the same, it may not be able to come online in time for the 2028-2029 season, when meeting resource adequacy standards is (as noted above) projected to require additional resources. This is supported by E3's projection that the Greater Northwest System metrics are significantly improved compared to baseline estimates from 2026 forward when In-Development Resources (including Centralia's conversion to natural gas) are considered. Ex. 41-23 (E3 NW RA – Data for WA AG 2026-01-17).

| System Metrics including "In-Development" Resources | Unit | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|
| **Reliability Position *with "In-Development" Resources*** Surplus (+) / Shortfall (-) | *MW* | 1,221 | -380 | -1,932 | -3,150 | -4,753 | -5,641 |
| **Loss-of-Load Expectation** | *MWh/year* | 63 | 1,212 | 6,987 | 20,398 | 58,132 | 98,067 |
| | *Hours/year* | 0.14 | 1.65 | 5.58 | 14.70 | 36.43 | 56.57 |
| | *Days/year* | 0.01 | 0.15 | 0.68 | 1.77 | 4.14 | 6.01 |
| | *% chance/year* | 0.3% | 5.2% | 21.0% | 40.5% | 59.4% | 67.5% |

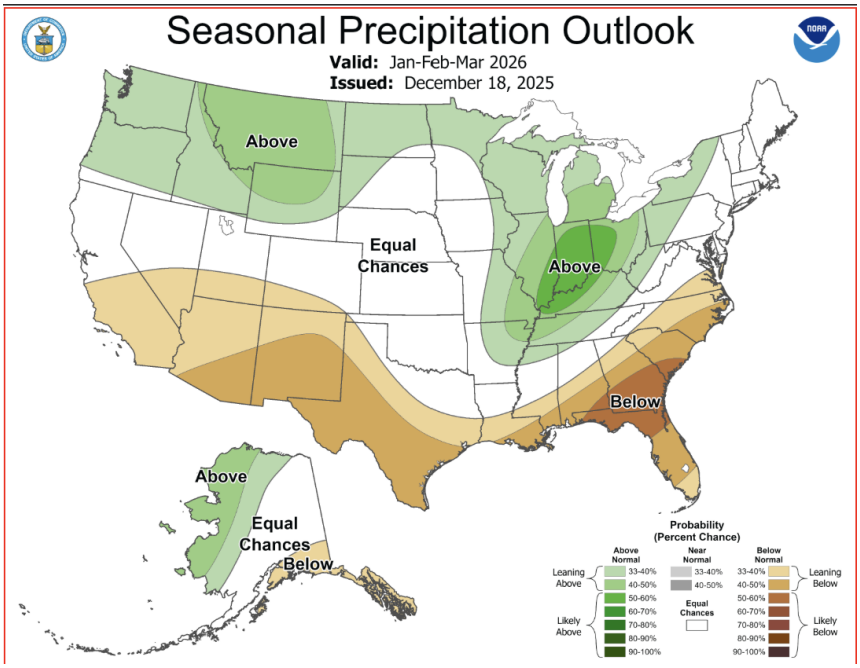
7. Additionally, the Northwest is a winter peaking region. Ex. 41-2 (EIA, *Northwest heat wave leads to record levels of summer electricity demand,* (Aug. 23, 2017)); Ex. 41-1 (Northwest Power and Conservation Council, *Historic Trends in Energy Use*). Delaying the conversion of Centralia even by 90 days would move the online date of the new plant to after the winter peak in the 2028-2029 season, exacerbating reliability concerns.

8. The risk of energy shortfalls is exacerbated in low hydropower years. Ex. 3 at 12. My team met with Arne Olson, one of the authors of the E3 study, in January 2026, who confirmed that the study's findings indicate no risk of loss of load in high hydropower years and very low loss of load in normal hydropower years.




9. Current hydropower projections indicate that 2025-2026 will be an above average hydropower year. Ex. 41-21 (National Oceanic and Atmospheric Administration, National Weather Service Climate Prediction Center, *Three-Month Outlook for Jan-Feb-Mar 2026*). Furthermore, Bureau of Reclamation data shows that the Grand Coulee Dam power discharge (variable name "QV") and reservoir water storage (variable name "AF") are currently higher than the 5-year average. This data is available through the Bureau of Reclamation's Hydromet Historical Data Access website: https://www.usbr.gov/pn/hydromet/arcread.html). United States Geological Survey (USGS) water condition data indicates that most locations along the Columbia River Basin have water

conditions above normal. Ex. 41-6 (United States Geological Survey, *Washington water conditions*).




10. Additionally, U.S. Army Corps of Engineers Water Management Data indicates that most dams in Bonneville Power Administration's service territory are full, with many dams over their spillway level. For example, the Grand Coulee, Chief Joseph, Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary, John Day, Dalles, Bonneville, Wanapum, and Rock Island Dams all have water levels over their spillway level, and have had levels above their spillways since December 8, 2025, before the Emergency Order. Exs. 41-8 through 41-20.

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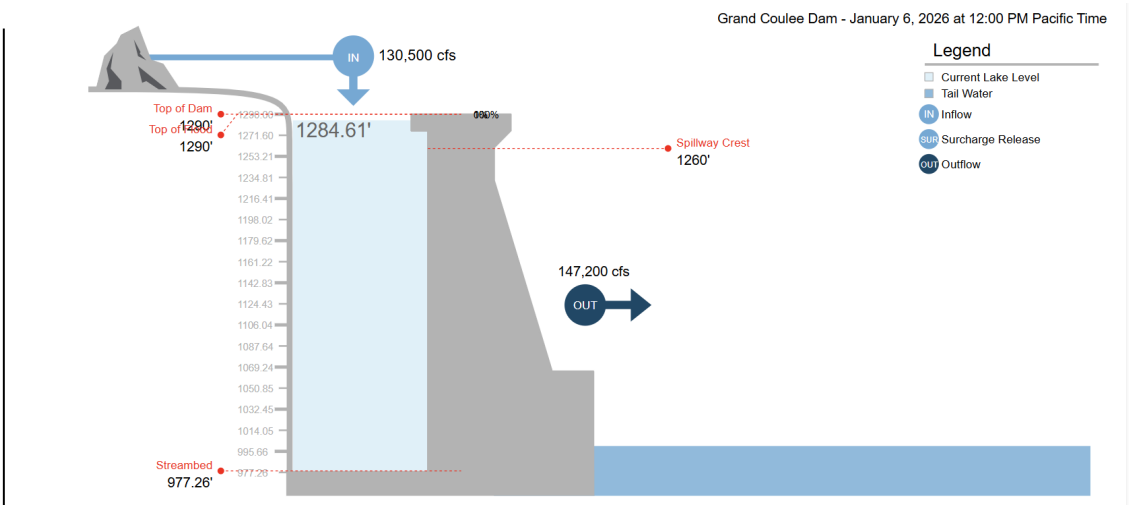
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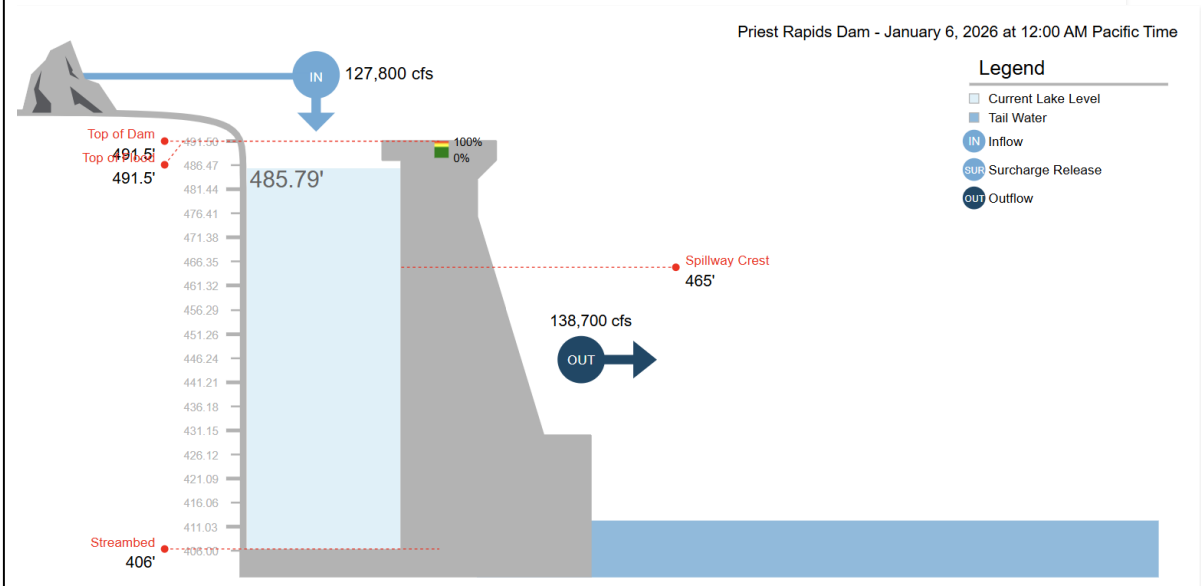
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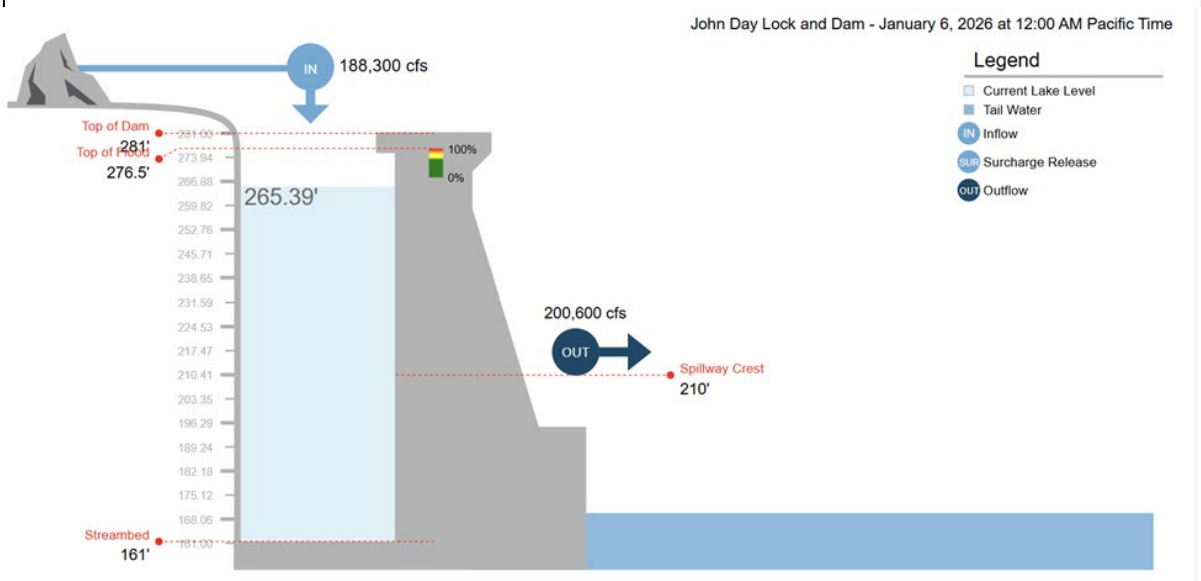
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Grand Coulee Dam - January 6, 2026 at 12:00 PM Pacific Time
Legend
Current Lake Level
Tail Water
Inflow
Surcharge Release
Outflow
IN
130,500 cfs
Top of Dam
1290'
1284.61'
100%
0%
Spillway Crest
1260'
147,200 cfs
OUT
Streambed
977.26'


Priest Rapids Dam - January 6, 2026 at 12:00 AM Pacific Time
Legend
Current Lake Level
Tail Water
Inflow
Surcharge Release
Outflow
IN
127,800 cfs
Top of Dam
491.5'
485.79'
100%
0%
Spillway Crest
465'
138,700 cfs
OUT
Streambed
406'


John Day Lock and Dam - January 6, 2026 at 12:00 AM Pacific Time
Legend
Current Lake Level
Tail Water
Inflow
Surcharge Release
Outflow
IN
188,300 cfs
Top of Dam
281'
276.5'
265.39'
100%
0%
200,600 cfs
OUT
Spillway Crest
210'
Streambed
161'

11. We do not know, however, if 2028-2029 will be a high or low hydropower year. Extending a coal plant during a high hydropower year is unnecessary from a resource adequacy perspective, particularly given the high-water levels this winter. It would be a more appropriate risk management strategy to ensure a resource will be available in the future when the level of hydropower is, as yet, unknown (i.e. riskier).

**Natural gas plants have more capability for ancillary services.**

12. Natural gas plants can provide a variety of already commercially available ancillary services, including inertial response, frequency responsive reserve, regulation, load following, spinning reserve, non-spinning reserve, replacement reserve, voltage support, and black start. Ex. 41-3 at 21 (U.S. Department of Energy, GE Energy Consulting, & Univ. of Hawaii, *Ancillary Services Definitions and Capability Study* (Dec. 2012)). The same E3 study cited by the Order states that natural gas is better poised to ensure resource adequacy than coal. Ex. 3 at 19-20.

13. Coal plants, however, are not capable of providing non-spinning reserve, replacement reserve, or black start ancillary services. Ex. 41-3 at 21.

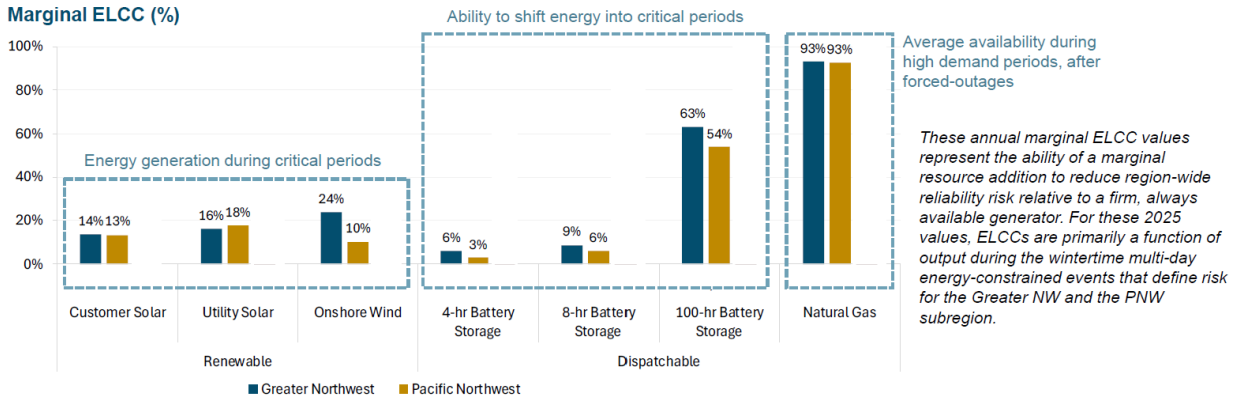
a. Coal plants are incapable of providing non-spinning reserves because they cannot quickly ramp up like natural gas plants can. That is, non-spinning reserves means reserves that do not need to already be online. Ex. 41-4 at 1 (DOE's Electricity Advisory Committee, *Optimizing Reserves* (Oct. 2019)).

b. Black start ancillary services mean that a plant can start without an external electricity source, which is valuable in the case of a major blackout. Coal plants are unable to provide black start ancillary services. Ex. 41-3 at 4.

c. Coal plants cannot provide replacement reserve services due to a lack of operational flexibility. Ex. 41-3 at 64.


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14. Therefore, the conversion of Centralia from coal to gas better serves reliability in the long-term by providing more ancillary services to the region. According to E3's study, natural gas provides the best support to resource reliability due to gas plants' ability to run when needed for several days with access to firm fuel resources. Ex. 3 at 19. This is exactly how the Centralia plant is intended to run once it is converted to natural gas fuel.




**Centralia Coal Plant's current price is higher than the wholesale market price in the region.**

15. Under its current Purchase Power Agreement (PPA), the energy price from Centralia's coal is significantly higher than the wholesale energy market price. Specifically, under the current contract, Puget Sound Energy (PSE) pays $62.04 per MWh, while the wholesale market price is $54.32 per MWh. Ex. 41-22 at Sheet "Centralia Coal PPA(R)" (PSE, Docket UE-250747, Attachment B (Impact of portfolio updates) (Oct. 1, 2025)). This indicates that Centralia is not currently economic to run as a coal plant. Accordingly, PSE projects saving money from the retirement of Centralia as a coal plant. Ex. 41-22.

16. This makes Centralia not economical to dispatch as a coal plant when compared to other resources available in the region. Maintaining the fixed costs of the plant without obtaining income from energy sales will be a burden on TransAlta and ratepayers. Or, if the plant is dispatched, whoever is forced to purchase the energy will likely pay a higher price than


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the other option they would have had available otherwise. This has a potentially significant negative cost impact on ratepayers.

DATED this 13 day of January, in Seattle, Washington.

Callahan Moriyasu

CALLAHAN MORIYASU



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Ecology Division
PO Box 40117
Olympia, WA 98504-0117
(360) 586-6770

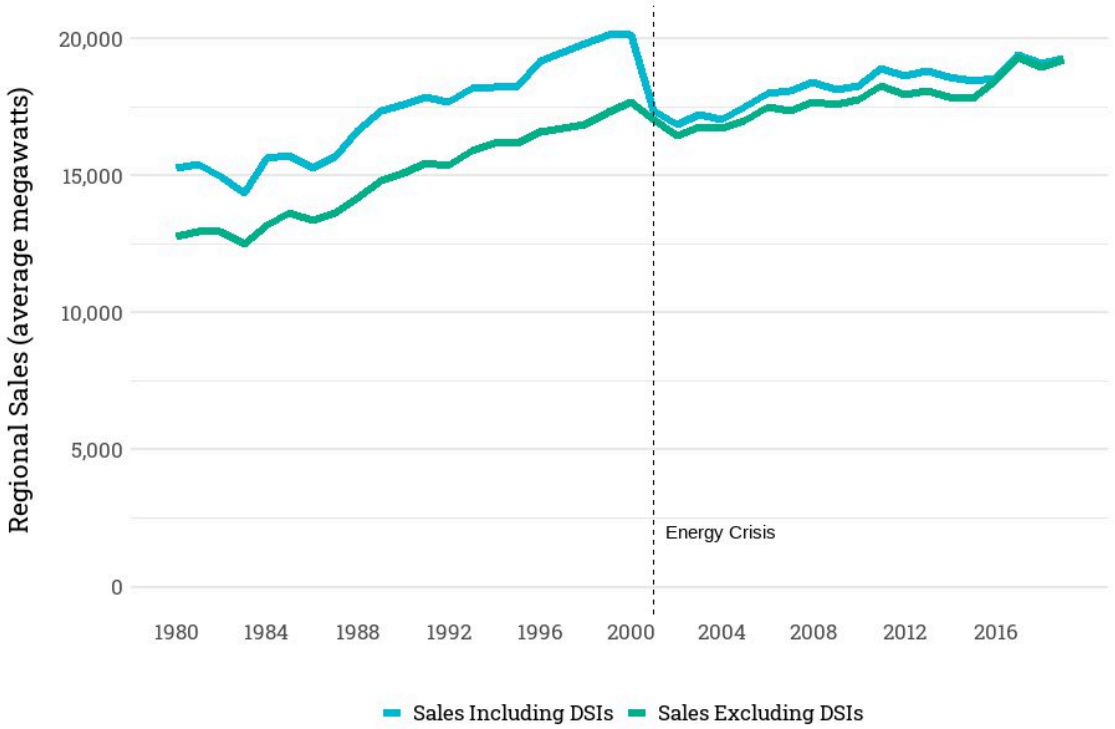
# EXHIBIT 41-1

# Historic Trends in Energy Use

## Changing Intensity of Regional Energy Use

It has been about 40 years since Council's establishment and 38 years since the release of the first power plan in 1983. Since then, the region's energy environment has undergone many changes. These changes have enabled the Northwest economy to grow, while growth in demand for energy has been kept low. In the decade prior to the Northwest Power Act, regional electricity load was growing at 3.5 percent per year and load (excluding the direct service industries – mainly aluminum smelting) grew at an annual rate of 4.3 percent. In 1970, regional load was about 11,000 average megawatts, and during that decade demand grew by about 4,700 average megawatts. During the 1980s, load growth slowed significantly but continued to grow at about 1.5 percent per year, experiencing load growth of about 2,300 average megawatts. In the 1990s, another 2,000 average megawatts were added to the regional load, making load growth in the last decade of the 20th century about 1.1 percent. Since 2000, regional load has declined. As a result of the energy crisis of 2000-2001 and the recession of 2001-2002, regional load decreased by 3,700 average megawatts between 2000 and 2001. Loss of many of the aluminum and chemical companies that were direct service industries contributed to reduction in demand for electricity. For the past 20 years, total regional demand has been recovering, but has not surpassed the demand level recorded in the year 2000. This growth has been driven by increasing demand from the commercial and residential sectors. The following figure and table track the regional electricity sales from 1980s-2018. In 2001-2018 the average annual growth rate is between 0.2 and 0.3 percent.

**Total and Non-DSI Regional Electricity Sales (aMW)[1]**



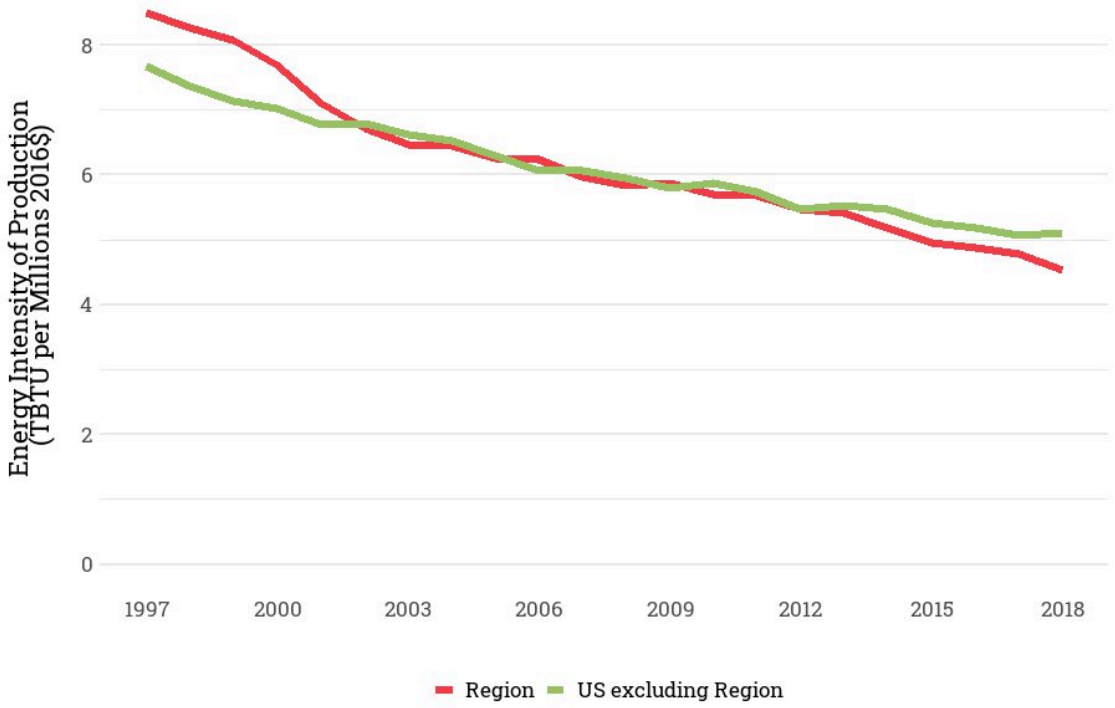

**Average Annual Growth Rate for Total and Non-DSI Regional Electricity Sales**

| | 1980-1989 | 1990-2000 | 2001-2007 | 2008-2018 |
|---|---|---|---|---|
| Total Sales | 1.6% | 1.4% | 0.4% | 0.1% |

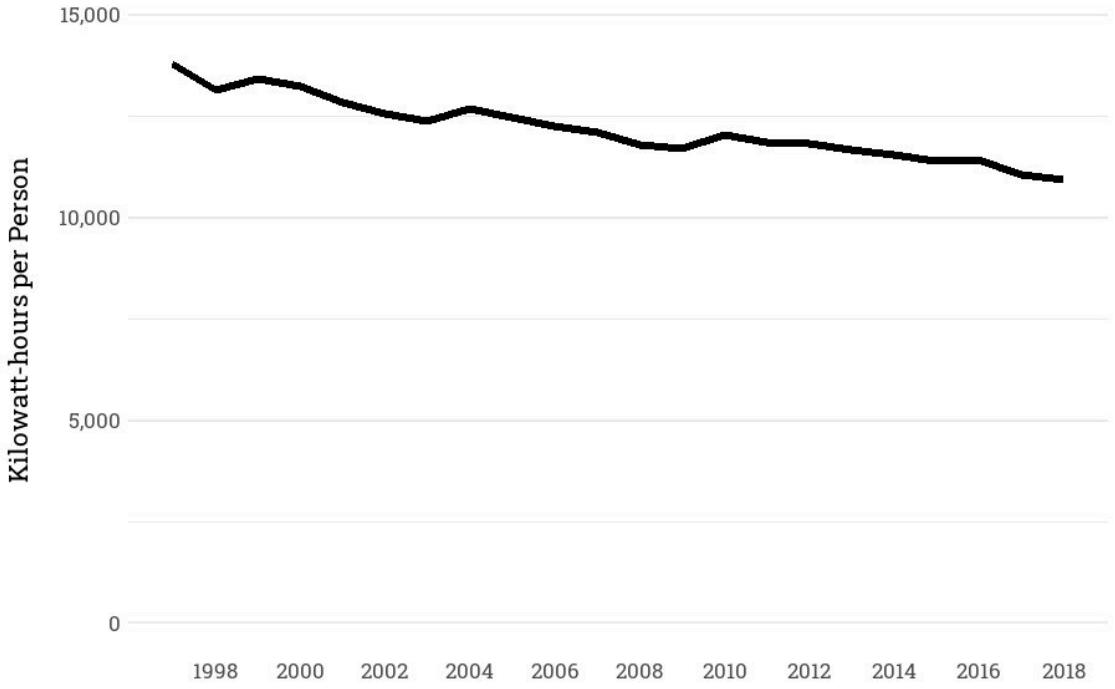
| | | | | |
|---|---|---|---|---|
| Sales net DSI | 1.9% | 1.6% | 0.2% | 0.5% |

The dramatic decrease in the growth of electricity demand shown in the above table was not due to a slowdown in economic growth in the region. On the contrary, the region added over 5.6 million people between 1986 and 2018. The decrease in demand was the result of a move to less energy-intensive activities as well as expanded energy efficiency investments. As shown in figures below, both energy and electric intensity (TBTU per dollar of output and per capita electricity use) show significant declines in the past decades. This shift reflects industry changes, increasing electricity prices, and regional and national conservation efforts. Note that the graph below shows total energy intensity (includes all forms of energy) not just electricity.

**Trends in Energy Intensity Per dollar of Gross State Product 1997-2018**

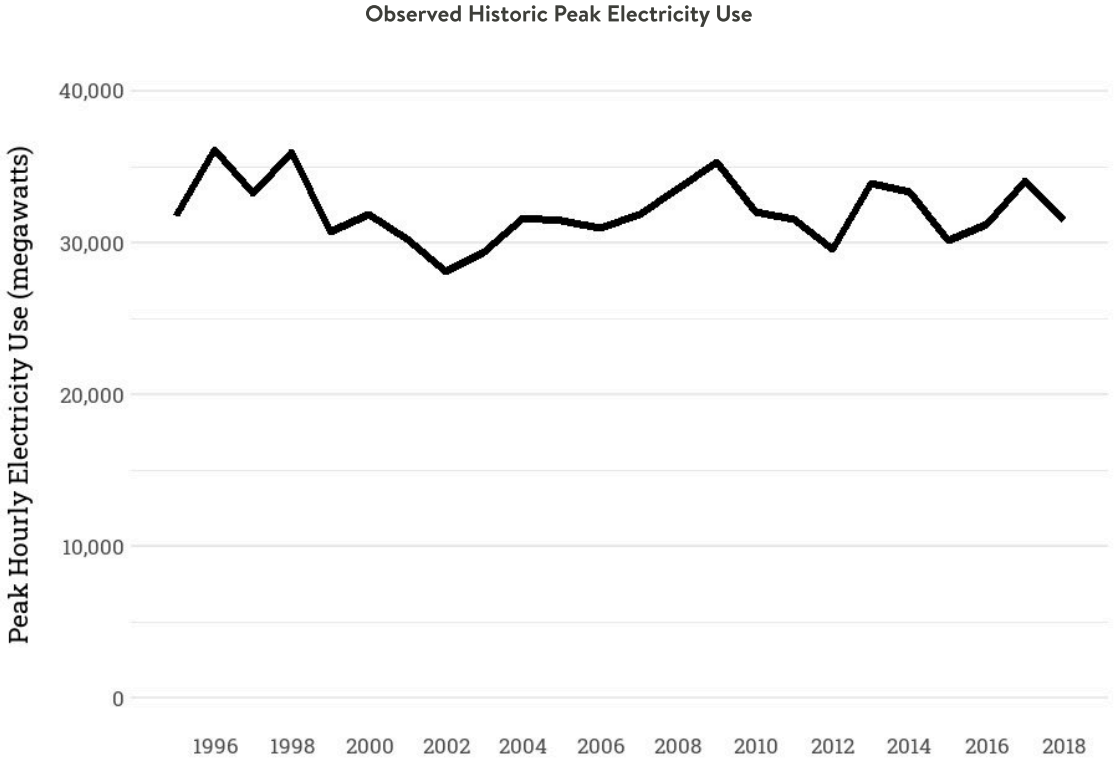



**Per Capita Demand for Non-DSI Electricity (Weather Normalized)**




## Historic Regional Peak Electricity Use

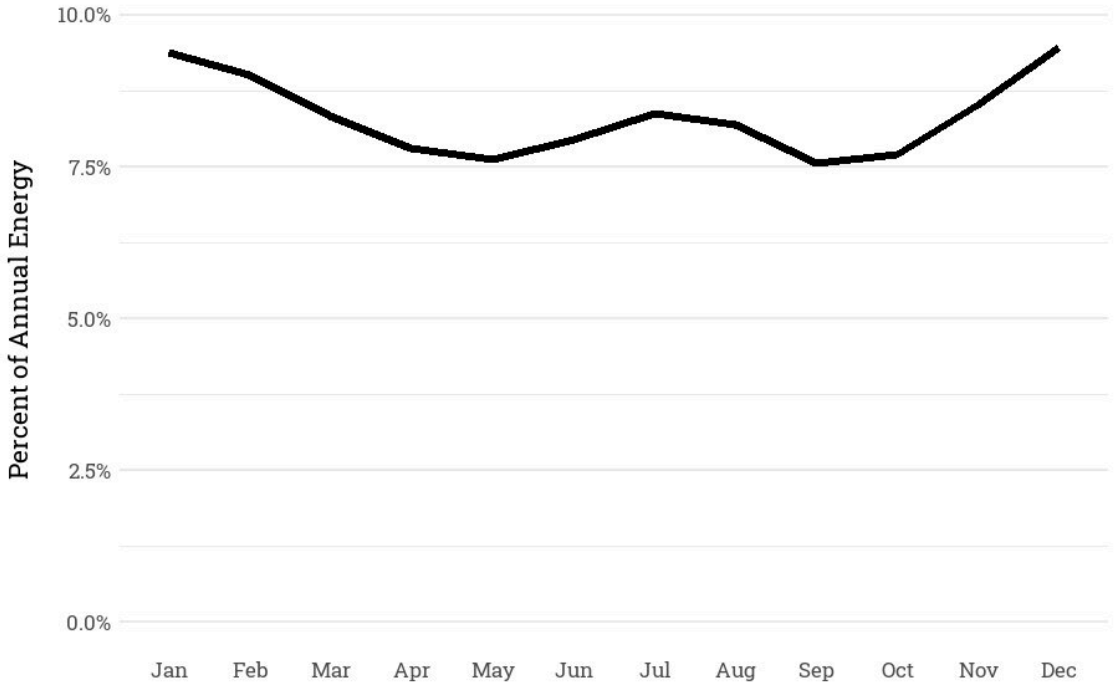
The electrical system in the Northwest must meet loads 24/7 throughout the year. Not only average load but also peak and off-peak loads must be met. In this section we provide our range of forecast for peak and off-peak loads. The actual peak loads shown for 1995-2012 reflect weather conditions at the time of system peak. The peak load projections for the forecast period assumes normal weather. Peak loads in the historic period 1995-2018 have not shown much growth; they have actually gone down by about -0.05% per year.



## Seasonality of Historic Regional Energy Use

The annual loads we have been discussing so far are not evenly distributed throughout the year. The electric system in the Northwest is a winter peaking system. The historic demand for electricity for the region shows a "W"-shaped profile. Approximately 9-10 percent of annual electricity in the region is consumed in the winter months of January and December. In the shoulder months (March through June, and September through November) monthly energy consumption is about 8 percent. In summer months, it is slightly above 8 percent. Similar patterns can be observed in each one of the four states, with electricity demand in Idaho slightly higher in summer and slightly lower than the regional average in winter months.

**Monthly Pattern of Demand for Electricity**

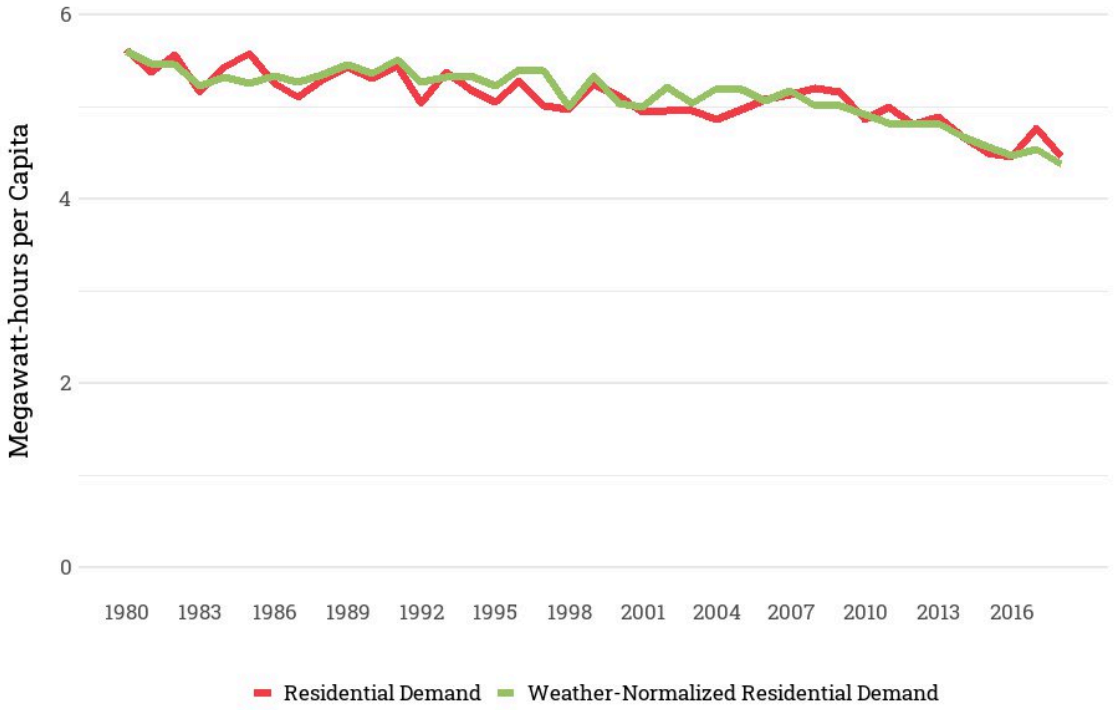



## Historic Trends by Economic Sector

### Residential Sector

Residential load for electricity grew from 5,350 average megawatts in 1986 to about 8,116 average megawatts in 2018. Although residential demand for electricity has been increasing, the per capita consumption of electricity in the residential sector shows continued decline. Improved building codes and more efficient appliances helped to keep the consumption level down. Since 1980, per capita demand for electricity fell from over 5.5 MWH to less than 4.4 MWH a decline of over 20 percent.

**Residential Demand for Electricity per Person**



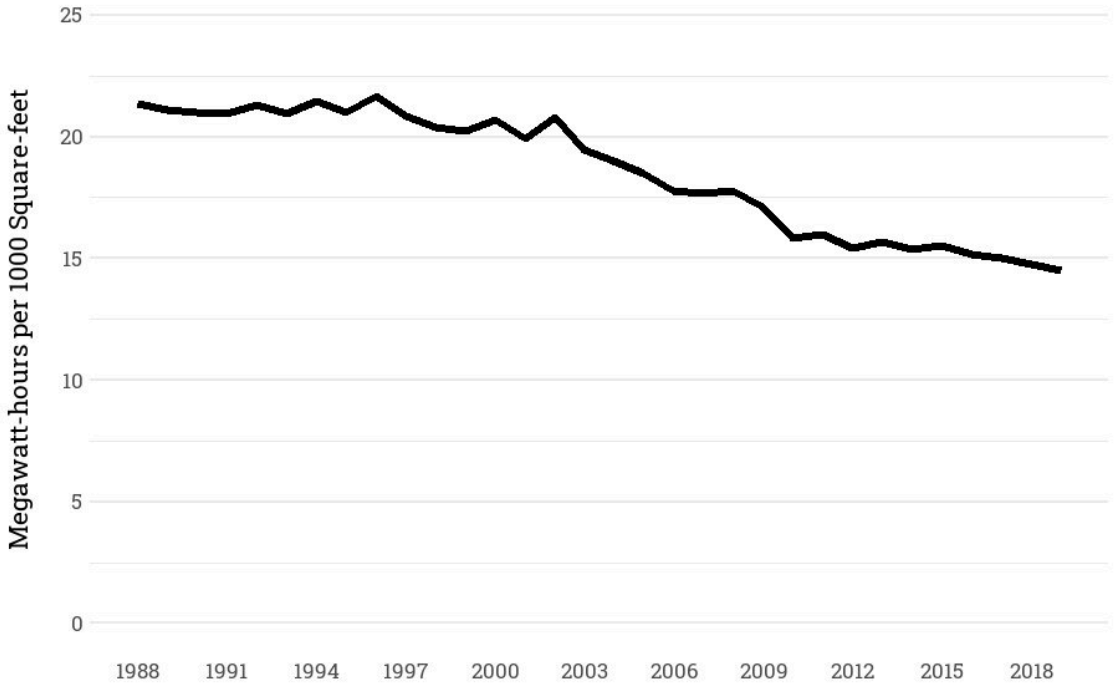

The drop in residential per capita consumption of electricity is even more significant when considering the tremendous increase in home electronics and air-conditioning. Electronic devices that did not even exist 30 years ago, have added to residential demand. The demand for information, communication, and entertainment (ICE) appliances has sky-rocketed and are expected to continue. However, the more recent trends suggest a slowdown in growth for this sector. This is in part due to changes in consumer preferences, expansion of mobile communication devices and a number of voluntary industry and federal standards.

## Commercial Sector

Electricity load in the commercial sector has increased regionally and nationally. In 1986, demand in the commercial sector of the region was about 4,000 average megawatts and by 2018 this sector required over 6000 average megawatts. Electricity use intensity in the sector has improved, both in terms of value of goods and services produced by commercial sector per MWH of electricity demand and in terms of electricity demand per square footage of commercial business. The graph below shows, electricity intensity in the commercial sector measured in megawatt hours used per square foot of space. In 1997, the commercial sector's average electricity intensity was about 19 megawatt hours per 1000 square foot (19 kWh/sf). By 2018, it had dropped to about 14.6 megawatt hours per 1000 square foot (14.6 kWh/sf).

A major factor that influences the demand for electricity in the commercial sector is the presence of embedded data centers. These data centers are different that the stand-alone data centers where the main business of the business is providing data services. In the embedded data centers, the main function of the data center is to support the key business.

**Electricity Intensity in the Commercial Sector by Floorspace**




### Industrial Sector

The Northwest industries have been able to increase their electricity efficiency of use over time. From 1985 to the late 1990s industrial production per unit MWH was between 1000-1500 $2016/MWH. After the fall of Direct Service Industries (particularly aluminum smelting operations) the value of manufacturing output per MWH increased to about $2500/MWH.

In the Northwest, the non-DSI industrial sector demand is dominated by pulp and paper, food processing, chemical, primary metals other than aluminum, and lumber and wood products industries. Many of these industries have declined or are experiencing slow growth. These traditional resource-based industries are becoming less important to regional electricity demand forecasts, while new industries, such as semiconductor manufacturing, are growing faster and commanding a growing share of the industrial-sector load.

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[1] Two electricity sales trends are shown in the graph; the first set is for total sales and the second set is for non-DSI sales

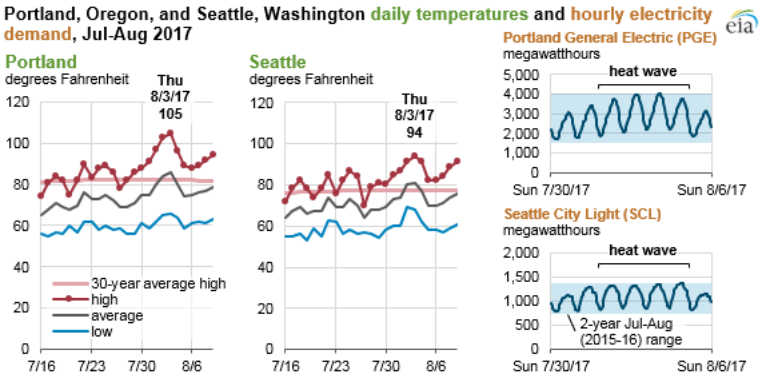
# EXHIBIT 41-2

U.S. Energy Information Administration

**Today in Energy**

August 23, 2017

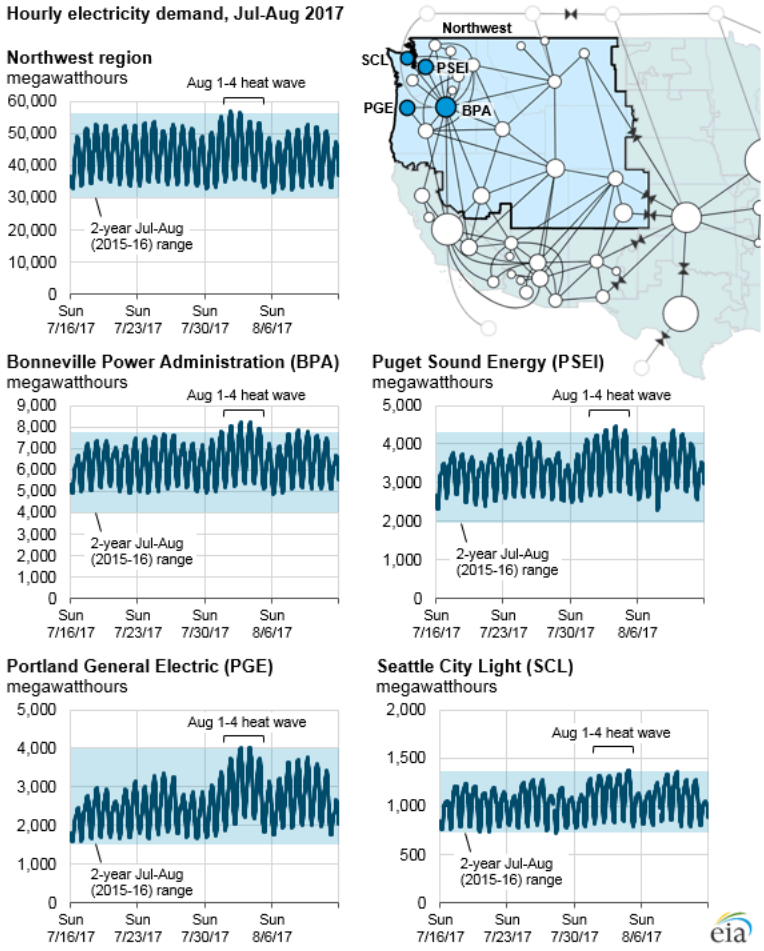
# Northwest heat wave leads to record levels of summer electricity demand




**Source:** U.S. Energy Information Administration, based on National Weather Service and National Centers for Environmental Information

Multiple record-breaking heat waves swept across the western United States this summer, with the latest occurring in the Pacific Northwest from August 1–4, 2017. Coincident with the hot weather, some of the largest electricity balancing authorities in the area experienced record-high summer electricity demand on their systems.

In the region's largest cities, the highest temperatures were seen on Thursday, August 3, when Portland reached 105 degrees and Seattle reached 94 degrees. These highs were 23 degrees and 17 degrees higher than the 30-year (1981–2010) average highs for that day for Portland and Seattle, respectively. Despite the proximity of the cities, Seattle's summer temperatures can be notably lower than Portland's because of the nearby Puget Sound and the Pacific Ocean's moderating effect on Seattle's climate.



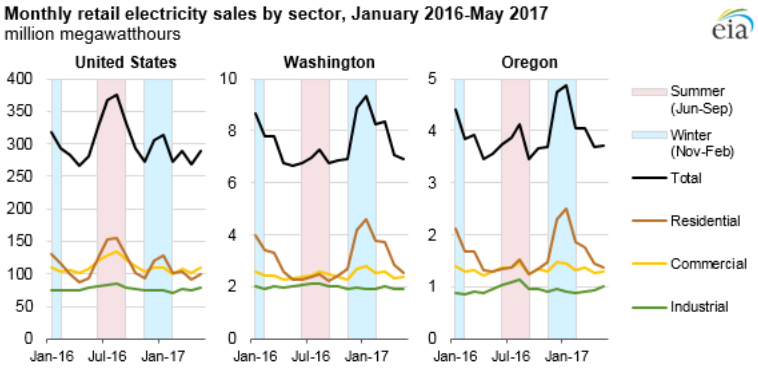

**Source:** U.S. Energy Information Administration, U.S. Electric System Operating Data
**Note:** The map illustrates the general location of the balancing authorities. See a more detailed map of service areas.

**Bonneville Power Administration (BPA)** is a federal power marketing administration that supplies large volumes of hydropower to other balancing authorities in the region. BPA broke its previous summer peak demand record of 7,861 megawatts (MW) from 2014 every day between August 1–3, with the highest peak of 8,226 MW occurring on Wednesday, August 2, 2017.

**Portland General Electric (PGE)** serves about 45% of Oregon's population, including most of Portland and its metropolitan area. PGE set a new summer peak demand record of 3,967 MW on Wednesday, August 2, only about 100 MW lower than PGE's all-time peak demand of 4,073 MW from December 1998.

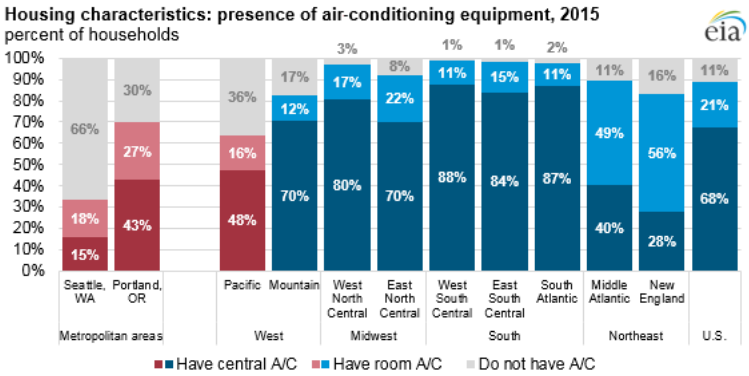
**Seattle City Light (SCL)** serves the city of Seattle and, with **Puget Sound Energy, Inc (PSEI)**, most of its surrounding areas. These utilities saw higher demand during the heat wave than in the previous two July–August periods but did not exceed their historical summer peak records, which occurred in July 2009 when temperatures in the area reached 103–104 degrees.

Unlike most of the country, many electric systems in the Northwest are winter-peaking, meaning their highest electricity demand usually occurs in the winter during the heating season. The Northwest typically experiences mild summers, leading to lower cooling-related electricity usage compared with other regions.




**Source:** U.S. Energy Information Administration, Electricity Data Browser

The Northwest region also has a relatively large percentage of homes without air conditioning, further reducing the impact of hot weather on electricity usage in the summer. Although 89% of homes in the United States have some form of air conditioning, only 34% and 70% of homes in Seattle and Portland, respectively, have air conditioning.




**Source:** U.S. Energy Information Administration, based on U.S. Census Bureau, American Housing Survey

**Principal contributor:** April Lee

# EXHIBIT 41-3

# Ancillary Services Definitions and Capability Study

**Prepared for the**

**U.S. Department of Energy**
**Office of Electricity Delivery and Energy Reliability**

**Under Cooperative Agreement No. DE-EE0003507**
**Hawai‘i Energy Sustainability Program**

**Task 2: Energy Modeling and Scenario Analysis**

**Prepared by**

**GE Energy Consulting**

**Submitted by**

**Hawai‘i Natural Energy Institute**
**School of Ocean and Earth Science and Technology**
**University of Hawai‘i**

**December 2012**

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GE Energy Management

# Ancillary Services Definitions and Capability Study

## Part 1, Tasks 1-2, Final Report

### For Hawaii Natural Energy Institute


Principal Contributors:

**Harjeet Johal**
**Rameet Kohli**
**Beth LaRose**
**Michael O'Connor**
**Sundar Venkataraman**


Revision 1

Date: 12/19/2012



imagination at work

# Table of Contents

**1 Study Background and Objectives ..... 1**

**2 Summary of Results ..... 2**

**2.1 Key Terminology ..... 5**

**3 Study Results ..... 7**

**3.1 Task 1:** Identify and define ancillary services needed for integration of new generation resources, including various renewable generation technologies **..... 7**

3.1.1 Developments in Ancillary services – Emerging regulations, services and requirements ..... 13

3.1.2 Interconnection Requirements ..... 14

3.1.3 Other Considerations ..... 17

3.1.4 Unique characteristics of Hawaiian system warrant attention to ancillary services and interconnection requirements ..... 18

**3.2 Task 2:** Identify which technologies can provide each ancillary service. **..... 20**

**4 Part 1 Summary ..... 24**

**5 References ..... 25**

**6 Appendix A - 2012_12_10_Hawaii_Ancillary_Services_Report_PART1FINAL.pptx 27**

# List of Figures

**Figure 3-1** Normal Operating Conditions ..... 9

**Figure 3-2** Contingency Operating Conditions ..... 9

**Figure 3-3** Interconnection requirements for Variable Energy Resources ..... 15

# List of Tables

**Table A.2-1** Ancillary Services Definitions ..... 3

**Table A.3-1** Ancillary Services Definitions ..... 11

**Table A.3-2** Interconnection Requirements ..... 16

**Table A.3-3** Ancillary Services Capabilities by technology ..... 21

**Table A.3-4** Technology characteristics ..... 23

# Foreword

This report was prepared by General Electric International, Inc. acting through its Energy Consulting group based in Schenectady, NY through the support of the Hawaii Natural Energy Institute and under a contract with the Research Corporation of the University of Hawaii. Technical and commercial questions and any correspondence concerning this document should be referred to:

**Technical**

Beth LaRose

Managing Director, Power Economics

Energy Consulting
General Electric International, Inc.
One River Road
Building 53-313
Schenectady, NY 12345
Phone: (518) 385-3994
E-mail: elizabeth.larose@ge.com

**Commercial**

Denise Benoit
Senior Contract Risk Manager
Energy Consulting
General Electric International, Inc.
One River Road
Building 53-313
Schenectady, NY 12345
Phone: (518) 385-3994
E-mail: denise.benoit@ge.com

# 1 Study Background and Objectives

The purpose of this study is to identify, define and quantify ancillary services necessary to integrate new generation resources, including renewable generation, for bulk power systems and particularly the Hawaiian Islands. The results of this study may be: incorporated into the Hawaii Reliability Standards Working Group's proposals for new reliability standards; used to develop recommendations for revised generation interconnection technical requirements; provided to the Hawaii Public Utility Commission for consideration and adoption; and used to inform the Hawaii utilities' Integrated Resource Planning process.

The GE team has been deeply involved in analyzing the impact of renewable generation on the HECO systems and has performed 9 system-level studies over the past 5 years. The power output form Variable Generators (VG) such as wind and solar plants, by definition is variable. Also, there is a certain amount of uncertainty associated with this generation in the hours preceding actual operations. The generation from VGs is not only variable within the hour and is also variable on a longer timeframe such as daily, weekly and monthly time frame. The variability of VGs within the hour (along with the variability associated with the load) is handled by the system operator through the use of regulation and load-following (spinning) reserves. This study will leverage the findings of the renewable impact studies performed by GE.

The project focuses on four tasks[1]:

- Task 1: Define a standardized set of ancillary services along with their associated definitions (in functional, technology-neutral, performance based terms) that can be used to meet the operational needs of Hawaii and other bulk power systems, and provide for the integration of variable generation technologies.
- Task 2: Assess resource technologies (generation, transmission, storage, and demand response (DR)) for their ability to support the respective ancillary services, to maximize the diversity and optionality for ancillary service acquisition and delivery.
- Task 3: Identify the physical requirements of the ancillary services needed for each Hawaiian island (Oahu, Maui, Big Island).
- Task 4: Outline considerations for specifying / acquiring ancillary services for the Hawaii grids that protect reliability, incent renewable generation, and minimize production costs.

This report presents the results of Tasks 1 and 2 of the study. The results of Tasks 3 and 4 will be presented in a separate report.

[1] After the study was commenced, it was decided that Task 1 should be generic and address all ancillary services that are in service or under development in the U.S., as well as internationally, regardless of their applicability to the Hawaii system. The applicability of the ancillary services to the Hawaii system was included as a portion of Task 3 of the study. Therefore, in Task 1, the difficulty in adopting some of the researched ancillary services for the Hawaii system will be acknowledged, but not discussed in detail.

# 2 Summary of Results

Ancillary services are required to maintain reliable operations of the electric power system. With Hawaii Natural Energy Institute (HNEI), in cooperation with the Hawaii Reliability Standards Working Group (RSWG), GE has worked to identify, define and quantify ancillary services necessary to integrate new generation resources, including renewable generation, for the Hawaiian Islands. This written summary report for Tasks 1-2 and the attached PowerPoint slides in Appendix A documenting Tasks 1-2[2], comprise the Part 1 final report from GE for use by HNEI and the Hawaii RSWG. This portion of the study focuses on ancillary services definitions, interconnection requirements and technologies capable of providing these ancillary services in technology-neutral, functional terms. These definitions may not reflect the current practices on the Hawaiian Islands for delivering ancillary services, but the ancillary services as defined here represent viable options for any electric power system to maintain reliable operations and should be considered as options for the Hawaiian Islands. Table A.2-1 summarizes the ancillary service definitions.

[2] 2012_12_10_Hawaii_Ancillary_Services_Report_PART1FINAL.pptx

**Table A.2-1***Ancillary Services Definitions*

| **Ancillary Service:**<br><br>**Normal and contingency conditions** | **Brief Description:** | **Notes:** |
|---|---|---|
| Frequency Responsive Reserves/ Primary Frequency Response: | Automatic response triggered by frequency swings. Typically deployed during contingency events. Arrests and helps to recover the frequency change. | - Immediate response<br>- Typically less than 15 min<br>- Provided continuously<br>- Proportional to frequency deviation |
| Regulation: | Used continuously during normal operations to correct short-term imbalances between supply and demand. Deployed via AGC signals. | - At least every 6 seconds<br>- Typically 5-10 min<br>- Provided continuously<br>- Magnitude varies, proportional to size of imbalance |
| Load Following: | Slower than "Regulation" and used primarily during normal operations. Typically deployed via economic dispatch to correct an imbalance that will occur in the future. | - Response time and duration needs to be established<br>- Anticipated to be continuous<br>- Magnitude varies, proportional to size of imbalance |
| **Contingency Conditions** | | |
| Spinning Reserves: | Type of contingency reserve that consists of resources which are connected to the power system and poised, ready to respond immediately. | - Response is immediate will full response within 10 min<br>- Various durations<br>- Intermittent use, after a disturbance<br>- Magnitude varies |

| | | |
|---|---|---|
| Non-spinning Reserves: | Type of contingency reserve that consists of resources which are capable of providing full response within a specified time; however, the response does not need be immediate. | - Full response within 10 min<br>- Various durations<br>- Intermittent use, after a disturbance<br>- Magnitude varies |
| Replacement Reserves: | Deployed following a contingency event. Intended to replenish contingency reserves; response does not need to begin immediately. | - Response within 30 to 60 min<br>- Various durations<br>- Intermittent use, after a disturbance<br>- Magnitude varies |
| **Additional Services** | | |
| Black Start: | Provided by resources capable of starting themselves quickly without support of an external electricity source. Used to restore a power system following a major blackout. | - Resources available after a black-out<br>- Various durations<br>- Only after a black-out<br>- Magnitude varies |
| Reactive Power/ Voltage Support: | Provided by resources capable of injecting/consuming reactive power which is required to maintain voltages within acceptable limits throughout the power system. | - Response in seconds<br>- Various durations<br>- Provided continuously<br>- Typical power factor range of 0.95 leading to 0.95 lagging |

The Part 2 final report documents the GE study results for Tasks 3-4 and provide analysis of Hawaii-specific scenarios including comparison of current practices on the Hawaiian Islands to the ancillary services and interconnection requirements proposed in Part 1. Part 2 offers a number of procedures and methodologies to determine the need for, provide, and value ancillary services for an electric system. While the examples and data used in Part 2 are Hawaii-specific, the procedures and approaches outlined should be applicable and useful for any system.

## 2.1 Key Terminology

The following definitions for key terminology are relevant throughout the content of this study and should be interpreted as described below.

Area Control Error (ACE):

The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error. Source - NERC Glossary (2008)

Conventionally, **ACE = (NIA – NIS) – 10B (FA – FS) – IME**, where:

**NIA** is the algebraic sum of actual flows on all tie lines.

**NIS** is the algebraic sum of scheduled flows on all tie lines.

**B** is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.

**FA** is the actual frequency.

**FS** is the scheduled frequency. FS is normally 60 Hz but may be offset to effect manual time error corrections.

**IME** is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NIA) and the hourly net interchange demand measurement.

Due to a lack of inter-area power flows, the definition of ACE has been modified for Hawaii. Specifically, for **Hawaii, ACE = – 10B (FA – FS).** This modified definition of ACE is still applicable for Hawaii as it correctly represents the fact that 100% of difference between supply and demand will manifest itself as a frequency error. Source - Revised definition per Hawaii RSWG Glossary

Automatic Generation Control (AGC):

Equipment that automatically adjusts generation, storage devices, and/or responsive load in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule, plus the Frequency Bias (i.e. ACE). Source - NERC Glossary (2008) with modifications to accommodate additional resource types such as load and storage devices

Although AGC was originally conceived as a means to provide fast (3-6 second signals) to generators, the concept of leveraging AGC to provide "MW raise/lower" commands to demand-side and storage resources is equally applicable and is in practice in some locations.

Droop Response:

Droop response is a near instantaneous means of proportionally adjusting a resource's real-power to resist a change in frequency; allowing a system of resources to operate in a stable manner.

The magnitude of a given resource's response is proportional to the frequency deviation and typically characterized by "x%" droop. For example, a resource with operating range available will provide

100% additional output per "x%" change in system frequency. Response is typically a percentage of the resource's full-capability.

Droop response can be provided by any frequency-sensitive resource.

Resource:

A resource may consist of any generation, storage, load (i.e. demand-side), or transmission technology.

Spinning / Non-Spinning:

Historically, the terms "spinning" and "non-spinning" have referred to the rotational nature of synchronized generators. Over time, this terminology has migrated to imply the "relative state of readiness and responsiveness" as it relates to the ability for a resource to fulfill its ancillary obligation. In an effort to leverage contemporary industry vernacular, this latter interpretation was adopted for use in this presentation.

# 3 Study Results

## 3.1 Task 1: Identify and define ancillary services needed for integration of new generation resources, including various renewable generation technologies

Every bulk system requires a suite of ancillary services to provide grid reliability today and to integrate variable renewable generation. The objective of Task 1 is to gather information to help define a standard set of ancillary services with functional performance requirements/definitions, interconnection requirements and other system considerations. Although each power system uses the same ancillary services in functional terms, in practice there are significant differences across regions and balancing areas in which entities produce specific ancillary services and how these services are acquired, controlled, delivered and compensated. Thus it is important to distinguish between the functional role of each ancillary service and the local, system-specific practices for its provisioning (for instance, whether a particular service is performed only by a utility-owned generator or included as an operational interconnection requirement of third party generators). Tasks 1 and 2 therefore describe the ancillary services, and include descriptions to distinguish some of the ways by which Hawaii's electric systems name and deliver these services today.

GE identified and defined all of the ancillary services that are currently being used or under development in different parts of the world, in regulated as well as deregulated regions, with a focus on real-power energy balancing services such as regulation, load following and various types of contingency reserves which are impacted more by renewables. The purpose of this task is to gather the most recent information and best practices with respect to ancillary services with the full understanding that some of these ancillary services may not be applicable to the Hawaii utilities.

Ancillary services[3] are those functions performed by the equipment and people that generate, control, transmit, and distribute electricity to support the basic services of generating capacity, energy supply, and power delivery. They are required to maintain reliable operations of the electric power system. In addition to ancillary services, other interconnection requirements are placed on resources to ensure reliable operation of the grid. These ancillary services and interconnection requirements enable the system operator to meet the required operations and reliability standards set by NERC. The ancillary services, interconnection requirements, and reliability standards are dependent on the characteristics of a power system.

[3] FERC defines ancillary services as those "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

The set of ancillary services that provide direct support for the reliable and economic operation of the power system are:

Real-Power Energy Balancing Services

- Frequency Responsive Reserve /Primary Frequency Response
- Regulation
- Load Following
- Spinning Reserve
- Non-Spinning Reserve
- Replacement Reserves

Additional Services

- Black Start
- Reactive Power/Voltage Support

Generation characteristics that are specified via Interconnection Requirements are:

- Power Factor & Voltage Control
- Voltage and Frequency Ride Through
- Ramp Rate Limits and minimum response
- Over and Under Frequency Controls
- Inertia

Real power balancing services that come into play during normal and contingency operating conditions are shown in the figures below. ***Figure 3-1*** and ***Figure 3-2*** illustrate the operational timeframes for some services.

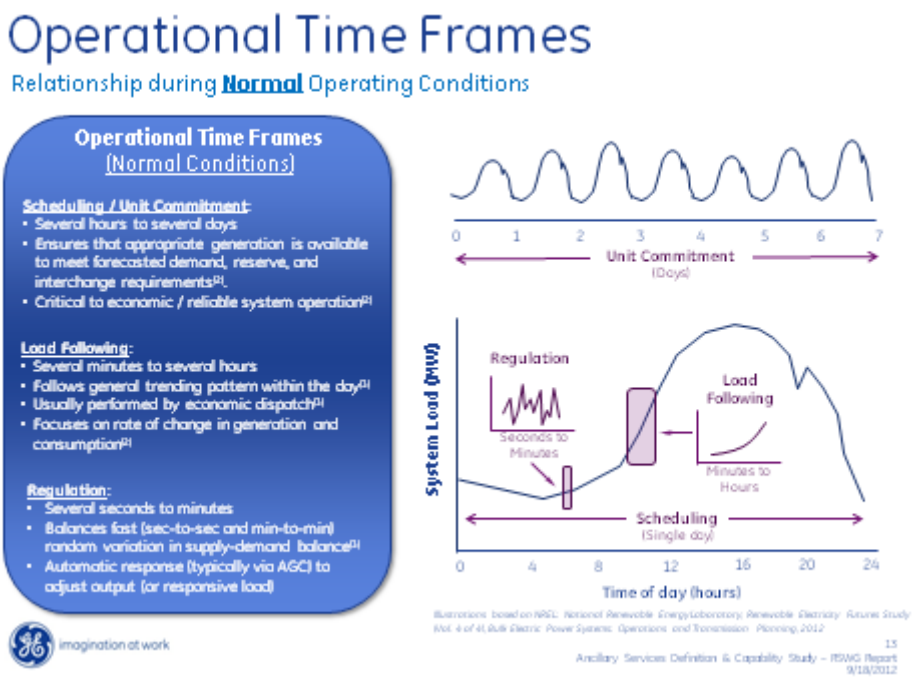



**Figure 3-1** *Normal Operating Conditions*

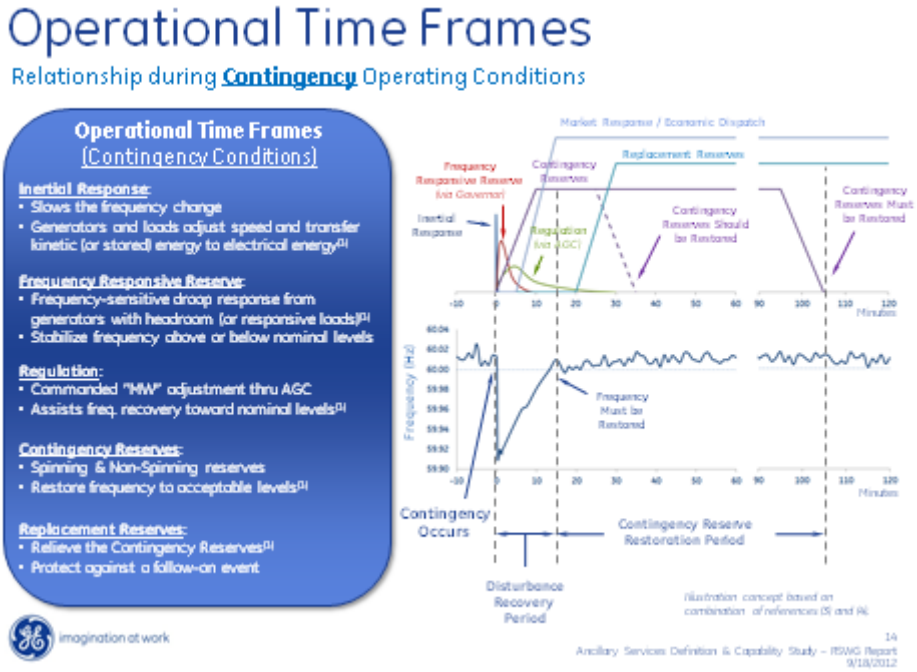



**Figure 3-2** *Contingency Operating Conditions*

The purposes of these ancillary services are defined below. See the attached PowerPoint slides in Appendix A entitled "2012_12_10_Hawaii_Ancillary_Services_Report_PART1FINAL.pptx" slides 17-27 for the detailed definition for each ancillary service in functional terms for its performance requirements (e.g., reaction speed for service provision, time duration, deployment frequency, and MW magnitude of response). Differences from these functional definitions and the current practices of the Hawaiian Islands are explored in Part 2 of this study.

For normal and contingency conditions:

*Inertial Response*: Provides system stability during normal conditions; slows frequency change during contingency events. Provided by synchronized resources (also via power electronics). Inertial response is not obtained as an ancillary service. Rather it is autonomously provided by all synchronous units. It can also be provided by variable generators if they are equipped with synthetic inertia feature. These inertial response requirements for VGs are addressed through the interconnection requirements.

*Frequency Responsive Reserves/ Primary Frequency Response*: Automatic response triggered by frequency swings. Typically deployed during contingency events. Arrests and helps to recover the frequency change.

*Regulation*: Used continuously during normal operations to correct short-term imbalances between supply and demand. Deployed via AGC signals.

*Load Following*: Slower than "Regulation" and used primarily during normal operations. Typically deployed via economic dispatch to correct an imbalance that will occur in the future.

For contingency conditions:

*Spinning Reserves*: Type of contingency reserve that consists of resources which are connected to the power system and poised, ready to respond immediately.

*Non-spinning Reserves*: Type of contingency reserve that consists of resources which are capable of providing full response within a specified time; however, the response does not need be immediate.

*Replacement Reserves*: Deployed following a contingency event. Intended to replenish contingency reserves; response does not need to begin immediately.

Additional Services:

*Black Start*: Provided by resources capable of starting themselves quickly without support of an external electricity source. Used to restore a power system following a major blackout.

*Reactive Power/ Voltage Support*: Provided by resources capable of injecting/consuming reactive power which is required to maintain voltages within acceptable limits throughout the power system.

The definitions and details of these ancillary services are summarized in Table XX below and discussed in further detail in Appendix A.

**Table A.3-1***Ancillary Services Definitions*

| **Ancillary Service:**<br><br>**Normal and contingency conditions** | **Brief Description:** | **Notes:** |
|---|---|---|
| Frequency Responsive Reserves/ Primary Frequency Response: | Automatic response triggered by frequency swings. Typically deployed during contingency events. Arrests and helps to recover the frequency change. | - Immediate response<br>- Typically less than 15 min<br>- Provided continuously<br>- Proportional to frequency deviation |
| Regulation: | Used continuously during normal operations to correct short-term imbalances between supply and demand. Deployed via AGC signals. | - At least every 6 seconds<br>- Typically 5-10 min<br>- Provided continuously<br>- Magnitude varies, proportional to size of imbalance |
| Load Following: | Slower than "Regulation" and used primarily during normal operations. Typically deployed via economic dispatch to correct an imbalance that will occur in the future. | - Response time and duration needs to be established<br>- Anticipated to be continuous<br>- Magnitude varies, proportional to size of imbalance |
| **Contingency Conditions** | | |
| Spinning Reserves: | Type of contingency reserve that consists of resources which are connected to the power system and poised, ready to respond immediately. | - Response is immediate will full response within 10 min<br>- Various durations<br>- Intermittent use, after a disturbance<br>- Magnitude varies |

| | | |
|---|---|---|
| Non-spinning Reserves: | Type of contingency reserve that consists of resources which are capable of providing full response within a specified time; however, the response does not need be immediate. | - Full response within 10 min<br>- Various durations<br>- Intermittent use, after a disturbance<br>- Magnitude varies |
| Replacement Reserves: | Deployed following a contingency event. Intended to replenish contingency reserves; response does not need to begin immediately. | - Response within 30 to 60 min<br>- Various durations<br>- Intermittent use, after a disturbance<br>- Magnitude varies |
| **Additional Services** | | |
| Black Start: | Provided by resources capable of starting themselves quickly without support of an external electricity source. Used to restore a power system following a major blackout. | - Resources available after a black-out<br>- Various durations<br>- Only after a black-out<br>- Magnitude varies |
| Reactive Power/ Voltage Support: | Provided by resources capable of injecting/consuming reactive power which is required to maintain voltages within acceptable limits throughout the power system. | - Response in seconds<br>- Various durations<br>- Provided continuously<br>- Typical power factor range of 0.95 leading to 0.95 lagging |

### 3.1.1 Developments in Ancillary services – Emerging regulations, services and requirements

Recent developments in ancillary services for several regions in North America were researched to help identify emerging and additional services that may be applicable to Hawaii. As renewable penetration increases, many systems are challenged to examine existing and future requirements for reliability. Here are some highlights of the findings of this research.

Inertial Response (ERCOT)[4]

ERCOT is evaluating requirements for inertial response. Introduced tool (2010) to monitor online conventional generation, spinning reserves, and ratio of wind to total generation … system operator can adjust unit commitment if available inertial response is insufficient.

Primary Frequency Response

Frequency Responsive Reserve (WECC):

A Frequency Responsive Reserve (FRR) procedure was proposed by WECC in 2005[5].

NERC BAL-002-WECC-1 *(2008)* requires 50% of contingency reserves to be spinning AND frequency responsive. NERC BAL-012-WECC-2-CR *(FRR Criterion, 2009) e*stablishes minimum required FRR to prevent under-freq. load shedding (UFLS) during loss of generation event.

Primary Frequency Response (ERCOT):

ERCOT is the only balancing area that guides its minimum frequency response. The protocols also discuss the required primary frequency response from wind powered generation resources with standard generation interconnection agreements signed after January 1, 2010. Wind units are required to provide primary frequency response in response to high system frequency similar to a thermal unit with a droop of 5%.

Secondary Frequency Response

Load Following (CAISO): Flexible Ramping Revised Draft Proposal – August 2012

In WECC there is a stakeholder effort to develop market-based flexible ramping products. The load following service attempts to provide sufficient ramping and flexibility to handle 5-minute supply/demand changes.

Analogous to Load Following: Flexible ramping product addresses ramping issue before the binding real-time dispatch (RTD) … Regulation addresses ramping issue after binding RTD.

As part of NERC Project 2010-14.1 standard BAL-012-1 is developed to require a balancing authority to develop and document plants for the appropriate mix of operating reserves. This will include adequate Regulating Reserve, Contingency Reserve and Frequency Responsive

[4] Reference [3] NREL: National Renewable Energy Laboratory, Operating Reserves and Variable Generation, August 2010

[5] See above footnote 5, Reference [3]

Reserve. Comments have been received (period closed July 2012) and are available here: http://www.nerc.com/docs/standards/sar/comments_received_BAL-012_070312.pdf

Hawaii requires 100% of all contingency reserves to be frequency responsive.

Ramp Capability for Load Following (MISO): MISO white-paper - July 2011

MISO is investigating improved Load Following options … considering several approaches for "pre-ramping" resources for better future interval positioning.

They appear to be gravitating toward a "market product" which prices ramp capability. An incentive is provided to participate to avoid "out of merit" dispatch. The price would be "cleared" based on resource opportunity cost, and "paid-for" thru cost allocation similar to other ancillary products.

Regulation Performance Compensation (FERC Order 755): Issued in October 2011

FERC found "current methods for compensating resources for the provision of regulation are unduly discriminatory". Order 755 requires all RTOs and ISOs to modify their tariffs to provide for a two-part payment to regulation resources:

- 1st Part: Payment for keeping a resource's capacity in reserve in the event that it is needed to provide regulation.
- 2nd Part: Payment shall be a performance payment that reflects the amount of work that each resource performs in real-time.

### 3.1.2 Interconnection Requirements

Interconnection standards enable the system to meet its reliability standards by requiring generators:

- To have certain capabilities that directly helps with the system reliability
- To have certain capabilities that enable it to provide ancillary services that are required for system reliability.

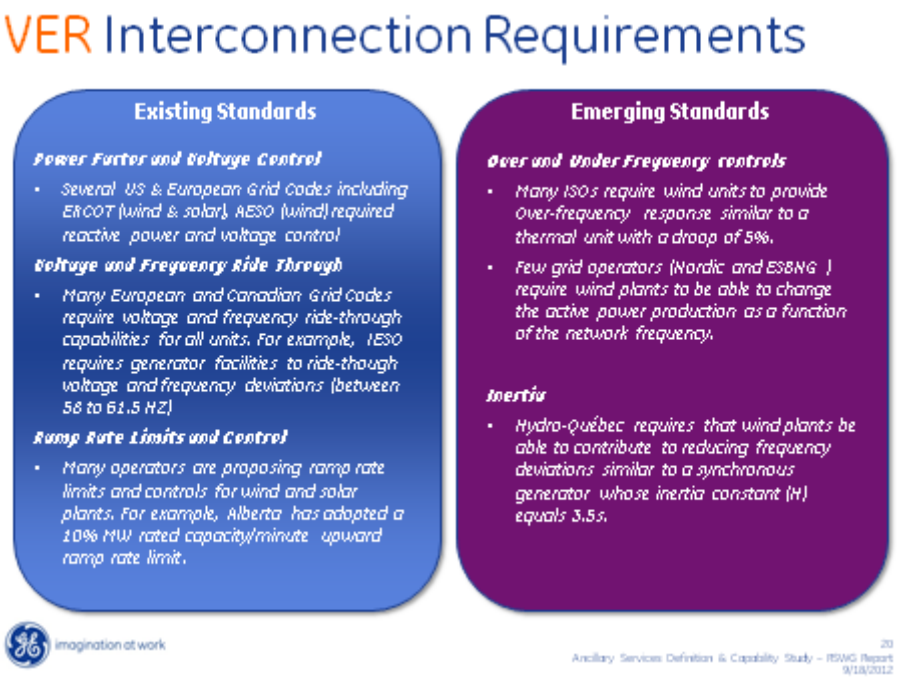



**Figure 3-3** *Interconnection requirements for Variable Energy Resources*

More information on these interconnection requirements and example of regions that have implemented some of these interconnection standards can be found in Appendix A slides 44-52. More detail on recommended interconnection requirements can be found in the Part 2 report and are summarized in Table A.3-2 below.

**Table A.3-2***Interconnection Requirements*

| Interconnection Requirement: | Brief Definition: |
|---|---|
| Reactive Power & voltage Control | Capability to provide reactive power output within a certain power factor range and the capability to regulate voltage within this range |
| Fault Ride-through | Capability of the generator to ride-through (predetermined) temporary voltage and frequency deviations |
| Ramp Rate Limits and Control | Capability to ramp limit the output of a generator under certain conditions |
| Over and under Frequency Control | Capability to automatically increase and decrease (sustained) output under low and high frequency conditions respectively |
| Inertia | Capability to provide an immediate response to a drop in system frequency |

Per a recent NREL paper (spring 2012): common active power control requirements in the US for wind are as follows:

- Curtailment control
- Ramp rate control (for curtailments and startup)
- Regulation UP (for under-frequency)
  - Adjustable droop
- Regulation down for over-frequency
  - Adjustable droop
- High wind shutdown
- Rate variation control
- Inertia
- Primary frequency response

Of the above, a couple of the key developments with respect to interconnection requirements are discussed below.

Inertia Requirement for Hydro Quebec:

Hydro-Québec requires that wind plants be able to contribute to reducing frequency deviations similar to a synchronous generator whose inertia constant (H) equals 3.5s

Primary Frequency Response Requirement for ERCOT:

Many ISOs require wind units to provide Over-frequency response similar to a thermal unit with a droop of 5%. .

Few grid operators (Nordic and ESBNG) require wind plants to be able to change the active power production as a function of the network frequency. In ERCOT, wind units are required to provide primary frequency response in response to high system frequency similar to a thermal unit with a droop of 5%.

Recommendations regarding which of the above-mentioned ancillary services and interconnection requirements are suitable for Hawaii will be discussed in Task 3.

### 3.1.3 Other Considerations

Several additional considerations affect ancillary service delivery and system economics and the ability to meet renewable energy goals. These considerations cannot be addressed directly by interconnection requirements or ancillary services. There may be a need for other mechanism as listed below.

Reduced Minimum Generation Capability:

Enabling resources to operate with reduced minimum generation capacity increases the potential for increased online reserves and the potential for more granular ancillary service participation. More online reserves may help avoid curtailment of renewable and lower cost generating assets.. This should also improve system-level load following capability and provide options for improved portfolio management to hedge against uncertain conditions. In general, there needs to be a mechanism within power systems such as planning rules or tariffs to incent more flexibility in generators, i.e. lower turndown, faster ramp rate, shorter start time and the ability to cycle.

Short-circuit Strength:

Short-circuit levels on transmission lines may decrease if synchronous generators are replaced by renewables. Synchronous generators may need to be online to maintain minimum short-circuit levels on the system. Relays and protection devices that detect short circuits by monitoring the current and need a minimum current for reliable operation (lower limit for short circuit levels). Since Hawaii anticipates high penetrations of renewables, additional studies are recommended to try and identify any issues with short-circuit strength.

Short-circuit Ratio:
The short circuit ratio as seen at the point of interconnection of non-synchronous generators can decrease. This can happen even at the same level of commitment of synchronous generators but at higher penetration of non-synchronous resources. The decreased short-circuit ratio can lead to controller instability issues in the power electronics control of wind and solar generators.

Load Shaping:

Load shaping considers proactive movement of demand-side resources or non-dispatchable load to provide a more manageable daily load shape, i.e. incentivize / prohibit charging of PEVs at certain times of day. "Load shaping" may provide an opportunity to reduce the amount of other ancillary services that are required. We anticipate that this would be a procedural implementation rather than ancillary-service based approach. System operators need to carefully consider how to monitor, incentivize, and enforce the targeted load adjustments.

### 3.1.4 Unique characteristics of Hawaiian system warrant attention to ancillary services and interconnection requirements

The unique characteristics of the Hawaii system needs to be taken into account in order to determine the additional ancillary service and interconnection requirements. These characteristics are discussed below.

- The Hawaiian Islands are comprised of relatively small island systems: HECO~1200 MW, MECO ~200MW, HELCO~195 MW peak load. The relative small island systems make it challenging to maintain frequency.
- There are no interconnections between the Hawaiian Islands or the Mainland. Any imbalance between load and generation affects frequency, a small frequency bias.
- There is a higher Rate of Change of Frequency (ROCOF) due to system events. The ratio of unit size or renewable energy project size to system size is high.
- Hawaii has leaner operations than other systems. There is a relatively high cost of energy and ancillary services (that are currently provided as a bundled service with energy) due to high fuel prices.
- Historical reasons such as existing purchase power agreements, system requirements for UFLS, ROCOF, transmission constraints, ramping, physical and emission limits require the use of some Must run/scheduled units.
- Each Hawaiian Island has a single vertically integrated utility, multiple IPPs and third-party dispersed generation with no centralized power markets to purchase or sell excess generation
- While fewer opportunities for transaction "liquidity", ancillary service value can be calculated/estimated to provide incentives/payments to providers of ancillary services – ancillary services do not need to remain in bundled utility offering.
- The Hawaiian Islands have large amounts of distributed generation.

- Clean Energy Mandate includes RPS target of 40% and 4,300 GWH reduction for Energy Efficiency Portfolio Standards by 2030; high wind and solar generation potential in MECO, geothermal in HELCO.
- Hawaii has specific operating criteria to maintain system frequency and voltage and provide adequate reserves.

The unique characteristics of the Hawaii system will be taken into account while determining the applicability of the researched ancillary services and interconnection requirements.

The current operating criteria of note and the impact on the current provision of ancillary services on the Hawaiian Islands are included in Task 3.

## 3.2 **Task 2:** Identify which technologies can provide each ancillary service.

Using the ancillary service definitions developed in Task 1, GE identified and summarized in a table which generation, transmission, storage and demand-side technologies are able to provide each ancillary service given current technology capabilities and fuel availability, without screening or limiting the options with respect to economic cost-effectiveness. As requested, GE generally limited technologies to those that are available in commercial or pilot applications today and provide current deployment cost estimates, but do not speculate about future cost projections.

The generation technologies are broken down by fuel (for example, gas units) and type (for example, simple cycle gas turbine) without focus on the actual make or model. GE Identified the approximate resource size for each technology and each ancillary service. Background and reference citations as available for each technology and ancillary service capability match are provided.

**Table A.3-3***Ancillary Services Capabilities by technology*

| Technologies | Ancillary Services Compatibility | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Inertial Response | Frequency Responsive Reserve | Regulation | Load Following | Spinning Reserve | Non-Spinning Reserve | Replacement Reserve | Voltage Support | Black Start |
| **Generation** | | | | | | | | | |
| Solar Thermal | A | T | T | T | T | --- | --- | A | T |
| Solar Photovoltaic (Transmission Connected) | T | T | T | T | T | T | T | T | --- |
| Wind (non-synchronized / power conversion) | A | A | A | A | A | T | T | A | --- |
| Wind (synchronized) | A | A | A | A | A | T | T | A | T |
| Hydropower | A | A | A | A | A | A | A | A | A |
| Geothermal | A | A | A | A | A | --- | --- | A | T |
| Biomass | A | A | A | A | A | --- | --- | A | --- |
| Coal | A | A | A | A | A | --- | --- | A | --- |
| Combined Cycle (Gas/Oil: Sm. HD/Aero) (1x1) | A | A | A | A | A | A | A | A | A |
| Combined Cycle (Gas/Oil: Heavy-duty) (1x1) | A | A | A | A | A | A | A | A | A |
| Simple Cycle (Gas/Oil: Small HD/Aero) | A | A | A | A | A | A | A | A | A |
| Simple Cycle (Gas/Oil: Heavy-duty) | A | A | A | A | A | A | A | A | A |
| Reciprocating Engines (Gas/Diesel/Bio) | A | A | A | A | A | A | A | A | A |
| **Energy Storage** | | | | | | | | | |
| Pumped Hydropower | A | A | A | A | A | A | A | A | A |
| CAES - Comp. Air Energy Storage | E | E | E | E | E | E | E | E | T |
| Solid Batteries | E | E | A | E | A | E | E | E | E |
| Flow Batteries (Redox) | T | T | T | T | T | T | T | T | T |
| Flywheels | E | E | A | --- | --- | --- | --- | T | --- |
| PEV | T | T | E | T | T | T | T | T | T |
| Fuel Cells (PEM) | T | T | T | T | T | T | T | T | T |
| **Demand Response** | | | | | | | | | |
| Fast Auto DR | T | A | A | T | A | A | A | --- | --- |
| Direct Load Control | T | A | E | T | A | A | A | --- | --- |
| Interruptible Load | T | A | T | T | A | A | A | --- | --- |
| Price Responsive Demand | T | T | T | T | A | A | A | --- | --- |
| **Transmission** | | | | | | | | | |
| Synch. Cond.: Large motor frame | A | --- | --- | --- | --- | --- | --- | A | --- |
| Synch. Cond.: Air-cooled generator frame | A | --- | --- | --- | --- | --- | --- | A | --- |
| Synch. Cond.: H2-cooled generator frame | A | --- | --- | --- | --- | --- | --- | A | --- |
| Shunt FACTS devices (STATCOM, SVCs)* | --- | --- | --- | --- | --- | --- | --- | A | --- |
| HVDC Transmission Technologies* | --- | --- | --- | --- | --- | --- | --- | A | A |
| **Desirable Attributes / Retrofit Options** | | | | | | | | | |
| Improved Turndown (MinGen) Capability | ✓ | ✓ | ✓ | ✓ | ✓ | | | ✓ | |
| Elevated Ramp-rate Capability | | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | | ✓ |
| Faster Startup Capability | | | | | | ✓ | ✓ | | |
| **Dynamic voltage support* | | | | | | | | | |

| | |
|---|---|
| A | Available commercially |
| E | Emerging capability in demonstration phase |
| T | Technically feasible, but not currently being pursued |

Note: GE Wind Turbines are capable of providing governor response with a dead-band of up to +/- 36 mHz. For frequency deviations that extend beyond +/- 36 mHz, the default response for the turbine governors is to provide a proportional response back to the droop characteristic. Further, synthetic inertia can also be availed from the wind turbines in events of severe frequency excursions. The stored kinetic energy in the wind blades can be released during such events to assist the grid and arrest the frequency drop and frequency nadir. GE Wind Turbines have a deadband of 200 mHz for provision of synthetic inertia. For AGC-based "MW raise/ MW lower" regulation signals, the governor dead-band does not apply. Wind turbines are also capable of providing sufficient responsiveness for spinning reserve; however, a related factor that needs to be considered is the required duration that the spinning reserve response must be sustained once it is deployed. The required response period is more directly tied to the site-specific wind sustainability than the equipment itself.

**Table A.3-4***Technology characteristics*

| Technologies | Plant Size (MW) | | | | Cost Estimates | | Flexibility | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Minimum | Minimum (Typical) | Maximum (Typical) | Maximum | Total Overnight Cost in 2010 (2009 $/kW) for stated size (MW) | Resource Size Assumed in Cost Estimate (MW) | Turndown Load Level | Ramp Rate Capability (thermally stable) | 10-Minute Output Available (from offline) | 30-Minute Output Available (from offline) |
| **Generation** | | | | | $/kW | MW | %MW | %MW/min | %MW | %MW |
| Solar Thermal | 0.1 | 1 | 100 | 200 | $4600 - 8100 | 200 | 12-15% | 3-7%* | 0% | 0% |
| Solar Photovoltaic (Transmission Connected) | 0.001 | 0.05 | 5 | 150 | $2100 - 3900 | 10 | --- | Rapid* | 100% | 100% |
| Wind (non-synchronized / power conversion) | 0.001 | 1 | 100 | 450 | $1500 - 2500 | 100 | < 10% | Rapid* | 100% | 100% |
| Wind (synchronized) | 0.001 | 1 | 100 | 450 | $1500 - 2500 | 100 | < 10% | Rapid* | 100% | 100% |
| Hydropower | 0.001 | 0.5 | 50 | 650 | $2200 - 4800 | 500 | 20-40% | 25-100% | 100% | 100% |
| Geothermal | 0.05 | 1 | 30 | 180 | $2500 - 9900 | 50 | 12-15% | 3-7% | 0% | 0% |
| Biomass | 0.1 | 5 | 50 | 75 | $2900 - 5800 | 50 | 35-40% | 3-7% | 0% | 0% |
| Coal | 0.1 | 10 | 400 | 1300 | $1900 - 3900 | 600 | 35-40% | 3-7% | 0% | 0% |
| Combined Cycle (Gas/Oil: Sm. HD/Aero) (1x1) | 10 | 25 | 60 | 120 | $1000 - $1800 | 55 | 20-40% | 20-40% | 0-75% | 75-100% |
| Combined Cycle (Gas/Oil: Heavy-duty) (1x1) | 60 | 120 | 300 | 500 | $900 - 1500 | 615 | 25-70% | 3-11% | 0-60% | 10-100% |
| Simple Cycle (Gas/Oil: Small HD/Aero) | 1 | 20 | 40 | 100 | $800 - 1300 | 45 | 25-50% | 25-50% | 0-100% | 100% |
| Simple Cycle (Gas/Oil: Heavy-duty) | 40 | 80 | 200 | 330 | $500 - 800 | 211 | 15-70% | 4-16% | 0-75% | 100% |
| Reciprocating Engines (Gas/Diesel/Bio) | 0.01 | 1 | 5 | 20 | $700 - 1300 | 10 | 50% | 35% | 100% | 100% |
| **Energy Storage** | | | | | | | Resp. Time | %MW/min | %MW | %MW |
| Pumped Hydropower | --- | 100 | 1000 | --- | $1000 - 3000 | 500 | 10s | 25-100% | 100% | 100% |
| CAES - Comp. Air Energy Storage | --- | 50 | 500 | --- | $600 - 1600 | 260 | 1-10min | 4% | 100% | 100% |
| Solid Batteries | 0.1 | 1 | 20 | 50 | $1000 - 4000 | 50 | 100ms | 500% | 100% | 100% |
| Flow Batteries (Redox) | --- | 0.1 | 20 | 50 | $1700 - 4200 | 50 | 100ms | 500% | 100% | 100% |
| Flywheels | 0.1 | 1 | 20 | 40 | $900 - 1100 | 20 | 1-4s | 1500% | --- | --- |
| PEV | --- | 0.02 | 0.05 | --- | --- | --- | 100ms | --- | --- | --- |
| Fuel Cells (PEM) | 1E-04 | 0.001 | 0.1 | 10 | $3,000 | 1 | 10s | 500% | 100% | 100% |
| **Demand Response** | | | | | | | | | | |
| Fast Auto DR | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Direct Load Control | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Interruptible Load | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Price Responsive Demand | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Transmission** | | | | | | | | | | |
| Synch. Cond.: Large motor frame | --- | 0 | 50 | --- | --- | --- | --- | --- | --- | --- |
| Synch. Cond.: Air-cooled generator frame | --- | 38 | 113 | --- | --- | --- | --- | --- | --- | --- |
| Synch. Cond.: H2-cooled generator frame | --- | 198 | 478 | --- | --- | --- | --- | --- | --- | --- |
| Shunt FACTS devices (STATCOM, SVCs) | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| HVDC Transmission Technologies | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Desirable Attributes / Retrofit Options** | | | | | | | | | | |
| Improved Turndown (MinGen) Capability | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Elevated Ramp-rate Capability | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Faster Startup Capability | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |

More detailed descriptions of each resource are included on slides 58-87 of Appendix A.

# 4 Part 1 Summary

Part 1 of the Hawaii Ancillary Services study focuses on ancillary services definitions, interconnection requirements and technologies capable of providing these ancillary services in functional terms. They may not reflect the current practices on the Hawaiian Islands but represent viable options for any electric power system to maintain reliable operations and should be considered as options for the Hawaiian Islands. The ancillary services are currently provided to the Hawaiian Islands under bundled service by the utility operators. Part 2 of the final report will document the GE study results for Task 3-4 and provide analysis of Hawaii specific scenarios including comparison of current practices on the Hawaiian Islands to proposed ancillary services and interconnection requirements. The interconnection requirements can help designate some of the desired capabilities required to deliver ancillary services. These services may be provided by a utility or independent power producer and compensated in accordance to the value that capability brings to the system, to be discussed in Task 3 and 4.

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# 6 Appendix A - 2012_12_10_Hawaii_Ancillary_Services_Report_PART1FINAL.pptx

# Ancillary Services Definitions & Capability Study Part 1, Task 1-2, Final Report

December 10, 2012

Prepared by: GE Energy Consulting

Prepared for: Hawaii Natural Energy Institute (HNEI) and Hawaii Reliability Standards Working Group (RSWG)



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# Table of Contents

## Ancillary Services Definition & Capability Study


Study Background and Objectives

Key Terminology

Study Results:

- Task 1 – Identify and Define Ancillary Services
  - Real Power Ancillary Services
  - Ancillary Service Definitions
  - Ancillary Services Allocations (on the Mainland)
  - Interconnection Requirements
  - Hawaii Specific Differences/Additions
- Task 2 - Identification of technologies capable of providing each ancillary service: Enabling Technology Details

References

# Study Background and Objectives

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# Ancillary Services Def. & Cap. Study

## Overview of Study

Purpose:

Study sponsored by HNEI with support and guidance from Hawaii RSWG to identify, define, and quantify ancillary services required to support new generation (including renewable generation) for bulk power systems and particularly the Hawaiian islands.

Objectives:

- Define a standardized set of ancillary services along with their associated definitions (in functional, performance based terms) that can be used to meet the operational needs of Hawaii and other bulk power systems.
- Technologies (generation, transmission, storage, and demand response (DR)) will be assessed for their ability to support the respective ancillary services to maximize the diversity and optionality for ancillary service acquisition and delivery.
- Identify the physical requirements of the ancillary services needed for each Hawaiian island (Oahu, Maui, Big Island)
- Outline considerations for specifying / acquiring ancillary services for the Hawaii grids that protect reliability, incent renewable generation, and minimize production costs.

# Introduction

## Ancillary services & additional functions required for power system operation

- **Ancillary services*** are those functions performed by the equipment and people that generate, control, transmit, and distribute electricity to support the basic services of generating capacity, energy supply, and power delivery. They are required to maintain reliable operations of the electric power system.

- In addition to ancillary services, other **interconnection requirements** are placed on resources to ensure reliable operation of the grid

- These ancillary services and interconnection requirements enable the system operator to meet the required operations **reliability standards** set by NERC.

- The ancillary services, interconnection requirements, and reliability standards are related to the characteristics of a power system.

** FERC defined ancillary services as those "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."*

# Key Terminology

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# Key Terminology

The following definitions are relevant throughout the content of this presentation and should be interpreted as described below:

**Area Control Error (ACE):** The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error. *NERC Glossary (2008)*

Conventionally, **ACE = (NIA – NIS) – 10B (FA – FS) – IME**, where:

- **NIA** is the algebraic sum of actual flows on all tie lines.
- **NIS** is the algebraic sum of scheduled flows on all tie lines.
- **B** is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- **FA** is the actual frequency.
- **FS** is the scheduled frequency. FS is normally 60 Hz but may be offset to effect manual time error corrections.
- **IME** is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NIA) and the hourly net interchange demand measurement.

Due to a lack of inter-area power flows, the definition of ACE has been modified for Hawaii. Specifically, for Hawaii, **ACE = – 10B (FA – FS) – IME**. This modified definition of ACE is still applicable for Hawaii as it correctly represents the fact that 100% of difference between supply and demand will manifest itself as a frequency error. *Revised definition per Hawaii RSWG Glossary.*

# Key Terminology (cont'd)

The following definitions are relevant throughout the content of this presentation and are intended to provide clarification on their intended interpretation:

**Automatic Generation Control (AGC):** Equipment that automatically adjusts generation, storage devices, and/or responsive load in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias (i.e. ACE). *NERC Glossary (2008) with modifications to accommodate additional resource types such as load and storage devices.*

Although AGC was originally conceived as a means to provide fast (3-6 second signals) to generators, the concept of leveraging AGC to provide "MW raise/lower" commands to demand-side and storage resources is equally applicable and is in practice in some locations.

# Key Terminology (cont'd)

The following definitions are relevant throughout the content of this presentation and are intended to provide clarification on their intended interpretation:

**Droop Control / Governor:** Droop speed control is near instantaneous means of using frequency deviations to distribute load set-point adjustments to a system of resources in a stable manner.

The magnitude of a given resource's response is proportional to the frequency deviation and typically characterized by "x%" droop. For example, a resource with operating range available will provide 100% additional output per "x%" change in system frequency. Response is typically a percentage of the resource's full-capability.[3]

Droop response can be provided by any frequency-sensitive resource.

**Resource:** A resource may consist of any generation, storage, load (i.e. demand-side), or transmission technology.

**Spinning / Non-Spinning:** Historically, the terms "**spinning**" and "**non-spinning**" have referred to the rotational nature of synchronized generators. Over time, this terminology has migrated to imply the "relative state of readiness and responsiveness" as it relates to the ability for a resource to fulfill its ancillary obligation. In an effort to leverage contemporary industry vernacular, this latter interpretation was adopted for use in this presentation.

# Study Results

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# Task 1: Scope & Deliverables

## Identification & definition of ancillary services

Objectives:

- Provide a standardized set of ancillary services along with their associated definitions (in functional terms).
  - Highlight emerging ancillary services and the entities pursuing them
  - Scope added by GE: Discussion on interconnection requirements due to inter-relationship w/ ancillary services

- Explain how each ancillary service is used for grid operation
  - Incorporate perspective during normal and contingency conditions

- Identify "Hawaii-specific" differences relative to the standardized definitions
  - Consider how ancillary functionality is currently provided
  - Adjust standardized definitions for Hawaii (finalize during Tasks 3 & 4)

# Ancillary Services & Interconnection Requirements

Emphasis on **Ancillary Services** that provide direct support for the reliable and economic operation of the power system:

Real-Power Energy Balancing Services
- Frequency Responsive Reserve/Primary Frequency Response
- Regulation
- Load Following
- Spinning Reserve
- Non-Spinning Reserve
- Replacement Reserves

Additional Services
- Black Start
- Reactive Power/ Voltage Support

Generation requirements that are specified via **Interconnection Requirements** are:

Interconnection Requirements
- Power Factor & Voltage Control
- Voltage and Frequency Ride Through
- Ramp Rate Limits and Control
- Over and Under Frequency Controls
- Inertia

Other Considerations

# Real-Power Energy Balancing Services

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# Operational Time Frames

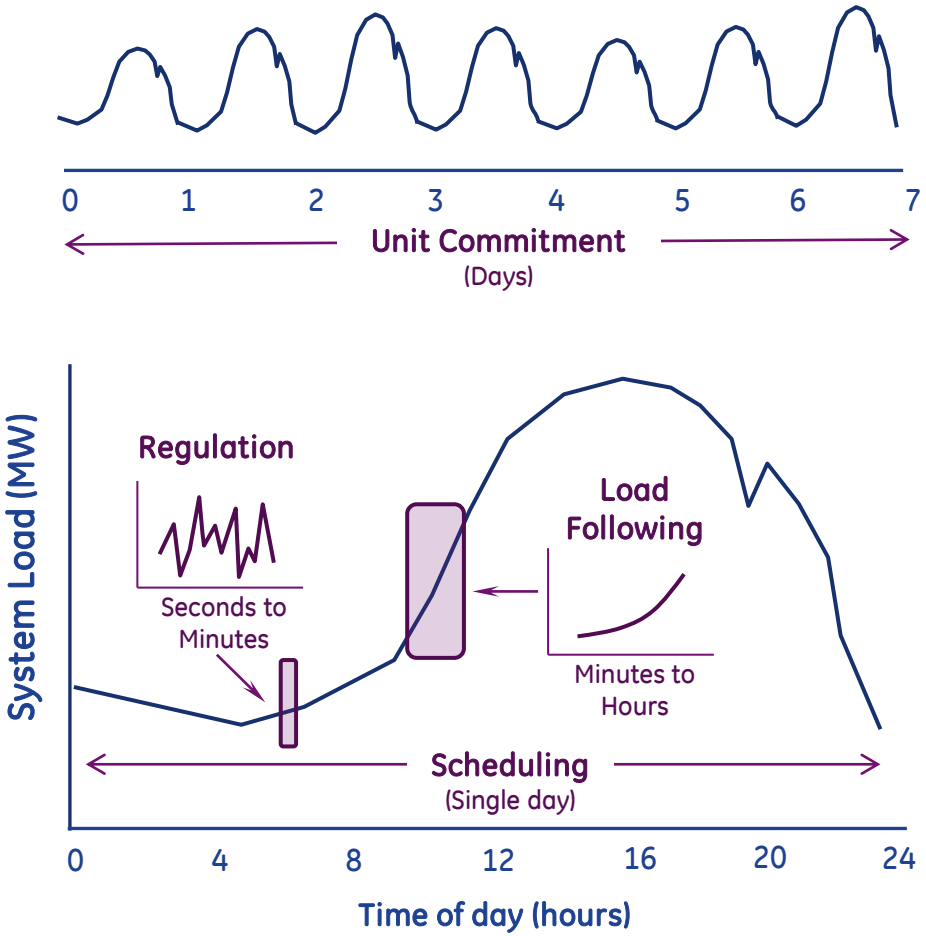
## Relationship during **Normal** Operating Conditions

### Operational Time Frames (Normal Conditions)

**Scheduling / Unit Commitment**:
- Several hours to several days
- Ensures that appropriate generation is available to meet forecasted demand, reserve, and interchange requirements[2].
- Critical to economic / reliable system operation[2]

**Load Following**:
- Several minutes to several hours
- Follows general trending pattern within the day[3]
- Usually performed by economic dispatch[3]
- Focuses on rate of change in generation and consumption[2]

**Regulation**:
- Several seconds to minutes
- Balances fast (sec-to-sec and min-to-min) random variation in supply-demand balance[3]
- Automatic response (typically via AGC) to adjust output (or responsive load)




*Illustrations based on NREL: National Renewable Energy Laboratory, Renewable Electricity Futures Study (Vol. 4 of 4), Bulk Electric Power Systems: Operations and Transmission Planning, 2012*

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# Operational Time Frames

## Relationship during Contingency Operating Conditions

### Operational Time Frames (Contingency Conditions)

**Inertial Response**:
- Arrests the frequency change
- Generators and loads adjust speed and transfer kinetic (or stored) energy to electrical energy[3]

**Frequency Responsive Reserve**:
- Frequency-sensitive droop response from generators with headroom (or responsive loads)[3]
- Stabilize frequency at or below nominal levels

**Regulation**:
- Commanded "MW" adjustment thru AGC
- Assists freq. recovery toward nominal levels[3]

**Contingency Reserves**:
- Spinning & Non-Spinning reserves
- Restore frequency to nominal levels[3]

**Replacement Reserves**:
- Relieve the Contingency Reserves[3]
- Protect against a follow-on event

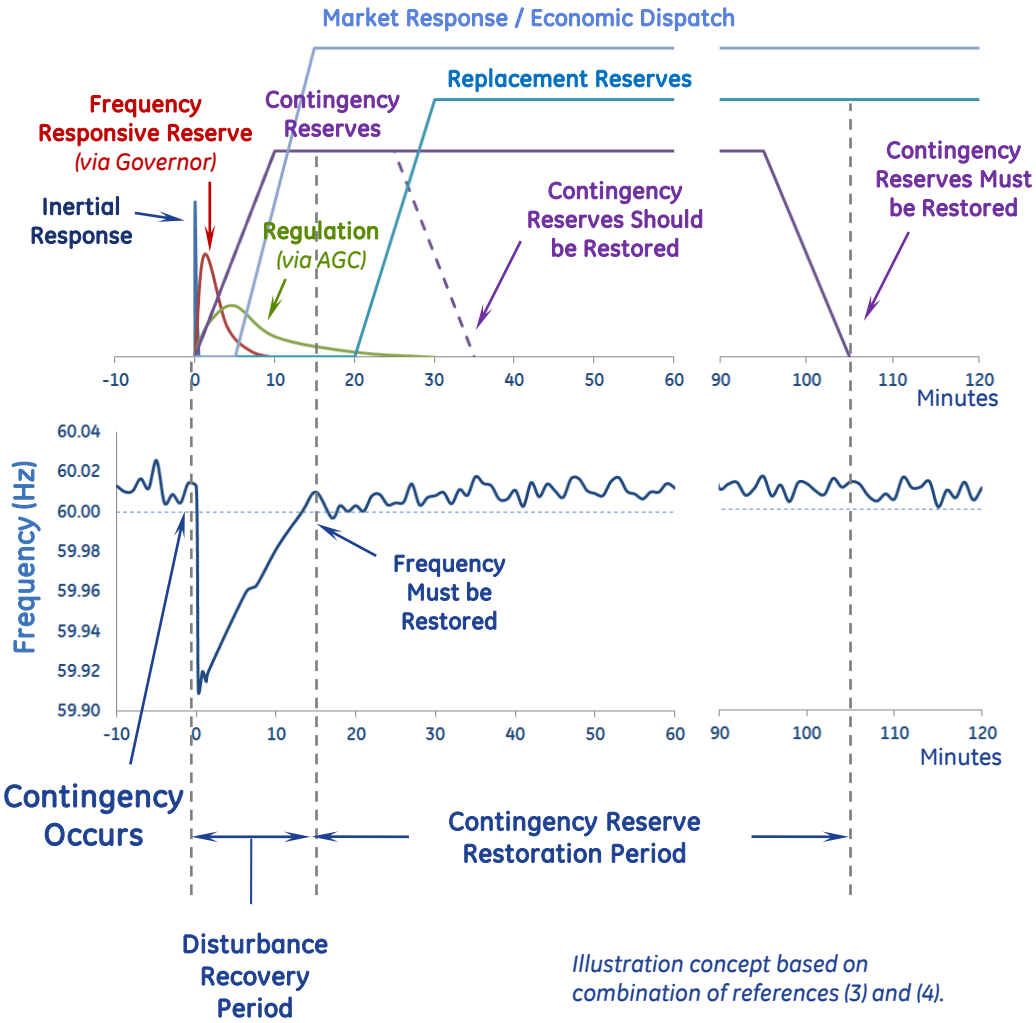



*Illustration concept based on combination of references (3) and (4).*

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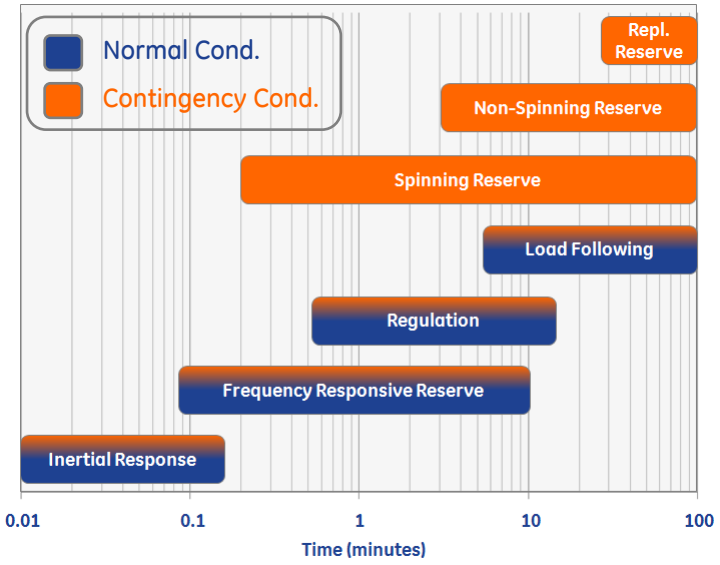
# Continuous Spectrum of Protection

## Progressive series of inter-related responses to ensure system reliability

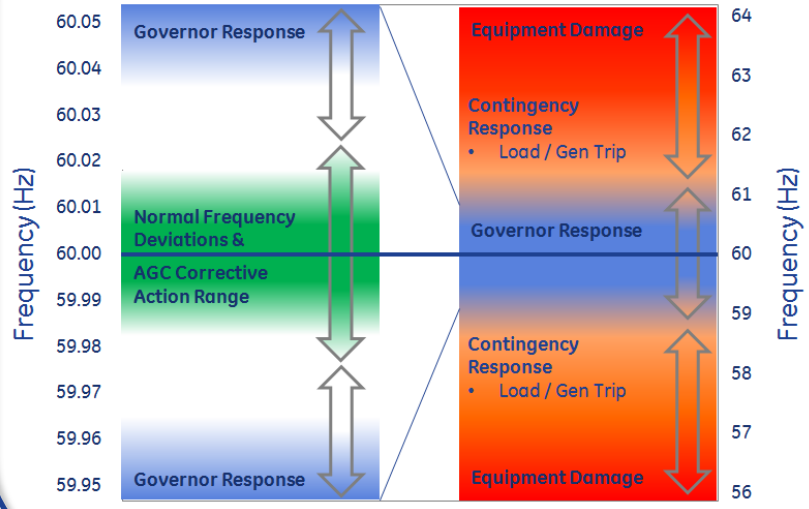
**Combination of automated and manual actions link Normal and Contingency Conditions**

- Inertial Response provided autonomously from synchronized generation (or synthesized via power electronics)
- Frequency Responsive Reserve/ Primary Frequency Response automatically driven by frequency deviations (droop governor response, etc.)
- Regulation drives automatic output adjustments thru Automatic Generation Control (AGC), precipitated by changes in Area Control Error (ACE)
- Automatic and Manually deployed reserves (Spinning / Non-Spinning / Replacement)

### Response Times and Durations[5]




### Progression from Normal to Contingency Conditions[5]



# Ancillary Service Definitions

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# Ancillary Services

## Functions Required to Maintain System Flexibility & Reliability




| | |
|---|---|
| Frequency Responsive Reserve/ Primary Frequency Response | Automatic response triggered by frequency swings. Typically deployed during contingency events. Arrests and helps to recover the frequency fall-off. |
| Regulation | Used continuously during normal operations to correct short-term imbalances between supply and demand. Deployed via AGC signals. |
| Load Following | Slower than "Regulation" and used primarily during normal operations. Typically deployed via economic dispatch to correct an imbalance that will occur in the future. |
| Spinning Reserve | Type of contingency reserve that consists of resources which are connected to the power system and poised, ready to respond immediately. |
| Non-Spinning Reserve | Type of contingency reserve that consists of resources which are capable of providing full response within a specified time; however, the response does not need be immediate. |
| Replacement Reserve | Deployed following a contingency event. Intended to replenish contingency reserves; response does not need to begin immediately. |
| Black Start | Provided by resources capable of starting themselves quickly without support of an external electricity source. Used to restore a power system following a major blackout. |
| Reactive Power/ Voltage Support | Provided by resources capable of injecting/consuming reactive power which is required to maintain voltages within acceptable limits throughout the power system. |

# Inertial Response

Emerging Ancillary Service

- **Definition**: Inertial response is the autonomous and immediate[3]:
  (1) Transfer of kinetic (or stored) energy into electrical energy during a frequency reduction
  (2) Transfer of electrical energy into kinetic (or stored) energy during a frequency increase

  Inertial response is not obtained as an ancillary service. Rather, Inertial response is provided by synchronized resources and variable generation (VG) resources with power converters that can provide synthesized inertia[4]. These inertial response requirements for VGs are addressed through the interconnection requirements. The immediate injection/ consumption of real power reduces the rate of change of frequency (ROCOF) and assists in stabilizing the frequency of the power system.

- **Reaction Speed**: Inertial response is initiated and fully deployed within seconds[2].
- **Response Duration**: Response is only effective during the first few seconds following a disturbance and, *with the exception of power converters*, is not directly controlled / purposefully sustained.
- **Frequency of Use**: For synchronous resources, the inertial response is continuously active and providing stability to the power system. Resources connected with power electronics may utilize a dead-band to withhold the response during normal operation and deploy only during major disturbances.
- **Magnitude of Response**: Resources will autonomously consume/inject until they reach their respective over/under-frequency trip set-points OR until system frequency stabilizes.

# Frequency Responsive Reserve/ Primary Frequency Response

Emerging Ancillary Service

- **Definition**: Frequency responsive reserve is the immediate and automatic increase/decrease in real power output provided by frequency-sensitive resources[3],[4].
- **Reaction Speed**: Response should begin immediately and is typically fully deployed within a few seconds.
- **Response Duration**: Varies. Often defined as part of grid compliance / interconnection requirements and in-proportion to the magnitude of the frequency deviation. Typically, the response is less than 15 minutes* to ensure compliance with NERC BAL-002 which states that ACE must be returned to zero (or pre-disturbance level if originally negative) within 15-minutes* after the start of a reportable disturbance.
- **Frequency of Use**: For all resources which have upward/downward operating range available (relative to their current set-point), and are connected with governors, the frequency responsive reserve is continuously provided. In many cases, a small 10-50 mHz dead-band is applied so that small frequency deviations are ignored[3].
- **Magnitude of Response**: Magnitude of the response is proportional to the frequency deviation and typically characterized by "x%" droop response. For example, a resource with operating range available will provide 100% additional output per "x%" change in system frequency. Response is typically a percentage of the resource's full-capacity.[3]

* Represents the mainland and might be different for Hawaii

# Regulation

Well-established Ancillary Service

- **Definition**: Regulation service is the capability to adjust real power by resources capable of responding appropriately to a system operator's AGC signal in order to correct for actual or expected Area Control Error (ACE) needs. Regulation is distinguishable from Frequency Responsive Reserve. *Updated definition per FERC Order 755, but also recognized as an official ancillary service per FERC Order 888.*
- **Reaction Speed**: Regulation signal provided to participating resources must be updated at least every six (6) seconds (per NERC BAL-005, Requirement 8). Resources should begin to respond immediately with full response achieved in five (5) to ten (10) minutes for most locations (assuming a sustained AGC signal).
- **Response Duration**: Varies – full response typically required to be sustainable for a minimum of the economic dispatch interval (typically five (5) to ten (10) minutes).
- **Frequency of Use**: Continuous. Energy neutral service with up/down fluctuation balancing out in reasonably short-time.
- **Magnitude of Response**: Varies – typically distributed to participating resources in proportion to the size of the imbalance and the allocation of regulation MW's each resource is responsible for.

*Note: NERC (per BAL-001) requires an amount of regulation required to satisfy control performance standards (CPS1 and CPS2). Lack of interconnection reduces CPS1 and CPS2 to statistical measures. May be appropriate to define statistical frequency control requirements (for each Hawaiian island) to provide basis for determining regulation amount – Kirby Proposed Ancillary Services (10/31/2011)*

# Load Following

Emerging Ancillary Service

- **Definition**: Load following is similar to Regulation, but on a slower time-scale.[4] It focuses on the rate of change in supply and demand and is intended to correct for anticipated imbalances that will occur in the next several minutes to hours.[3] Load following can be provided by any resource type capable of adjusting its real-power set-point in this time-frame.

  *Increased penetrations of VG can increase net-load ramping requirements. Load Following can be used to address sustained ramps and periods when preferred low-cost resources cannot ramp quickly enough. Can also use to bridge-gap between Regulation and Contingency Reserves.*[3],[4],[5],[6]

- **Reaction Speed**: Requirements for reaction speed, duration, accuracy measurement, and a mechanism for communicating set-points to participating resources would need to be established. It is anticipated that economic dispatch algorithms would be used to communicate set-points and resources would be remunerated for committing to more stringent response requirements.
- **Response Duration**: Similar to economic dispatch. Sustainable response at given set-point.
- **Frequency of Use**: Anticipated to be continuous, similar to economic dispatch.
- **Magnitude of Response**: Similar to economic dispatch and proportional to the anticipated future imbalance between supply and demand.

# Spinning Reserve

Well-established Ancillary Service

- **Definition**: Spinning Reserve is a type of contingency reserve and consists of resources that are connected to the power system and poised, ready to respond immediately.[2] One of the officially recognized ancillary services per FERC Order 888.
- **Reaction Speed**: Spinning reserve begins to respond immediately and must achieve full response within ten (10) minutes.[2] Per NERC BAL-002, ACE must be returned to zero (or pre-disturbance level if originally negative) within 15-minutes* after the start of a reportable disturbance.
- **Response Duration**: Varies. Per NERC Disturbance Control Standard (DCS) BAL-002, all contingency reserves must be fully restored (replenished) 90 minutes* after the end of the disturbance recovery period (or 105 minutes* after the start of a reportable disturbance).
- **Frequency of Use**: Intermittent, but typically deployed following a reportable disturbance.
- **Magnitude of Response**: Participating resources will be deployed up to their allocated MW level to ensure compliance with NERC Disturbance Control Standard (DCS) requirements.

* Represents the mainland and might be different for Hawaii

# Non-Spinning Reserve

Well-established Ancillary Service

- **Definition**: Non-Spinning Reserve is a type of contingency reserve and consists of resources that are capable of providing full response within a specified time; however, the response does not need be begin immediately.[2] One of the officially recognized ancillary services per FERC Order 888 (referred to as Operating Reserve - Supplemental Reserve by FERC).

- **Reaction Speed**: Non-Spinning Reserve must achieve full response within ten (10) minutes. Per NERC BAL-002, ACE must be returned to zero (or pre-disturbance level if originally negative) within 15-minutes* after the start of a reportable disturbance.

- **Response Duration**: Varies. Per NERC Disturbance Control Standard BAL-002, all contingency reserves must be fully restored (replenished) 90 minutes* after the end of the disturbance recovery period (or 105 minutes* after the start of a reportable disturbance).

- **Frequency of Use**: Intermittent, but typically deployed following a reportable disturbance.

- **Magnitude of Response**: Participating resources will be deployed up to their allocated MW level to ensure compliance with NERC DCS requirements.

* Represents the mainland and might be different for Hawaii

# Replacement Reserve

Well-established Ancillary Service

- **Definition**: Replacement Reserve consists of resources that are capable of providing full response within a specified time; however, the response does not need be begin immediately. Replacement Reserve is not one of the officially recognized ancillary services per FERC Order 888.
- **Reaction Speed**: Replacement Reserve begins responding in thirty (30) to sixty (60) minutes and is intended to replenish contingency reserves in order to protect against a second event or reportable disturbance.[(2),(3)] NERC BAL-002 does not explicitly require Replacement Reserves.
- **Response Duration**: Varies.
- **Frequency of Use**: Intermittent, but typically deployed to restore Contingency Reserves following a reportable disturbance.
- **Magnitude of Response**: Participating resources will be deployed up to their allocated MW level to ensure Contingency Reserves are replenished in accordance with NERC DCS requirements.

# Black Start

Well-established Ancillary Service

- **Definition**: Black start is an ancillary service acquired for the benefit of all loads provided by resources capable of starting themselves quickly without support of an external electricity source.[5],[7] Black start resources must have sufficient real and reactive power capability to be able to energize transmission lines and restart other generators.[5]

- **Reaction Speed**: Resources must be available to begin re-energizing the power system immediately following a major blackout.

- **Response Duration**: Varies, but is required until the power system has been fully restored.

- **Frequency of Use**: Deployed following a major blackout of the power system.

- **Magnitude of Response**: Participating resources must be able to withstand off-nominal frequency and voltage during the restoration and have the ability to accept block-load increases on the order of 10% (or more) of the individual black start resource's full capacity.

# Reactive Power/ Voltage Support

Well-established Ancillary Service

- **Definition**: Voltage support is an ancillary service that is provided by resources capable of injecting/consuming reactive power which is required to maintain voltages within acceptable limits throughout the power system.[5]
- **Reaction Speed**: Reactive power can be adjusted very rapidly (seconds).
- **Response Duration**: Varies, but is typically provided continuously.
- **Frequency of Use**: Continuous.
- **Magnitude of Response**: Participating resources will typically be deployed to provide reactive power within a power factor range of 0.95 leading to 0.95 lagging.

*Note: Interconnection requirements can be used as a mechanism for sourcing voltage support. Specifically, resources are often required to have a specified reactive power capability which is controlled by the power system operator.*

# Developments in Ancillary Services

## Emerging Regulations, Services, and Requirements

**Inertial Response (ERCOT):**[3]

- Evaluating requirements for inertial response.
- Inertial Frequency Response Estimator Tool (IFRET) introduced in February 2010
  - Monitors system load, online conventional generation, spinning reserves and ratio of wind to total generation.
  - If insufficient inertial response available, system operator can adjust unit commitment

**Frequency Responsive Reserve/ Primary Frequency Response (WECC):**

- Frequency Responsive Reserve (FRR) procedure proposed by WECC in 2005[3]
- NERC BAL-002-WECC-1 *(Version 1: April 2008)* requires 50% of contingency reserves:
  - To be spinning **AND** able to "immediately and automatically respond proportionally to frequency deviations … through the action of a governor or other control systems."
- NERC BAL-012-WECC-2-CR *(Frequency Responsive Reserve Criterion, May 2013)*
  - Purpose: Ensure reliable operation during freq. deviation from a loss of generation
  - Applies to: WECC balancing authorities, Reserve Sharing Groups, and Reliability Coords.
  - Establishes minimum required FRR to prevent under-freq. load shed (UFLS) for simultaneous loss of two largest generators in WECC
  - Includes performance measurement criterion to gauge how generation adjusts to support the interconnection

# Developments in Ancillary Services

## Emerging Regulations, Services, and Requirements

**Regulation Performance Compensation (FERC Order 755):** Issued in October 2011

- Commission found "current methods for compensating resources for the provision of regulation are unduly discriminatory".
- Require all RTOs and ISOs to modify their tariffs to provide for a two-part payment to regulation resources:
  - 1st Part: Payment for keeping a resource's capacity in reserve in the event that it is needed to provide regulation.
  - 2nd Part: Payment shall be a performance payment that reflects the amount of work that each resource performs in real-time.

**Secondary Frequency Response and Load Following (CAISO):** Flexible Ramping Revised Draft Proposal – August 2012

- Stakeholder effort to develop market-based flexible ramping products
- CAISO currently deploys 10-min. Regulation service and 5-min. Real-time Dispatch (RTD)
- Flex-Ramping product addresses "lack of sufficient ramping and flexibility" to handle 5-minute supply/demand changes
- Increases in renewable penetration will drive need for increased ramping capability.
- Analogous to Load Following: Flexible ramping product addresses ramping issue before the binding real-time dispatch (RTD) … Regulation addresses ramping issue after binding RTD.
- Purpose is to have resources poised to cover the variation and uncertainty in net system demand following the current RTD interval under consideration.

# Developments in Ancillary Services

## Emerging Regulations, Services, and Requirements

**Secondary Frequency Response and Ramp Capability for Load Following (MISO) :** MISO white-paper - July 2011

- Investigating improved Load Following options
- Current practice: Use economic dispatch for "load following" … coverage of any additional unexpected variation in net load is provided by residual resource flexibility.
- MISO recognizes variability of the net load will likely increase in the future (due to intermittent resources)
  - Strains the ramp response of controllable resources
  - Potential for increase in the frequency of short-term scarcity events … due to ramping capacity shortage.
- Solution requires balance between increased op costs and avoided scarcity event cost
- Appear to be gravitating toward "market product" which prices for ramp capability:
  - Provides incentive to participate
  - Avoids "out of merit" dispatch which is not consistent w/ location-based marginal price
  - Load following product would be "cleared" based on resource opportunity cost and "paid-for" thru cost allocation similar to other ancillary products
- Several approaches proposed:
  - Single-interval: Ramp-capability would be considered for future 10-min. (2 RTD intervals)
  - Multi-interval: Similar to single-interval, but also identifies opportunities in future intervals to "pre-ramp" resources … early interval adjustment for better future interval positioning.

# Ancillary Service Allocations *(On the Mainland)*

imagination at work

# Inertial Response

## As implemented on the mainland

**CAISO/NYISO:**

- Inertial Response is not a stand-alone ancillary service product

**ERCOT:**

- ERCOT requirement that new wind plants supply primary frequency response for over-frequency events

**PJM:**

- Inertial Response is not a stand-alone ancillary service product

**ISO-NE:**

- Inertial Response is not a stand-alone ancillary service product

# Frequency Responsive Reserve/ Primary Frequency Response

## As implemented on the mainland

**ERCOT:**
- FRR is not a stand-alone ancillary service product
- All online generation resources must have governors in-service and unblocked

**NYISO/IESO:**
- FRR is not a stand-alone ancillary service product

**PJM:**
- FRR is not a stand-alone ancillary service product
- All resources providing spinning reserve must be synchronized to the grid and frequency responsive.

**WECC:**
- In process of developing FRR criteria [NERC BAL-012-WECC-2-CR - May 2009]
- Unclear if new criteria would replace spinning reserve or be a subset of spinning reserve
    - Current proposal is to base FRR criteria on NERC Category "C" event
- Criteria (as proposed) would share the total obligation among the respective balancing authorities (BA's) and would be proportional to BA's load and generation.

*Extracted from Reference [6] NERC: North American Electric Reliability Corporation, Special Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, March 2011*

# Regulation

## As implemented on the mainland

**ERCOT:**

- Market-based and deployed via AGC
- MW requirement is a function of the month and daily hour number
    - Based on the amount historically deployed and amount of time it was exhausted
    - Considers additional wind penetration relative to the historically benchmarked levels
        - i.e. + "x" MW of additional regulation per 1000 MW of additional wind (also assessed monthly and hourly)
- All online generation resources must have governors in-service and unblocked

**IESO:**

- IESO contracts for regulation service.
- Terms / Conditions of the contract include:
    - Minimum of +/- 100 MW of regulation must be scheduled (system-level) at all-times
    - Minimum overall system ramp rate requirement is 50 MW / min

**NYISO:**

- Market-based product and deployed via AGC (every 6 seconds)
- MW requirement is a function of the month and daily hour number
- All resources providing spinning reserve must be synchronized to the grid and frequency responsive.

*Extracted from Reference [6] NERC: North American Electric Reliability Corporation, Special Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, March 2011*

# Regulation (cont'd)

## As implemented on the mainland

**MISO:**

- Market-based and deployed via AGC (every 4 seconds)
- No fixed "MW" requirement; however, must carry sufficient reserve which is responsive to AGC to comply w/ NERC's Control Performance Criteria

**PJM:**

- Regulation service is scheduled via two (2) methods:
  - Self-scheduled
  - PJM RTO Regulation Market
- Resources providing regulation receive two (2) signals:
  - AReg (Assigned Regulation): Assigned regulation for hour. Typically constant for the hour, but adjusted on a 10 second scan rate.
  - RegA (Real-time Instantaneous Target): +/- MW signal deployed via AGC every 2 sec.
- MW requirement determined for two (2) daily periods
  - On-Peak (0500 – 2359): 1% of the forecast peak load for the day
  - Off-Peak (000-0459): 1% of the forecast valley load for the day

**SPP / WECC:**

- Deployed via AGC.
- No fixed "MW" requirement; however, must carry sufficient reserve which is responsive to AGC to comply w/ NERC's Control Performance Criteria

*Extracted from Reference [6] NERC: North American Electric Reliability Corporation, Special Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, March 2011*

# Spinning Reserve

## As implemented on the mainland

**ERCOT:**

- Market-based 10-minute spinning reserve product
- Minimum "MW" requirement is 2300 MW (~3.5% peak demand) and can go up to 2800 MW (~4.3% peak demand).
- May be provided by:
  - Unloaded generation resources
  - Demand-side resources (up to 50% of the total spinning reserve MW)
  - Resources controlled by under-frequency relays
  - Direct Current (DC) tie-line response (must be fully deployed in 15 seconds)
- Load following / spin deployed as necessary to minimize use of 10-minute reserves

**IESO:**

- IESO has two market-based 10-minute products: (1) Spinning and (2) Non-spinning
- Spinning reserve must be provided by resources synchronized to the power system
- 10-min Spin/Non-Spin MW requirement is based on largest single contingency on the system
  - Minimum of 25% of the 10-minute reserve requirement must be spinning
  - Could be more based on historical ACE performance during contingency events

*Extracted from Reference [6] NERC: North American Electric Reliability Corporation, Special Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, March 2011*

# Spinning Reserve (cont'd)

## As implemented on the mainland

*Extracted from Reference [6] NERC: North American Electric Reliability Corporation, Special Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, March 2011*

**NYISO:**

- Market-based 10-minute spinning reserve product
- 50% of the 10-minute contingency reserve requirement must be sourced from synchronized resources (including load reductions, curtailed resource capacity, or canceled off-system energy sales)
- Total 10-minute contingency reserve must be greater than the operating capacity loss caused by the most severe observed contingency OR the largest energy loss caused by the cancellation of an interruptible off-system energy purchase.

**MISO:**

- Market-based ancillary service product.
- Provided by synchronized generation resources which are capable of achieving response within the NERC Disturbance Recovery Period (15 min.)
- Residual regulating reserves (in excess of the requirement) may be applied to Spinning Reserve
- 40% of the contingency reserves must be spinning

**SPP:**

- Provided by frequency-sensitive synchronized resources
- 50% of the contingency reserve must be spinning reserve
- Spinning Reserve allocation (per resource) is limited to the increase in output associated w/ a frequency drop to 59.5 Hz. Under 5% droop, this is 16.7% of the individual resource capacity.

# Spinning Reserve (cont'd)

## As implemented on the mainland

*Extracted from Reference [6] NERC: North American Electric Reliability Corporation, Special Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, March 2011*

**PJM:**

- Market-based 10-minute ancillary product
- PJM consists of two (2) zones:

  ReliabilityFirst Corporation (RFC) Reserve Zone:
  - Consists of all PJM companies except for SERC-based companies
  - Total contingency reserve must be able to cover the minimum imposed RFC requirement (150% largest generator) or largest contingency on the system.
  - Per NERC BAL-002-RFC-02, at least 50% of the contingency reserves must be spinning and no more than 25% should be interruptible load.

  Southern Reserve Zone:
  - Consists of the Dominion load share of VACAR (NERC Sub-region: VA/NC/SC)
  - Total contingency reserve req's for Southern Zone determined annually (~430 MW)
  - Spinning reserves must be able to cover the largest contingency within the zone less the 15-minute quick-start capability in the zone.

**WECC:**

- Requires 50% of its contingency reserves to be spinning reserves; unloaded generation that can be loaded in 10-min. can be considered spinning reserve.
- Contingency reserves shall be sufficient meet the NERC Disturbance Control Standard (DCS) and be at least greater than:
  - Most severe single contingency
  - Sum of 5% of hydro generation load responsibility and 7% of thermal generation load responsibility

# Non-Spinning Reserve

## As implemented on the mainland

**ERCOT:**

- Market-based 30-minute ancillary service product
- Calculated for each hour of the day each month
- Can be provided by off-line generation resources or loads capable of being interrupted within 30-minutes for a duration of at least 1-hour.

**NYISO**

- Market-based 10-minute ancillary service product
- Represents the residual portion of the 10-minute contingency reserve (which is not covered by spinning reserve)
- Total 10-minute operating reserve must be greater than the operating capacity loss caused by the most severe observed contingency OR the largest energy loss caused by the cancellation of an interruptible off-system energy purchase.

**MISO:**

- Consists of off-line generation able to be loaded or interruptible load able to be removed within the NERC DCS period (15-minutes).

*Extracted from Reference [6] NERC: North American Electric Reliability Corporation, Special Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, March 2011*

# Non-Spinning Reserve (cont'd)

## As implemented on the mainland

**PJM:**

- Not a formalized ancillary service product
- Consists of any resource capable of providing full response in 10-min (RFC Zone) or 15-min. (Southern Zone).
- Represents the residual portion of the 10-minute contingency reserve (which is not covered by spinning reserve)

**SPP:**

- Provided by any resource (which does not have to be connected to the network), but can be connected and applied to meet NERC DCS requirements (15-min.).

**WECC:**

- Represents 50% of the total contingency reserve obligation
- Consists of any resource capable of providing full response in 10-min, including:
    - Load which can be interrupted within 10 minutes
    - Interruptible exports
    - On-demand rights from other Balancing Areas (BA's)
    - Spinning Reserve in excess of requirement
    - Off-line generation that qualifies as non-spinning reserve

*Extracted from Reference [6] NERC: North American Electric Reliability Corporation, Special Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, March 2011*

# Replacement Reserve

## As implemented on the mainland

**IESO:**

- Market-based 30-minute reserve product
- Replacement reserve addresses the residual portion of the largest single contingency plus half of the second largest contingency (typically, this is the loss of the two largest generators), which is not covered by 10-minute spinning and non-spinning reserves.

**NYISO:**

- Market-based 30-minute reserve product
- Equivalent to 50% of the total 10-minute contingency reserve (including both spinning and non-spinning resources)

**PJM:**

- Not a formalized ancillary service product
- Consists of any resource capable of providing full response within a 10 – 30 minute notification.

*Extracted from Reference [6] NERC: North American Electric Reliability Corporation, Special Report: Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, March 2011*

# Reactive Power/ Voltage Support

## As implemented on the mainland

**CAISO:**

- Maintains acceptable voltage levels and VAR flow on the Controlled Grid using all voltage control support equipment required to meet the operating criteria specified in the NERC and WECC Minimum Operating Reliability Criteria
- If notified of the loss of an automatic voltage regulator control (AVR),and the Scheduling Coordinator (SC) has not notified the PTO then notify the applicable PTO of the status of the device (the TO will direct the Generator Operator to maintain or change either its voltage Schedule or its Reactive Power Schedule as appropriate)

**NYISO:**

- Resource must be able to produce and absorb Reactive Power within its tested reactive capability range
- Resource must be able to automatically respond to voltage control signals; for a generator, a functioning Automatic Voltage Regulator (AVR) is required
- Resource must be under the operational control of the NYISO or a Transmission Owner

**PJM:**

- Not a formalized ancillary service product

**ERCOT:**

- As provided by ERCOT to the QSEs: The coordinated scheduling of voltage profiles at transmission busses to maintain transmission voltages on the ERCOT System in accordance with Operating Guides
- As provided by a QSE to ERCOT: The provision of Generation Resource capacity whose power factor and output voltage level can be scheduled by ERCOT to maintain transmission voltages within acceptable limits throughout the ERCOT System in accordance with Operating Guides

# Black Start

## As implemented on the mainland

**CAISO:**

- Cost of Service - units are identified for black start and their documented costs are then funded and rolled into a tariff for cost recovery

**PJM/NYISO:**

- Cost of Service - units are identified for black start and their documented costs are then funded and rolled into a tariff for cost recovery
- NYISO selects the generating resources with black start capability by considering the following operating characteristics: electrical location in the NYCA; startup time: from NYISO order to start to minimum output; maximum response rate (MW/minute) above minimum output; and maximum power output

**ISO-NE:**

- Flat Rate Payment which increases black start remuneration to encourage provision - the monthly compensation paid to a generator is determined by multiplying a flat rate (in $/KWyr and referred to as the $Y value) by the unit's Monthly Claimed Capability for that month

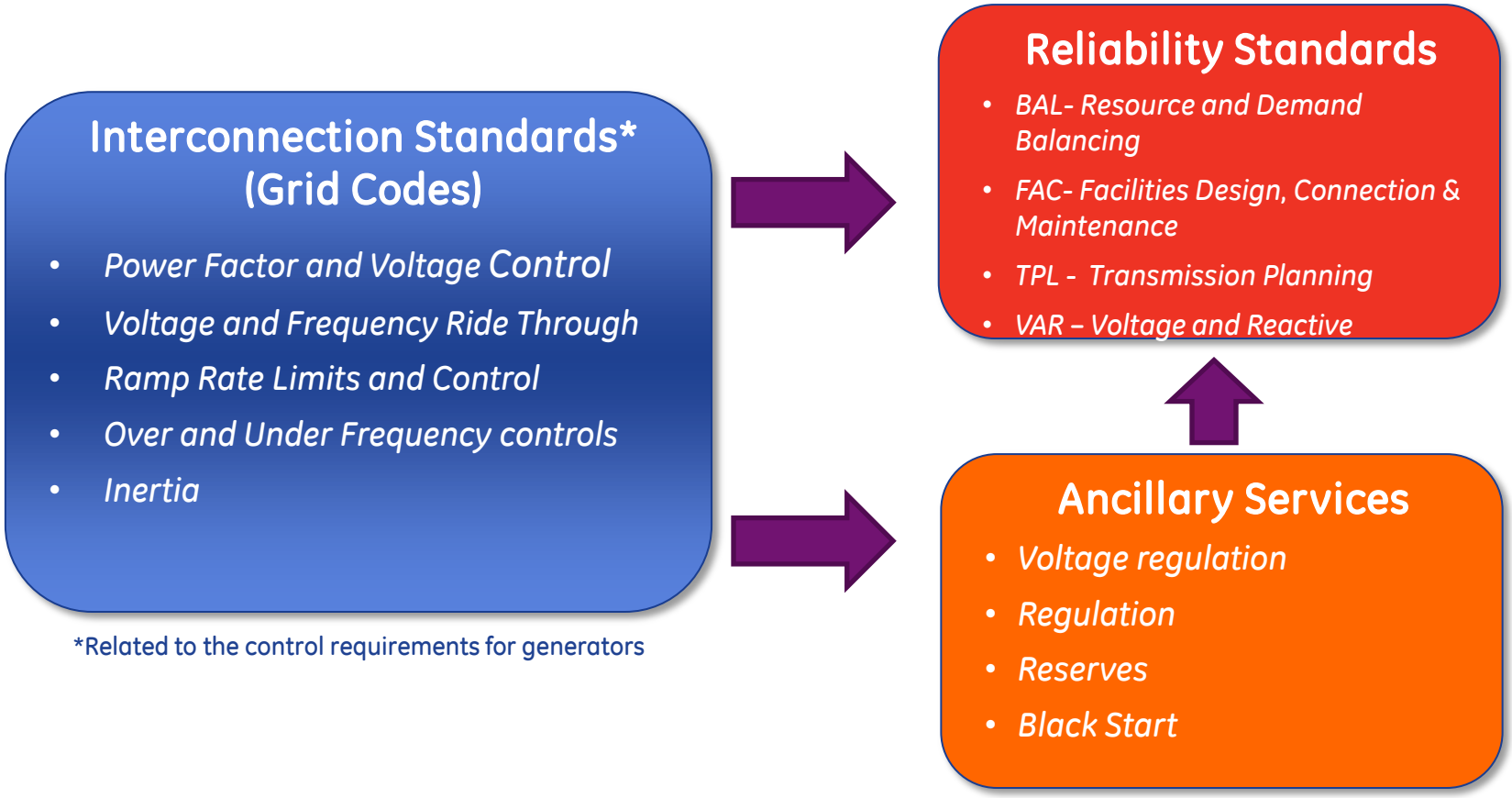
**ERCOT:**

- Competitive Procurement - under this approach ERCOT runs a market for black start services and each black start unit must be able to demonstrate that it can startup another unit in close proximity to begin the islanding and synchronization of the grid
- As provided by ERCOT to QSEs: The procurement by ERCOT through Agreements, pursuant to emergency dispatch by ERCOT and emergency restoration plans of Resources which are capable of self-starting without support from the ERCOT System in the event of a blackout, in order to begin restoration of the ERCOT System to a secure operating state
- As provided by a Generator or a QSE to ERCOT: The provision of Resources under a Black Start Agreement, pursuant to emergency dispatch, which are capable of self-starting without support from the ERCOT System in the event of a blackout

# Interconnection Requirements

imagination at work

# Interconnection Requirements




*Related to the control requirements for generators

Interconnection Standards enables the system to meet its reliability standards by requiring all generators:

- To have certain capabilities that directly helps with the system reliability
- To have certain capabilities that enables it to provide ancillary services that are required for system reliability

# VER Interconnection Requirements

## Existing Standards

***Power Factor and Voltage Control***

- *Several US & European Grid Codes including ERCOT (wind & solar), AESO (wind) required reactive power and voltage control*

***Voltage and Frequency Ride Through***

- *Many European and Canadian Grid Codes require voltage and frequency ride-through capabilities for all units. For example, IESO requires generator facilities to ride-though voltage and frequency deviations (between 58 to 61.5 HZ)*

***Ramp Rate Limits and Control***

- *Many operators are proposing ramp rate limits and controls for wind and solar plants. For example, Alberta has adopted a 10% MW rated capacity/minute upward ramp rate limit.*

## Emerging Standards

***Over and Under Frequency controls***

- *Many ISOs require wind units to provide Over-frequency response similar to a thermal unit with a droop of 5%.*
- *Few grid operators (Nordic and ESBNG ) require wind plants to be able to change the active power production as a function of the network frequency.*

***Inertia***

- *Hydro-Québec requires that wind plants be able to contribute to reducing frequency deviations similar to a synchronous generator whose inertia constant (H) equals 3.5s.*

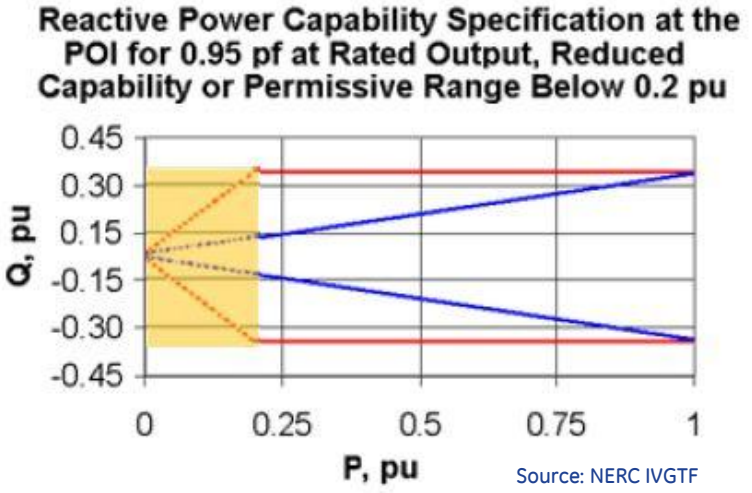
# Reactive Power & Voltage Control

Capability to provide reactive power output within a certain power factor range and the capability to regulate voltage within this range

- Required for reliable operations
- Synchronous generators required to have 0.95 lead/**0.90 lag** capability. Automatic Voltage Regulator (AVR) required.
- Capable units participate in voltage support ancillary service
  - assumed to provide (and compensated)- NYISO
  - Only units that operate outside their PF range are paid opportunity cost - CAISO

Requirements for Wind and/or Solar Plants

- Order 661-A requires study by TO to justify the reactive capability requirement up to 0.95 lag to lead at POI
- ERCOT (wind & solar), AESO (wind), several European Grid Codes required reactive power and voltage control
- Typically, baseline capability of 0.95 lag to lead at full output (POI) and permissive reactive power range
- Some grid codes require a certain portion of the reactive power range be dynamic.



Source: NERC IVGTF

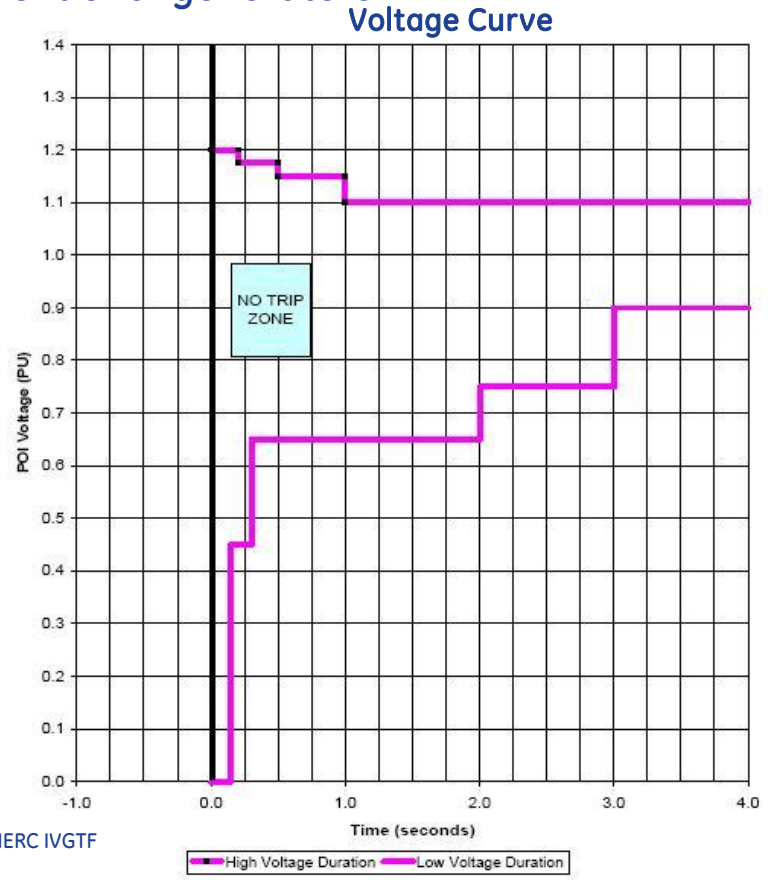
# Fault Ride-through

Capability of the generator to ride-through (predetermined) temporary voltage and frequency deviations

- Inadvertent loss of generators after a fault compounds frequency and voltage problems
- No explicit ride through requirement specified for conventional generators

Requirements for Wind and Solar Plants

- FERC Order 661-A requires that wind plants remain connected for three phase faults with normal clearing
- NERC PRC-024-1 (draft) proposes voltage and frequency curves for all units
- Many European and Canadian Grid Codes require voltage and frequency ride-through capabilities for all units.
- For example, IESO requires generator facilities (10MW/50MW) to ride-though voltage and frequency deviations (between 58 to 61.5 HZ)
- In the U.S., most regions have voltage ride-through requirements for wind




Source: NERC IVGTF

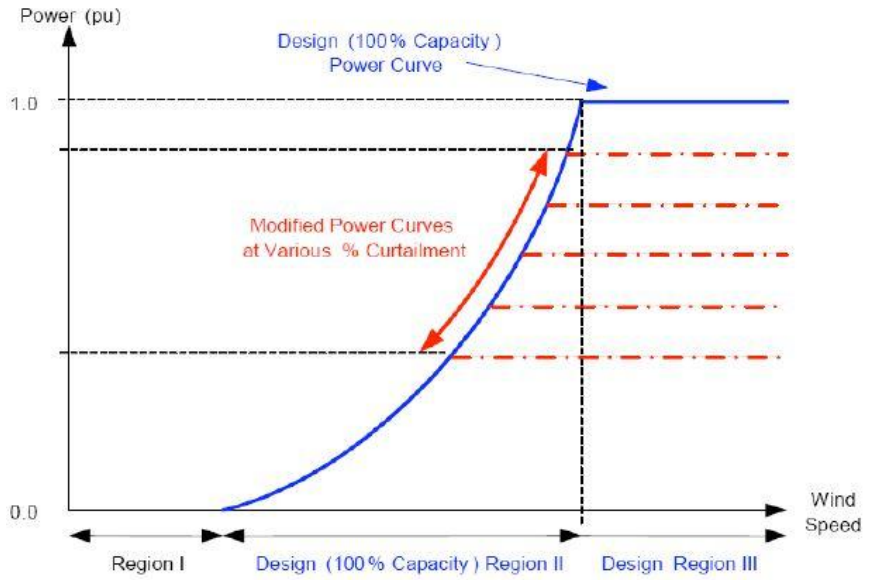
# Ramp Rate Limits and Control

Capability to ramp the output of a generator under certain conditions

- Sudden changes in the output that are otherwise controllable may have a negative impact on system reliability
- No specific ramp rate and control requirements for synchronous generators … conventional generator have "gradual" ramp rates

<u>Requirements for Wind and Solar Plants</u>

- Many operators are proposing ramp rate limits and controls for wind and solar plants
- Alberta ISO has adopted a 10% MW rated capacity/minute upward ramp rate limit.
- ERCOT and NYISO have the capability to dispatch wind generation




Source: NERC IVGTF

# Over and Under Frequency Control

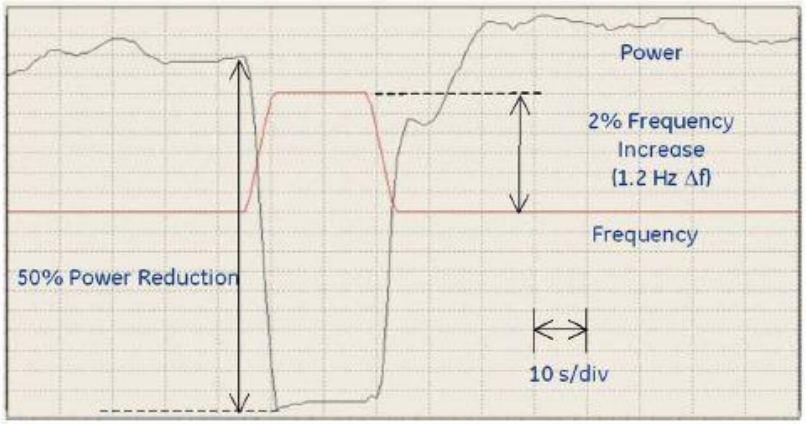
Capability to automatically increase and decrease (sustained) output under low and high frequency conditions respectively

- System frequency should be maintained around nominal value
- Synchronous generators are required to have governors with droop control
- Provide MWs in response to a drop in frequency… however, need "headroom"
- Reduce MWs in response to an increase in frequency… however, need to be operating above their minimum generation level

Requirements for Wind and Solar Plants

- Capable of providing over-frequency response (by pitch control or inverter control)
- Can provide under-frequency response… however, need to spill energy which has high opportunity cost
- Many ISOs require wind units to provide Over-frequency response in response to high system frequency similar to a thermal unit with a droop of 5%.
- Few grid operators (Nordic and ESBNG ) require wind plants to be able to change the active power production as a function of the network frequency.

**Over-frequency Response (test) of Wind Plant**




Source: NERC IVGTF

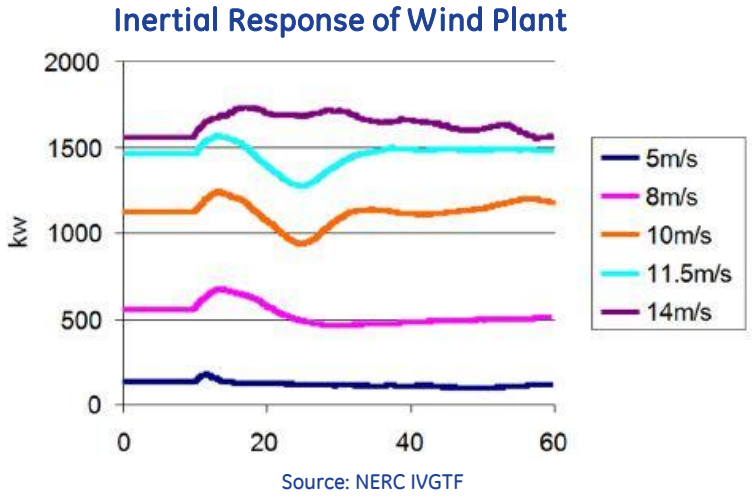
# Inertia

Capability to provide an immediate response to a drop in system frequency

- Conventional generating units give up a portion of their stored kinetic energy as increased power output, which helps to retard the frequency decline after a fault.
- No specific inertia requirement for synchronous generators

Requirements for Wind and Solar Plants

- Stored kinetic energy from the turbine-generator rotors can be temporarily donated to the grid in the form of MWs
- Response depends on wind speed and is tunable
- For PV spilling is required to provide this response
- Hydro-Québec requires that wind plants be able to contribute to reducing large (> 0.5 Hz), short-term (< 10 s) frequency deviations on the power system, as does the inertial response of a conventional synchronous generator whose inertia constant (H) equals 3.5s.



Source: NERC IVGTF

# Other Considerations

## Items not addressed directly thru Ancillary Services or Interconnection Requirements

**Reduced Minimum Generation Capability**:

- Potential to avoid curtailment of renewable and economically preferred generating assets
- Enables more online reserve … potential for more granular ancillary service participation
- Improved system-level load following capability
- Provides options for improved portfolio management … hedge against uncertain conditions

**Short-circuit Strength**:

- Short-circuit levels may decrease if synchronous generators are replaced by renewables
- Synchronous generators may need to be online to maintain minimum short-circuit levels
- Additional studies are required

**Load Shaping**:

- Consider proactive movement of demand-side resources or non-dispatchable load to provide a more manageable daily load shape
  - i.e. incentivize / prohibit charging of PEV's at certain times of day
- "Load shaping" may provide an opportunity to reduce the amount of other ancillary services that are required.
- Anticipate that this would be a procedural implementation rather than ancillary-service based approach … need to carefully consider how to monitor, incentivize, and enforce the targeted load adjustments.

# Hawaii-Specific Differences / Additions

imagination at work

# Ancillary Services – Hawaii

Unique characteristics of Hawaiian system warrant attention to ancillary services and interconnection requirements

- Relatively small island systems: HECO~1200 MW, MECO ~200MW, HELCO~195 MW peak load… challenge to maintain frequency
- No interconnections … imbalance between load and generation affects frequency, a small frequency bias
- High Rate of Change of Frequency (ROCOF)… units are large compared to the size of the system
- High cost of energy and ancillary services due to high fuel import prices… lean operations
- Many must run/scheduled units… historical operations
- Small system with few units… single vertically integrated utility, multiple IPPs and third-party dispersed generation on each island with no centralized power markets

# Ancillary Services – Hawaii (con't)

Unique characteristics of Hawaiian system warrant attention to ancillary services and interconnection requirements

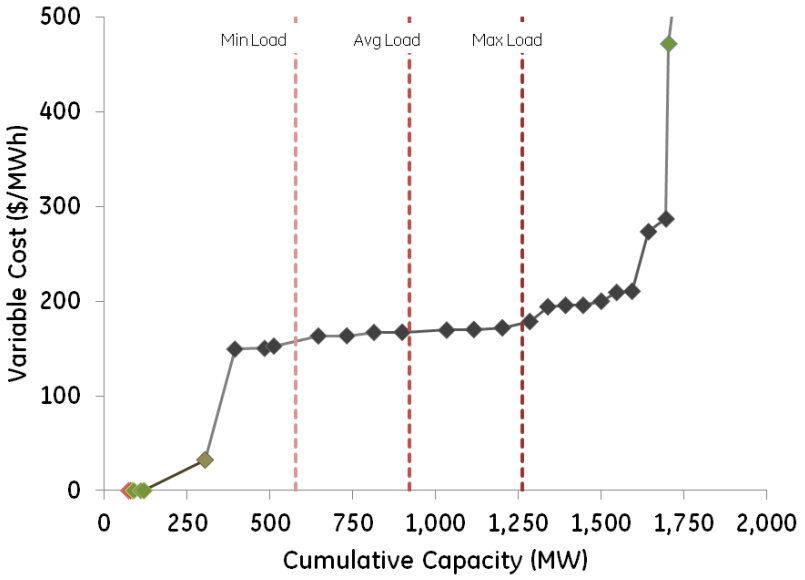
- While fewer opportunities for transaction "liquidity", ancillary service value can be calculated/estimated to provide incentives/payments to providers of ancillary services - does not need to remain in bundled utility offering
- Large amounts of distributed generation
- Clean Energy Mandate includes RPS target of 40% and 4,300 GWH reduction for Energy Efficiency Portfolio Standards by 2030; high wind and solar generation potential in MECO, geothermal in HELCO
- Hawaii specific operating criteria to maintain system frequency and voltage and provide adequate reserves

# Ancillary Services – Hawaii

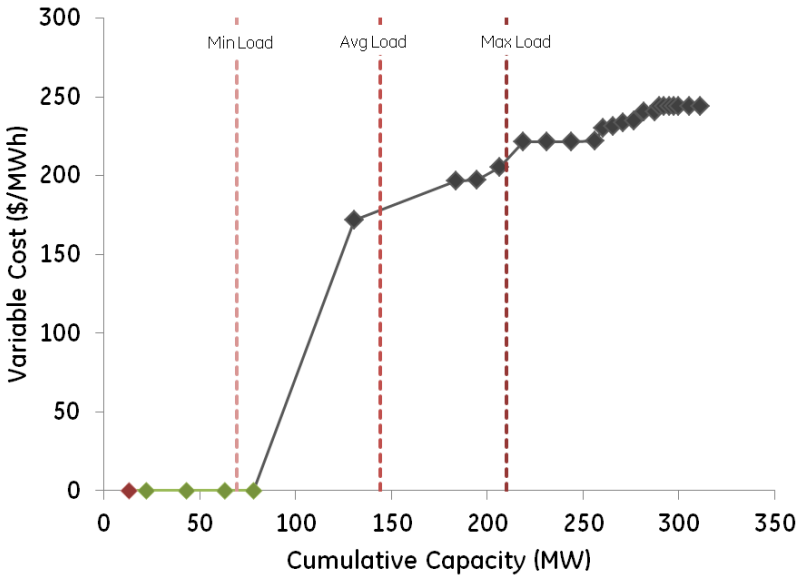
## Characteristics of the Hawaii Grids

Size (MW) of power grids and resource size and mix result in limited options to serve demand and noticeable dispatch stack step changes

### HECO (Oahu) Dispatch Stack




### MECO (Maui) Dispatch Stack




* Renewable capacity is derated per ongoing Stage 2 interconnection study

# System Operating Criteria

Hawaii specific operating criteria to maintain system frequency and voltage and provide adequate reserves

- A few criteria of note:
  - Under Frequency Load Shed is used to maintain frequency: instantaneous load shed occurs at 58.9 Hz, 58.7 Hz and 58.8 Hz for the three islands respectively. Both HECO and HELCO also have time delay blocks starting at 59 Hz and 59.3 Hz respectively
  - Each Island has several "must run" units for stability and contractual reasons
  - HECO carries spinning reserves for large single contingency while MECO and HELCO do not

- GE recognizes that understanding the current system operating criteria and practices is important to the study recommendations and therefore will confirm understanding while working through Tasks 3&4

# Enabling Technologies

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# Task 2: Scope & Deliverables

## Identification of technologies capable of providing each ancillary service

Objectives:

- Develop a summary table which identifies which technologies can supply each ancillary service. Consider:
  - Generation (including both conventional and variable renewable), storage, demand-response, and transmission technologies
  - Identify the approximate resource sizes
  - Include perspective on product attributes which can be used to assess ancillary compatibility

- Adhere to the following constraints:
  - Limit discussion to technologies in commercial or pilot applications today
  - Focus on current deployment costs – do not speculate about future costs
  - Avoid screening technologies based on cost-effectiveness

- Provide reference citations (as available) for each technology / ancillary match-up

# Enabling Technologies

## Aligning Technologies with Ancillary Service Capability

**Approach**:

- Spectrum of generation, transmission, storage, and demand-response technologies considered for their ability to support the defined ancillary services.
- Focus was placed on technologies in commercial or pilot applications today.
- Each resource-type was evaluated based on its capital cost, response capability, and degree of commercial penetration / experience providing each type of ancillary service.



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# Technology Capability Table

## Screening Resources for their Ancillary Service Compatibility

| Technologies | Ancillary Services Compatibility | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Inertial Response | Frequency Responsive Reserve | Regulation | Load Following | Spinning Reserve | Non-Spinning Reserve | Replacement Reserve | Voltage Support | Black Start |
| **Generation** | | | | | | | | | |
| Solar Thermal | A | T | T | T | T | --- | --- | A | T |
| Solar Photovoltaic (Transmission Connected) | T | T | T | T | T | T | T | T | --- |
| Wind (non-synchronized / power conversion) | A | A | A | A | A | T | T | A | --- |
| Wind (synchronized) | A | A | A | A | A | T | T | A | T |
| Hydropower | A | A | A | A | A | A | A | A | A |
| Geothermal | A | A | A | A | A | --- | --- | A | T |
| Biomass | A | A | A | A | A | --- | --- | A | --- |
| Coal | A | A | A | A | A | --- | --- | A | --- |
| Combined Cycle (Gas/Oil: Sm. HD/Aero) (1x1) | A | A | A | A | A | A | A | A | A |
| Combined Cycle (Gas/Oil: Heavy-duty) (1x1) | A | A | A | A | A | A | A | A | A |
| Simple Cycle (Gas/Oil: Small HD/Aero) | A | A | A | A | A | A | A | A | A |
| Simple Cycle (Gas/Oil: Heavy-duty) | A | A | A | A | A | A | A | A | A |
| Reciprocating Engines (Gas/Diesel/Bio) | A | A | A | A | A | A | A | A | A |
| **Energy Storage** | | | | | | | | | |
| Pumped Hydropower | A | A | A | A | A | A | A | A | A |
| CAES - Comp. Air Energy Storage | E | E | E | E | E | E | E | E | T |
| Solid Batteries | E | E | A | E | A | E | E | E | E |
| Flow Batteries (Redox) | T | T | T | T | T | T | T | T | T |
| Flywheels | E | E | A | --- | --- | --- | --- | T | --- |
| PEV | T | T | E | T | T | T | T | T | T |
| Fuel Cells (PEM) | T | T | T | T | T | T | T | T | T |
| **Demand Response** | | | | | | | | | |
| Fast Auto DR | T | A | A | T | A | A | A | --- | --- |
| Direct Load Control | T | A | E | T | A | A | A | --- | --- |
| Interruptible Load | T | A | T | T | A | A | A | --- | --- |
| Price Responsive Demand | T | T | T | T | A | A | A | --- | --- |
| **Transmission** | | | | | | | | | |
| Synch. Cond.: Large motor frame | A | --- | --- | --- | --- | --- | --- | A | --- |
| Synch. Cond.: Air-cooled generator frame | A | --- | --- | --- | --- | --- | --- | A | --- |
| Synch. Cond.: H2-cooled generator frame | A | --- | --- | --- | --- | --- | --- | A | --- |
| Shunt FACTS devices (STATCOM, SVCs)* | --- | --- | --- | --- | --- | --- | --- | A | --- |
| HVDC Transmission Technologies* | --- | --- | --- | --- | --- | --- | --- | A | A |
| **Desirable Attributes / Retrofit Options** | | | | | | | | | |
| Improved Turndown (MinGen) Capability | ✓ | ✓ | ✓ | ✓ | ✓ | | | ✓ | |
| Elevated Ramp-rate Capability | | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | | ✓ |
| Faster Startup Capability | | | | | | ✓ | ✓ | | |

*Dynamic voltage support*

| | |
|---|---|
| A | Available commercially |
| E | Emerging capability in demonstration phase |
| T | Technically feasible, but not currently being pursued |

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# Technology Capability Table (cont'd)

## Screening Resources for their Ancillary Service Compatibility

| Technologies | Plant Size (MW) | | | | Cost Estimates | | Flexibility | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Minimum | Minimum (Typical) | Maximum (Typical) | Maximum | Total Overnight Cost in 2010 (2009 $/kW) for stated size (MW) | Resource Size Assumed in Cost Estimate (MW) | Turndown Load Level | Ramp Rate Capability (thermally stable) | 10-Minute Output Available (from offline) | 30-Minute Output Available (from offline) |
| **Generation** | | | | | $/kW | MW | %MW | %MW/min | %MW | %MW |
| Solar Thermal | 0.1 | 1 | 100 | 200 | $4600 - 8100 | 200 | 12-15% | 3-7%* | 0% | 0% |
| Solar Photovoltaic (Transmission Connected) | 0.001 | 0.05 | 5 | 150 | $2100 - 3900 | 10 | --- | Rapid* | 100% | 100% |
| Wind (non-synchronized / power conversion) | 0.001 | 1 | 100 | 450 | $1500 - 2500 | 100 | < 10% | Rapid* | 100% | 100% |
| Wind (synchronized) | 0.001 | 1 | 100 | 450 | $1500 - 2500 | 100 | < 10% | Rapid* | 100% | 100% |
| Hydropower | 0.001 | 0.5 | 50 | 650 | $2200 - 4800 | 500 | 20-40% | 25-100% | 100% | 100% |
| Geothermal | 0.05 | 1 | 30 | 180 | $2500 - 9900 | 50 | 12-15% | 3-7% | 0% | 0% |
| Biomass | 0.1 | 5 | 50 | 75 | $2900 - 5800 | 50 | 35-40% | 3-7% | 0% | 0% |
| Coal | 0.1 | 10 | 400 | 1300 | $1900 - 3900 | 600 | 35-40% | 3-7% | 0% | 0% |
| Combined Cycle (Gas/Oil: Sm. HD/Aero) (1x1) | 10 | 25 | 60 | 120 | $1000 - $1800 | 55 | 20-40% | 20-40% | 0-75% | 75-100% |
| Combined Cycle (Gas/Oil: Heavy-duty) (1x1) | 60 | 120 | 300 | 500 | $900 - 1500 | 615 | 25-70% | 3-11% | 0-60% | 10-100% |
| Simple Cycle (Gas/Oil: Small HD/Aero) | 1 | 20 | 40 | 100 | $800 - 1300 | 45 | 25-50% | 25-50% | 0-100% | 100% |
| Simple Cycle (Gas/Oil: Heavy-duty) | 40 | 80 | 200 | 330 | $500 - 800 | 211 | 15-70% | 4-16% | 0-75% | 100% |
| Reciprocating Engines (Gas/Diesel/Bio) | 0.01 | 1 | 5 | 20 | $700 - 1300 | 10 | 50% | 35% | 100% | 100% |
| **Energy Storage** | | | | | | | Resp. Time | %MW/min | %MW | %MW |
| Pumped Hydropower | --- | 100 | 1000 | --- | $1000 - 3000 | 500 | 10s | 25-100% | 100% | 100% |
| CAES - Comp. Air Energy Storage | --- | 50 | 500 | --- | $600 - 1600 | 260 | 1-10min | 4% | 100% | 100% |
| Solid Batteries | 0.1 | 1 | 20 | 50 | $1000 - 4000 | 50 | 100ms | 500% | 100% | 100% |
| Flow Batteries (Redox) | --- | 0.1 | 20 | 50 | $1700 - 4200 | 50 | 100ms | 500% | 100% | 100% |
| Flywheels | 0.1 | 1 | 20 | 40 | $900 - 1100 | 20 | 1-4s | 1500% | --- | --- |
| PEV | --- | 0.02 | 0.05 | --- | --- | --- | 100ms | --- | --- | --- |
| Fuel Cells (PEM) | 1E-04 | 0.001 | 0.1 | 10 | $3,000 | 1 | 10s | 500% | 100% | 100% |
| **Demand Response** | | | | | | | | | | |
| Fast Auto DR | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Direct Load Control | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Interruptible Load | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Price Responsive Demand | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Transmission** | | | | | | | | | | |
| Synch. Cond.: Large motor frame | --- | 0 | 50 | --- | --- | --- | --- | --- | --- | --- |
| Synch. Cond.: Air-cooled generator frame | --- | 38 | 113 | --- | --- | --- | --- | --- | --- | --- |
| Synch. Cond.: H2-cooled generator frame | --- | 198 | 478 | --- | --- | --- | --- | --- | --- | --- |
| Shunt FACTS devices (STATCOM, SVCs) | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| HVDC Transmission Technologies | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Desirable Attributes / Retrofit Options** | | | | | | | | | | |
| Improved Turndown (MinGen) Capability | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Elevated Ramp-rate Capability | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Faster Startup Capability | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |

# Generation Technologies

**Heavy-duty (HD) Gas Turbines / Combined Cycles**:
- Well-positioned to provide all of the defined ancillary services
- Continued advancements in flexibility will enable greater penetration & reduce curtailment of renewable generation
    - Turndown, ramp-rates, part-load efficiency, hot-day output, daily cycling capability, etc.
- Much focus from both Aero and Heavy-duty GT/CC manufacturers on improved flexibility, reduced footprint, and lower startup/running emissions

**Aero-derivative Gas Turbines / Combined Cycles**:
- Similar ancillary capabilities as HD options; however, typically include more efficient simple cycle operation, minimal cycling penalties and improved quick-start / ramping capabilities.
- Reduced footprint, quick-delivery, and typically smaller block-sizes.

**Reciprocating Engines**:
- Able to provide 'full-spectrum' of ancillary services
- Effectiveness of inertial response (due to lower rotating mass) is less-than other conventional thermal generators
- Typically provide some of the fastest startup times and ramp-rates of all generation technologies.
    - Most offer full output (from offline) inside 10-minutes and more than 30% / min ramp rate
- Ideal for black start, particularly on smaller power systems

# Generation Technologies

**Coal / Biomass**:
- Available to provide all "on-line" ancillary services
- ST-based generation … operating range & ramping capability typically less-than GT/CC assets
- Not well-suited for applications which require startups inside 1-hr
    - Non-spinning reserve, Replacement reserves, Black start
- Excellent for inertial response

**Geothermal**:
- Similar ancillary capabilities as Coal / Biomass
- Improved operating range relative to coal / biomass (enabled by deeper turndown)
    - Lack of combustion process reduces limitations to ST aero / mechanical limits.
- Natural / continuously available fuel source enables potential for use as a black start resource
- Ancillary service potential not limited by fuel supply interruptions

**Hydropower**:
- Excellent resource-type for providing ancillary services … used extensively on mainland.
- Superior operating range, ramp-rates, and startup times relative to other generation technologies
- Only restrictions would include release schedules (environmental / wildlife / recreational) and/or availability of water … particularly for "run-of-river" applications

# Generation Technologies

**Solar Thermal**[8]:
- Capable of providing inertial response similar to conventional steam generators
- Requires curtailment* to establish required headroom for services such as frequency responsive reserve, regulation, load following, and spinning reserve.
- Technically feasible to develop facilities capable of providing both black start and particularly voltage support services

**Solar PV**[8]:
- Not yet capable of providing inertial response, but feasible
  - Inverters likely possess the required response speed; however, on-site energy storage mechanism would be required.
- Curtailment* required for frequency responsive reserve, regulation, load following, and spinning reserve
- Response speed/accuracy better than most conventional generators can supply
- Voltage support services technically feasible

**Wind**[8]:
- Synthetic inertia from wind turbines is commercially available.
  - Energy extracted from the wind turbine rotor OR head-room provided by operation at curtailed output level.
- Curtailment* required for frequency responsive reserve, regulation, load following, and spinning reserve
- Response speed/accuracy better than most conventional generators can supply
- Voltage support services technically feasible

* Curtailment only required for upward movement. Downward movement can be provided without curtailment.

# Emerging Req's / Opportunities

## Specific to Variable Generation (VG)

**CAISO**:

- Exploring incentives to encourage greater participation in economic dispatch by wind and solar resources.[8]
- Considering reduction in the continuous energy requirements for ancillary services … would benefit VG resources[8]
    - Spinning and Non-Spinning Reserve: From 2 hours down to 30 minutes
    - Regulation: 60 minutes for DAH and 30 minutes for RT

**ERCOT**:

- New requirements for wind generators – applicability based on the date of signing the Generation Interconnect Agreement *[3]
    - New generators required to provide "governor-like" response to frequency deviations[8] : Requires adjustable dead-bands and droop response of 5%(3)
    - Includes Voltage Ride-Through (VRT) requirements[8]
- Wind generators must be capable of producing reactive power equal to ±95 percent power factor (based on current load set-point) down to 10% of nameplate capacity. [8]
- Variable generation resources expected to respond to dispatch instructions[8]

* Required for all wind generators with standard generation interconnection agreements signed after January 1, 2010. Wind generation resources with interconnection agreements signed on or before January 1, 2010, shall have primary frequency response capabilities by December 1, 2010, if ERCOT believes this is physically practical.[3]

# Emerging Req's / Opportunities

## Specific to Variable Generation (VG)

**NYISO**:

- Wind scheduled / dispatched similar to other generation[8]
  - Bids a price-curve (based on operating costs only) … required for RT and optional for DAH market
  - Must be able to accept electronic base-point signals … penalties assessed for non-compliance
    - Equivalent to MW-deviation multiplied by regulation clearing price (3% tolerance allowed)
- VG allowed to provide reserves if all technical requirements are met[8]
  - Limited energy storage resources (LESR) allowed to provide regulation service. Rule change accepted by FERC to allow 15-minute continuous reserve (vs. 1-hour).[3]
  - Energy Management System (EMS) modified to monitor LESR energy levels & adjust regulating range to allow for charging (if required).[3]

**Hydro Quebec**:

- Wind plants larger than 10 MW must provide emulated inertial response similar to conventional synchronous generator (3.5s)[3]
- Demonstrations conducted with wind turbines supplying regulation service[8]

# Desirable Attributes / Retrofit Options

## Preferred Characteristics for New or Existing Generation Technologies

**Improved Turndown (Minimum Generation) Capability**:

- Enhances ability to provide all online ancillary services
  - Inertial Response, FRR, Regulation, Load Following, Spinning Reserve, Voltage Support
- Minimizes fuel cost during off-peak periods
- Potential to avoid curtailment of renewable and economically preferred resources

**Elevated Ramp-Rate Capability**:

- Increases the amount of available Regulation, Load Following and Spinning Reserve
- Potential to improve the quality of the response for smaller "MW" swings
- Aids in allowing offline reserves to contribute more quickly during contingency events

**Faster Startup Capability**:

- Enables Non-Spinning and Replacement Reserves to be delivered more quickly
- Opportunity to reduce fuel consumption thru replacement of some online reserves
- Typically accompanied by reduced startup emissions

**Improved Cycling Capability**:

- Ability to accommodate daily (and sometimes multi-daily) startups with minimal variable operation & maintenance penalties along w/ reduced minimum up/down time req's.
- Enables more options at the power system level and further limits required curtailments

# Energy Storage – Flywheels

## Technology Overview

- Mass rotating about an axis to store mechanical energy
- Mechanical energy converted to electrical energy via generator
- Practical for short charge-discharge cycles (less than 15 minutes)
- Flywheel energy storage provides >10 seconds of ride-through power to protect the load from that 99% of disturbances
- Backup gen-sets typically provides the other 1%

# Energy Storage – Flywheels

## Impact on Ancillary Services

- **Inertial Response:** Flywheels are coupled to the grid through a power electronic interface that should allow for emulation of inertial response
- **Regulation:** In regards to regulation, flywheels can use their power electronic front ends to accurately respond to automatic generation control (AGC) signals faster and more efficiently than traditional conventional generators, potentially reducing the total amount of comparable regulating reserve carried on traditional units
- **Load Following:** Some flywheel technology can apparently provide load following capability above the capacity rating of the distribution generation (DG) asset as well as voltage and reactive power support and control; For Combined Heat and Power (CHP) systems, this technology has the potential to facilitate the use of gas turbines as part of a CHP system, by improving these systems' ability to follow fast-changing loads
- **Spinning/Non-Spinning Reserve:** All energy storage technologies except for flywheels are well suited to provide spinning/non-spinning reserve; The only limiting factor for flywheels is the duration of the response required; However the introduction of energy storage can act to further reduce diesel fuel consumption by using the stored energy to provide both load following and supplying the occasional shortfall, while leaving the generator turned off - some flywheel energy storage technology could be ideal for this application due to its low maintenance, long design life, high cycling capability without any degradation in storage value, its ability to respond almost instantaneously (thus improving load following), and its ability to provide real and/or reactive power
- **Voltage Support:** All energy storage technologies are capable of providing voltage support

# Energy Storage – Batteries

## Technology Overview (applies to both Solid State and Flow types)

- A Battery Energy Storage System (BESS) system can cover a wide range making them suitable for almost all energy storage applications; One installation can be used for multiple applications such as spinning reserve and voltage & frequency control
- Lithium-Ion batteries are good for inertial/frequency response, regulation, reserves
- Energy batteries good for load following but could also be good for response
- Energy batteries (some sodium based batteries, flow batteries) can also provide power

# Energy Storage – Batteries

## Impact on Ancillary Services (applies to both Solid State and Flow types)

- **Inertial Response:** BESS do not include any rotating mass, but rather they interface to the grid through a power electronic front-end and the power electronic controls should be configurable to provide an emulation of inertial response over very short durations of up to a few seconds
- **Frequency Responsive Reserve:** The power electronics for battery energy storage can be controlled to provide frequency response
- **Regulation:** If BESS are used to provide regulation, then cycle life (number of charge/discharge cycles in the life of the battery), the round-trip energy efficiency and O&M costs will play a major role; On the other hand, these factors will be less important than the capital and replacement costs when BESS are used in black start applications - this is particularly true considering that these batteries will only be discharged and recharged when a major black out occurs and black start is required - shelf life, rather than cycle life will be important and round-trip efficiency will be of little or no concern
- **Load Following:** BESS can provide dispatched balance, with flow batteries potentially having the capability to provide the longer duration load following
- **Voltage Support:** All energy storage technologies are capable of providing voltage support

# Energy Storage – PSH

## Technology Overview (PSH - Pumped Storage Hydropower or Pumped Storage)

- Pumped Storage Hydropower (PSH) can quickly accommodate disturbances that occur on transmission grids – loss of generators, failure of transmission lines, instant demands (or cessation of demands) Low operating cost, reliable, long lifetime, can have large power ratings
- Fast response – can go from full load pumping to full load generation in minutes (as little as 10s). Additionally, a configuration with two penstocks could be deployed for pumping water and generating electricity simultaneously.
- Efficiency: >70-75% round trip (and may be upto 85%)

# Energy Storage – PSH

## Impact on Ancillary Services (PSH - Pumped Storage Hydropower or Pumped Storage)

- **Inertial Response:** PSH interface with the grid through a rotating machine that allows them to provide inertial response just like any conventional synchronous generator
- **Frequency Responsive Reserve:** PSH can provide primary frequency response and is available while the plant is generating but they must be designed with variable pumping control if they are to provide primary frequency response while pumping
- **Regulation:** In regards to regulation, PSH can respond to AGC Controls in the same manner as traditional hydro and gas turbine plants while generating and can provide regulation when pumping if they are initially designed to do
- **Load Following:** When it comes to load following, PSH can follow system operator dispatch commands to provide sub-hourly to multi-hour energy balancing in the generating mode; As with primary frequency response, pumped hydro plants can provide load following or ramping when pumping if they are initially designed to do so
- **Spinning Reserves:** PSH is well suited to provide spinning reserve; The amount of response available from a pumped storage plant while pumping depends on the plant design
- **Non-Spinning Reserves:** Because non-spinning reserves do not need to respond as quickly as spinning reserves, PSH is well suited to provide non-spinning reserve
- **Voltage Support:** All energy storage technologies are capable of providing voltage support

# Energy Storage – CAES

## Technology Overview (CAES – Compressed Air Energy Storage)

- Gas Turbine (GT) that uses 40% less fuel - 2/3 of GT fuel is used to compress air
- Air is pre-compressed (using off-peak energy) in an underground chamber
- The pre-compressed air supplements gas turbine
- Shorter construction time, greater site flexibility, lower capital costs than PSH
- Low operating costs, reliable, long lifetime, can have large power ratings
- Fast response – can go from full load pumping to full load generation in minutes
- Efficiency: >70-75% round trip

# Energy Storage – CAES

## Impact on Ancillary Services (CAES – Compressed Air Energy Storage)

- **Inertial Response:** CAES plants interface with the grid through a rotating machine that allows them to provide inertial response just like any conventional synchronous generator
- **Frequency Response:** CAES plants can provide primary frequency response and is available while the plant is generating
- **Regulation:** When it comes to regulation, CAES plants can respond to AGC Controls in the same manner as traditional hydro and gas turbine plants while generating
- **Load Following:** In regards to load following, CAES plants can follow system operator dispatch commands to provide sub-hourly to multi-hour energy balancing in the generating mode
- **Spinning Reserves:** CAES is well suited to provide spinning reserve - the fast response is easily met by CAES
- **Non-Spinning Reserves:** Because non-spinning reserves do not need to respond as quickly as spinning reserves, CAES is well suited to provide non-spinning reserve
- **Voltage Support:** All energy storage technologies are capable of providing voltage support

# Plug-in Electric Vehicle (PEV)

## Technology Overview

- Very low capital cost
- Very fast response
- High power/low energy (per vehicle)
- Capable of storing electricity from an intermittent generator such as PV or wind (wind is the cheapest, low-CO2 emissions energy source, but is intermittent)
- Potential to supply energy back to the grid on demand
- Day time opportunity charging could go really well with high PV penetration since the HSIS is showing daytime PV curtailment

# Plug-in Electric Vehicle (PEV)

## Impact on Ancillary Services

- **Inertial Response:** PEV chargers have the advantage that they can both increase and decrease consumption, providing the opportunity for full inertial response
- **Frequency Responsive Reserve:** The solid-state control capability of PEV chargers make providing primary frequency response feasible
- **Regulation:** PEV solid-state charger control potentially allows for the provision of regulation; Communications will be required to deliver the system operator's AGC signals to the PEV chargers every few seconds
- **Load Following:** PEV chargers can supply load following and ramping response well and are better suited for this service if the balancing requirements are more or less neutral and are not in one direction for a sustained period of time, such as when the load or variable generation forecast errs significantly
- **Spinning Reserves:** PEVs could provide spinning reserves and can respond immediately after receiving a control signal, particularly by reducing its charging though reserve capabilities may be limited in certain circumstances such as in the final hours of the night to honor requirements to PEV owners of a full overnight charge
- **Non-Spinning Reserves:** PEVs can supply non-spinning reserves though reserve capabilities may be limited in certain circumstances such as in the final hours of the night to honor requirements to PEV owners of a full overnight charge
- **Voltage Support:** The interface of the PEVs to the power system is through inverters that have the ability to provide reactive power to the grid and support system voltage

# Demand Response (DR)

## Impact on Ancillary Services

- **Inertial Response:** Distributed resources' contributions to system inertial response needs is not anticipated to be significant
- **Frequency Responsive Reserve:** The potential contribution of DR to system primary frequency response has been low so far
- **Regulation:** Regulation is the most difficult ancillary service to provide (though fast DR can), requiring the load to adjust consumption every few seconds in response to the system operator's AGC commands; Responsive load is beginning to provide Regulation Reserve
- **Spinning Reserves:** Appropriately responsive load can provide any of the contingency reserves; Technically, demand can provide better reliability response than generation since full response is usually achieved immediately by tripping the load
- **Non-Spinning Reserves:** Appropriately responsive load can provide any of the contingency reserves, including non-spinning reserve; ERCOT's "Loads acting as a Resource" (LaaR) are capable of being interrupted within 30 minutes and are capable of running (or being interrupted) at a specified output level for at least 1 hour (small loads can be used for spin as well)
- **Supplemental Reserves:** Supplemental reserve is reserve capability that can be fully converted into energy or load that can be removed from the system within a 10-to-30 minute interval following the request of the an ISO dispatcher (i.e. PJM)
- **Voltage Support:** DR is not well suited for supporting system voltage or reactive needs; Reducing loads may have a small localized impact on system voltage, but the ability to supply reactive power to support bulk system voltages is limited

# Demand Response (DR)

## Available DR Programs Cross-referenced with Ancillary Service Potential

| DR Programs | Ancillary Services |
|---|---|
| Direct Load Control (DLC) | Frequency Resp. Reserve & Regulation (w/ enhanced communication and control), Spinning Reserve, Non-Spinning Reserve |
| Interruptible Load | Spinning reserve, Non-Spinning Reserve |
| Load as a Capacity Resource | Non-Spinning Reserve |
| Demand-side Spinning Reserves | Spinning Reserve |
| Demand-side Non-Spinning Reserves | Non-Spinning Reserve |
| Demand-side Regulation Service | Frequency Responsive Reserve, Regulation, Load Following |
| Peak Time Rebate (PTR) and also Critical Peak Rebate (CPR) | Spinning Reserve, Non-Spinning Reserve |
| Real-Time Pricing (RTP) | Not a traditional A/S function but can be used for "Load Leveling/Load Shifting" |
| Critical Peak Pricing (CPP) | Spinning reserve, Non-Spinning Reserve |
| Time of Use Pricing (TOU) | Not a traditional A/S function but can be used for "Load Leveling/Load Shifting" |
| Fast Auto-DR / Aggregated DR / Integrated DR | Frequency Responsive Reserve, Regulation, Load Following, Spinning Reserves, Non-Spinning Reserves |

# Demand Response (DR)

## Program Details

- **Direct Load Control (DLC):** In a DLC Program, the program sponsor remotely shuts down or cycles a customer's electrical equipment, e.g. air conditioner, water heater, lighting, on short notice; DLC programs are primarily offered to residential or small commercial customers
- **Interruptible Load:** In an interruptible load program, electric consumption is subject to curtailment or interruption under tariffs or contracts that provide a rate discount or bill credit for agreeing to reduce load during system contingencies; In some instances, the demand reduction may be effected by action of the system operator, called 'remote tripping', after notice to the customer in accordance with contractual provisions
- **Load as a Capacity Resource:** A Load as Capacity Resource commits to make pre-specified load reductions when system contingencies arise
- **Demand-side Spinning Reserves:** Spinning Reserves are demand-side resources synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an emergency event
- **Demand-side Non-Spinning Reserves:** Non-Spinning Reserves are demand-side resources that may not be immediately available, but may provide solutions for energy supply and demand imbalance after a delay of ten minutes or more
- **Fast Auto-DR and also Aggregated DR/Integrated DR:** Aggregated and Integrated DR capable of managing load via high-speed, automated EMS that can deliver second-to-second and minute-to-minute variations in load under grid operator or load scheduler direction

# Demand Response (DR)

## Program Details (cont'd)

- **Demand-side Regulation Service:** Regulation Service is a type of demand response service in which a demand resource increases and decreases load in response to real-time signals from the system operator; Demand resources providing Regulation Service are subject to dispatch continuously during a commitment period; This service is usually responsive to Automatic Generation Control (AGC) to provide normal regulating margin; Also known as regulation or regulating reserves, up-regulation and down-regulation
- **Peak Time Rebate (PTR) and also Critical Peak Rebate (CPR):** Peak Time Rebates allow customers to earn a rebate by reducing energy use from a baseline during a specified number of hours on critical peak days; Like CPP, the number of critical peak days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices
- **Real-Time Pricing (RTP):** In RTP rate and price structures, the retail price for electricity typically fluctuates hourly or more often to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis
- **Critical Peak Pricing (CPP):** CPP is the rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate or price for a limited number of days or hours
- **Time-of-Use Pricing (TOU):** TOU Pricing is a rate where usage unit prices vary by time period, and where the time periods are typically longer than one hour within a 24-hour day; TOU rates reflect the average cost of generating and delivering power during those time periods

# Demand Response (DR)

## Available Resources and Processes that can be used for Demand Response

### Residential/Small Comm. End-uses

- A/C Cycling & PCT
- Water Heating
- Space Heating
- Lighting
- Smart Appliances
- Refrigeration
- Fans
- Pumps (Fountain, Pool, Irrigation)
- Thermal Storage (Heat & Cool)
- Battery Storage
- Building Thermal Mass
- EV Charging

### C&I Customer Type / Process Uses

- Water Utilities and Water Pumping
- Wastewater Treatment
- Pulp & Paper Product Making
- Fruit + Vegetable Preserving
- Evaporative Processes
- Water Desalination
- Bakeries + Food Manufacturing
- Chemical Manufacturing
- Batch Operations: Hammer Mills
- Air Liquefaction/Separation
- Dairy Product Manufacturing
- Fabricated Metal Product Manufacturing
- Beverage Manufacturing
- Cold Storage & Refrigerated Warehouses
- Arc Furnace & Induction Processes
- Electrolysis and Electroplating
- Oil Pipelines and Pump Stations
- Smelting Processes

# Demand Response (DR)

## Additional Comments

- All these end-use devices and processes can be aggregated into a larger DR grouping which with proper sizing and integration; With the required communication, command, and control systems, they can provide any of the needed A/S functions, as long as the system architecture and technical characteristics meet the A/S functionality requirements in terms of size, metering, speed and timing of response

- Virtual DR Plants with Energy Management System, Demand Response Management Systems, and Fast Auto-DR all could refer to such an aggregated and integrated system; Large loads can participate individually, but smaller loads are most likely to participate in an Aggregated DR system managed either by the utility or by third party DR aggregators; Suitability of the end-uses and processes would depend on the underlying DR program

# Fuel Cells

## Technology Overview

- Fuel cells are playing an increasing role in energy storage
- PEM Fuel Cells are currently common for storage but Solid Oxide Fuel Cells (SOFCs), which use natural gas as a fuel and would be viewed more as power generation as opposed to storage, are being researched and tested - there currently is not sufficient information at the system level for this technology but some are targeting 1-10MW at <$2000/kW – baseload
- The Naval Air Warfare Center in China Lake, California, is developing a system that will use solar power to create hydrogen for use in a fuel cell during periods with insufficient sunlight
- In Canada, a partnership between the federal government, BC Hydro, Powertech, and General Electric is converting excess off-peak electricity into hydrogen, reducing diesel consumption by an estimated 200,000 liters per year and greenhouse gas (GHG) emissions by an estimated 600 tons per year
- Germany's Enertrag AG, one of the world's largest wind power companies, is building a facility to use excess wind energy to produce hydrogen for energy storage and for transport applications

# Transmission Technologies

- The following data applies to new 60 Hz GE synchronous condensers* only

| Frame | Rotor | + MVArs | H Range |
|---|---|---|---|
| Large motor frame | 4 or 6 poles (salient design) | Up to +50 | ~1.50 to ~2.0 |
| Air-cooled generator frame | Round rotor | +38 to +113 | ~3.0 to ~2.3 |
| Hydrogen-cooled generator frame | Round rotor | +198 to +478 | ~1.28 to ~0.88 |

*-inertia is relatively low for these machines

# HVDC and Shunt FACTS for Grid Support

- HVDC technology can be a more economically feasible option for integration of off-island wind power.
  - There are two types of technologies: (1). Conventional line commutated converter (LCC) HVDC, and (2). Voltage-source converter (VSC) technology
  - Voltage source converter technology is capable of providing dynamic voltage support to the grid and is flexible to connect with weak AC systems
  - World's first Ultra high voltage DC solution: Southern power grid China, Conventional LCC HVDC project 5000 MW +/- 800 kV, 1418 km
  - World's first off-shore VSC HVDC: North Sea, 88MW (in 2005) being expanded to additional 100 MW in 2015, 66kV, 70 km,

- Shunt FACTS devices (such as SVC's, STATCOMS) have been deployed worldwide to provide voltage support to the grid.
  - These devices are capable of providing dynamic reactive VAR and voltage support
  - Typical STATCOM ratings for grid applications: 10's – 100's of MVA
  - Energy storage can also be coupled with such devices to provide dynamic real power compensation

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GE Energy Management

# Ancillary Services Definitions and Capability Study

## Part 2, Tasks 3-4, Final Report

### For Hawaii Natural Energy Institute


Principal Contributors:

**Harjeet Johal**
**Rameet Kohli**
**Beth LaRose**
**Michael O'Connor**
**Sundar Venkataraman**


Date: 12/19/2012



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# Table of Contents

**1 Study Background and Objectives ..... 1**

**2 Summary of Results ..... 2**

**2.1 Key Terminology ..... 6**

**3 Study Results ..... 8**

3.1 **Task 3:** Identify the physical requirements of ancillary services needed for each Hawaiian island. **..... 8**

3.1.1 Additional Quantities of Existing Ancillary Services Required Under Study Scenarios ..... 10

3.1.2 Recommendations for New Ancillary Services and Interconnection Requirements ..... 17

3.1.3 Storage and Demand Response ..... 22

3.1.4 Changes to Interconnection Requirements ..... 22

3.1.5 Fundamentals of Power System Operation ..... 24

3.1.6 Process for Evaluating and Selecting a Potential Future Technology Mix ..... 30

**3.2 Task 4:** Outline considerations for specifying and acquiring A/S **..... 34**

3.2.1 Procuring Ancillary Services – Overview of Approaches for Obtaining, Compensating, and Incentivizing ..... 34

3.2.2 Forward Planning Approach to Derive Rational Ancillary Service Contract Prices ..... 36

3.2.3 Hawaii-specific Ancillary Service Procurement ..... 37

3.2.4 Risk Considerations ..... 38

**4 References ..... 41**

**5 Appendix A:** Power Point Presentation **..... 43**

# List of Figures

**Figure 3.1** HECO Scenario 4A – Loss of AES (with frequency ride through of Dist PV) ..... 11

**Figure 3.2** HECO Scenario 4A – Loss of AES (without frequency ride through of Dist PV) ..... 11

**Figure 3.3** HECO Scenario 4B - Synthetic Inertia from Online Wind Plants & Frequency Responsive Load Reserves ..... 12

**Figure 3.4** HECO Scenario 5 - Synthetic Inertia from Online Wind Plants ..... 13

**Figure 3.5** HECO Spinning Reserve Requirement as a Function of Online Renewable Generation ..... 13

**Figure 3.6** MECO Spinning Reserve Requirement as a Function of Online Renewable Generation ..... 15

**Figure 3.7** Opportunity Cost illustration ..... 27

**Figure 3.8** Co-optimization illustration ..... 28

**Figure 3.9** Instantaneous opportunity cost for shifting capability from energy to A/S ..... 29

**Figure 3.10** Opportunity cost as the deviation from the economic dispatch increases ..... 29

# List of Tables

**Table 3.1** Scenarios of renewable development ..... 8

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# Foreword

This report was prepared by General Electric International, Inc. acting through its Energy Consulting group based in Schenectady, NY through the support of the Hawaii Natural Energy Institute and under a contract with the Research Corporation of the University of Hawaii.

Technical and commercial questions and any correspondence concerning this document should be referred to:

**Technical**
Beth LaRose
Managing Director, Power Economics
Energy Consulting
General Electric International, Inc.
One River Road
Building 53-313
Schenectady, NY 12345
Phone: (518) 385-3994
E-mail: elizabeth.larose@ge.com

**Commercial**
Denise Benoit
Senior Contract Risk Manager
Energy Consulting
General Electric International, Inc.
One River Road
Building 53-313
Schenectady, NY 12345
Phone: (518) 385-3994
E-mail: denise.benoit@ge.com

# 1 Study Background and Objectives

The purpose of this study is to identify, define and quantify ancillary services necessary to integrate new generation resources, including renewable generation, for bulk power systems and particularly the Hawaiian Islands. The results of this study may be: incorporated into the Hawaii Reliability Standards Working Group's proposals for new reliability standards; used to develop recommendations for revised generation interconnection technical requirements; provided to the Hawaii Public Utility Commission for consideration and adoption; and used to inform the Hawaii utilities' Integrated Resource Planning process.

The GE team has been deeply involved in analyzing the impact of renewable generation on the HECO systems and has performed 9 system-level studies over the past 5 years. The power output form Variable Generators (VG) such as wind and solar plants, by definition is variable. Also, there is a certain amount of uncertainty associated with this generation in the hours preceding actual operations. The generation from VGs is not only variable within the hour and is also variable on a longer timeframe such as daily, weekly and monthly time frame. The variability of VGs within the hour (along with the variability associated with the load) is handled by the system operator through the use of regulation and load-following (spinning) reserves. This study will leverage the findings of the renewable impact studies performed by GE.

The project focuses on four tasks[1]:

- Task 1: Define a standardized set of ancillary services along with their associated definitions (in functional, technology-neutral, performance based terms) that can be used to meet the operational needs of Hawaii and other bulk power systems, and provide for the integration of variable generation technologies.
- Task 2: Assess resource technologies (generation, transmission, storage, and demand response (DR)) for their ability to support the respective ancillary services, to maximize the diversity and optionality for ancillary service acquisition and delivery.
- Task 3: Identify the physical requirements of the ancillary services needed for each Hawaiian island (Oahu, Maui, Big Island).
- Task 4: Outline considerations for specifying / acquiring ancillary services for the Hawaii grids that protect reliability, incent renewable generation, and minimize production costs.

This report presents the results of Tasks 3 and 4 of the study. The results of Tasks 1 and 2 were presented in a separate report, GEA30441 Hawaii Ancillary Services Study PART 1 REPORT and PRESENTATION_12192912r1.pdf.

[1] After the study commenced, it was decided that Task 1 should be generic and address all ancillary services that are in service or under development in the U.S., as well as internationally, regardless of their applicability to the Hawaii system. The applicability of the ancillary services to the Hawaii system was included as a portion of Task 3 of the study. Therefore, in Task 1, the difficulty in adopting some of the researched ancillary services for the Hawaii system was acknowledged, but not discussed in detail.

# 2 Summary of Results

Ancillary services are required to maintain reliable operations of the electric power system. With Hawaii Natural Energy Institute (HNEI), in cooperation with the Hawaii Reliability Standards Working Group (RSWG), GE has worked to identify, define and quantify ancillary services necessary to integrate new generation resources, including renewable generation, for the Hawaiian Islands. This written summary report for Tasks 3-4 and the attached PowerPoint slides documenting Tasks 3-4, comprise the Part 2 final report from GE for use by HNEI and the Hawaii RSWG.

The purpose of a companion report on Part 1 of the study was to define a standardized set of ancillary services along with their associated definitions that can be used to meet the operational needs of any bulk power systems, and provide for the integration of variable generation technologies. Part 1 also provided an assessment of resource technologies (generation, transmission, storage, and demand response (DR)) for their ability to support the respective ancillary services, to maximize the diversity and optionality for ancillary service acquisition and delivery.

The purpose of the Part 2 study was to identify the physical requirements of the ancillary services needed for each Hawaiian island and to outline considerations for specifying / acquiring ancillary services for the Hawaii grids that protect reliability, incent renewable generation, and minimize production costs[2]. The Part 2 study was performed under two tasks – Task 3 and Task 4.

The primary focus of Task 3 was to investigate the need for additional ancillary services and interconnection requirements under a couple of different renewable generation scenarios for the three Hawaii electric power systems. The results of past renewable integration studies performed for the Hawaii utilities, where available, were used to understand the impact of renewables on operations under the different scenarios. This information along with the lessons learnt from Part 1 on the best practices in the industry was used to determine the additional ancillary services and interconnection requirements for Hawaii. The unique characteristics of the Hawaii systems were taken into account in determining these additional ancillary services and interconnection requirements. Another important deliverable of Task 3 was to develop a process for evaluating various resource options that were summarized in the technology section (Part 1 - Task 2) for providing the ancillary services required under future system conditions.

The purpose of Task 4 of the report was to outline considerations for promoting a least-cost portfolio of resources that can supply ancillary services and interconnection requirements that attempt to protect reliability, maximize renewable output and minimize energy costs.

The major recommendations related to ancillary services and interconnection requirements are given below.

[2] Production costs include all costs associated with the operation of a power system. These costs include (but are not limited to): fuel costs, variable O&M costs, fixed O&M costs, startup/shutdown & cycling costs, impact of transmission losses, environmental compliance costs, and any explicit compensation which is paid to resources. Production costs do not include capital expenditure associated with the initial purchase of a resource or associated upgrades costs. Consumer cost is highly correlated with Production cost; however, the primary differentiator is that that Consumer cost includes the impact of capital expenditure on the price rate-payers are exposed to. In addition, consumer cost also includes other distribution-related expenses which are not typically included in the production cost.

- Require synthetic inertia capability for future utility-scale wind plants. The parameters for synthetic inertia (deadband, active power contribution, duration of response, maximum generation reduction etc.) should be designed to meet the Hawaii system requirements.
- Require droop control to be a part of the interconnection requirements for future utility-scale wind and solar plants in addition to the requirement for dispatchable generators.
- Variable Generation (VG) should be compensated for providing up reserves if their generation is curtailed for the explicit purpose of providing reserves. Recommend the development of tools to reliably calculate the amount of reserves that VG can provide.
- VG should be required to provide down reserves without any explicit compensation similar to other dispatchable units in the system. Need to design and employ forecasting methodology/tool to calculate the amount of down reserves that VGs can reliably provide based on actual and forecasted generation from VGs.
- VG should be required to provide up reserves without any explicit compensation when they are curtailed for reasons other than providing up reserves since their opportunity cost is zero when they are already curtailed.
- Recommend AGC (ability of wind plant to directly accept and act on a maximum dispatch signal delivered by AGC) capability to be a part of the interconnection requirements for all future utility-scale generators including wind and solar plants.
- Recommend that VG be compensated for providing up regulation if their generation is curtailed for the explicit purpose of providing regulation.
- In general, storage and demand response should be allowed to provide regulation and reserves as long as they are economical.

As mentioned before, another important deliverable of Task 3 was to develop a process for evaluating various resource options. A methodology that can be exercised during a resource planning process to evaluate and assist with the selection of a future technology mix that is compatible with the system-level interconnection and ancillary service requirements was developed. Specifically, the methodology focuses on minimizing the overall production cost and capital expenditure required to obtain a "least-cost" portfolio while observing system reliability needs. Additional consideration is given to parameters which are more difficult to quantify economically, such as propensity for a given portfolio to improve future renewables penetration and/or reduce risk exposure. There are 10 specific steps included in the body of the report and corresponding presentation material.

The objective of Task 3 was also to evaluate methods for procuring the recommended ancillary services. Four potential approaches for obtaining, compensating, and incentivizing ancillary services were included the report. The details of each approach along with their respective pros/cons are discussed further in the report body and corresponding presentation material. Specifically, the four approaches are:

1. Market Clearing Price

2. Reimbursement of Offer Price
3. "Make-whole" Compensation
4. Condition of Interconnection

On Hawaii, ancillary services are presently obtained from dispatchable resources through a method which is similar to the previously mentioned "Condition of Interconnection" approach. Specifically, the utilities have the ability to dispatch resources to provide ancillary services without explicit compensation to the respective resources. Going-forward, there will be a continued desire to increase the penetration of renewable resources on the Hawaiian system which has the potential to increase the system-level ancillary service requirements. As the system-need for ancillary services increases, it may be necessary to incentivize new resources to provide (or existing resources to expand upon) their ancillary service capability. This incentive could likely come in the form of explicit financial compensation and include aspects of either the "make-whole compensation" or "reimbursement of offer price" methods. However, it should be noted the use of these methods has the potential to increase the overall production cost as a result of the explicit compensation for [some of/all of] the ancillary services. Careful consideration is required before introducing such remuneration methods or unbundling the ancillary services.

As outlined in the technology table (Part I, Task 2), renewable resources (i.e. wind/solar) are capable of providing many ancillary services. The use of these resources for providing A/S may help to facilitate their increased penetration and potentially reduce production costs as it introduces another degree of freedom for commitment & dispatch. Current RFP's and draft PPA's are seeking to leverage this capability from VG resources. Relative to the current environment, in which dispatchable resources are not explicitly compensated for fulfilling the system-level ancillary obligations, requiring the wind/solar to provide ancillary services via the "Condition of Interconnection" approach would certainly be considered as an equitable option. Due to the fact that wind/solar resources are presently compensated based on their energy contract price, which likely includes some fixed and capital cost recovery, there are periods when wind/solar are more expensive to operate than some non-renewable resources on the system (i.e. periods where the energy contract price is higher than the marginal system cost). During these periods, it may result in a system level production cost savings to curtail wind/solar to provide ancillary services. However, the existing wind/solar contracts have provisions which preclude the curtailment of these resources for economic reasons. Therefore, during periods where wind/solar are curtailed exclusively for the purposes of providing ancillary services (i.e. up-reserves), the use of "Make-whole Compensation", to explicitly compensate for costs (including opportunity costs) associated with providing ancillary services, would be recommended. It should be noted that the existing wind/solar contracts purposefully prevented curtailment for economic reasons in an effort to maximize renewable penetration.[3] Therefore, to adopt the previous recommendation, an adjustment to the existing contracts would be required.

Energy storage devices have the potential to enhance penetration of renewable resources and/or lower the overall production cost. The process for "Evaluating and Selecting a Potential Resource

[3] The provisions which preclude economic curtailment of renewable VG have not been extended to dispatchable renewables such as hydropower or biomass.

Mix" developed in Task 3 and discussed earlier, could be leveraged to help quantify these potential benefits. Due to the fact that energy storage resources are energy-neutral and operate exclusively for the purposes of providing ancillary services, the use of "make-whole compensation" is not applicable (i.e. storage resources have no opportunity costs). Therefore, an explicit remuneration method, such as "Reimbursement of Offer Price" may be required to incentivize the development & participation of energy storage resources to supply ancillary services. To obtain a value for the ancillary services offered by the energy storage resources, it is likely that the previously mentioned "system-level" use of a production cost simulation would be required. Specifically, the simulation could be exercised by individually enabling / disabling the respective ancillary service capability for each resource under consideration. The resulting benefit (i.e. "reduction") in the overall annual production cost could be used as a basis for assessing the ancillary service offer price.

Ancillary service participation from DR, transmission, and retrofit options has the potential to reduce production costs, improve renewables penetration, and avoid/defer/attenuate major capital expenditure. Similar to energy storage resources, an explicit compensation method would likely be required to incentivize participation from DR and/or transmission-related technologies. To incentivize the modification (i.e. retrofit) of existing resources to provide, or expand upon, their ancillary service capability, further use of explicit compensation may be required to cover upgrade costs.

It should be noted that some resources have the potential to increase (or decrease) the required amount of ancillary services on the system. Further, some resources have the potential to provide more ancillary capability than other resource types. In some cases, such as wind/solar, an individual resource has the potential to increase the required amount of ancillary services on the system. However, these resources also have [typically] low variable operating cost and have the have the potential to reduce the overall production cost for the system. As a result, it is not recommended that individual resources, which induce additional ancillary obligations on the system, be additionally penalized. Instead, it is recommended that the impact on overall consumer cost (including total ancillary services costs), coupled with other policy-related directives such as renewable penetration targets, be used as the metric to assess the viability of a particular resource.

## 2.1 Key Terminology

The following definitions for key terminology are relevant throughout the content of this study and should be interpreted as described below.

Area Control Error (ACE):

The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error. Source - NERC Glossary (2008)

Conventionally, **ACE = (NIA – NIS) – 10B (FA – FS) – IME**, where:

**NIA** is the algebraic sum of actual flows on all tie lines.

**NIS** is the algebraic sum of scheduled flows on all tie lines.

**B** is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.

**FA** is the actual frequency.

**FS** is the scheduled frequency. FS is normally 60 Hz but may be offset to effect manual time error corrections.

**IME** is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NIA) and the hourly net interchange demand measurement.

Due to a lack of inter-area power flows, the definition of ACE has been modified for Hawaii. Specifically, for **Hawaii, ACE = – 10B (FA – FS).** This modified definition of ACE is still applicable for Hawaii as it correctly represents the fact that 100% of difference between supply and demand will manifest itself as a frequency error. Source - Revised definition per Hawaii RSWG Glossary

Automatic Generation Control (AGC):

Equipment that automatically adjusts generation, storage devices, and/or responsive load in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule, plus the Frequency Bias (i.e. ACE). Source - NERC Glossary (2008) with modifications to accommodate additional resource types such as load and storage devices

Although AGC was originally conceived as a means to provide fast (3-6 second signals) to generators, the concept of leveraging AGC to provide "MW raise/lower" commands to demand-side and storage resources is equally applicable and is in practice in some locations.

Droop Response:

Droop response is a near instantaneous means of proportionally adjusting a resource's real-power to resist a change in frequency; allowing a system of resources to operate in a stable manner.

The magnitude of a given resource's response is proportional to the frequency deviation and typically characterized by "x%" droop. For example, a resource with operating range available will provide

100% additional output per "x%" change in system frequency. Response is typically a percentage of the resource's full-capability.

Droop response can be provided by any frequency-sensitive resource.

Resource:

A resource may consist of any generation, storage, load (i.e. demand-side), or transmission technology.

Spinning / Non-Spinning:

Historically, the terms "spinning" and "non-spinning" have referred to the rotational nature of synchronized generators. Over time, this terminology has migrated to imply the "relative state of readiness and responsiveness" as it relates to the ability for a resource to fulfill its ancillary obligation. In an effort to leverage contemporary industry vernacular, this latter interpretation was adopted for use in this presentation.

# 3 Study Results

## 3.1 **Task 3:** Identify the physical requirements of ancillary services needed for each Hawaiian island.

The objective of this task was to answer the following questions:

1. How much additional quantity of existing ancillary services (example, additional MWs of spinning reserves) may be required in the future under high renewable generation scenarios?
2. What new ancillary services and interconnection requirements may be needed in the future under high renewable generation scenarios?
3. What is the process to determine a cost-effective way of using existing as well as new technology to meet the additional ancillary service requirements?

Drawing on recent Hawaii renewables integration studies conducted by GE, the project teams' expertise from these and similar large scale renewable integration studies, and other sources, GE and the HPUC and HECO companies hypothesized the following scenarios of renewables development for the three utilities.

**Table 3.1** *Scenarios of renewable development*

| | HECO (Oahu) | MECO (Maui) | HELCO (Big Island) |
|---|---|---|---|
| **Most Recent IRP** | HECO IRP 2009-2028 (Sep 2008) | MECO IRP 2007-2026 (April 2007) | HELCO IRP 2007-2026 (May 2007) |
| **Resource Planning Study to support future IRP** | ? | Available from MECO | HELCO Resource Planning Study (June 2012) |
| **Other renewable integration studies** | OWIST & HSIS (Available from GE) | HSIS (Available from GE) | |
| **Load Forecast** | From OWIST and HSIS | Base Line From HSIS | Base Line From Resource Planning Study |
| **Scenario 1: Moderate penetration Renewables or mix definition** | HSIS Scenario 4A<br>360 MW Dist Solar PV<br>400 MW Cent Solar PV<br>100 MW On-shore Wind<br>No Off-Shore Wind | HSIS Base Line (2012 system)<br>15 MW Dist Solar PV<br>0 MW Cent Solar PV<br>72 MW On-shore Wind | HELCO 100% renewables intermittent – heavy<br>**22 MW Biomass**<br>**100 MW Wind (centralized)**<br>**100 MW PV (centralized or distributed)**<br>**50 MW Geothermal** |
| **Scenario 2: High penetration Renewables or mix definition** | HSIS Scenario 4B<br>160 MW Dist Solar PV<br>200 MW Cent Solar PV<br>100 MW On-shore Wind<br>200 Off-Shore Wind<br>(same solar & wind MWH as 4A) | HSIS Scenario 3<br>30 MW Dist Solar PV<br>15 MW Cent Solar PV<br>72 MW On-shore Wind<br>**Scenario 3: Heavy Intermittent Renewables**<br>**22 MW Biomass**<br>**100 MW Wind, 100 MW PV**<br>**50 MW Geothermal** | HELCO 100% renewables geothermal/ dispatchable – heavy<br>**42 MW Biomass**<br>**50 MW Wind (centralized)**<br>**50 MW PV (centralized or distributed)**<br>**100 MW Geothermal** |

Details regarding existing interconnection requirements and ancillary services were gathered and summarized by GE using various sources such as typical design criteria for new units, model PPAs etc. GE also reviewed pertinent documents from HPUC and Hawaii utilities such as Docket 2008-0273 Feed-in Tariff ("FIT") and the updates to the information contained in the docket provided by the HECO utilities.

The attached workbooks[4] include the details regarding existing interconnection requirements and ancillary services for all three HECO utilities as well as forecasted ancillary services (primarily increase in MWs of operating reserves) for the chosen scenarios where available. To the extent that the scenarios had been previously studied by the GE teams as part of the renewable integration studies, the additional reserve requirements (HECO and MECO Scenarios 1&2) were available. For MECO Scenario 3 and HELCO Scenarios 1&2, more detailed studies would need to be performed to determine the additional reserve requirements. The process for determining the additional reserve requirements is included in Appendix A (Methodology for Determining Operating Reserves). For the purposes of this study, GE worked with the MECO and HELCO to try and define the directional change and magnitude of ancillary services for those scenarios. Where practical, GE estimated the amount of ancillary services required based on studies performed in Hawaii and the mainland.

The results from the primary frequency response simulations were available for some of the selected scenarios from the HSIS and OWIS study performed by GE. These simulations were also used in the determination of the need for new ancillary services.




4

HECO Workbook: HECO Ancillary Services for Scenarios_DRAFT_Rev7.xlsx
MECO Workbook: MECO Ancillary Services for Scenarios_DRAFT_rev6.xlsx
HELCO Workbook: HELCO Ancillary Services for Scenarios_DRAFT_Rev4.xlsx

### 3.1.1 Additional Quantities of Existing Ancillary Services Required Under Study Scenarios

This section discusses the additional quantities of existing ancillary services required under the study scenarios for each HECO utility, where available.

#### *3.1.1.1 HECO*

The following two scenarios were studied:

**Scenario 1 - HSIS Scenario 4A**

360 MW Dist. Solar PV

400 MW Cent Solar PV

100 MW On-shore Wind

No Off-Shore Wind

**Scenario 2HSIS-Scenario 4B**

160 MW Dist. Solar PV

200 MW Cent Solar PV

100 MW On-shore Wind

200 Off-Shore Wind

(same solar & wind MWH as 4A)

**Inertia and Primary Frequency Response**

Results of HSIS study show that 1) enforcing no trip of Distributed PV on under-frequency excursion helped to reduce the frequency drop by 2.2-3.4 Hz (if UFLS is not active), 2) use of frequency responsive load (50MW @ 59.5 Hz trip), and synthetic inertia from off-shore wind plants can support the system during loss of generation contingency by reducing the frequency drop (raising the nadir) by up to 0.3 Hz, in cases where synchronous generators are displaced by renewables. Please see figures.

**Figure 3.1** *HECO Scenario 4A – Loss of AES (with frequency ride through of Dist PV)*

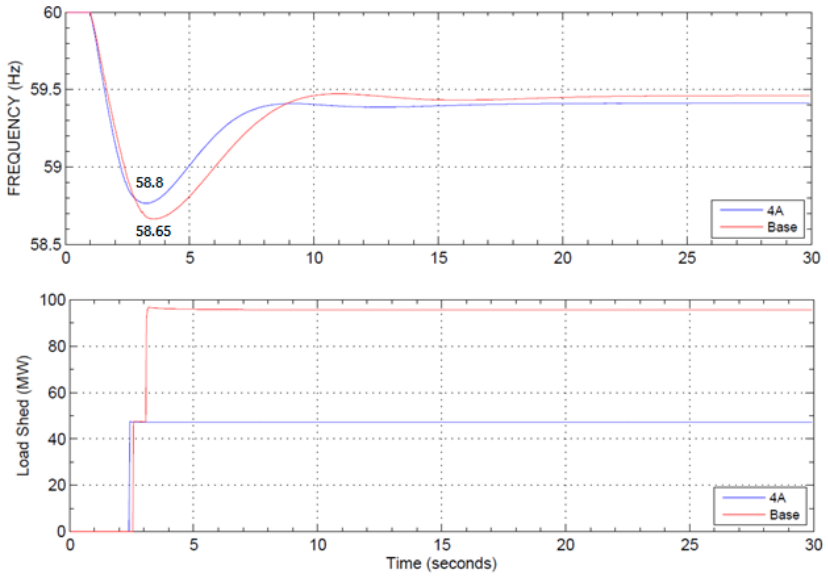



**Figure 3.2** *HECO Scenario 4A – Loss of AES (without frequency ride through of Dist PV)*

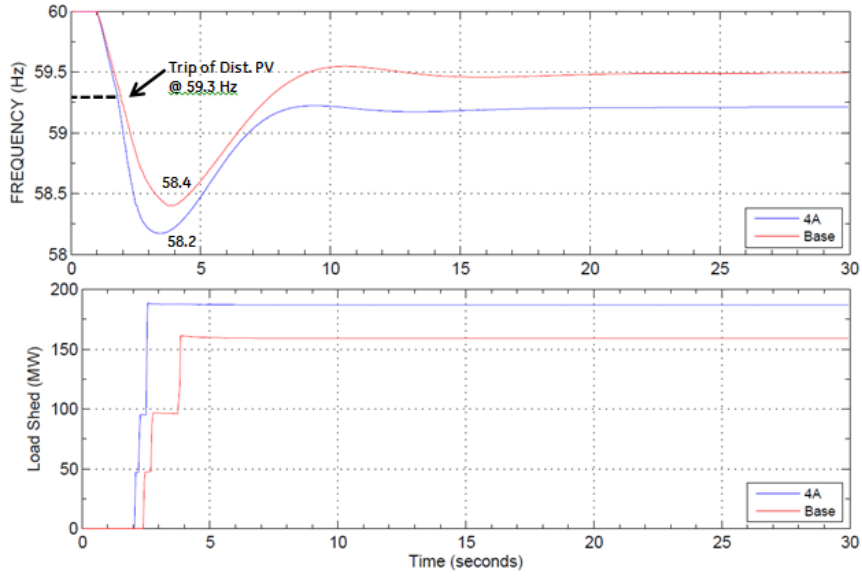
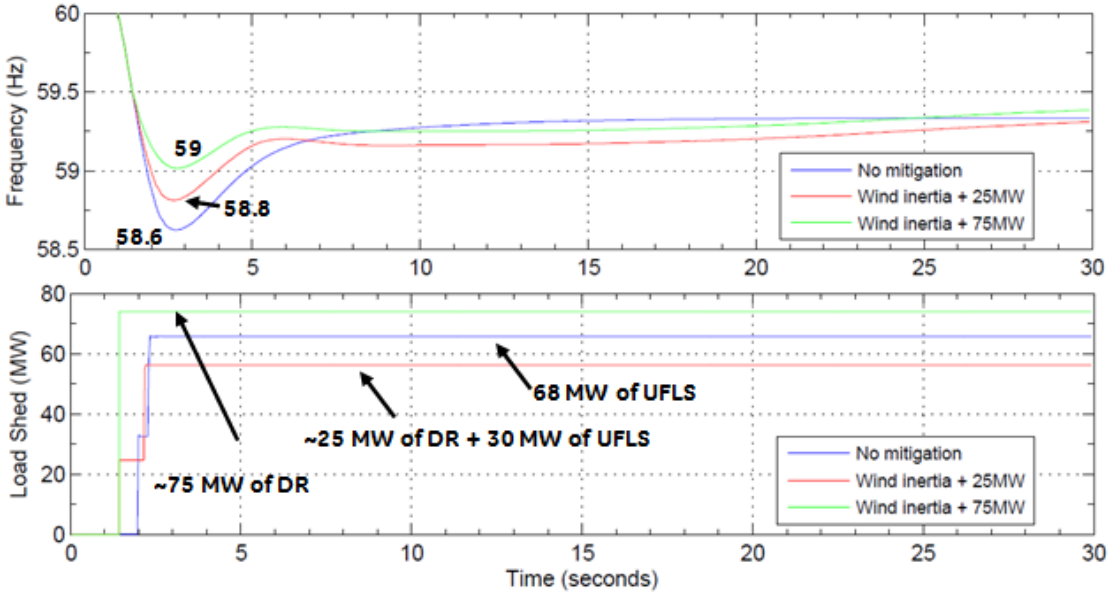
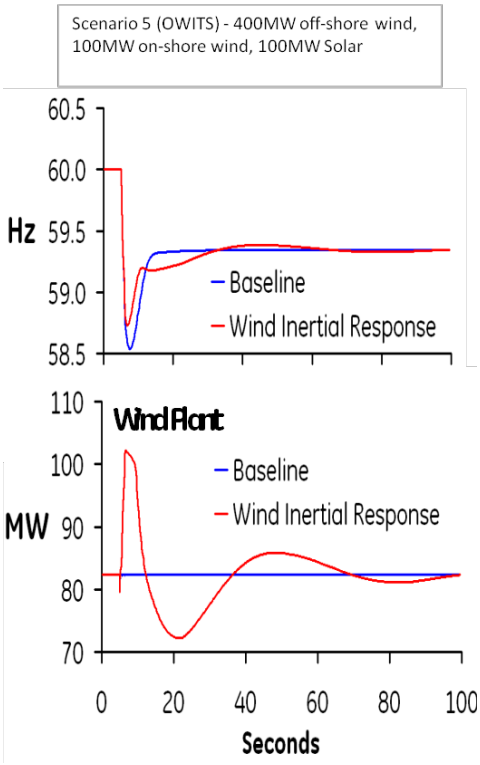


**Figure 3.3** *HECO Scenario 4B - Synthetic Inertia from Online Wind Plants & Frequency Responsive Load Reserves*




Preventing distributed PV trips has the most beneficial effect on the frequency response. The frequency nadir without distributed PV trip is 58.1 Hz, 0.9 below the first stage of UFLS. For a safe margin, other recommendations (i.e., synthetic inertia and frequency responsive load) should also be implemented.

**Figure 3.4** *HECO Scenario 5 - Synthetic Inertia from Online Wind Plants*



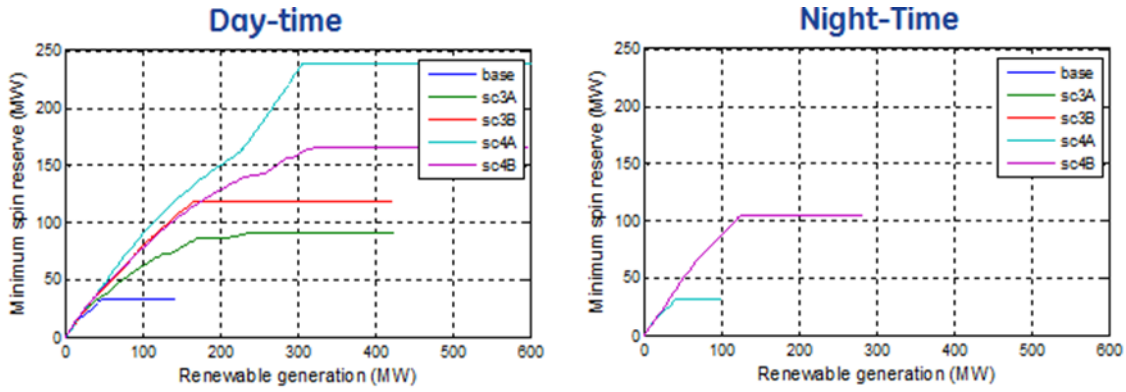

**Regulation**

The additional regulation reserves required to accommodate variability in wind and solar generation is given below.

Scenario 1 - HSIS Scenario 4A: Max Day-time (6am-8pm) = 239MW; Night-time (8pm-6am) = 32MW.

Scenario 2HSIS-Scenario 4B: Day-time (max) = 166MW; Night-time (max) = 104MW

**Figure 3.5** *HECO Spinning Reserve Requirement as a Function of Online Renewable Generation*




Inter-hour results from the simulation of these scenarios confirm that the operating reserves requirement helps the system (in Scenarios 4A and 4B) to carry enough reserves to sustain the worst sub-hourly event in each hour of the year as well as to ride the system through forecast error/uncertainty. Further analysis is required to determine the economics of the existing capacity meeting the additional reserve requirement. If the existing capacity is insufficient or uneconomic, then other means of obtaining spinning reserves (for example, from battery storage and DR) should be explored. This is further discussed in the next section on the methodology to estimate technology mix.

### *3.1.1.2 MECO*

The following two scenarios were studied:

**Scenario 1 – Maui Baseline**

15 MW Dist Solar PV
0 MW Cent Solar PV
72 MW On-shore Wind

**Scenario 2- Maui Scenario 3**

30 MW Dist Solar PV
15 MW Cent Solar PV
72 MW On-shore Wind

**Scenario 3- Heavy Intermittent Renewables Scenario**

22 MW Biomass
100 MW Wind
100 MW PV
50 MW Geothermal

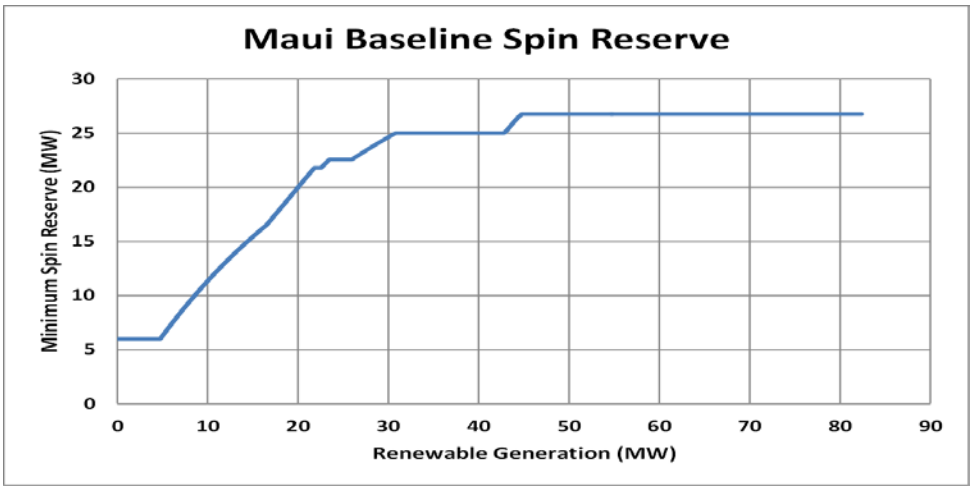
**Inertia and Primary Frequency Response**

**Regulation**

Scenario 1 & 2: As a function of forecast of wind+solar power. Max Reserves approximately 27 MW as shown in the figure.

Scenario 3: As a function of forecast of wind+solar power. Max Reserves estimated to be approximately 50 MW.

**Figure 3.6** *MECO Spinning Reserve Requirement as a Function of Online Renewable Generation*



#### *3.1.1.3 HELCO*

The following two scenarios were studied:

**Scenario 1 – Heavy Intermittent**

Geothermal - 50MW

ROR Hydro - 16.85MW

Wind - 100MW

Distributed PV - 12MW

Central/Dist PV - 88MW

Biomass - 22MW

**Scenario 2- Heavy Dispatchable**

Geothermal - 100MW

ROR Hydro - 16.85MW

Wind - 50MW

Distributed PV - 12MW

Central/Dist PV - 38MW

Biomass - 42MW

**Inertia and Primary Frequency Response**

(No data available)

**Regulation**

(No data available)

### 3.1.2 Recommendations for New Ancillary Services and Interconnection Requirements

Task 1 (Part 1 study) researched the ancillary services and interconnection requirements that are currently being employed or under consideration globally. The ancillary services are as follows:

- Frequency Responsive Reserve/Primary Frequency Response
- Regulation
- Load Following
- Spinning Reserve
- Non-Spinning Reserve
- Replacement Reserves

The emerging interconnection requirements fall in the categories below:

- Power Factor and Voltage Control
- Voltage and Frequency Ride Through
- Ramp Rate Limits and Control
- Over and Under Frequency controls
- AGC Response Capability
- Inertia

It should be noted that the above-mentioned ancillary services and interconnection requirements have been employed in various parts of the world and may or may not be applicable to the Hawaii system. These ancillary services and interconnection requirements were discussed in detail in the Part 1 report. The information presented in Section 3.1.1 along with the lessons learnt from the Part 1 study on the best practices in the industry were used to determine the additional ancillary services and interconnection requirements for Hawaii. The unique characteristics of the Hawaii systems were taken into account in determining these additional ancillary services and interconnection requirements. Below is a list of the recommendations.

#### *3.1.2.1 Inertial Response*

Inertial response is very important for the Hawaii utilities since they are small islanded systems with relatively high Rate-of-Change-of-Frequency (ROCOF) due to system events. Currently, the desired inertial response from dispatchable synchronous renewable generation (RE) resources such as geothermal plants is obtained as a condition of contract. There is no synthetic inertia requirement in the interconnection requirements for Variable Generation (VG) resources such as wind and solar plants. However, recent PPAs for renewable generation have included inertia requirement.

Based on the information gathered in Part 1, it can be concluded that, at present, there is no ancillary service or market associated with inertial response anywhere in the world. Where implemented, the inertial response requirements have been through interconnection requirements. For example, Hydro Quebec[5] requires wind power to provide an emulated inertial response. Based on the Part 1 study, we have also determined that with the current technology, it is possible for wind plants to provide synthetic inertial response, which if designed properly can help the system ride through

[5] Hydro-Québec requires that wind plants be able to contribute to reducing large (> 0.5 Hz), short-term (< 10 s) frequency deviations on the power system, as does the inertial response of a conventional synchronous generator whose inertia constant (H) equals 3.5s

frequency events. Therefore, we recommend synthetic inertia capability for future utility-scale wind plants. The parameters for synthetic inertia (deadband, active power contribution, duration of response, maximum generation reduction etc.) should be designed to meet the Hawaii system requirements. The utilities should also perform offline studies to determine the impact of synthetic inertia on inertial and primary frequency response and how it impacts inertia requirements from other (future) interconnecting resources, Under Frequency Load Shedding (UFLS) practices, and spinning reserve requirements. The offline studies should be used to guide for determining combinations of resources that need to be online.

#### *3.1.2.2 Primary Frequency Response*

Primary frequency control involves the autonomous, automatic, and rapid action (i.e., within seconds) of a generator to change its output to oppose large changes in frequency. Primary frequency control actions are especially important during the period following the sudden loss of generation to prevent the frequency from collapsing. Primary frequency response is provided by units that are selected to provide spinning reserves.

HECO uses spinning reserves to cover 100% of its largest single contingency (185MW). The units providing spinning reserves are on governor and AGC control. In addition, HECO also carries spinning reserves to meet the variations in load and renewable energy within the hour. These units are also on governor and AGC control and provide frequency response.

In MECO, no separate spinning reserves are carried for contingencies. The units that provide regulation are on governor and AGC control and also provide frequency response and provide spinning reserves for contingencies. The regulating reserves are a function of forecast of wind and solar generation - minimum of 6MW and a maximum of 50MW in the up direction and up to 9 MW in the down direction. Under Frequency Load Shedding (ULFS) is used to prevent the frequency from collapsing. Fast-starting offline resources are used to restore shed load.

In HELCO, the units that provide regulation are on governor and AGC control and also provide frequency response and spinning reserve. The regulating reserves are a function of forecast of wind and solar generation with a minimum of 6 MW plus up to 15 MW to account for the wind regulation. ULFS is used to prevent the frequency from collapsing. Fast-starting offline resources are used to restore shed load.

Currently, the interconnection requirements for HECO utilities require all dispatchable generators (conventional, as well as synchronous RE) to have a 4% droop that is adjustable. HECO utilities also have the capability to dispatch units to provide reserves as needed. As such, the HECO utilities currently obtain primary frequency response as a condition of interconnection.

Based on our research in the Part 1 study, Primary Frequency Response ancillary service is an emerging ancillary service that is being investigated in the U.S. mainland systems[6]. FRR (Frequency

[6] All systems carry contingency reserves (spinning and non-spinning) to help bring the frequency to its original value after the loss of a generator or transmission line. However, having sufficient contingency reserves in itself does not guarantee adequate primate frequency response. Currently, NERC is investigating the need for Frequency Responsive Reserves to ensure adequate primary frequency response. This is because the speed of response of resources that can provide

Responsive Reserves) is already being used in the markets in Australia[7]. However, in Hawaii all the dispatchable generators are on both governor and AGC control and are already required to have fast response (100% response within 30 seconds) in emergency situations. This fact needs to be considered in determining if there is a need for an additional primary frequency response ancillary service. Also, how such an ancillary service would work in a non-market environment should be investigated.

Based on the research performed on technical capabilities of resources in the Part 1 study, wind and solar plants are capable of providing primary frequency response improving the reliability of the grid.

Our recommendations with respect to primary frequency response are as follows:

- We recommend droop control to be a part of the interconnection requirements for future utility-scale wind and solar plants in addition to this requirement for dispatchable generators.
- We also recommend that VG be compensated for providing up reserves if their generation is curtailed for the explicit purpose of providing reserves. The payment mechanism will be discussed later in the section on ancillary service procurement. We also recommend the development of tools to reliably calculate the amount of reserves that VG can provide.
- VG should be required to provide down reserves without any explicit compensation similar to other dispatchable units in the system. In many instances, using VG to provide reserves also reduces their curtailment. For example, using wind generation to provide down reserves (instead of carrying the down reserves by dispatching up a thermal generator) reduces the curtailment of wind generation. Tools to determine the amount of down reserves that VGs can reliably provide should be developed.
- VG should be required to provide up reserves without any explicit compensation when they are curtailed for reasons other than providing up reserves since their opportunity cost is zero when they are curtailed.

contingency reserve is driven by NERC standard BAL-002 requirement R4 requires that the ACE be returned to zero (or to its pre-disturbance level if its pre-disturbance level is originally negative) within 15 minutes. In FERC Order 693, FERC ordered NERC to revise its standard so that it "defines the necessary amount of Frequency Response needed for Reliable Operation for each Balancing Authority with methods of obtaining and measuring that the frequency response is achieved." NERC is pursuing a frequency response initiative that is looking at what types of requirements are needed. A frequency responsive reserve (FRR) procedure has been proposed in a WECC whitepaper. The proposal suggests a FRR amount for all of WECC that is based on the largest credible contingency the system is prepared to deal with without activating UFLS (a 3200 MW Category C double generator contingency) allocated to each balancing authority based on peak load.

[7] In Australia, the NEM has 6 FCAS (Frequency Control Ancillary Services) related to primary frequency response
Fast Raise (6 Second Raise)
Fast Lower (6 Second Lower)
Slow Raise (60 Second Raise)
Slow Lower (60 Second Lower)
Delayed Raise (5 Minute Raise)
Delayed Lower (5 Minute Lower)

- Allowing VG to provide primary frequency response as suggested above can help reduce the production cost of the system, improve the reliability and lower curtailment. It should also be noted that the above provisions are similar to those used in the ERCOT[8] market.

#### *3.1.2.3 Frequency Regulation Ancillary Service (Secondary Frequency Response)*

Regulation is very important for Hawaii utilities unlike the mainland where shortages may only result in CPS violations and do not show up in the system frequency. This ancillary service is required to follow the changes in load, as well as renewable generation. Regulation is not only required under normal operations, but also after an event to restore the frequency after primary frequency response has been provided.

- Currently, HECO does not quantify up regulation but it is carried as part of its spinning reserve requirement. The generators selected for providing primary frequency response (that are also on AGC) provide up regulation.
- The amount of up regulation carried by MECO is a function of forecast of wind and solar generation, with a minimum of 6MW and a maximum of 50MW. 6-8 MW of down regulation is also held depending on number of CTs online.
- In HELCO, the regulating reserve requirement is determined by the anticipated near-term balancing needs, which the system operator determines by observing the variability of apparent demand (due to wind variability, solar PV) and forecasted customer demand. HELCO also carries sufficient down regulating reserve to cover largest off-peak load loss due to a single contingency.
- Currently, the interconnection requirements require all dispatchable generators (conventional, as well as synchronous RE) to be on AGC. All the existing wind contracts also include active power control (APC) provision to enable automatic curtailment.
- In Hawaii, the AGC signal is sent to generators every 4 seconds. There are two components to a generator signal: a regulation component, and an economic component. The regulation component has larger gains and more aggressive time of implementation and therefore will override the economic signals when frequency is off-normal (HELCO).

Based on the findings in the Part 1 study, markets such as California ISO are looking into a separate load-following ancillary service product to handle changes in variable generation that are sustained. However, this is an artifact of the CAISO (and other) markets where regulation is only used to handle variations in net load within the dispatch interval, typically 5 minutes. In Hawaii, regulating reserves are maintained to manage anticipated variability within the hour in the apparent demand, which includes forecast changes in load and the imbalances caused by changes in variable generation[9]. Therefore, there is no need for a separate load-following

[8] The wind generation plants should have adjustable dead bands to match those of other conventional resources or that which is provided in the operating guides, and a similar droop to the other resources of 5%. In ERCOT, wind generators are required to provide down response all the time and up response when curtailed.

[9] Regulating reserves are designed to meet the inter-hour variability of wind and solar. The nature of the fleet is such that there are abundant up-reserves to sustain forecast uncertainty (in load and renewables). Also, load variability in shorter time scales is smaller than the renewable variability and in the high penetration scenarios it is not at all visible. With

reserve in Hawaii. However, higher amounts of regulation reserves will be required to integrate higher amounts of variable generation as shown later through the scenarios. Variable generation resources and other emerging technologies should be allowed to provide regulation. Based on the research performed in the Part 1 study, wind plants have the capability[10] to provide regulation.

Our recommendations with respect to secondary frequency response are as follows:

- We recommend AGC (ability of wind plant to directly accept and act on a maximum dispatch signal delivered by AGC) capability to be a part of the interconnection requirements for all future utility-scale generators including wind and solar plants.
- We recommend that VG be compensated for providing up regulation if their generation is curtailed for the explicit purpose of providing regulation. The payment mechanism will be discussed later. We also recommend the development of tools to reliably calculate the amount of regulation that VG can provide.
- VG should be required to provide down regulation without any explicit compensation similar to other dispatchable units in the system. Need tools to determine the amount of down regulation that VGs can reliably provide.
- VG should be required to provide up regulation without any explicit compensation when they are curtailed for reasons other than providing up regulation since their opportunity cost is zero when they are curtailed.
- Allowing VG to provide regulation as suggested above can help reduce the production cost of the system, improve the reliability and lower curtailment.

#### *3.1.2.4 Non-Spinning Reserves*

Non-spinning reserves in the form of quick start resources serve a number of purposes. Following an outage or unexpected loss of generation, diesels are initially used (offline contingency reserves) to replace lost generation and/or UFLS restoration; following this intermediate and/or more efficient generation is started to replace the diesels. Quick start units are also used to offset regulating requirements within the hour. All three utilities carry varying amounts of QS resources. No changes to non-spinning reserves ancillary services are proposed. However, faster/more contribution from non-spinning assets may help to reduce the spinning regulation reserves requirement and should be evaluated.

#### *3.1.2.5 Black Start Service*

All three utilities have a number of units with black start capability. No changes to black start service proposed.

changes to the operating practices or in baseload fleet, it maybe required to assess reserves requirement for forecast uncertainty (in net load).

[10] Grid codes in Ireland and Denmark require Active Power Control (APC) for wind farms which give them the capability of responding to operator power set-point commands (equivalent to AGC)

### 3.1.3 Storage and Demand Response

In general, storage and demand response should be allowed to provide regulation and reserves as long as they are economical. However, the following need to be considered:

- Need to consider the interaction between DR response and UFLS since UFLS uses 75-80% of all load. The interaction of UFLS and DR must be developed and coordinated to ensure adequate protection for the UFLS system.

- The modification of PV to being required to trip on lower frequency set-points than standard IEEE 1547 trip settings, which are higher than UFLS trip settings, to mitigate loss of PV during a system low-frequency events was completed by the recent modification to Hi Rule 14h. However, there are still legacy installations that trip in accordance with IEEE 1547 and will compound the impact of unit trips. HECO uses 57.3 Hz for low frequency trip of distributed PV (not sure about other utilities). Legacy PV trips at 59.3 Hz and still must be considered in all studies. Since the 1547 standard and, similarly, Rule 14H specify in terms of a must-trip instead of ride-through, confirmation that the existing change results in the desired ride-through is important - a future change to a ride-through requirement may be necessary.

- Need to consider feeder net load for UFLS system as distributed PV increases and feeder net load decreases during some hours.

### 3.1.4 Changes to Interconnection Requirements

Below are the suggested changes to the interconnection requirements.

#### *3.1.4.1 Reactive Power and Voltage Regulation*

- Hawaii utilities have voltage regulation and control requirements for dispatchable and variable generation. No changes proposed.

#### *3.1.4.2 Voltage and Frequency Ride-thru*

- Hawaii utilities have voltage and frequency ride-thru requirements for dispatchable and variable generation. Utilities should develop requirements for unbalanced ride thru requirements. Unbalanced voltage capability is required in weak systems and is currently a much larger issue than LVRT since turbine manufacturers do not currently have a standard to meet and the current technology of WTG is much less than conventional generation.

#### *3.1.4.3 Ramp Rate Limits and Control*

- Hawaii utilities have ramp rate limits in the up direction for variable generation. Ramping requirements in the up and down direction are included as requirements for dispatchable generation. No changes proposed.

#### *3.1.4.4 Over and Under Frequency Controls*

- Per recommendation before, require wind and solar plants to have primary frequency response capabilities.

#### *3.1.4.5 Inertia*

- Per recommendation before, require wind plants to have inertial response capabilities.

#### *3.1.4.6 AGC Capability*

- Per recommendations before, require all generators including wind and solar plants to have the ability to accept and respond to AGC commands. Active power set-point is a current requirement for VG to enable curtailment. This would require modifications to the AGC program.

### 3.1.5 Fundamentals of Power System Operation

This section is intended to serve as a primer which provides a common foundation for the general terminology and concepts that will be referred to throughout the balance of this report. In addition, it is intended to provide insight into the processes and considerations that are required to leverage available power system resources to "serve the load" in the most cost effective and reliable manner. Downstream sections of this report will contain more Hawaii-specific discussion, considerations, and where possible, recommendations which reference these concepts. The "fundamentals" are outlined here and in the PowerPoint presentation for Tasks 3&4 in Appendix A.

In a power system, resources are committed and dispatched based on their ability to:

1. Directly provide energy
2. Support the reliable delivery of energy

Often, the same resource may serve both functions. The degree to which this occurs depends upon the attributes of the individual resource, resource mix, and the respective needs of the power system. To supply "energy", a resource is primarily evaluated based on its variable cost structure:

- Startup Cost: Typically on a "$/startup" basis. Represents the cost incurred for bringing a resource to a state where it is available for dispatch.
- Minimum Generation Cost: Typically on a "$/hr" basis. Represents the variable cost required to sustain operation at the minimum permissible "real-power" operating level.
- Incremental Variable Cost: Typically on a "$/MWh" basis. This represents the cost for the next incremental adjustment in the real-power set-point.

To support the "reliable delivery of energy", a resource is considered based on additional attributes that characterize its flexibility. Examples include, but are not limited to:

- Inertial Response: Typically measured by a resource's inertial constant "H" (in seconds). This is a normalized value that relates a resource's kinetic energy to its respective capacity.
- Ramp-rate: Typically on a "MW/min" basis. Characterizes the rate at which a resource is able to adjust it's real-power set-point. This rate can be set "tuned" differently dependent upon whether the need is for frequency response (i.e. FRR), regulation, (i.e. AGC), load following, spinning reserve, and/or startup periods.
- Quick-start capability: Typically on a "minutes or hours" basis. Characterizes the time-delay required for a unit that is offline or disconnected from the power system to become available for the purposes of providing energy or supporting the reliable delivery of energy.
- Operating Range: Characterized on a "real-power" and "reactive power" basis.
- Real-power range: Characterizes the range over which a resource is able to inject or consume actual "MW" to support the load on the power system.

- Reactive-power range: Characterizes the range over which a resource is able to provide "MVAR" to assist with maintaining system voltage levels.
- Minimum Operating Period:
- Minimum up-time: The minimum time for which the unit needs to be online once started
- Minimum down-time: The minimum time for which the unit needs to be offline once shutdown
- Black-start capability: Ability to start a unit without support from the grid

Determining the balance between using a resource for its "energy" vs. its ability to support the "reliable delivery of energy" often requires sophisticated algorithms. Typically, this balance is achieved through "security-constrained unit-commitment (SCUC)" and "security-constrained economic dispatch (SCED)" algorithms. For long-term power system planning, a production cost model is often leveraged to execute the SCUC and SCED algorithms. For day-to-day and week-to-week operations, similar algorithms are used in energy management system (EMS) software. The objective of the algorithms is to ensure that sufficient resources will be online (i.e. committed) to meet the anticipated load forecast (including variability) and satisfy reserve requirements in the most economical manner (i.e. lowest system cost) while observing reliability constraints. Emphasis is placed on leveraging assets with the lowest variable operating costs. More expensive resources are only selected if their flexibility is required to ensure reliable delivery of the energy, relieve system constraints, or they benefit increased renewables penetration, etc.

Once a resource is "committed", the "security-constrained economic-dispatch" algorithms are then utilized to obtain a resource's load set-point (i.e. "dispatch-point"). To achieve a solution, these algorithms attempt to "park" all committed resources at the same incremental variable cost (additional details in following slides). Typically, the "most-economical" manner for operating the system is for all committed resources to be dispatched to the same "incremental variable cost" (provided the resource is not at the extremes of its operating range). This is referred to as "economic dispatch". The resource which will provide the "next most economical MW" is referred to as the marginal unit. And, at that instant, the "system marginal cost" is equivalent to the incremental variable cost of that resource. Often, there are multiple units "on or near the margin".

To satisfy the reliability needs of the power system, it is often necessary to adjust the dispatch of the resources away from their economic optimum set-point. This movement creates additional "headroom/legroom" and increases the available reserves to satisfy system requirements. To ensure that these adjustments are made in the most economical manner, a process referred to as "co-optimization" is often deployed. This process assists in identifying which resources to adjust, and by how much. Specifically, it attempts to minimize the "opportunity costs" associated with moving a resource away from its economic optimum to meet the reliability needs of the system.

The concept of using opportunity costs to rank/prioritize resources and make system-level trade-offs between energy vs. ancillary capability is still applicable regardless of whether an explicit payment is made to the resources for their ancillary participation.

Typically, ancillary service needs are "best-served" by marginal resources. This is driven by the fact that they often have the lowest opportunity cost for providing the service. For example, a wind farm[11] typically has a very low variable operating cost. Curtailing the wind for the specific purpose of providing an ancillary service would [typically] result in very high opportunity cost (for both the plant and the power system). However, during periods where renewables are curtailed, due to must-run resources and/or corresponding over-supply, allocation of ancillary services to the renewables would likely be very cost-effective. In situation where renewables are not curtailed, selecting a combustion turbine or storage device[12] would likely result in lower opportunity cost and lower system cost.

[11] In Hawaii, during off-peak periods, wind energy contract prices can higher than the variable cost of other thermal generation. For these circumstances (and while wind contracts do not separate fixed & variable costs), curtailing wind for the purposes of providing ancillary services may be recommended.

[12] Storage devices are unique. Such resources are often "energy-neutral" (i.e. zero net-output on a nominal basis). As a result, storage devices do not have an "opportunity cost" per se. The variable cost to provide ancillary services from a storage device is typically driven by the cost to initiate the devices operation (i.e. startup) and the corresponding variable O&M during operation. As a result of their energy-neutral / zero-opportunity cost, storage devices are typically prioritized ahead of other resources for providing ancillary services.

The following illustrations are intended to provide further clarification on some of the key tools and concepts that were discussed in this section. Specifically, Figure 3-7 and Figure 3-8 illustrate the calculations for opportunity costs and co-optimization. The accompanying PowerPoint presentation in Appendix A has additional details on production cost modeling, average vs. incremental variable cost, and economic dispatch.

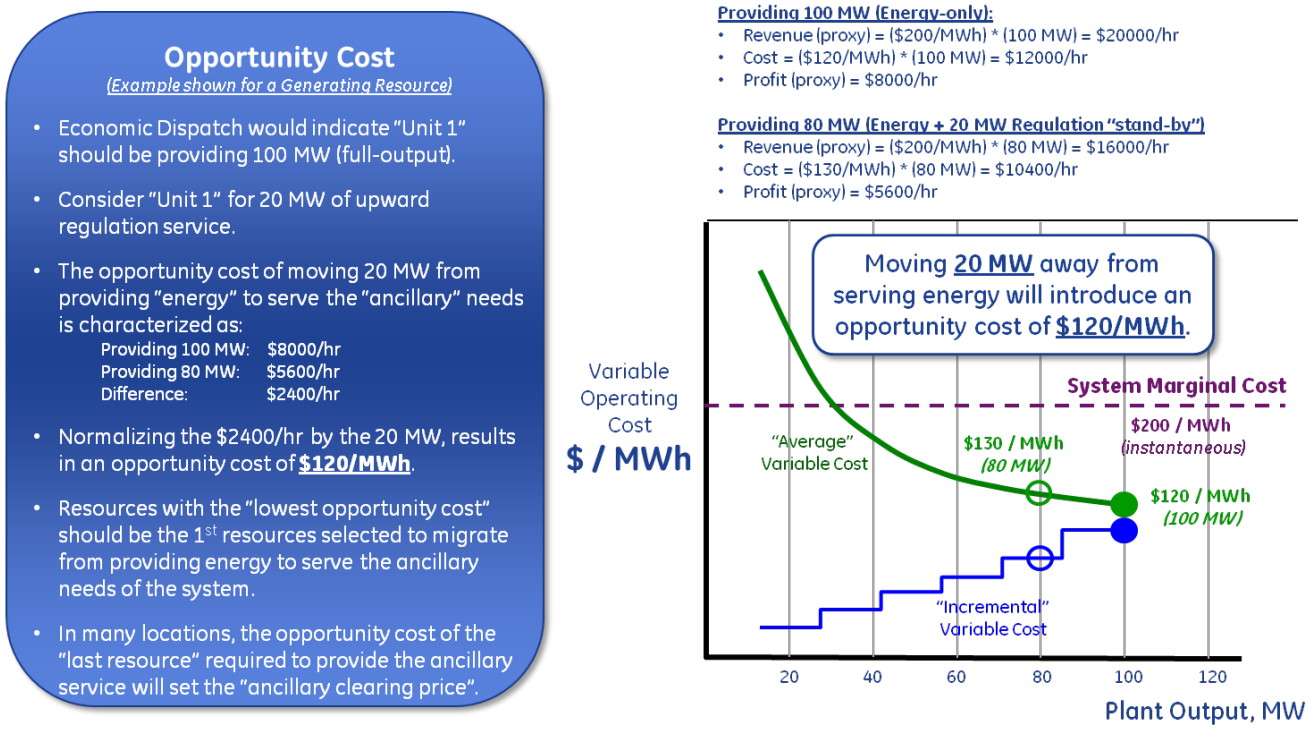



**Figure 3.7** *Opportunity Cost illustration*

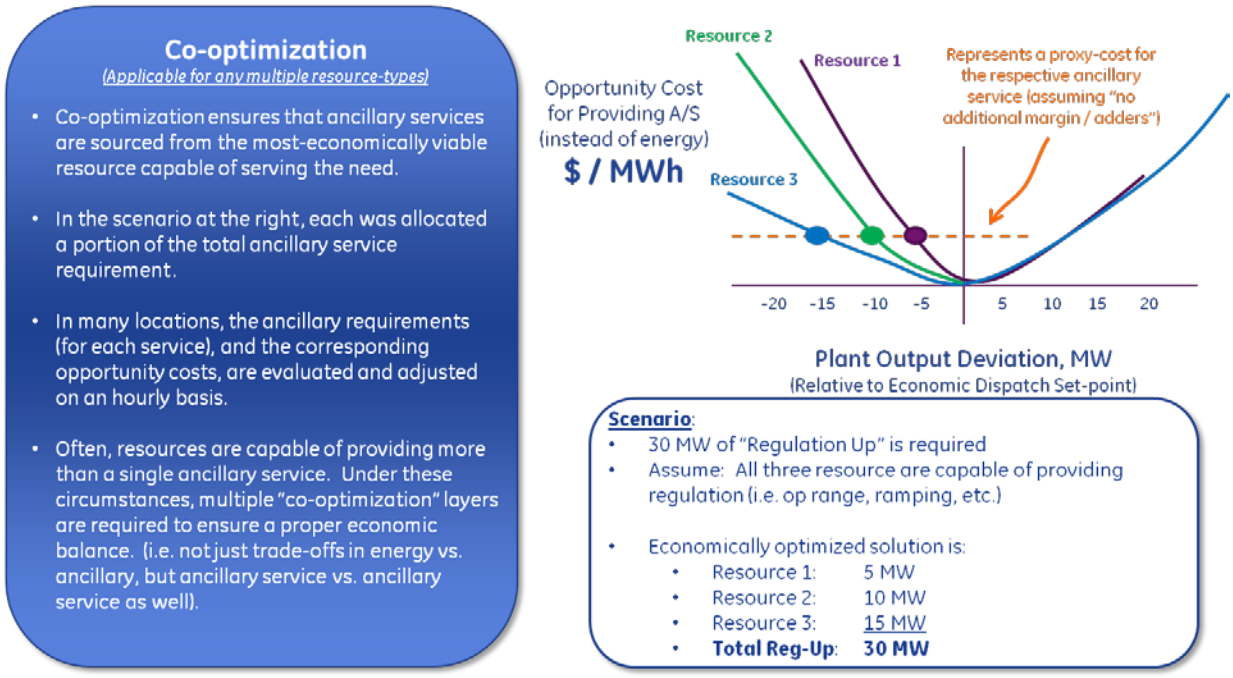



**Figure 3.8** *Co-optimization illustration*

In an effort to place the preceding material in context, the accompanying PowerPoint presentation provides some HECO-specific perspective on the opportunity cost associated with migrating a resource away from providing energy and into ancillary participation. For the following example, which is an excerpt from the PowerPoint in Appendix A, we'll be assuming an instantaneous marginal system level cost of $190 / MWh.

Figure 3.9 shows the instantaneous opportunity cost for ancillary service for HECO based on the data available in the HSIS study. Figure 3.10 shows the Opportunity cost as the deviation from the economic dispatch set-point is increased for the HECO units.

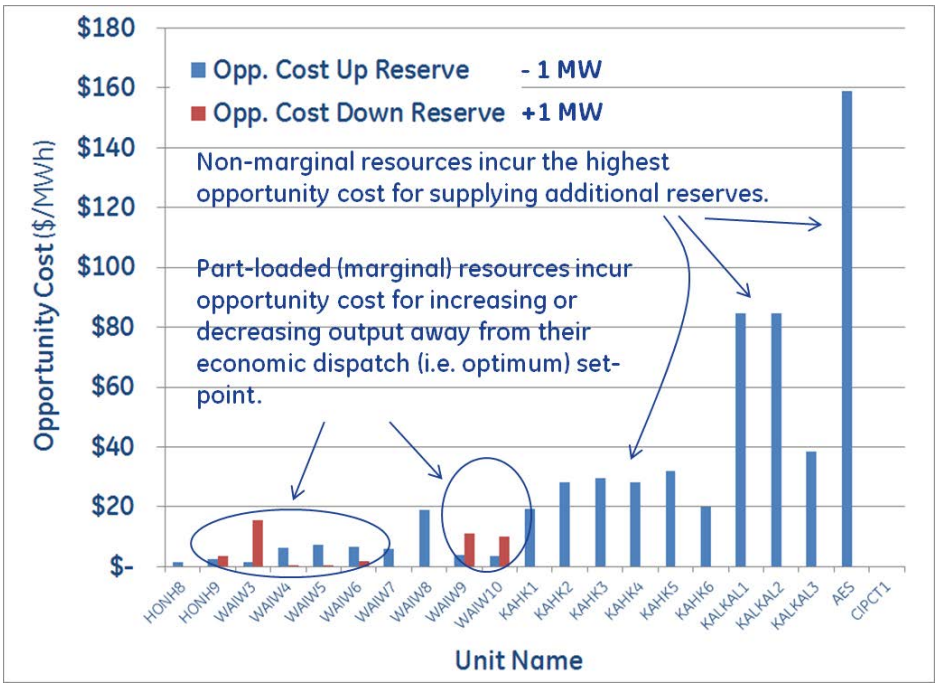



***Figure 3.9*** *Instantaneous opportunity cost for shifting capability from energy to A/S*

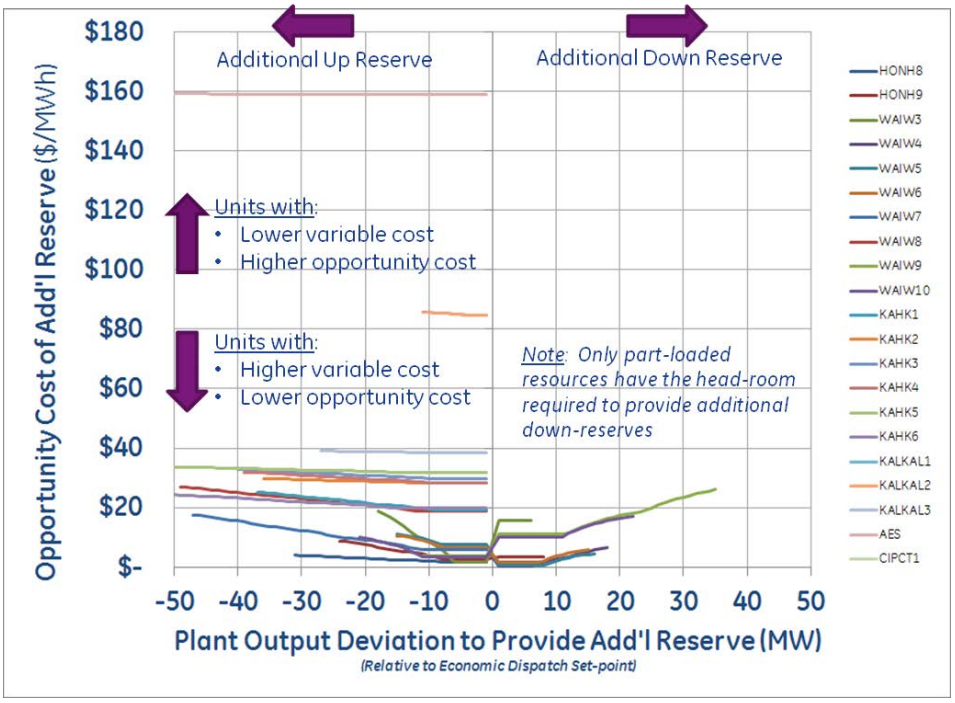



**Figure 3.9** *Opportunity cost as the deviation from the economic dispatch increases*

### 3.1.6 Process for Evaluating and Selecting a Potential Future Technology Mix

This section outlines a methodology that can be exercised during a resource planning process to evaluate and assist with the selection of a future technology mix that is compatible with the system-level interconnection and ancillary service requirements. Specifically, the methodology focuses on minimizing the overall production cost and capital expenditure required to obtain a "least-cost" portfolio while observing system reliability needs. Additional consideration is given to parameters which are more difficult to quantify economically, such as propensity for a given portfolio to improve future renewables penetration and/or reduce risk exposure.

Using HECO Scenario 4A (as an example), each of the steps outlined in the above-mentioned process will are placed in context (see PowerPoint in Appendix A). It should be noted that many options are available to fulfill any observed ancillary service deficiencies, such as: new generation, energy storage, demand response programs, transmission technologies, and existing generation modifications/retrofits. To ensure that an optimal (economic, risk, environmental) solution is achieved, it is recommended that a series of options be developed and analyzed via the following process.

Due to the complexity of the simulations required to generate the data that would be required to perform this analysis, the following process will not be able to be demonstrated in its entirety. A separate study would be required to calibrate a suitable simulation and fully execute the process.

The process is outlined here and in the PowerPoint presentation for Tasks 3&4 in Appendix A.

1. **Identify Current or Future Scenario**: Begin with an established current or future scenario. It is assumed that the resource-specific variable cost characteristics (i.e. heat rate curves, variable O&M cost, startup costs), min-up/down times, ramp-rates, storage capacity, DR availability/activation thresholds, and system-level future economic scenario (i.e. fuel cost/availability, system load forecast, etc.) are known values.

   To provide a comprehensive evaluation, it may be necessary to perform an uncertainty analysis of the key parameters which influence the characterization of a given future scenario.[13] The results of the uncertainty analysis would yield the relevant bounds for each key parameter. With the uncertainty bounds understood, a matrix of the desired evaluation conditions for a parametric sensitivity analysis could be established. This process would be executed for each evaluation condition to ensure a robust analysis of the potential resource mix.

[13] A contemporary example of why the up-front uncertainty analysis would be beneficial is the increased adoption of distributed solar PV on the Hawaiian islands. The increase in the use of distributed solar PV has a tendency to change the system load forecast (i.e. net-load shape) which will be served by the centralized resource technologies targeted by this report. Without an uncertainty analysis, an inaccurate representation of the load forecast could result; this would have the potential to drive a sub-optimal resource mix.

Similar uncertainty analysis of the resource-specific variable cost characteristics, operability constraints, storage/DR characteristics, fuel cost/availability, etc. may be required to develop a robust evaluation matrix to guide the sensitivity analysis.

2. **Obtain Production Cost Simulation**: Obtain a production cost simulation that is capable of performing security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED)
    a. The production cost simulation (or post-processing algorithms) should be capable of analyzing intra-hour behavior to fully evaluate the ancillary service performance.
    b. Simulation needs to be able to "co-optimize" the energy and ancillary services.
3. **Estimate required "system-level" amounts for each ancillary service**: Assess/anticipate the required amount (and minimal level of acceptable responsiveness) that is required for each ancillary service. Provide these ancillary requirements to the production cost simulation and corresponding post-processing algorithms. These ancillary requirements will be interpreted as constraints by the simulation so that it can reserve the respective ancillary capability from each of the available resources. Note: Iteration will be required to optimize.
4. **Identify "resource-level" ancillary service capability**: Identify the amount of each ancillary service that can be performed by each resource. This establishes the subset of the respective resource's capability that could be allocated to the given ancillary service. Items such as operating range, startup times, ramp-rates, min-up/down times, inertial response, black start capability, etc. are key considerations.
5. **Execute the Production Cost Simulation**: Execute the production cost simulation for the respective scenario. Review the hourly (and sub-hourly data as applicable) to ensure that all ancillary services requirements (plus other relevant system constraints) were observed. i.e. sufficient system-level regulation, spinning reserve, etc. was reserved.
6. **Identify Trends in the Results**: If the ancillary service requirements were not successfully achieved, or it appears that excess ancillary capability is available, consider the trends in the deficiencies (or excess):
    a. Are the deficiencies (or excess) driven by inadequate responsiveness from the available resources?
    b. Are the deficiencies (or excess) driven by inadequate operating range?
    c. Are the deficiencies (or excess) present in all hours or only some hours?

7. **Consider potential solutions to alleviate deficiencies and improve system efficiency**. To assist in identifying solutions, consider the trends in the deficiencies (or excess):

   Adjustments to operating procedures:

   - Adjusted minimum run-times
   - Relaxed qualifications/requirements for respective A/S participation
   - Activation thresholds for DR,
   - storage device charging procedures
   - Relaxed "must-run" rules

   Retrofits of existing resources:

   - Increased plant output
   - Improved turndown on thermal units
   - Elevated ramp-rates
   - Reduced start times
   - Synthetic inertia & governor response from renewables

   New resources:

   - Fossil
   - Storage
   - Demand response
   - Renewable assets
   - Inter-island connectivity

8. **Evaluate the economic viability of each potential solution**:

   a. Consider/evaluate the change in total cost required to serve the anticipated system load profile.

   b. Potential for the respective solution to facilitate the desired trajectory of renewables penetration over-time.

9. **Perform a cost-benefit analysis**: This analysis evaluates the year-over-year (YOY) system-level benefit (typically in the form of reduced production cost) of the proposed solution relative to the capital cost required to achieve the respective solution. Rank the solutions according to their economic viability (i.e. NPV, IRR, etc.)
10. **Evaluate the risks associated of each potential solution**: A comprehensive risk assessment of the potential options should also be conducted and weighted against to the economic viability to ensure that the selected solution is robust and reliable:

    Potential Risks to consider (not limited to the following):

    - Inadequate response from renewables due to instantaneous availability
    - Available down-reserves and stable operating region of thermal units during loss of load events
    - Voltage/VAR support sufficiency
    - Reductions in inertial response capability
    - Unfavorable impacts to "system-level" variable cost of operation
    - Impact to existing utility / IPP contracts may require modifications to accommodate schedule changes
    - Challenges associated with monitoring / controlling DR participation on a centralized basis

# 3.2 Task 4: Outline considerations for specifying and acquiring A/S

## 3.2.1 Procuring Ancillary Services – Overview of Approaches for Obtaining, Compensating, and Incentivizing

This section puts forth some potential approaches and mechanisms which can be used to obtain, compensate, and incentivize resources for providing ancillary services. The following four approaches will be highlighted in this section:

1. Market Clearing Price
2. Reimbursement of Offer Price
3. "Make-whole" Compensation
4. Condition of Interconnection

The above listing is not intended to be exhaustive; however, the GE team believes that it contains a representative subset of the most viable techniques which could be considered. Further, it should be noted that each option is not mutually exclusive and may incorporate aspects of the surrounding approaches.

**Method #1: Market Clearing Price**

The Marketing Clearing Price approach is leveraged primarily by wholesale power markets. For this method, each resource submits (or is assigned) an offer price for the respective ancillary service. Most often, resources submit offer prices that are based on their opportunity cost to reserve the headroom or legroom required to provide the service. Some resources, such as storage devices, do not have an opportunity cost because they do not directly provide energy. Instead, their offer price may be based on startup, variable O&M, charging costs, or other expenses associated with providing the respective A/S.

In addition to the cost to provide the service, many markets allow resources to include "additional margin" in their offer price. In some cases, the resource may use to the additional margin to hedge against increased variable O&M costs (i.e. cycling wear & tear). In other cases, the resources may simply leverage the additional margin to cover "cost uncertainty" and/or attempt to enhance their ancillary profitability.

In some markets, the offer price is capped. The cap is often derived by calculating the cost for a unit to provide the service and adding [up to] a maximum allowable margin. The lesser of the submitted price and the capped price is then used as the offer price in the market clearing algorithms.

The "market clearing price" for the ancillary service is driven by the offer price of the last rank-ordered[14] resource required to satisfy the system-level ancillary requirement (for the respective ancillary service). For this approach, all participating resources will receive the "same price" for the

[14] A "low to high" ranking of the offer prices for each participating resource.

given period (typically 1-hour increments).[15] To incentivize "no risk" participation, some markets will compensate for "actual incurred" costs which are larger than the revenues derived from the ancillary market clearing price via "make-whole" payments. This ensures that resources are "no worse off" for having provided ancillary services.

Due to the fact that all participating resources receive the same price for a given ancillary service, it is important to note that most resources, with the exception of the marginal ancillary resource, will earn a financial benefit (i.e. profit) for providing the respective A/S.

**Method #2: Reimbursement of Offer Price**

The Reimbursement of Offer Price is an alternative that could potentially be leveraged between two contracting parties seeking to enter into a bilateral agreement for A/S. It is a logical compromise between the "market clearing price" and "make-whole compensation" approach. Instead of a "clearing price" for the ancillary service, each resource is compensated on an individual basis for providing the service. The offer price for each resource would likely be derived in a similar fashion to the Market Clearing Price methodology. Specifically, the resource's "cost to provide + margin" (including opportunity costs) would serve as a rational basis for the offer price. If the agreement is between a utility and IPP, the offer price could be based on the anticipated production cost savings for the utility. The final ancillary service price would be based on a negotiated value between the respective parties.

The period for which this contractually agreed to price is valid could be varied (i.e. hourly, daily, monthly, annually, or simply set at a constant rate for contract period, etc.). Similar to the Market Clearing Price approach, it is recommended that the Reimbursement of Offer Price incentivize participation by providing a "no-risk" contract architecture through the reimbursement of "actual incurred" costs (i.e. if incurred costs are higher than the compensation that would be derived via the offer-price).

Due to the fact that resources are compensated on an individual basis, profitability (for the resource providing the service) is limited to the margin included in the offer price.

**Method #3: Make-whole Compensation**

The Make-whole Compensation approach is another alternative that could potentially be leveraged between two contracting parties seeking to enter into a bilateral agreement for A/S. Most wholesale markets include "make-whole compensation" provisions in their architecture. This method extracts the "spirit & intent" of those provisions. At its core, the rationale for "Make-whole Compensation" is to explicitly compensate participating resources for their costs (including opportunity costs) associated with providing A/S. This method is designed to make the participating resource indifferent toward providing ancillary services. Instead of negotiating an offer-price, the resource-specific cost

[15] In many wholesale markets, there exists both a day-ahead clearing price and a real-time (or supplemental) clearing price (as-required) to ensure sufficient ancillary availability.

structure would be shared between the contracting parties so that an accurate assessment of incurred costs could be obtained.

Due to the fact that resources are compensated on an individual basis, and only for their cost to provide the service, there is no additional profitability potential for participating in A/S. For the three approaches discussed thus far, this method will typically result in the lowest overall production cost to reliably serve the load. It is important to note that while this approach adequately and explicitly compensates resources for their A/S participation, it does not incentivize that participation.

**Method #4: Condition of Interconnection**

It is important to note that all power systems (historical, existing, and future) require the use of certain interconnection requirements and ancillary services to ensure the system reliability is maintained. In many cases, such as with regulated utilities, the explicit compensation of resources for ancillary participation has not been required to maintain a reliable system. For this reason, the Condition of Interconnection approach was included in this list of options. The "Condition of Interconnection" approach would simply require ancillary service capability and participation from interconnecting resources. Resources would not be explicitly remunerated for providing ancillary service capability or for the associated costs incurred.

The incentive for resources to provide ancillary service capability would be driven by the accompanying right to participate in selling energy. For this type of agreement, it is implied that the participating resources would derive financial benefit from the sale of energy alone that was sufficiently large enough to cover both the cost to provide energy and the cost to provide A/S. Due to the lack of explicit compensation, the "Condition of Interconnection" approach has the potential to offer the lowest production cost of the four methods described.

### 3.2.2 Forward Planning Approach to Derive Rational Ancillary Service Contract Prices

Much attention has been focused on obtaining ancillary services from resources with the lowest offer price and/or lowest "cost to provide" (including opportunity costs).

One potential method for assessing the basis of a "rational" ancillary service offer price would be to leverage a production cost simulation with the capability to co-optimize energy and ancillary services. For a given future scenario, with a known resource mix, the simulation could be exercised and evaluated at both a resource-level and a system-level to draw conclusions about a rational offer price for the respective resource:

- At a **resource-level**, the results of the simulation could be interrogated to identify the perceived cost (including opportunity cost) for each resource to provide a given ancillary service. To develop an offer price, the hourly observations for each resource could then be aggregated and averaged over a period that aligned w/ the desired contractual period.

- At a **system-level**, the simulation could be exercised by individually enabling / disabling the respective ancillary service capability for each resource under consideration. The resulting benefit (i.e. "reduction") in the overall annual production cost could be used as a basis for assessing the ancillary service offer price for each particular resource.

To adequately bound the offer price, it is recommended that both the resource-level and system-level assessments be conducted.

### 3.2.3 Hawaii-specific Ancillary Service Procurement

On Hawaii, ancillary services are presently obtained from dispatchable resources through a method which is similar to the previously mentioned "Condition of Interconnection" approach. Specifically, the utilities have the ability to dispatch resources to provide ancillary services without explicit compensation to the respective resources. Going-forward, there will be a continued desire to increase the penetration of renewable resources on the Hawaiian system which has the potential to increase the system-level ancillary service requirements. As the system-need for ancillary services increases, it may be necessary to incentivize new resources to provide (or existing resources to expand upon) their ancillary service capability. This incentive could likely come in the form of explicit financial compensation and include aspects of either the "make-whole compensation" or "reimbursement of offer price" methods. However, it should be noted the use of these methods has the potential to increase the overall production cost as a result of the explicit compensation for [some of/all of] the ancillary services. Careful consideration is required before introducing such remuneration methods or unbundling the ancillary services.

As outlined in the technology table (Part I, Task 2), renewable resources (i.e. wind/solar) are capable of providing many ancillary services. The use of these resources for providing A/S may help to facilitate their increased penetration and potentially reduce production costs as it introduces another degree of freedom for commitment & dispatch. Current RFP's and draft PPA's are seeking to leverage this capability from VG resources. Relative to the current environment, in which dispatchable resources are not explicitly compensated for fulfilling the system-level ancillary obligations, requiring the wind/solar to provide ancillary services via the "Condition of Interconnection" approach would certainly be considered as an equitable option. Due to the fact that wind/solar resources are presently compensated based on their energy contract price, which likely includes some fixed and capital cost recovery, there are periods when wind/solar are more expensive to operate than some non-renewable resources on the system (i.e. periods where the energy contract price is higher than the marginal system cost). During these periods, it may result in a system level production cost savings to curtail wind/solar to provide ancillary services. However, the existing wind/solar contracts have provisions which preclude the curtailment of these resources for economic reasons. Therefore, during periods where wind/solar are curtailed exclusively for the purposes of providing ancillary services (i.e. up-reserves), the use of "Make-whole Compensation", to explicitly compensate for costs (including opportunity costs) associated with providing ancillary services, would be recommended. It should be noted that the existing wind/solar contracts purposefully prevented curtailment for economic reasons in an effort to maximize renewable penetration. Therefore, to adopt the previous recommendation, an adjustment to the existing contracts would likely be required.

Energy storage devices have the potential to enhance penetration of renewable resources and/or lower the overall production cost. The process for "Evaluating and Selecting a Potential Resource Mix" developed in Task 3 and discussed earlier, could be leveraged to help quantify these potential benefits. Due to the fact that energy storage resources are energy-neutral and operate exclusively for the purposes of providing ancillary services, the use of "make-whole compensation" is not applicable (i.e. storage resources have no opportunity costs). Therefore, an explicit remuneration method, such as "Reimbursement of Offer Price" may be required to incentivize the development & participation of energy storage resources to supply ancillary services. To obtain a value for the ancillary services offered by the energy storage resources, it is likely that the previously mentioned "system-level" use of a production cost simulation would be required. Specifically, the simulation could be exercised by individually enabling / disabling the respective ancillary service capability for each resource under consideration. The resulting benefit (i.e. "reduction") in the overall annual production cost could be used as a basis for assessing the ancillary service offer price.

Ancillary service participation from DR, transmission, and retrofit options have the potential to reduce production costs, improve renewables penetration, and avoid/defer/attenuate major capital expenditure. Similar to energy storage resources, an explicit compensation method would likely be required to incentivize participation from DR and/or transmission-related technologies. To incentivize the modification (i.e. retrofit) of existing resources to provide, or expand upon, their ancillary service capability, further use of explicit compensation may be required to cover upgrade costs.

It should be noted that some resources have the potential to increase (or decrease) the required amount of ancillary services on the system. Further, some resources have the potential to provide more ancillary capability than other resource types. In some cases, such as wind/solar, an individual resource has the potential to increase the required amount of ancillary services on the system. However, these resources also have [typically] low variable operating cost and have the have the potential to reduce the overall production cost for the system. As a result, it is not recommended that individual resources, which induce additional ancillary obligations on the system, be additionally penalized. Instead, it is recommended that the impact on overall consumer cost (including total ancillary services costs), coupled with other policy-related directives such as renewable penetration targets, be used as the metric to assess the viability of a particular resource.

### 3.2.4 Risk Considerations

The process and methodologies developed in this study can help promote a least-cost portfolio of resources to supply ancillary services and interconnection requirements that attempt to protect reliability, maximize renewable output and minimize energy costs. The process to specify technologies for ancillary resources is outlined in Task 3. The technology combination is not unique.

For each scenario, the risks associated with the recommended ancillary services and potential technology mix may include:

- Hawaii specific resource costs and economics should be considered in any least cost planning exercises. Task 3 outlines the system operation cost considerations and the capital costs can be accounted for in resource planning and/or competitive resource solicitations.
- New/emerging technology availability such as batteries should be considered in future plans to account for potential difference in time of ancillary server requirements and technology implementation timeline.
- Ability to uprate/upgrade existing resources to provide additional capacity, energy and/or ancillary services must be considered. For instance, an existing resource may not have physical space to uprate or may not be able to permit increased capabilities.
- Fuel availability and fuel infrastructure will dictate the ability to get certain fuels to the resources. While build out of the fuel delivery systems should be considered in the total system planning to accommodate increased need due to load growth or change in purpose, potential for interruptions in emergency situations should also be considered along with the ability to provide ancillary services. Production and delivery of biofuels may also need to be considered along with more traditional oil and natural gas.
- Wind and solar forecasting should be implemented in system operations to more accurately predict when these resources will be available. And in the case of wind, energy production must be available to provide frequency response and down regulation.
- Interconnection costs of the resources should be considered if new resources are being added to provide ancillary services.
- Inter-Island transmission connections, if in place, can be used to provide ancillary services between islands, but must be monitored for flow and outages to ensure that service is not interrupted. A minimum amount of certain ancillary services should be specified locally, as is the case is in other island/peninsular systems such as Long Island, in case the inter-island transmission connection is lost.
- Demand-side participation and programs can be used to provide certain ancillary services, like operating reserves, but the grid operator needs to have control over those resources on a centralized basis. Preferably via physical control such as demand response switches.
- Load shaping programs such as electric vehicle charging schedules, may be implemented to help shape the system load and thereby make planning for ancillary service deployment easier.
- Inadequate response from renewables due to instantaneous availability
- Available down-reserves and stable operating region of thermal units during loss of load events
- Voltage/VAR support sufficiency
- Reductions in inertial response capability
- Unfavorable impacts to “system-level” variable cost of operation
- Impact to existing utility / IPP contracts may require modifications to accommodate schedule changes such as with must run units

Additional details on the individual "technology-specific" risks are included in the PowerPoint Presentation in Appendix A which accompanies this report.

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# 5 **Appendix A:** Power Point Presentation

Filename: 2012_12_19_Hawaii_Ancillary_Services_Report_PART2FINAL.pptx

# Ancillary Services Definitions & Capability Study Part 2, Task 3-4, Final Report

December 19, 2012

Prepared by: GE Energy Consulting

Prepared for: Hawaii Natural Energy Institute (HNEI) and Hawaii Reliability Standards Working Group (RSWG)



imagination at work

# Table of Contents

## Ancillary Services Definition & Capability Study


Study Background and Objectives

Key Terminology

Study Results

- Task 3 – Identify Physical Requirements of Ancillary Services
  - Ancillary Services for Existing System and Future Scenarios
  - Recommendations Regarding New Ancillary Services and Interconnection Req's
  - Fundamentals of Power System Operation
  - Process for Evaluating and Selecting a Potential Future Technology Mix
- Task 4 - Outline Considerations for Specifying and Acquiring Ancillary Services
  - Methods for Procuring Ancillary Services
  - Hawaii-Specific Ancillary Service Procurement
  - Risk Assessment and Other Considerations

Appendix A – Methodology for Determining Operating Reserves

References

# Study Background and Objectives

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# Ancillary Services Def. & Cap. Study

## Overview of Study

Purpose:

Study sponsored by HNEI with support and guidance from Hawaii RSWG to identify, define, and quantify ancillary services required to support new generation (including renewable generation) for bulk power systems and particularly the Hawaiian islands.

Objectives:

- Define a standardized set of ancillary services along with their associated definitions (in functional, performance based terms) that can be used to meet the operational needs of Hawaii and other bulk power systems.
- Technologies (generation, transmission, storage, and demand response (DR)) will be assessed for their ability to support the respective ancillary services to maximize the diversity and optionality for ancillary service acquisition and delivery.
- Identify the physical requirements of the ancillary services needed for each Hawaiian island (Oahu, Maui, Big Island)
- Outline considerations for specifying / acquiring ancillary services for the Hawaii grids that protect reliability, incent renewable generation, and minimize production costs.

# Introduction

## Ancillary services & additional functions required for power system operation

- **Ancillary services*** are those functions performed by the equipment and people that generate, control, transmit, and distribute electricity to support the basic services of generating capacity, energy supply, and power delivery. They are required to maintain reliable operations of the electric power system.

- In addition to ancillary services, other **interconnection requirements** are placed on resources to ensure reliable operation of the grid

- These ancillary services and interconnection requirements enable the system operator to meet the required operations **reliability standards** set by NERC.

- The ancillary services, interconnection requirements, and reliability standards are dependent on the characteristics of a power system.

** FERC defined ancillary services as those "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."*

# Key Terminology

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# Key Terminology

The following definitions are relevant throughout the content of this presentation and should be interpreted as described below:

**Area Control Error (ACE):** The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error. *NERC Glossary (2008)*

Conventionally, **ACE = (NIA – NIS) – 10B (FA – FS) – IME**, where:

- **NIA** is the algebraic sum of actual flows on all tie lines.
- **NIS** is the algebraic sum of scheduled flows on all tie lines.
- **B** is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- **FA** is the actual frequency.
- **FS** is the scheduled frequency. FS is normally 60 Hz but may be offset to effect manual time error corrections.
- **IME** is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NIA) and the hourly net interchange demand measurement.

Due to a lack of inter-area power flows, the definition of ACE has been modified for Hawaii. Specifically, for Hawaii, **ACE = – 10B (FA – FS) – IME**. This modified definition of ACE is still applicable for Hawaii as it correctly represents the fact that 100% of difference between supply and demand will manifest itself as a frequency error. *Revised definition per Hawaii RSWG Glossary.*

# Key Terminology (cont'd)

The following definitions are relevant throughout the content of this presentation and are intended to provide clarification on their intended interpretation:

**Automatic Generation Control (AGC)**: Equipment that automatically adjusts generation, storage devices, and/or responsive load in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias (i.e. ACE). *NERC Glossary (2008) with modifications to accommodate additional resource types such as load and storage devices*.

Although AGC was originally conceived as a means to provide fast (3-6 second signals) to generators, the concept of leveraging AGC to provide "MW raise/lower" commands to demand-side and storage resources is equally applicable and is in practice in some locations.

# Key Terminology (cont'd)

The following definitions are relevant throughout the content of this presentation and are intended to provide clarification on their intended interpretation:

**Droop Control / Governor:** Droop speed control is near instantaneous means of using frequency deviations to distribute load set-point adjustments to a system of resources in a stable manner.

The magnitude of a given resource's response is proportional to the frequency deviation and typically characterized by "x%" droop. For example, a resource with operating range available will provide 100% additional output per "x%" change in system frequency. Response is typically a percentage of the resource's full-capability.[3]

Droop response can be provided by any frequency-sensitive resource.

**Resource:** A resource may consist of any generation, storage, load (i.e. demand-side), or transmission technology.

**Spinning / Non-Spinning:** Historically, the terms "**spinning**" and "**non-spinning**" have referred to the rotational nature of synchronized generators. Over time, this terminology has migrated to imply the "relative state of readiness and responsiveness" as it relates to the ability for a resource to fulfill its ancillary obligation. In an effort to leverage contemporary industry vernacular, this latter interpretation was adopted for use in this presentation.

# Study Results

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# Identify Physical Requirements of Ancillary Services

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# Task 3: Scope & Deliverables

## Identify physical requirements of ancillary services

Objectives:

- From recent renewable integration and planning studies, develop two future scenarios
- With HPUC and Hawaiian utilities, specify basic level of required bulk power system reliability for each island (Oahu, Maui, Big Island) [Task 1 and Task 3]
- Propose methodology to estimate required ancillary services and interconnection requirements (under the future scenarios) while taking into account other system considerations
- Suggest a process to determine a set of technologies and associated features

# Scenario Development

Approach:

- From recent renewable integration and planning studies, develop two future scenarios with HECO companies and HPUC

Observations:

- The HECO companies required to conduct a 20-year time horizon IRP study every three years.
- In May 2009, the HPUC proposed amendments to the framework for IRP based on the proposal of a new Clean Energy Scenario Planning (CESP) process.
- The revised goal of IRP is to develop an Action Plan that governs how the utility will meet energy objectives and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at reasonable cost, through the development of Resource Plans and Scenarios of possible futures that provide a broader long-term perspective.
- Some of the Hawaiian utilities (HELCO and MECO) have conducted resource planning studies. These studies are not intended to serve as IRPs. Rather, they seek to identify resource needs for Hawaii Island and identify resource options for consideration in a future IRP cycle.

# Scenario Development

## Sources for scenario planning

| | HECO (Oahu) | MECO (Maui) | HELCO (Big Island) |
|---|---|---|---|
| **Most Recent IRP** | HECO IRP 2009-2028 (Sep 2008) | MECO IRP 2007-2026 (April 2007) | HELCO IRP 2007-2026 (May 2007) |
| **Resource Planning Study to support future IRP** | ? | Available from MECO | HELCO Resource Planning Study (June 2012) |
| **Other renewable integration studies** | OWIST & HSIS (Available from GE) | HSIS (Available from GE) | |
| **Load Forecast** | From OWIST and HSIS | Base Line From HSIS | Base Line From Resource Planning Study |
| **Scenario 1: Moderate penetration Renewables or mix definition** | HSIS Scenario 4A<br>360 MW Dist Solar PV<br>400 MW Cent Solar PV<br>100 MW On-shore Wind<br>No Off-Shore Wind | HSIS Base Line (2012 system)<br>15 MW Dist Solar PV<br>0 MW Cent Solar PV<br>72 MW On-shore Wind | HELCO 100% renewables intermittent – heavy<br>**22 MW Biomass**<br>**100 MW Wind (centralized)**<br>**100 MW PV (centralized or distributed)**<br>**50 MW Geothermal** |
| **Scenario 2: High penetration Renewables or mix definition** | HSIS Scenario 4B<br>160 MW Dist Solar PV<br>200 MW Cent Solar PV<br>100 MW On-shore Wind<br>200 Off-Shore Wind<br>(same solar & wind MWH as 4A) | HSIS Scenario 3<br>30 MW Dist Solar PV<br>15 MW Cent Solar PV<br>72 MW On-shore Wind<br>**Scenario 3: Heavy Intermittent Renewables**<br>**22 MW Biomass**<br>**100 MW Wind, 100 MW PV**<br>**50 MW Geothermal** | HELCO 100% renewables geothermal/ dispatchable – heavy<br>**42 MW Biomass**<br>**50 MW Wind (centralized)**<br>**50 MW PV (centralized or distributed)**<br>**100 MW Geothermal** |

# Ancillary Services for Existing System and Future Scenarios

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# Level of Bulk Power System Reliability

Approach:

- Review pertinent documents from HPUC and Hawaii utilities to identify current specifications required for bulk power system reliability for each island (Oahu, Maui, Big Island) such as:
  - Docket 2008-0273 Feed-in Tariff ("FIT")
- Confirm findings and reliability levels to be used for this study with Hawaiian utilities and HPUC and identify any areas that may require further study beyond this project

Observations:

- The HECO Companies currently plan and operate their systems in accordance with reliability principles that are very much aligned with the NERC Reliability Standards
- FIT Reliability Standards were filed in Docket 2008-0273 Feed-in Tariff ("FIT") Proceeding HECO Companies Report on Reliability Standards per the direction of HPUC

# Methodology to Determine A/S

## Applied to future scenarios

Approach:

- Propose methodology to estimate required ancillary services and interconnection requirements (under the future scenarios) while taking into account other system considerations and using the basic level of bulk system reliability as the performance target
- Refer to renewable integration studies, both in Hawaii and on the mainland

Observations:

- The results from the simulation of the selected scenarios from the HSIS and OWIS study performed by GE were used to determine the need for additional ancillary services (for HECO and MECO).

# Recommendations Regarding New Ancillary Services and Interconnection Requirements

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# Recommendations Regarding New Ancillary Services and Interconnection Requirements

## Inertial Response

- Currently, the desired inertial response from dispatchable synchronous renewable generation (RE) resources such as geothermal plants is obtained as a condition of contract. Currently, there is no synthetic inertia requirement in the interconnection requirements for Variable Generation (VG) resources such as wind and solar plants.
- With the current technology, it is possible for wind plants to provide synthetic inertial response, which if designed properly can help the system ride through frequency events.
- We recommend synthetic inertia capability for future utility-scale wind plants. The parameters for synthetic inertia (deadband, active power contribution, duration of response, maximum generation reduction etc.) should be designed to meet the Hawaii system requirements.
- The utilities should also perform offline studies to determine the impact of synthetic inertia on inertial and primary frequency response and how it impacts inertia requirements from other (future) interconnecting resources, UFLS practices, and spinning reserve requirements. The offline studies should be used to guide for determining combinations of resources that need to be online.

# Recommendations Regarding New Ancillary Services and Interconnection Requirements

## Primary Frequency Response

- Currently, the interconnection requirements require all dispatchable generators (conventional, as well as synchronous RE) to have a 4% droop that is adjustable. HECO utilities also have the capability to dispatch units to provide reserves as needed. As such, the HECO utilities currently obtain primary frequency response as a condition of interconnection.
- Wind and solar plants are capable of providing primary frequency response improving the reliability of the grid. In many instances, using VG to provide reserves also reduces their curtailment. For example, using wind generation to provide down reserves (instead of carrying the down reserves by dispatching up a thermal generator) reduces the curtailment of wind generation.
- We recommend droop control to be a part of the interconnection requirements for future utility-scale wind and solar plants in addition to the requirement for dispatchable generators.
- We recommend that VG be compensated for providing up reserves if their generation is curtailed for the explicit purpose of providing reserves. The payment mechanism will be discussed later. We also recommend the development of tools to reliably calculate the amount of reserves that VG can provide.
- VG should be required to provide down reserves without any explicit compensation similar to other dispatchable units in the system. Need tools to amount of down reserves that VGs can reliably provide.
- VG should be required to provide up reserves without any explicit compensation when they are curtailed for reasons other than providing up reserves since their opportunity cost is zero when they are curtailed.
- The above provisions are similar to those used in the ERCOT market.

# Recommendations Regarding New Ancillary Services and Interconnection Requirements

## Secondary Frequency Response

- Currently, the interconnection requirements require all dispatchable generators (conventional, as well as synchronous RE) to be on AGC.
- All the existing wind contracts also include active power control (APC) provision to enable automatic curtailment.
- We recommend AGC (ability of wind plant to directly accept and act on a maximum dispatch signal delivered by AGC) capability to be a part of the interconnection requirements for all future utility-scale generators including wind and solar plants.
- We recommend that VG be compensated for providing up regulation if their generation is curtailed for the explicit purpose of providing regulation. The payment mechanism will be discussed later. We also recommend the development of tools to reliably calculate the amount of regulation that VG can provide.
- VG should be required to provide down regulation without any explicit compensation similar to other dispatchable units in the system. Need tools to amount of down regulation that VGs can reliably provide.
- VG should be required to provide up regulation without any explicit compensation when they are curtailed for reasons other than providing up regulation since their opportunity cost is zero when they are curtailed.

# Recommendations Regarding New Ancillary Services and Interconnection Requirements

## Storage and Demand Response

- In general, storage and demand response should be allowed to provide regulation and reserves as long as they are economical. However, the following need to be considered:
- Need to consider DR response and UFLS interaction. UFLS uses 75-80% of all load. The interaction of UFLS and DR must be developed and coordinated to ensure adequate protection for the UFLS system.
- The modification of PV to being required to trip on lower frequency set-points than standard IEEE 1547 trip settings, which are higher than UFLS trip settings, to mitigate loss of PV during a system low-frequency events was completed by the recent modification to Hi Rule 14h. However, there are still legacy installations that trip in accordance with IEEE 1547 and will compound the impact of unit trips. HECO uses 57.3 Hz for low frequency trip of distributed PV (not sure about other utilities). Legacy PV trips at 59.3 Hz and still must be considered in all studies. Since the 1547 standard and, similarly, Rule 14H specify in terms of a must-trip instead of ride-through, confirmation that the existing change results in the desired ride-through is important - a future change to a ride-through requirement may be necessary.
- Need to consider feeder net load for UFLS system as distributed PV increases and feeder net load during some hours reduces.

# Recommendations Regarding New Ancillary Services and Interconnection Requirements

## Changes to Interconnection Requirements

**Reactive Power and Voltage Regulation**

Hawaii utilities have voltage regulation and control requirements for dispatchable and variable generation. No changes proposed.

**Voltage and Frequency Ride-thru**

Hawaii utilities have voltage and frequency ride-thru requirements for dispatchable and variable generation. Utilities should develop requirements for unbalanced ride thru requirements. Unbalanced voltage capability is required in weak systems and is currently a much larger issue than LVRT since turbine manufacturers do not currently have a standard to meet and the current technology of WTG is much less than conventional generation.

**Ramp Rate Limits and Control**

Hawaii utilities have ramp rate limits in the up direction for variable generation. Ramping requirements in the up and down direction are included as requirements for dispatchable generation. No changes proposed.

**Over and Under Frequency Controls**

Per recommendation before, require wind and solar plants to have primary frequency response capabilities.

# Recommendations Regarding New Ancillary Services and Interconnection Requirements

## Changes to Interconnection Requirements

**Inertia**

Per recommendation before, require wind plants to have inertial response capabilities. Inertia response should be defined by utility based on system needs.

**AGC Capability**

Per recommendations before, require all generators including wind and solar plants to have the ability to accept and respond to AGC commands. Active power set-point is a current requirement for VG to enable curtailment. This would require modifications to the AGC program.

# Fundamentals of Power System Operation

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# Power System Operation

## Identifying the balancing point between resource capability and system needs

This section is intended to serve as a primer which provides a common foundation for the general terminology and concepts that will be referred to throughout the balance of this report.

In addition, it is intended to provide insight into the processes and considerations that are required to leverage available power system resources to “serve the load” in the most cost effective and reliable manner.

Downstream sections of this report will contain more Hawaii-specific discussion, considerations, and where possible, recommendations which reference these concepts.

# Power System Operation

## Identifying the balancing point between resource capability and system needs

In a power system, resources are committed and dispatched based on their ability to:

1. Directly provide energy
2. Support the reliable delivery of energy

- Often, the same resource may serve both functions. The degree to which this occurs depends upon the attributes of the individual resource, resource mix, and the respective needs of the power system.

To supply "energy", a resource is *primarily* evaluated based on its ***variable cost*** structure:

Startup Cost:

- Typically on a "$/startup" basis. Represents the cost incurred for bringing a resource to a state where it is available for dispatch.

Minimum Generation Cost:

- Typically on a "$/hr" basis. Represents the variable cost required to sustain operation at the minimum permissible "real-power" operating level.

Incremental Variable Cost:

- Typically on a "$/MWh" basis. This represents the cost for the next incremental adjustment in the real-power set-point.

# Power System Operation (cont'd)

## Identifying the balancing point between resource capability and system needs

To support the "reliable delivery of energy", a resource is considered based on additional attributes that characterize its ***flexibility***. Examples include, but are not limited to:

Inertial Response:

- Typically measured by a resource's inertial constant "H" (in seconds). This is a normalized value that relates a resource's kinetic energy to its respective capacity.

Ramp-rate:

- Typically on a "MW/min" basis. Characterizes the rate at which a resource is able to adjust it's real-power set-point. This rate can be set "tuned" differently dependent upon whether the need is for frequency response (i.e. FRR), regulation, (i.e. AGC), load following, spinning reserve, and/or startup periods.

Quick-start capability:

- Typically on a "minutes or hours" basis. Characterizes the time-delay required for a unit that is offline or disconnected from the power system to become available for the purposes of providing energy or supporting the reliable delivery of energy.

Operating Range:

- Characterized on a "real-power" and "reactive power" basis.
- Real-power range: Characterizes the range over which a resource is able to inject or consume actual "MW" to support the load on the power system.
- Reactive-power range: Characterizes the range over which a resource is able to provide "MVAR" to assist with maintaining system voltage levels.

# Power System Operation (cont'd)

## Identifying the balancing point between resource capability and system needs

To support the "reliable delivery of energy", a resource is considered based on additional attributes. Examples include, but are not limited to:

- Minimum Operating Period:
  - Minimum up-time: The minimum time for which the unit needs to be online once started
  - Minimum down-time: The minimum time for which the unit needs to be offline once shutdown
- Black-start capability:
  - Ability to start a unit without support from the grid

# Power System Operation (cont'd)

## Identifying the balancing point between resource capability and system needs

Determining the balance between using a resource for its "energy" vs. its ability to support the "reliable delivery of energy" often requires sophisticated algorithms. Typically, this balance is achieved through *"security-constrained unit-commitment (SCUC)"* and *"security-constrained economic dispatch (SCED)"* algorithms. For long-term power system planning, a ***production cost model*** is often leveraged to execute the SCUC and SCED algorithms. For day-to-day and week-to-week operations, similar algorithms are used in energy management system (EMS) software.

The objective of the algorithms is to ensure that sufficient resources will be online (i.e. committed) to meet the anticipated load forecast (including variability) and satisfy reserve requirements in the most economical manner (i.e. lowest system cost) while observing reliability constraints.

Emphasis is placed on leveraging assets with the lowest ***variable operating costs***. More expensive resources are only selected if their ***flexibility*** is required to ensure reliable delivery of the energy, relieve system constraints, or they benefit increased renewables penetration, etc.

Once a resource is "committed", the "security-constrained economic-dispatch" algorithms are then utilized to obtain a resource's load set-point (i.e. "dispatch-point"). To achieve a solution, these algorithms attempt to "park" all committed resources at the same incremental variable cost (*additional details in following slides*).

# Power System Operation (cont'd)

## Identifying the balancing point between resource capability and system needs

Typically, the "most-economical" manner for operating the system is for all committed resources to be dispatched to the same "incremental variable cost" (provided the resource is not at the extremes of its operating range). This is referred to as "*economic dispatch*".

The resource which will provide the "next most economical MW" is referred to as the marginal unit. And, at that instant, the "system marginal cost" is equivalent to the incremental variable cost of that resource. Often, there are multiple units "on or near the margin".

To satisfy the reliability needs of the power system, it is often necessary to adjust the dispatch of the resources away from their economic optimum set-point. This movement creates additional "headroom/legroom" and increases the available reserves to satisfy system req's.

To ensure that these adjustments are made in the most economical manner, a process referred to as "*co-optimization*" is often deployed. This process assists in identifying which resources to adjust, and by how much. Specifically, it attempts to minimize the "*opportunity costs*" associated with moving a resource away from its economic optimum to meet the reliability needs of the system.

The concept of using opportunity costs to rank/prioritize resources and make system-level trade-offs between energy vs. ancillary capability is still applicable regardless of whether an explicit payment is made to the resources for their ancillary participation.

# Power System Operation (cont'd)

## Identifying the balancing point between resource capability and system needs

Typically, ancillary service needs are "best-served" by marginal resources. This is driven by the fact that they often have the lowest opportunity cost for providing the service.

- For example, a wind farm* typically has a very low variable operating cost. Curtailing the wind for the specific purpose of providing an ancillary service would [typically] result in very high opportunity cost (for both the plant and the power system).
- However, during periods where renewables are curtailed (due to must-run resources and/or corresponding over-supply), allocation of ancillary services to the renewables would likely be very cost-effective.
- In situation where renewables are not curtailed, selecting a combustion turbine or storage device** would likely result in lower opportunity cost and lower system cost.

* *In Hawaii, during off-peak periods, wind energy contract prices can higher than the variable cost of other thermal generation. For these circumstances (and while wind contracts do not separate fixed & variable costs), curtailing wind for the purposes of providing ancillary services may be recommended.*

** *Storage devices are unique. Such resources are often "energy-neutral" (i.e. zero net-output on a nominal basis). As a result, storage devices do not have an "opportunity cost" per se. The variable cost to provide ancillary services from a storage device is typically driven by the cost to initiate the devices operation (i.e. startup) and the corresponding variable O&M during operation. As a result of their energy-neutral / zero-opportunity cost, storage devices are typically prioritized ahead of other resources for providing ancillary services.*

# Power System Operation (cont'd)

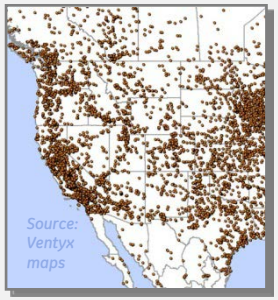
## Illustration of the key concepts & tools which facilitate the analysis

The illustrations on the following pages are intended to provide further clarification of some of the key tools & concepts that were discussed in the preceding slides:

- Production Cost Modeling
- Average vs. Incremental Variable Cost
- Economic Dispatch
- Opportunity Cost
- Co-optimization of Energy and Ancillary Services

# Production Cost Modeling

## Inputs




**Resource Definition**:
- Individual resource attrib.
- Variable cost structure
- Op Constraints & A/S Cap.
- Outage Schedules




**Transmission Definition**:
- Defines the electrical infrastructure
- Connects resources w/ loads
- Line capacity & routing

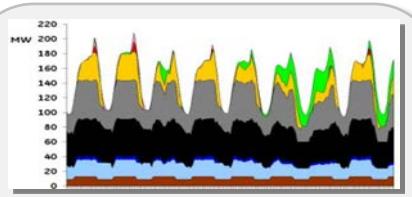



**Area Load Definition**:
- Specifies the location-based need for power
- Resources utilized to serve this load economically / reliably

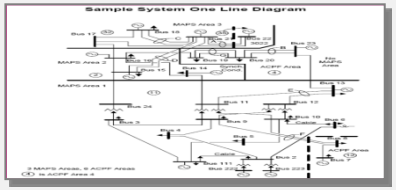
## Calcs

Production Cost Modeling Core Algorithms *(i.e. "the engine")*

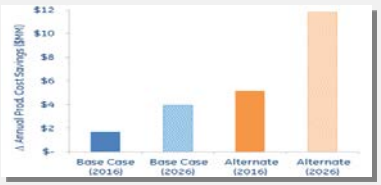
## Outputs




**Resource Utilization**:
- Operating profiles for all resources (online status, load level, operating hours, startups, etc.),




**Transmission Flows**:
- Load flow profiles
- Identification of limiting lines and constraints
- Congestion costs




**Financial Results**:
- Insight on both "system-level" and "plant-level" economics.
- For investment decisions, cost of reliability analysis, etc.

# Variable Operating Costs

## Incremental vs. Average Variable Cost

### Variable Operating Costs

*(Example shown for a Generating Resource)*

**Variable Operating Cost ($/hr):**

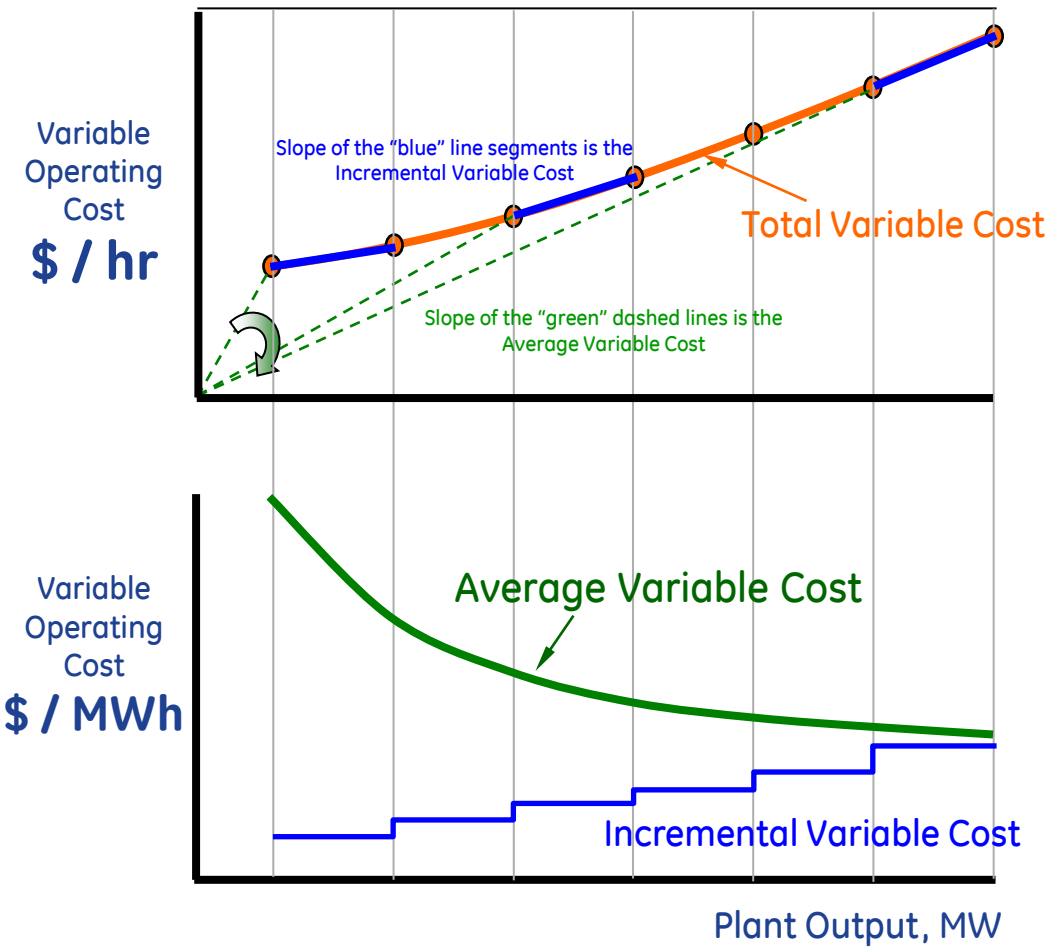
- Hourly cost required to sustain operation at a given load set-point.
- Driven by costs which are a function of utilization
- Typically consists of (but not limited to) :
  - Fuel cost
  - Variable O&M
  - Emissions (i.e. environmental compliance)

**Average Variable Cost ($/MWh):**

- Calculated by dividing the Variable Operating Cost by the respective output level
- Provides a normalized representation of the "actual" operating cost incurred at a given set-point.

**Incremental Variable Cost ($/MWh):**

- Represents the "additional cost" for the "next "MW" provided by the resource. Trend is "downward" sloping for DR resources.
- Critical to "economic dispatch"




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# Economic Dispatch

## Provides an "economically optimized" operating point for each resource

### Economic Dispatch

*(Example shown for a Generating Resource)*

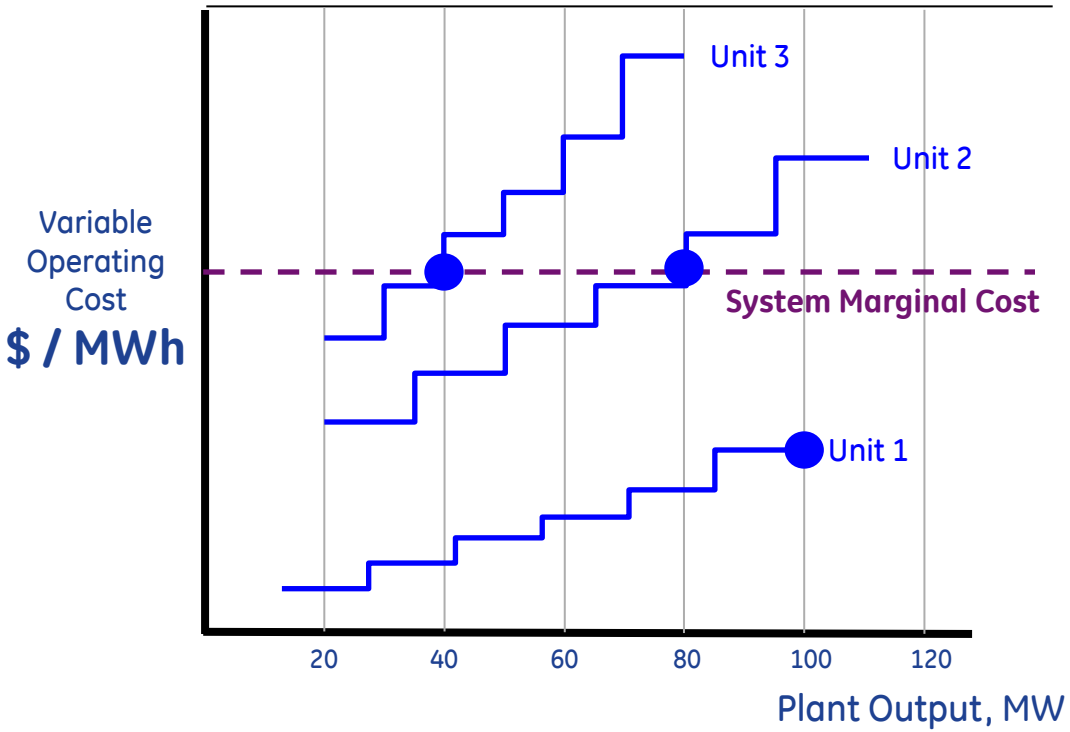
- Economic Dispatch is the process used to move the real-power set-point for resources upward and downward.
- At the power system-level, the cost to "serve the load" is minimized when committed resources are dispatched to the same "incremental variable cost".
- The "system marginal cost" is analogous to the "clearing price" in a power market.
- Exceptions for resources that are at the extremes of their operating range.
- Deviations from the economic optimum may be necessary to meet the reliability needs of the power system.
- Trade-offs are typically driven by the "opportunity cost" of migrating a resource away from its economic optimum.

**Scenario (for illustration only)**:

- Instantaneous system need is 220 MW
- Assume Units 1-3 are committed

**Principles of economic dispatch would yield**:

Unit 1 Set-point: 100 MW (upper extreme of op range)
Unit 2 Set-point: 80 MW (on the margin)
Unit 3 Set-point: 40 MW (on the margin)
Total Supply: 220 MW




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# Opportunity Cost

## Represents the cost for deviating from economic dispatch

### Opportunity Cost

*(Example shown for a Generating Resource)*

- Economic Dispatch would indicate "Unit 1" should be providing 100 MW (full-output).
- Consider "Unit 1" for 20 MW of upward regulation service.
- The opportunity cost of moving 20 MW from providing "energy" to serve the "ancillary" needs is characterized as:

| | |
|---|---|
| Providing 100 MW: | $8000/hr |
| Providing 80 MW: | $5600/hr |
| Difference: | $2400/hr |

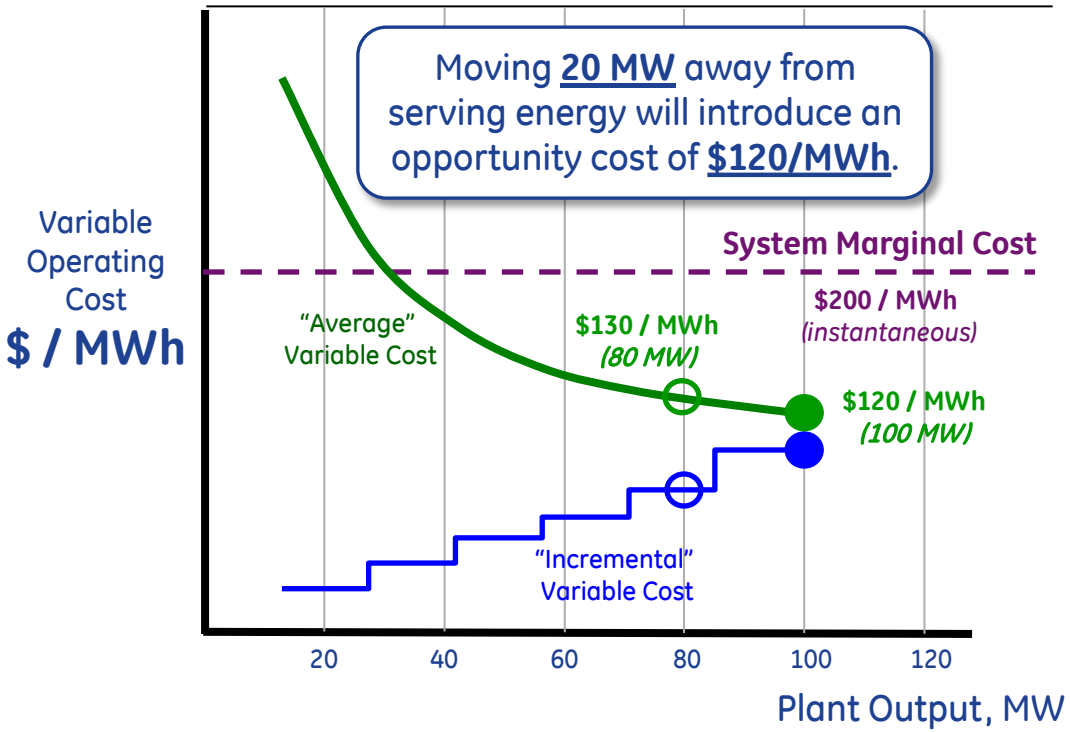
- Normalizing the $2400/hr by the 20 MW, results in an opportunity cost of **$120/MWh**.
- Resources with the "lowest opportunity cost" should be the 1st resources selected to migrate from providing energy to serve the ancillary needs of the system.
- In many locations, the opportunity cost of the "last resource" required to provide the ancillary service will set the "ancillary clearing price".

**Providing 100 MW (Energy-only):**

- Revenue (proxy) = ($200/MWh) * (100 MW) = $20000/hr
- Cost = ($120/MWh) * (100 MW) = $12000/hr
- Profit (proxy) = $8000/hr

**Providing 80 MW (Energy + 20 MW Regulation "stand-by")**

- Revenue (proxy) = ($200/MWh) * (80 MW) = $16000/hr
- Cost = ($130/MWh) * (80 MW) = $10400/hr
- Profit (proxy) = $5600/hr



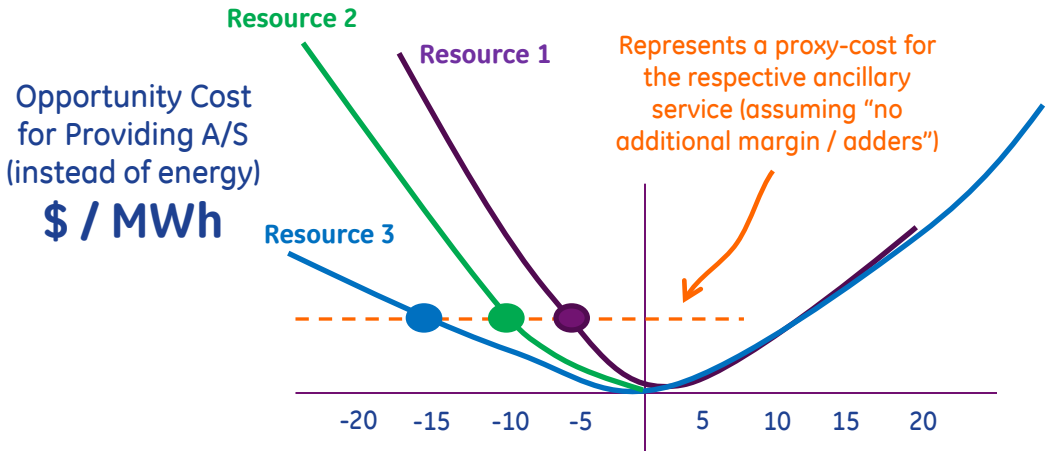
# Co-optimization

## A mechanism for minimizing the opportunity cost at a system-level

### Co-optimization

*(Applicable for any multiple resource-types)*

- Co-optimization ensures that ancillary services are sourced from the most-economically viable resource capable of serving the need.
- In the scenario at the right, each was allocated a portion of the total ancillary service requirement.
- In many locations, the ancillary requirements (for each service), and the corresponding opportunity costs, are evaluated and adjusted on an hourly basis.
- Often, resources are capable of providing more than a single ancillary service. Under these circumstances, multiple "co-optimization" layers are required to ensure a proper economic balance. (i.e. not just trade-offs in energy vs. ancillary, but ancillary service vs. ancillary service as well).




**Scenario**:

- 30 MW of "Regulation Up" is required
- Assume: All three resource are capable of providing regulation (i.e. op range, ramping, etc.)
- Economically optimized solution is:
  - Resource 1: 5 MW
  - Resource 2: 10 MW
  - Resource 3: 15 MW
  - **Total Reg-Up: 30 MW**

# Opportunity Cost Illustration for HECO

## HECO-specific Opportunity Cost

In an effort to place the preceding material in context, the following slides will provide some HECO-specific perspective on the opportunity cost associated with migrating a resource away from providing energy and into ancillary participation.

On an individual basis, the incremental variable cost structure for each of the HECO resources will be compared to the marginal system level cost to identify the appropriate economic dispatch if that resource had been online and available. *Note: For this illustration, each resource will be individually compared to a proxy system cost. Therefore, the summation of the load set-points for each resource does not necessarily constitute a valid system solution.*

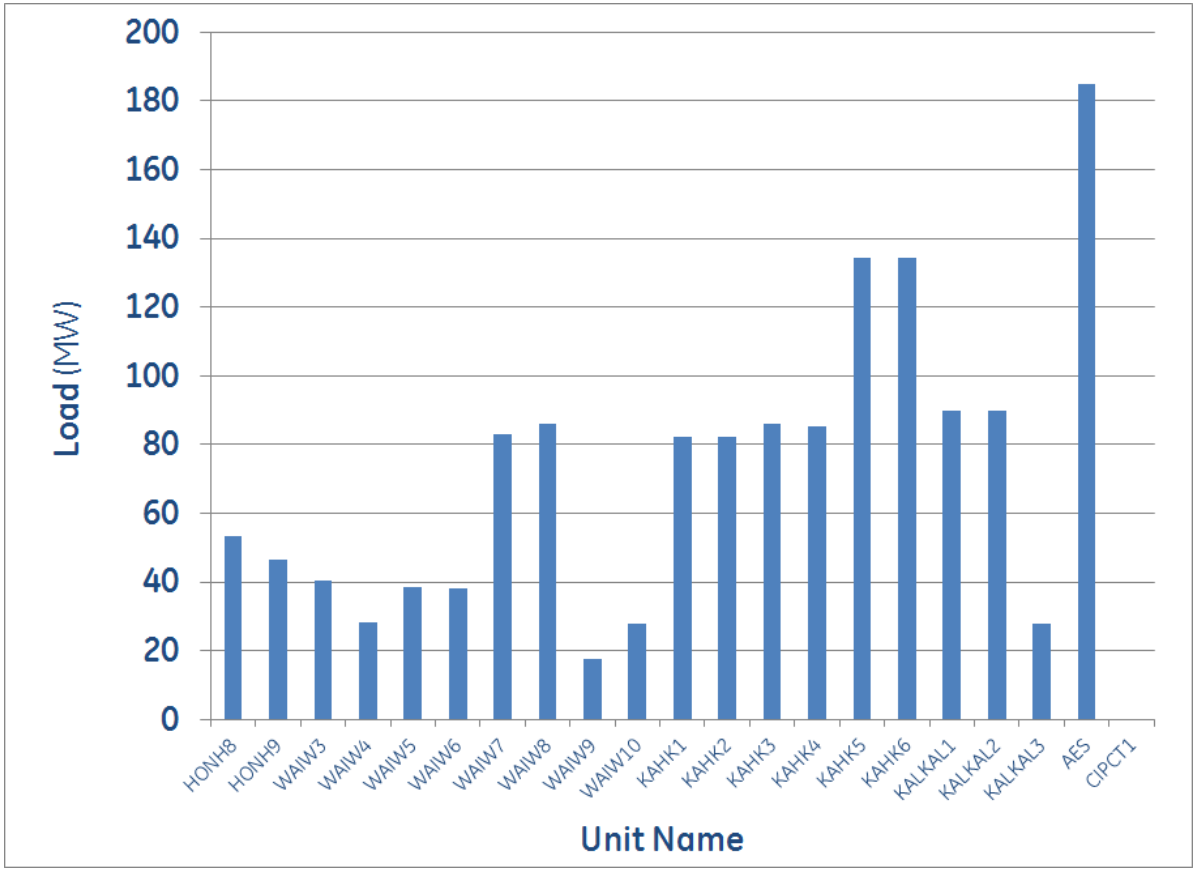
With an understanding of the economic dispatch set-point, each resource will then be perturbed away from this set-point to determine the associated opportunity cost of transferring capability away from providing energy.

Resources with the lowest opportunity cost should be the first resources transferred away from providing energy to fulfill ancillary requirements.

For this example, we'll be assuming an instantaneous marginal system level cost of $190 / MWh.

# Opportunity Cost Illustration for HECO

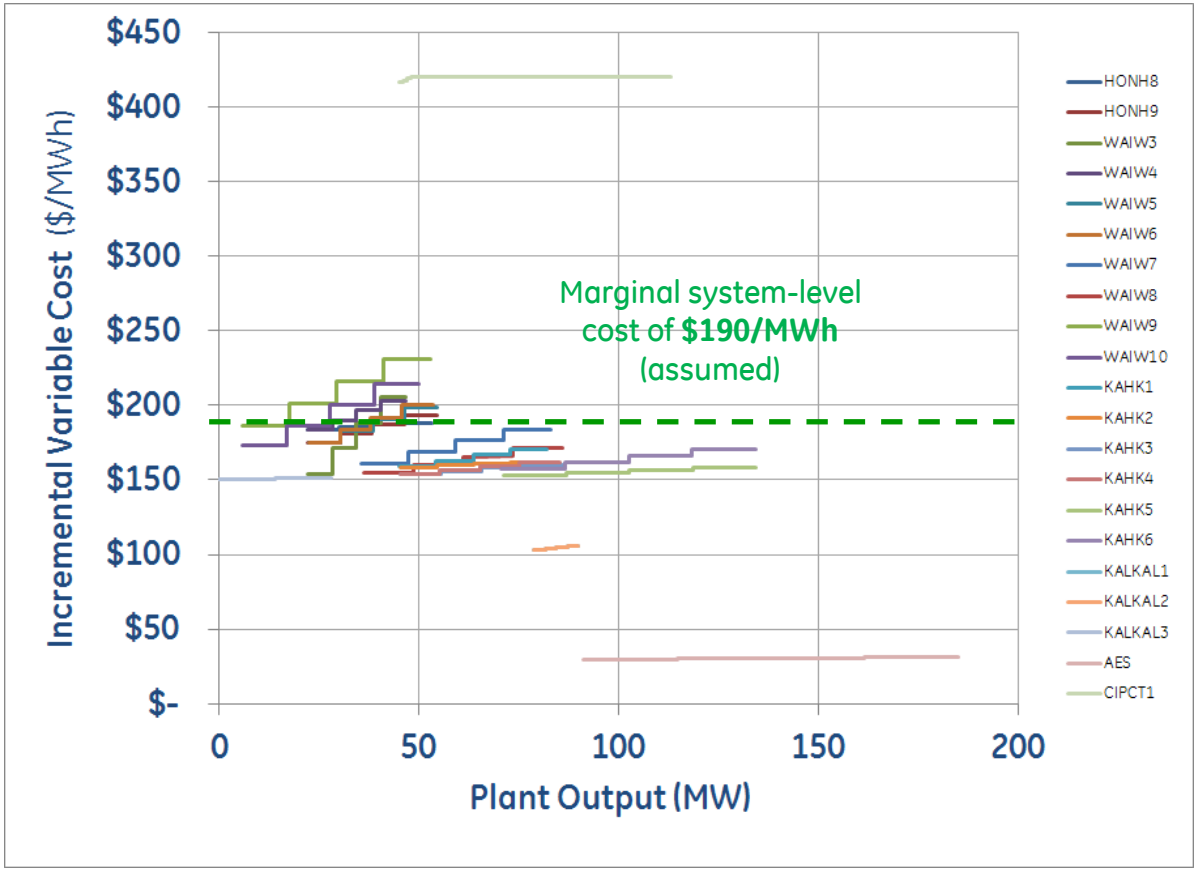
## Intersection of the marginal system cost and incremental cost establishes load level




For a $190 / MWh marginal system cost, the respective load level for each resource (if committed) would be as shown.

# Opportunity Cost Illustration for HECO

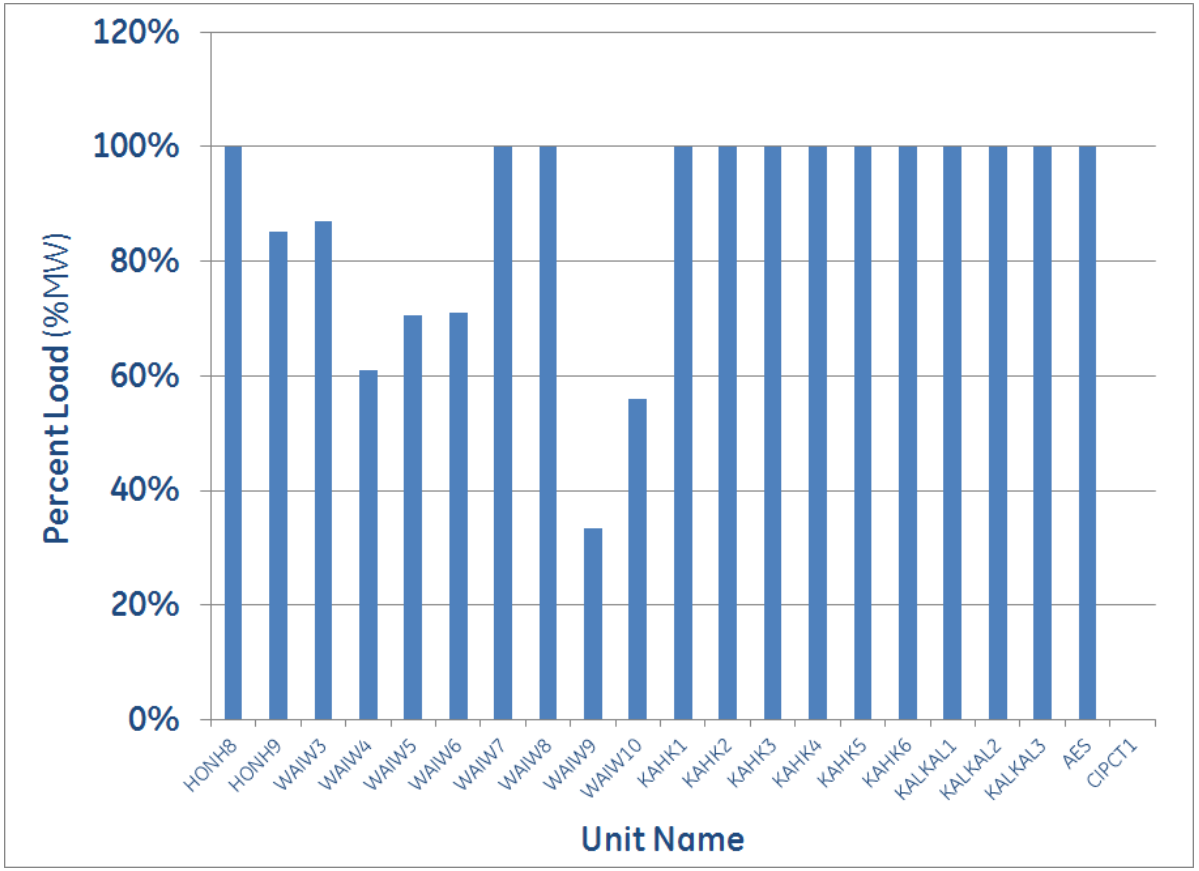
## Intersection of the marginal system cost and incremental cost establishes load level




All resources shown are initially dispatched economically per their incremental variable cost structure

# Opportunity Cost Illustration for HECO

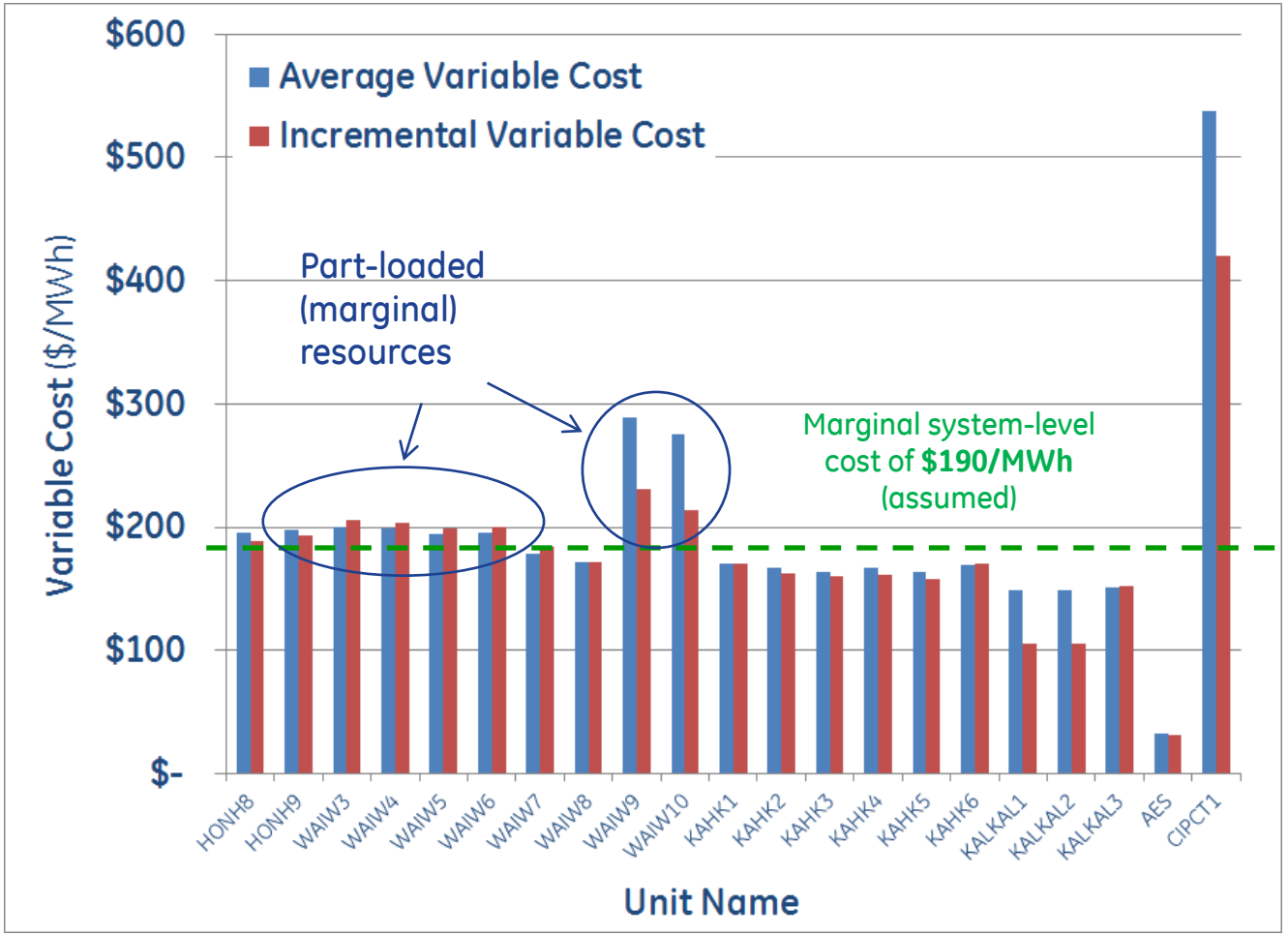
## Intersection of the marginal system cost and incremental cost establishes load level




For a $190 / MWh marginal system cost, the respective load level for each resource (if committed) would be as shown.

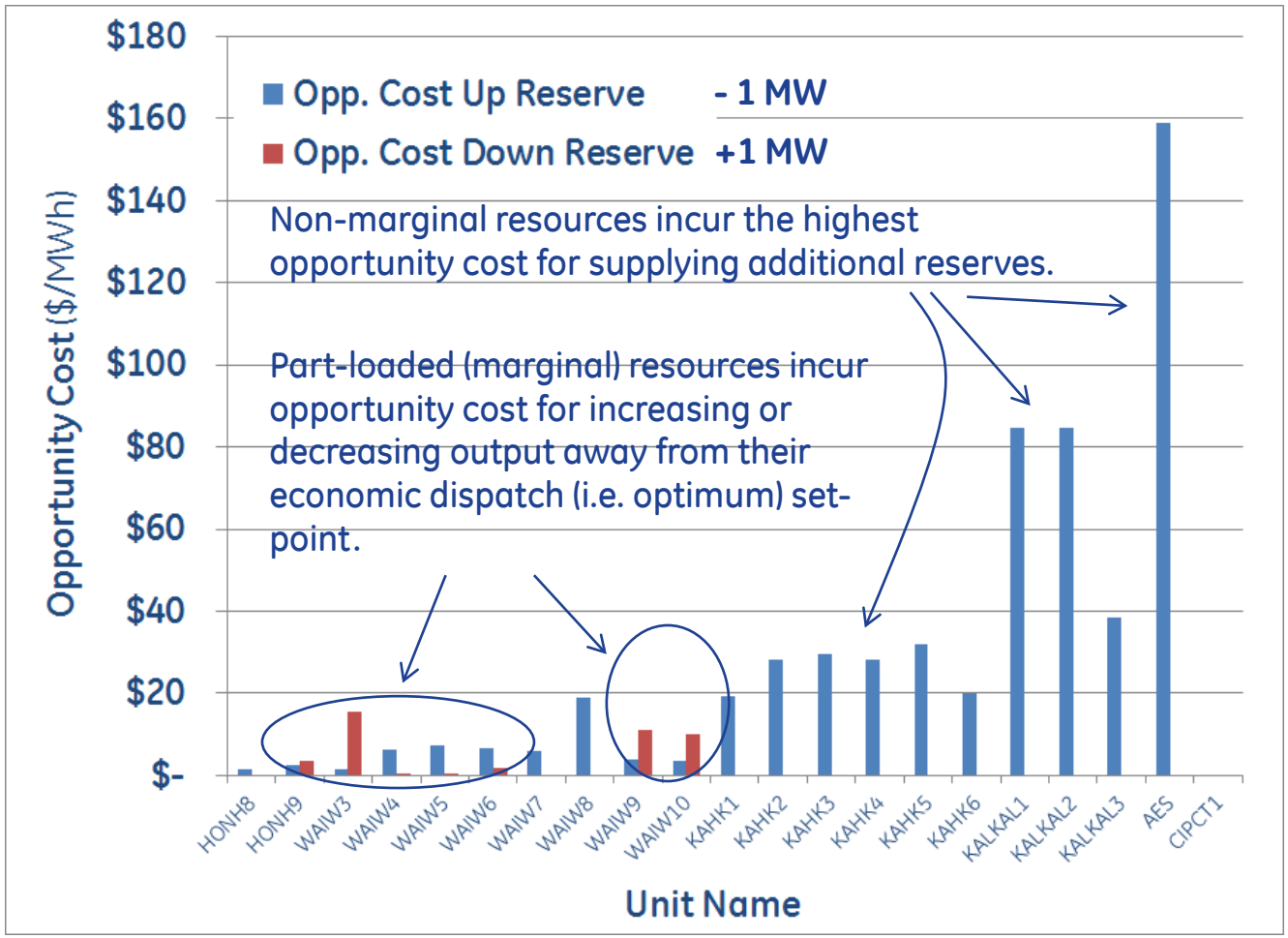
# Opportunity Cost Illustration for HECO

## Incremental and Average Variable Cost compared w/ the System Marginal Cost



# Opportunity Cost Illustration for HECO

## Instantaneous opportunity cost for shifting capability from energy to A/S

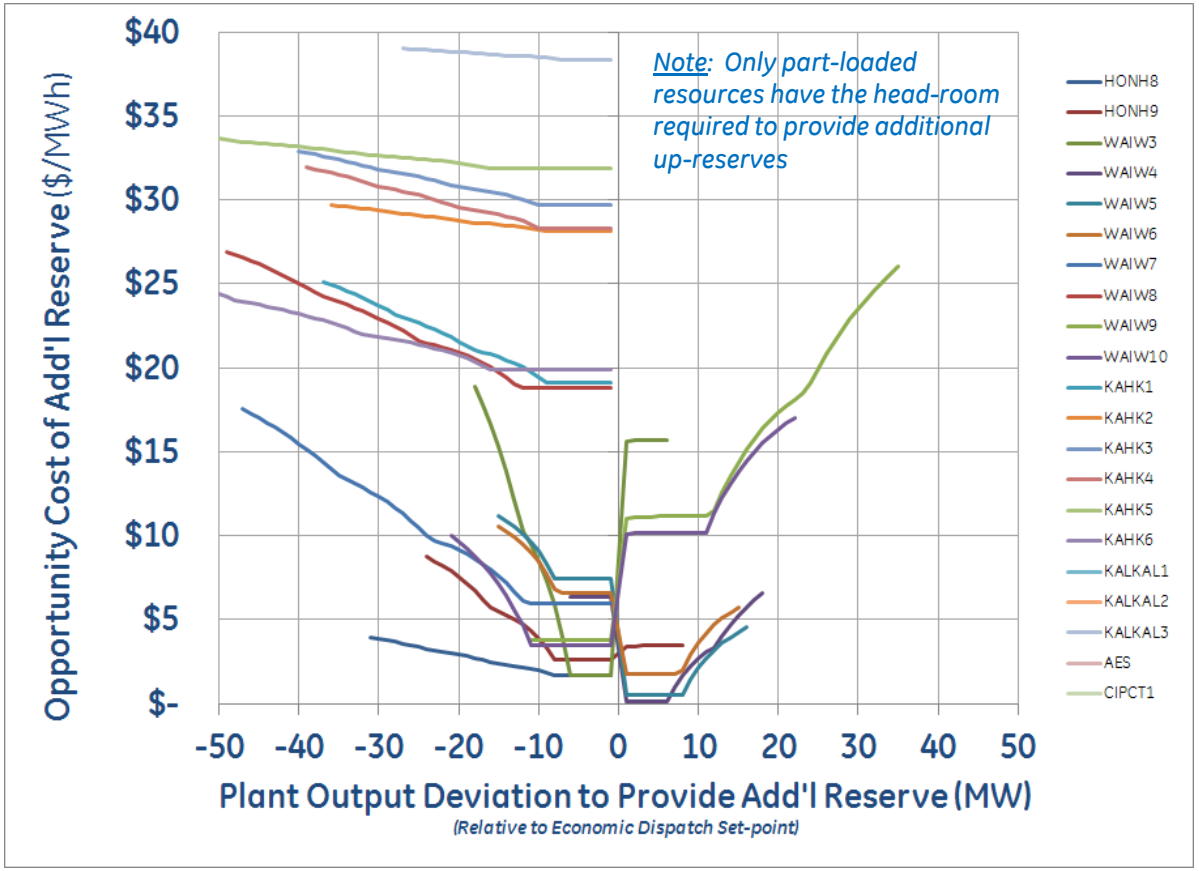


# Opportunity Cost Illustration for HECO

## Opportunity cost as the deviation from the economic dispatch set-point is increased

Units with:
- Lower variable cost
- Higher opportunity cost

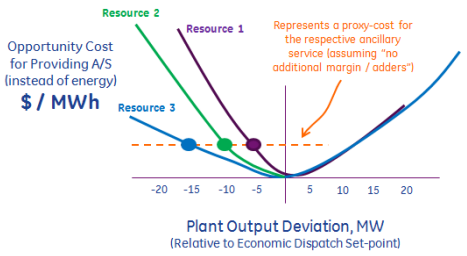
Units with:
- Higher variable cost
- Lower opportunity cost




Increasing Up Reserve

Increasing Down Reserve

*Reference: Fundamentals of Power System Operation*




imagination at work

# Process for Evaluating and Selecting a Potential Future Technology Mix

imagination at work

# Process for Evaluating a Resource Mix

## Overview

This section outlines a methodology that can be exercised during a resource planning process to evaluate and assist with the selection of a future technology mix that is compatible with the system-level interconnection and ancillary service requirements.

Specifically, the methodology focuses on minimizing the overall production cost and capital expenditure required to obtain a “least-cost” portfolio while observing system reliability needs.

Additional consideration is given to parameters which are more difficult to quantify economically, such as propensity for a given portfolio to improve future renewables penetration and/or reduce risk exposure.

# Process for Evaluating a Resource Mix

## Description of Approach

Using HECO Scenario 4A (as an example), each of the steps outlined in the above-mentioned process will be placed in context.

It should be noted that many options are available to fulfill any observed ancillary service deficiencies, such as: *New generation, Energy storage, Demand response programs, Transmission technologies, and Existing generation modifications/retrofits*

To ensure that an optimal (*economic, risk, environmental*) solution is achieved, it is recommended that a series of options be developed and analyzed via the process described on the following slides.

*Due to the complexity of the simulations required to generate the data that would be required to perform this analysis, the following process will not be able to be demonstrated in its entirety. A separate study would be required to calibrate a suitable simulation and fully execute the process.*

# Step 1: (Example)

## Identify Current or Future Scenario

Begin with an established current or future scenario. It is assumed that the resource-specific variable cost characteristics (i.e. heat rate curves, variable O&M cost, startup costs), min-up/down times, ramp-rates, storage capacity, DR availability/activation thresholds, and system-level future economic scenario (i.e. fuel cost/availability, system load forecast, etc.) are known values.

Select HECO 4A for this Example
*(including subsequent slides)*

| | HECO (Oahu) | MECO (Maui) | HELCO (Big Island) |
|---|---|---|---|
| **Most Recent IRP** | HECO IRP 2009-2028 (Sep 2008) | MECO IRP 2007-2026 (April 2007) | HELCO IRP 2007-2026 (May 2007) |
| **Resource Planning Study to support future IRP** | ? | Available from MECO | HELCO Resource Planning Study (June 2012) |
| **Other renewable integration studies** | OWIST & HSIS (Available from GE) | HSIS (Available from GE) | |
| **Load Forecast** | From OWIST and HSIS | Base Line From HSIS | Base Line From Resource Planning Study |
| **Scenario 1: Moderate penetration Renewables or mix definition** | HSIS Scenario 4A<br>360 MW Dist Solar PV<br>400 MW Cent Solar PV<br>100 MW On-shore Wind<br>No Off-Shore Wind | HSIS Base Line (2012 system)<br>15 MW Dist Solar PV<br>0 MW Cent Solar PV<br>72 MW On-shore Wind | HELCO 100% renewables intermittent – heavy<br>**22 MW Biomass**<br>**100 MW Wind (centralized)**<br>**100 MW PV (centralized or distributed)**<br>**50 MW Geothermal** |
| **Scenario 2: High penetration Renewables or mix definition** | HSIS Scenario 4B<br>160 MW Dist Solar PV<br>200 MW Cent Solar PV<br>100 MW On-shore Wind<br>200 Off-Shore Wind<br>(same solar & wind MWH as 4A) | HSIS Scenario 3<br>30 MW Dist Solar PV<br>15 MW Cent Solar PV<br>72 MW On-shore Wind<br>**Scenario 3: Heavy Intermittent Renewables**<br>**22 MW Biomass**<br>**100 MW Wind, 100 MW PV**<br>**50 MW Geothermal** | HELCO 100% renewables geothermal/ dispatchable – heavy<br>**42 MW Biomass**<br>**50 MW Wind (centralized)**<br>**50 MW PV (centralized or distributed)**<br>**100 MW Geothermal** |

# Step 1: (cont'd)

## Identify Current or Future Scenario

To provide a comprehensive evaluation, it may be necessary to perform an uncertainty analysis of the key parameters which influence the characterization of a given future scenario. The results of the uncertainty analysis would yield the relevant bounds for each key parameter. With the uncertainty bounds understood, a matrix of the desired evaluation conditions for a parametric sensitivity analysis could be established. This process would be executed for each evaluation condition to ensure a robust analysis of the potential resource mix.

- *A contemporary example of why the up-front uncertainty analysis would be beneficial is the increased adoption of distributed solar PV on the Hawaiian islands. The increase in the use of distributed solar PV has a tendency to change the system load forecast (i.e. net-load shape) which will be served by the centralized resource technologies targeted by this report. Without an uncertainty analysis, an inaccurate representation of the load forecast could result; this would have the potential to drive a sub-optimal resource mix.*

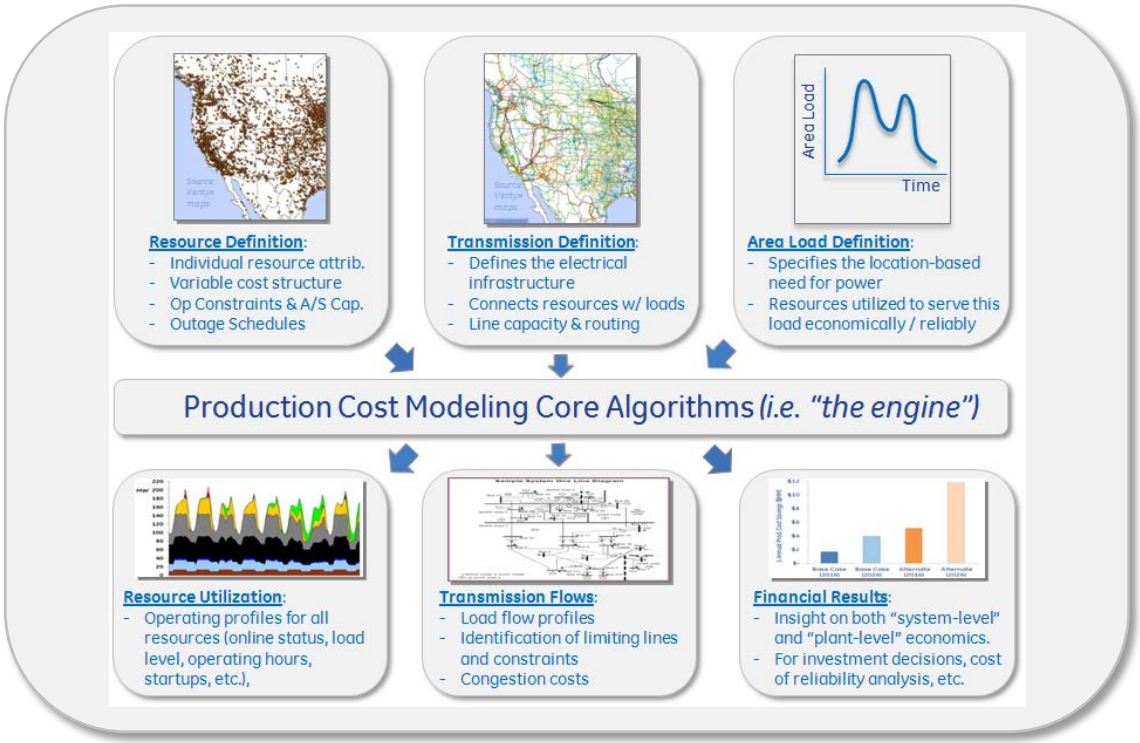
Similar uncertainty analysis of the resource-specific variable cost characteristics, operability constraints, storage/DR characteristics, fuel cost/availability, etc. may be required to develop a robust evaluation matrix to guide the sensitivity analysis.

# Step 2:

## Obtain Production Cost Simulation

Obtain a production cost simulation that is capable of performing security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED)

- The production cost simulation (or post-processing algorithms) should be capable of analyzing intra-hour behavior to fully evaluate the ancillary service performance
- Simulation needs to be able to "co-optimize" the energy and ancillary services.



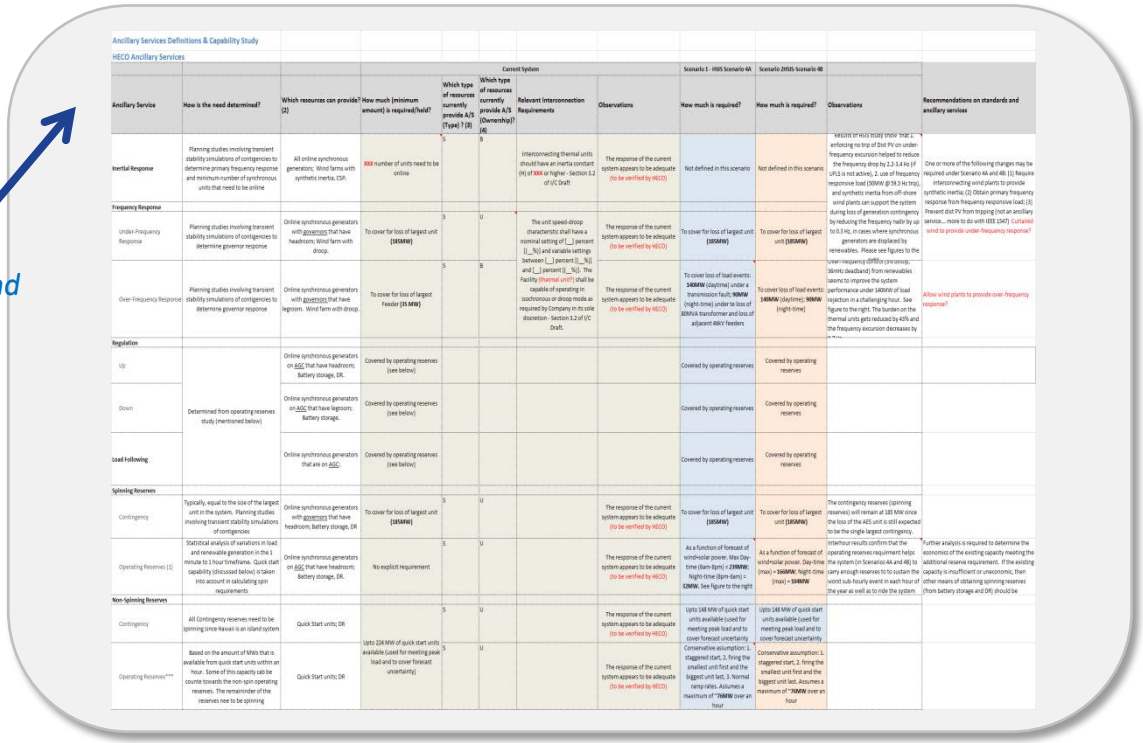
# Step 3:

## Estimate required "system-level" amounts for each ancillary service

Assess/Anticipate the required amount (and minimal level of acceptable responsiveness) that is required for each ancillary service. Provide these ancillary requirements to the production cost simulation and corresponding post-processing algorithms. These ancillary requirements will be interpreted as constraints by the simulation so that it can reserve the respective ancillary capability from each of the available resources. *Note: Iteration will be required to optimize.*

HECO Ancillary Service Matrix

*(Actual HECO spreadsheet accompanies this report and covers Scenarios 4A & 4B)*



Ancillary Services Definitions & Capability Study

HECO Ancillary Services

| Ancillary Service | How is the need determined? | Which resources can provide? (2) | How much (minimum amount) is required/held? | Current System: Which type of resources currently provide A/S (Type) ? (3) | Current System: Which type of resources currently provide A/S (Ownership)? (4) | Current System: Relevant Interconnection Requirements | Current System: Observations | Scenario 1 - HSIS Scenario 4A: How much is required? | Scenario 2HSIS-Scenario 4B: How much is required? | Scenario 2HSIS-Scenario 4B: Observations | Recommendations on standards and ancillary services |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Inertial Response | Planning studies involving transient stability simulations of contingencies to determine primary frequency response and minimum number of synchronous units that need to be online | All online synchronous generators; Wind farms with synthetic inertia; CSP; | XXX number of units need to be online | S | B | interconnecting thermal units should have an inertia constant (H) of XXX or higher - Section 3.2 of I/C Draft | The response of the current system appears to be adequate (to be verified by HECO) | Not defined in this scenario | Not defined in this scenario | Results of HSIS study show that 1. enforcing no trip of Dist PV on under-frequency excursion helped to reduce the frequency drop to 2.2-3.4 Hz (if UFLS is not active), 2. use of frequency responsive load (30MW @ 59.3 Hz trip), and synthetic inertia from off-shore wind plants can support the system during loss of generation contingency by reducing the frequency nadir by up to 0.3 Hz, in cases where synchronous generators are displaced by renewables. Please see figures to the | One or more of the following changes may be required under Scenario 4A and 4B: (1) Require interconnecting wind plants to provide synthetic inertia; (2) Obtain primary frequency response from frequency responsive load; (3) Prevent dist PV from tripping (not an ancillary service.... more to do with IEEE 1547) Curtailed wind to provide under-frequency response? |
| Frequency Response | | | | | | | | | | | |
| Under-Frequency Response | Planning studies involving transient stability simulations of contingencies to determine governor response | Online synchronous generators with governors that have headroom; Wind farm with droop. | To cover for loss of largest unit (185MW) | S | U | The unit speed-droop characteristic shall have a nominal setting of [__] percent [(__%)] and variable settings between [__] percent [(__%)] and [__] percent [(__%)]. The Facility (thermal unit?) shall be capable of operating in isochronous or droop mode as required by Company in its sole discretion - Section 3.2 of I/C Draft. | The response of the current system appears to be adequate (to be verified by HECO) | To cover for loss of largest unit (185MW) | To cover for loss of largest unit (185MW) | over-frequency droop (4% droop; 36mHz deadband) from renewables seems to improve the system performance under 140MW of load rejection in a challenging hour. See figure to the right. The burden on the thermal units gets reduced by 43% and the frequency excursion decreases by | |
| Over-Frequency Response | Planning studies involving transient stability simulations of contingencies to determine governor response | Online synchronous generators with governors that have legroom. Wind farm with droop. | To cover for loss of largest Feeder (35 MW) | S | B | | The response of the current system appears to be adequate (to be verified by HECO) | To cover loss of load events: 140MW (daytime) under a transmission fault; 90MW (night-time) under to loss of 80MVA transformer and loss of adjacent 46kV feeders | To cover loss of load events: 140MW (daytime); 90MW (night-time) | | Allow wind plants to provide over-frequency response? |
| Regulation | | | | | | | | | | | |
| Up | Determined from operating reserves study (mentioned below) | Online synchronous generators on AGC that have headroom; Battery storage, DR. | Covered by operating reserves (see below) | | | | | Covered by operating reserves | Covered by operating reserves | | |
| Down | | Online synchronous generators on AGC that have legroom; Battery storage. | Covered by operating reserves (see below) | | | | | Covered by operating reserves | Covered by operating reserves | | |
| Load Following | | Online synchronous generators that are on AGC. | Covered by operating reserves (see below) | | | | | Covered by operating reserves | Covered by operating reserves | | |
| Spinning Reserves | | | | | | | | | | | |
| Contingency | Typically, equal to the size of the largest unit in the system. Planning studies involving transient stability simulations of contingencies | Online synchronous generators with governors that have headroom; Battery storage, DR | To cover for loss of largest unit (185MW) | S | U | | The response of the current system appears to be adequate (to be verified by HECO) | To cover for loss of largest unit (185MW) | To cover for loss of largest unit (185MW) | The contingency reserves (spinning reserves) will remain at 185 MW since the loss of the AES unit is still expected to be the single largest contingency. | |
| Operating Reserves (1) | Statistical analysis of variations in load and renewable generation in the 1 minute to 1 hour timeframe. Quick start capability (discussed below) is taken into account in calculating spin requirements | Online synchronous generators on AGC that have headroom; Battery storage, DR. | No explicit requirement | S | U | | The response of the current system appears to be adequate (to be verified by HECO) | As a function of forecast of wind+solar power. Max Day time (6am-8pm) = 230MW; Night-time (8pm-6am) = 120MW. See figure to the right | As a function of forecast of wind+solar power. Day-time (max) = 160MW; Night-time (max) = 104MW | Interhour results confirm that the operating reserves requirement helps the system (in Scenarios 4A and 4B) to carry enough reserves to to sustain the worst sub-hourly event in each hour of the year as well as to ride the system | Further analysis is required to determine the economics of the existing capacity meeting the additional reserve requirement. If the existing capacity is insufficient or uneconomic, then other means of obtaining spinning reserves (from battery storage and DR) should be |
| Non-Spinning Reserves | | | | | | | | | | | |
| Contingency | All Contingency reserves need to be spinning since Hawaii is an island system | Quick Start units; DR | Upto 226 MW of quick start units available (used for meeting peak load and to cover forecast uncertainty) | S | U | | The response of the current system appears to be adequate (to be verified by HECO) | Upto 148 MW of quick start units available (used for meeting peak load and to cover forecast uncertainty | Upto 148 MW of quick start units available (used for meeting peak load and to cover forecast uncertainty | | |
| Operating Reserves(***) | Based on the amount of MWs that is available from quick start units within an hour. Some of this capacity can be counte towards the non-spin operating reserves. The remainder of the reserves nee to be spinning | Quick Start units; DR | | S | U | | The response of the current system appears to be adequate (to be verified by HECO) | Conservative assumption: 1. staggered start, 2. firing the smallest unit first and the biggest unit last, 3. Normal ramp rates. Assumes a maximum of ~70MW over an hour | Conservative assumption: 1. staggered start, 2. firing the smallest unit first and the biggest unit last. Assumes a maximum of ~70MW over an hour | | |

# Step 4:

## Identify "resource-level" ancillary service capability

Identify the amount of each ancillary service that can be performed by each resource. This establishes the subset of the respective resource's capability that could be allocated to the given ancillary service. Items such as operating range, startup times, ramp-rates, min-up/down times, inertial response, black start capability, etc. are key considerations.

**Example**: Representative Ramp Rate Capability for HECO Resources

*(other attributes would require similar definition for each resource)*

| Unit | Actual 2012 | Target Upward | Target Downward | Maximum Upward |
|---|---|---|---|---|
| | (MW/min) | (MW/min) | (MW/min) | (MW/min) |
| HONH8 | 1.4 | 1.4 | 1.4 | 5.0 |
| HONH9 | 1.3 | 1.3 | 1.3 | 5.0 |
| WAIW3 | 1.4 | 1.4 | 1.4 | 4.0 |
| WAIW4 | 0.7 | 0.7 | 0.7 | 4.0 |
| WAIW5 | 3.0 | 3.0 | 3.0 | 5.0 |
| WAIW6 | 3.0 | 3.0 | 3.0 | 5.0 |
| WAIW7 | 3.0 | 5.0 | 3.0 | 7.0 |
| WAIW8 | 3.0 | 5.0 | 3.0 | 7.0 |
| WAIW9 | 3.0 | 5.0 | 5.0 | 10.0 |
| WAIW10 | 3.0 | 5.0 | 5.0 | 10.0 |
| KAHK1 | 3.0 | 5.0 | 3.0 | 7.0 |
| KAHK2 | 1.6 | 5.0 | 3.0 | 7.0 |
| KAHK3 | 3.0 | 5.0 | 3.0 | 7.0 |
| KAHK4 | 3.0 | 5.0 | 3.0 | 7.0 |
| KAHK5 | 3.0 | 7.0 | 3.0 | 10.0 |
| KAHK6 | 3.0 | 6.0 | 3.0 | 8.0 |
| CIP CT-1 | 3.0 | 10.0 | 10.0 | 13.0 |
| AES | 2.5 | | | |

# Step 4: (cont'd)

## Identify "resource-level" ancillary service capability

The following table provides an overview of the ancillary service compatibility *that would be assumed* for each HECO resource if a detailed ancillary service assessment of Scenario 4A were performed. *Note: Previous simulations and analysis of Scenario 4A have not explicitly considered the ancillary service obligations with the granularity depicted in the table below.*

| | | | | | Ancillary Services Compatibility | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HECO Resources - Scenario 4A | Duty | Fuel | Prime Mover | Cap. (MW) | Inertial Response | Frequency Responsive Reserve | Regulation | Load Following | Spinning Reserve | Non-Spinning Reserve | Replacement Reserve | Voltage Support | Black Start |
| AES | Baseload | Coal | ST | 185 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ----- | ✓ | ----- |
| H POWER | Baseload | Biomass/Wast | ST | 73 | ✓ | ----- | ----- | ----- | ----- | ----- | ----- | ✓ | ----- |
| HONUA WASTE UNIT | Baseload | Biomass/Wast | ST | 6 | ✓ | ----- | ----- | ----- | ----- | ----- | ----- | ✓ | ----- |
| KAHE 1 | Baseload | LSFO | ST | 82 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ----- | ✓ | ✓ |
| KAHE 2 | Baseload | LSFO | ST | 82 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ----- | ✓ | ✓ |
| KAHE 3 | Baseload | LSFO | ST | 86 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ----- | ✓ | ✓ |
| KAHE 4 | Baseload | LSFO | ST | 85 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ----- | ✓ | ✓ |
| KAHE 5 | Baseload | LSFO | ST | 134 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ----- | ✓ | ----- |
| KAHE 6 | Baseload | LSFO | ST | 134 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ----- | ✓ | ----- |
| KALAELOA CC | Baseload | LSFO | CC | 90 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ----- | ✓ | ----- |
| KALAELOA CC | Baseload | LSFO | CC | 90 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ----- | ✓ | ----- |
| WAIAU 7 | Baseload | LSFO | ST | 83 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ----- | ✓ | ----- |
| WAIAU 8 | Baseload | LSFO | ST | 86 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ----- | ✓ | ----- |
| HONOLULU 8 | Cycling | LSFO | CT | 53 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ✓ | ✓ | ----- |
| HONOLULU 9 | Cycling | LSFO | CT | 54 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ✓ | ✓ | ----- |
| WAIAU 3 | Cycling | LSFO | CT | 47 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ✓ | ✓ | ----- |
| WAIAU 4 | Cycling | LSFO | CT | 47 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ✓ | ✓ | ----- |
| WAIAU 5 | Cycling | LSFO | CT | 55 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ✓ | ✓ | ----- |
| WAIAU 6 | Cycling | LSFO | CT | 54 | ✓ | ✓ | ✓ | ✓ | ✓ | ----- | ✓ | ✓ | ----- |
| AIRPORT DSG 8 MW | Peaking | Biomass/Wast | CT | 8 | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ----- |
| CIP CT BIODIESEL | Peaking | Biomass/Wast | CT | 113 | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ----- |
| WAIAU 10 | Peaking | Diesel | CT | 50 | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| WAIAU 9 | Peaking | Diesel | CT | 53 | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| OAHU CENTRALIZED SOLAR | Solar | Solar | Solar PV | 400 | ----- | ----- | ----- | ----- | ----- | ----- | ----- | ✓ | ----- |
| OAHU DISTRIBUTED SOLAR | Solar | Solar | Solar PV | 360 | ----- | ----- | ----- | ----- | ----- | ----- | ----- | ✓ | ----- |
| OAHU WIND 30MW | Wind | Wind | Wind | 30 | ----- | ----- | ----- | ----- | ----- | ----- | ----- | ✓ | ----- |
| OAHU WIND 70MW | Wind | Wind | Wind | 70 | ----- | ----- | ----- | ----- | ----- | ----- | ----- | ✓ | ----- |

# Step 5:

## Execute the Production Cost Simulation

Execute the production cost simulation for the respective scenario. Review the hourly (and sub-hourly data as applicable) to ensure that all ancillary services requirements (plus other relevant system constraints) were observed. *i.e. sufficient system-level regulation, spinning reserve, etc. was reserved.*

# Step 6:

## Identify Trends in the Results

If the ancillary service requirements were not successfully achieved, or it appears that excess ancillary capability is available, consider the trends in the deficiencies (or excess):

- Are the deficiencies (or excess) driven by inadequate responsiveness from the available resources?
- Are the deficiencies (or excess) driven by inadequate operating range?
- Are the deficiencies (or excess) present in all hours or only some hours?

# Step 7:

## Consider potential solutions to alleviate deficiencies and improve system efficiency

Adjustments to operating procedures:

- Adjusted minimum run-times
- Relaxed qualifications/requirements for respective A/S participation
- Activation thresholds for DR,
- storage device charging procedures
- Relaxed "must-run" rules

Retrofits of existing resources:

- Increased plant output
- Improved turndown on thermal units
- Elevated ramp-rates
- Reduced start times
- Synthetic inertia & governor response from renewables

New resources:

- Fossil
- Storage
- Demand response
- Renewable assets
- Inter-island connectivity

### Coupled Benefits

**Are there resource adjustments (or new resources) that would alleviate multiple deficiencies (or excess)?**

*i.e. Re-tuning the synthetic inertia of a wind-turbine in conjunction with pitch-control enhancement might facilitate improvements to both inertia and regulation capabilities.*

# Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled: "HECO Ancillary Services for Scenarios".

## Identify Trends / Consider Solutions: **Inertial Response** – Scenario 4A

*Observations*

- The inertial response of the system appears to be adequate in Scenario 4A.

*Recommendations*

- Consider requiring interconnecting wind and solar plants to provide synthetic inertia to further strengthen the inertial response capability.

# Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled: "HECO Ancillary Services for Scenarios".

## Identify Trends / Consider Solutions : **Frequency Responsive Reserve** – Scenario 4A

*Amount Required*

- Under-frequency response: Needs to be able to cover loss of largest unit (185 MW)
- Over-frequency response: To cover loss of load events: 140MW (daytime) under a transmission fault; 90MW (night-time) under the loss of 80MVA transformer and loss of adjacent 46kV feeders.

*Observations*

- For under-frequency*, the results of HSIS study show that:
  - Enforcing "no trip" of distributed PV on under-frequency excursion helped to reduce the frequency drop by 2.2-3.4 Hz (if UFLS is not active).
  - Use of frequency responsive load (50MW @ 59.5 Hz trip), and synthetic inertia from wind plants can support the system during loss of generation contingency by reducing the frequency nadir by up to 0.3 Hz, in cases where synchronous generators are displaced by renewables.
- For over-frequency*:
  - Over-frequency control (5% droop, 36mHz dead-band) from renewables seems to improve the system performance under 140MW of load rejection in a challenging hour. The burden on the thermal units gets reduced by 43% and the frequency excursion decreases by 0.7 Hz.

# Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled: "HECO Ancillary Services for Scenarios".

## Identify Trends / Consider Solutions : **Frequency Responsive Reserve** – Scenario 4A

*Recommendations*

- For under-frequency, *one or more of the following changes may be required under Scenario 4A and 4B (additional simulation / analysis would be required to confirm):*
  - *Obtain primary frequency response from frequency responsive load*
  - *Prevent distributed PV from tripping (not an ancillary service… more to do with IEEE 1547)*
  - *Permit curtailed wind and solar resources to provide under-frequency response*

- *For over-frequency:*
  - *Consider allowing wind and solar resources plants to provide over-frequency response.*

# Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled: "HECO Ancillary Services for Scenarios".

## Identify Trends / Consider Solutions : **Regulation & Load Following** – Scenario 4A

*Observations*

- The regulation and load following needs of the system are currently covered by operating reserves and deemed to be adequate.

*Recommendations*

- No firm recommendations at this time. Further analysis may yield a more economically optimal means of obtaining the regulation & load following services.

# Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled: "HECO Ancillary Services for Scenarios".

## Identify Trends / Consider Solutions : **Spinning Reserve** – Scenario 4A

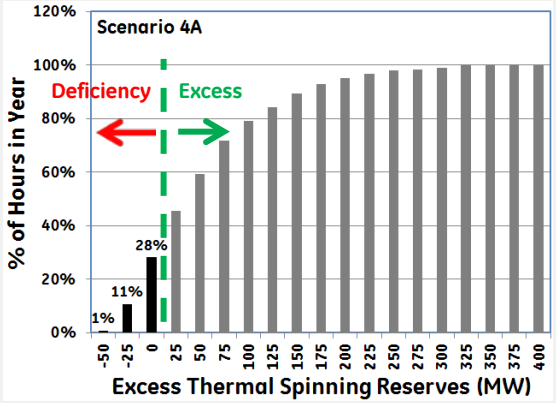
### *Amount Required*

- Contingency Reserves: Needs to be able to cover loss of largest unit (185 MW)
- Operating Reserves: No explicit requirement, but required to cover statistical variation in load and renewable generation in the 1 minute to 1 hour timeframe. Quick start capability is taken into account when calculating spinning reserve requirements.
  - Max variation: Day-time (6am-8pm) = 239MW; Night-time (8pm-6am) = 32MW.

### *Observations*

- In Scenario 4A, a deficiency of Spinning Reserves is anticipated 28% of the time (up to 50 MW maximum)
- Due to sufficient reserve participation from baseload units, the full 50 MW would only be required 1% of the time.
- However, in some hours, cycling units are committed to meet the higher operating reserves requirement & net load.

**Analysis of Spinning Reserve: HECO Scenario 4A**



# Steps 6/7: (cont'd)

Note: Comprehensive validation of the recommendations in this step require additional simulation runs and analysis which are presently determined to be outside the scope of this study.

## Identify Trends / Consider Solutions : **Spinning Reserve** – Scenario 4A

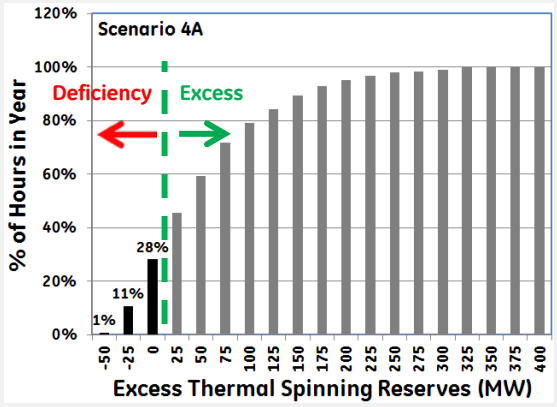
*Recommendations*

Multiple options exist to relieve the anticipated Spinning Reserve issues. Two options will be presented below:

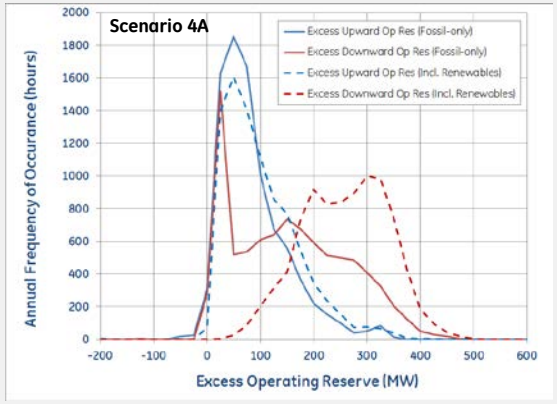
Option #1: To alleviate the deficiency, consider the addition of 50-MW BESS or DR resource. Beyond relieving the shortage, this option could potentially lower the reserves requirement on thermal units and help to de-commit cycling generation which would allow the system to absorb more solar & wind energy.

Option #2: To relieve the excess spinning reserve, consider allowing curtailed renewables to provide reserves. Modern Wind / Solar facilities are capable of responding quickly to load set-point adjustments. This action may reduce commitment on thermal units (reducing excess reserves), and potentially provide for increased penetration of renewable resources.

**Spinning Reserve Adequacy**




**Inherent Spinning Reserve From Renewables**




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# Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled: "HECO Ancillary Services for Scenarios".

## Identify Trends / Consider Solutions : **Non-Spinning Reserve** – Scenario 4A

*Amount Required*

- Contingency Reserves: All contingency reserves are required to be spinning on an island system.
- Operating Reserves: No explicit requirement for non-spinning operating reserves.

*Observations*

- The response of the current system appears to be adequate.

*Recommendations*

- None.

# Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled: "HECO Ancillary Services for Scenarios".

## Identify Trends / Consider Solutions : **Black Start** – Scenario 4A

*Amount Required*

- The MWs and location of black start units are determined based on a planning study
- Currently provided by the Kahe, Waiau, and Campbell units.

*Observations*

- Black start capability of the system is probably sufficient since there is no significant load growth in Scenario 4A. Further analysis may be required to confirm.

*Recommendations*

- None.

# Steps 6/7: (cont'd)

Note: Additional information can be found in the spreadsheet which accompanies this report titled: "HECO Ancillary Services for Scenarios".

## Identify Trends / Consider Solutions : **Voltage Support** – Scenario 4A

*Observations*

- Currently provided by all online generators with voltage and reactive power controls (including Wind, Solar, and Sync. Condensers)
- The response of the current system appears to be adequate.

*Recommendations*

- There may a need for additional voltage support if the "must-run" rules on existing thermal units is relaxed.

# Steps 6/7: (cont'd)

## Identify Trends / Consider Solutions : Many Permutations of Solutions are Available

| | |
|---|---|
| C | Currently deployed: Assumed to be available for HECO Scenario 4A |
| A | Future Option: Available commercially |
| E | Future Option: Emerging capability in demonstration phase |
| T | Future Option: Technically feasible, but not currently being pursued |

| Technologies | Ancillary Services Compatibility | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Inertial Response | Frequency Responsive Reserve | Regulation | Load Following | Spinning Reserve | Non-Spinning Reserve | Replacement Reserve | Voltage Support | Black Start |
| **Generation** | | | | | | | | | |
| Solar Thermal | A | T | T | T | T | --- | --- | A | T |
| Solar Photovoltaic (Transmission Connected) | T | T | T | T | T | T | T | T | --- |
| Wind (non-synchronized / power conversion) | A | A | A | A | A | T | T | A | --- |
| Wind (synchronized) | A | A | A | A | A | T | T | A | T |
| Hydropower | A | A | A | A | A | A | A | A | A |
| Geothermal | A | A | A | A | A | | | A | T |
| Biomass ST | C | A | A | A | A | --- | --- | C | --- |
| Oil-fired ST | C | C | C | C | C | --- | --- | C | C |
| Coal ST | C | C | C | C | C | --- | --- | C | --- |
| Combined Cycle (Gas/Oil/Biomass/Waste) | C | C | C | C | C | A | A | C | A |
| Simple Cycle (Gas/Oil/Biomass/Waste) | C | C | C | C | C | C | C | C | C |
| Reciprocating Engines (Gas/Diesel/Bio) | A | A | A | A | A | A | A | A | A |
| **Energy Storage** | | | | | | | | | |
| Pumped Hydropower | A | A | A | A | A | A | A | A | A |
| CAES - Comp. Air Energy Storage | E | E | E | E | E | E | E | E | T |
| Solid Batteries | E | E | A | E | A | E | E | E | E |
| Flow Batteries (Redox) | T | T | T | T | T | T | T | T | T |
| Flywheels | E | E | | | | --- | --- | T | --- |
| PEV | T | T | E | T | T | T | T | T | T |
| Fuel Cells (PEM) | T | T | T | T | T | T | T | T | T |
| **Demand Response** | | | | | | | | | |
| Fast Auto DR | T | A | A | T | A | A | A | --- | --- |
| Direct Load Control | T | A | E | T | A | A | A | --- | --- |
| Interruptible Load | T | A | T | T | A | A | A | --- | --- |
| Price Responsive Demand | T | T | T | T | A | A | A | --- | --- |
| **Transmission** | | | | | | | | | |
| Synch. Cond.: Large motor frame | A | --- | --- | --- | --- | --- | --- | A | --- |
| Synch. Cond.: Air-cooled generator frame | A | --- | --- | --- | --- | --- | --- | A | --- |
| Synch. Cond.: H2-cooled generator frame | A | --- | --- | --- | --- | --- | --- | A | --- |
| Shunt FACTS devices (STATCOM, SVCs)* | --- | --- | --- | --- | --- | --- | --- | A | --- |
| HVDC Transmission Technologies* | --- | --- | --- | --- | --- | --- | --- | A | A |
| **Desirable Attributes / Retrofit Options** | | | | | | | | | |
| Improved Turndown (MinGen) Capability | ✓ | ✓ | ✓ | ✓ | ✓ | | | ✓ | |
| Elevated Ramp-rate Capability | | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | | ✓ |
| Faster Startup Capability | | | | | | ✓ | ✓ | | |

Resource mix that was considered in the simulation of Scenario 4A

- Many alternative options are available to fulfill the desired renewables penetration levels associated with Scenario 4A.
- The associated A/S permutations of resource types (and modifications) along with technology readiness is captured in the table at the left.

# Steps 6/7: (cont'd)

## Identify Trends / Consider Solutions : Synergies between technology types

When selecting new resources and/or resource modifications to alleviate ancillary constraints, there may be synergies available. For example:

- When allowing VG (solar/wind) to participate in A/S, the addition of a moderate amount of storage may have the potential enable more periods where VG can provide the A/S needs. Further, the availability of the storage may help to cover a portion of the A/S requirements that would have otherwise been provided by dispatchable thermal generation … further increasing renewables penetration objectives. DR may offer benefits which are analogous to those of storage.
- As additional "non-synchronous" generation is added to the power system for the purposes of providing both energy and ancillary services, there may be a need for the addition of transmission technologies such as synchronous condensing units to be added to ensure sufficient reactive power.

It should be noted that the degree to which synergies will available and their corresponding benefit is highly dependent upon the respective scenario being considered. The current process being described provides a method for evaluating a technology mix in a given scenario. As each scenario/mix combination is evaluated, other potential synergies between technologies may emerge.

# Steps 8/9:

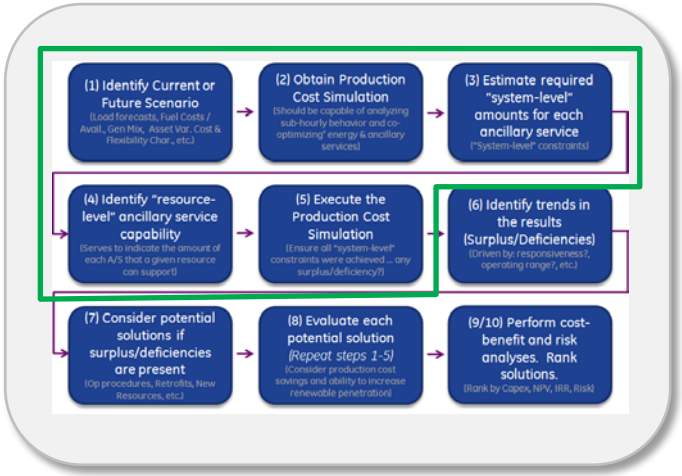
## Evaluate the economic viability of each potential solution

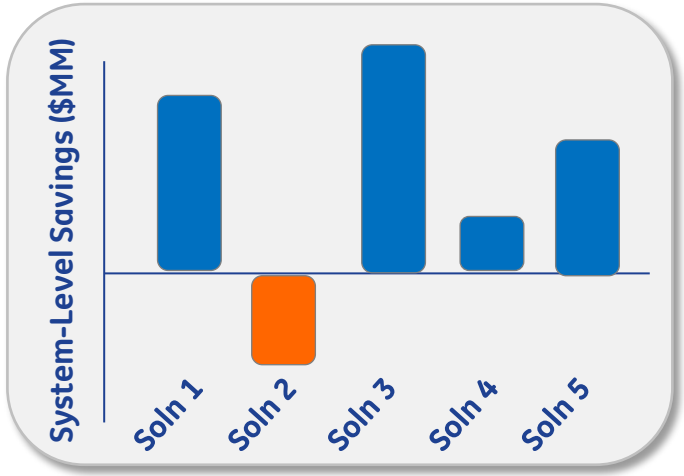
Note: Completion of this step requires additional simulation runs and analysis which are presently determined to be outside the scope of this study. Conceptual illustration only.

**Step 8**: For each potential solution identified, repeat steps 1-5:

- Consider/evaluate the change in total cost required to serve the anticipated system load profile.
- Potential for the respective solution to facilitate the desired trajectory of renewables penetration over-time.

**Step 9**: Perform a cost-benefit analysis which evaluates the year-over-year (YOY) system-level benefit (typically in the form of reduced production cost) of the proposed solution relative to the capital cost required to achieve the respective solution. Rank the solutions according to their economic viability (i.e. NPV, IRR, etc.)



# Step 10:

## Evaluate the risks associated of each potential solution

Note: Completion of this step requires additional simulation runs and analysis which are presently determined to be outside the scope of this study. Conceptual illustration only.

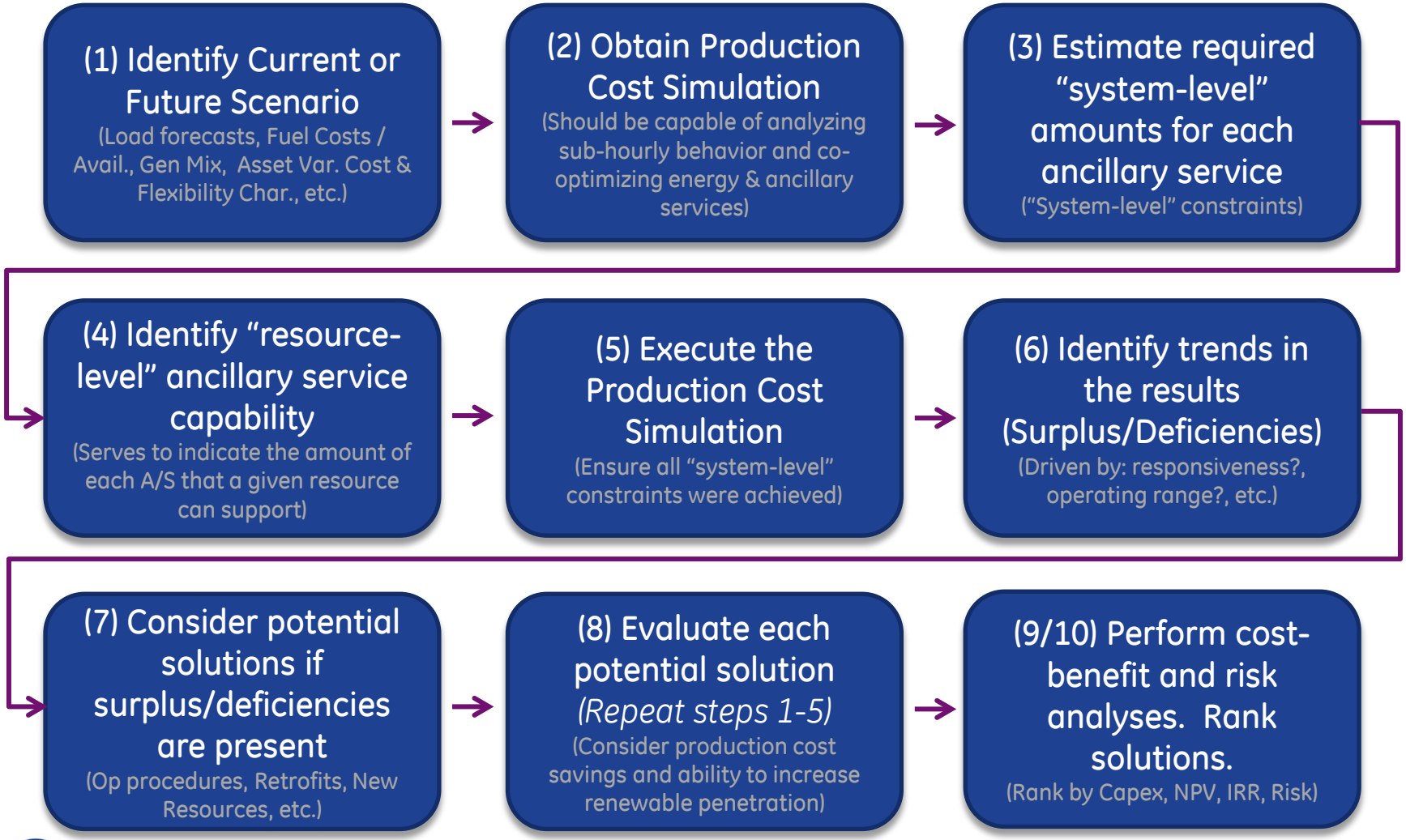
A comprehensive risk assessment of the potential options should also be conducted and weighted against to the economic viability to ensure that the selected solution is robust and reliable.

Potential Risks to consider (not limited to the following):

- Inadequate response from renewables due to instantaneous availability
- Available down-reserves and stable operating region of thermal units during loss of load events
- Voltage/VAR support sufficiency
- Reductions in inertial response capability
- Unfavorable impacts to "system-level" variable cost of operation
- Impact to existing utility / IPP contracts may require modifications to accommodate schedule changes
- Challenges associated with monitoring / controlling DR participation on a centralized basis

# Process to Estimate Technology Mix

## Summary



# Considerations for Specifying and Acquiring Ancillary Services

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# Task 4: Scope & Deliverables

## Outline considerations for specifying and acquiring ancillary services

Objectives:

- Promote a least-cost portfolio of resources that can supply ancillary services and interconnection requirements that attempt to protect reliability, maximize renewable output and minimize energy costs
- Highlight costs, technology availability, fuel availability or other risks associated with the recommended ancillary services and potential technology mix, with contributions from HPUC and HECO
- Outline factors and provisions to consider for future resources:
  - Type of ancillary services and performance requirements (Task 1)
  - Technology/manufacturer neutral response capabilities for interconnection requirements for new generators (Task 2)
  - Risk, cost and cost-effectiveness methods explored in other power systems
  - Process to compare alternative ancillary service offerings
- Describe any additional study work, including estimated timeline and cost, that may be required to identify the type and amount of ancillary services required

# Task 4: Scope & Deliverables

## Outline considerations for specifying and acquiring ancillary services

Approach:

- Summarize findings in Tasks 1-3
- Identify potential risks such as Hawaii specific resource costs, technology availability, fuel availability, and other that may impact the ability of the Hawaiian utilities and HPUC to build an effective portfolio of resources to provide ancillary services, fulfill interconnection requirements or address other system considerations

# Methods for Procuring Ancillary Services

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# Procuring Ancillary Services

## Overview of Approaches for Obtaining, Compensating, and Incentivizing

This section puts forth some potential approaches and mechanisms which can be used to obtain, compensate, and incentivize resources for providing ancillary services.

The following **four** approaches will be highlighted in this section:

1. Market Clearing Price
2. Reimbursement of Offer Price
3. "Make-whole" Compensation
4. Condition of Interconnection

The above listing is not intended to be exhaustive; however, the GE team believes that it contains a representative subset of the most viable techniques which could be considered. Further, it should be noted that each option is not mutually exclusive and may incorporate aspects of the surrounding approaches.

# Procuring Ancillary Services

## Method 1: Market Clearing Price

The Marketing Clearing Price approach is leveraged primarily by wholesale power markets:

- For this method, each resource submits (or is assigned) an offer price for the respective ancillary service.
  - Most often, resources submit offer prices that are based on their opportunity cost to reserve the headroom or legroom required to provide the service.
  - Some resources, such as storage devices, do not have an opportunity cost because they do not directly provide energy. Instead, their offer price may be based on startup, variable O&M, charging costs, or other expenses associated with providing the respective A/S.
  - In addition to the cost to provide the service, many markets allow resources to include "additional margin" in their offer price. In some cases, the resource may use to the additional margin to hedge against increased variable O&M costs (i.e. cycling wear & tear). In other cases, the resources may simply leverage the additional margin to cover "cost uncertainty" and/or attempt to enhance their ancillary profitability.
  - In some markets, the offer price is capped. The cap is often derived by calculating the cost for a unit to provide the service and adding [up to] a maximum allowable margin. The lesser of the submitted price and the capped price is then used as the offer price in the market clearing algorithms.

# Procuring Ancillary Services

## Method 1: Market Clearing Price (cont'd)

- The "market clearing price" for the ancillary service is driven by the *offer price of the last rank-ordered* resource required* to satisfy the system-level ancillary requirement (for the respective ancillary service). For this approach, all participating resources will receive the "same price" for the given period (typically 1-hour increments).
  - *In many wholesale markets, there exists both a day-ahead clearing price and a real-time (or supplemental) clearing price (as-required) to ensure sufficient ancillary availability.*
- To incentivize "no risk" participation, some markets will compensate for "actual incurred" costs which are larger than the revenues derived from the ancillary market clearing price via "make-whole" payments. This ensures that resources are "no worse off" for having provided ancillary services.
- Due to the fact that all participating resources receive the same price for a given ancillary service, it is important to note that most resources, with the exception of the marginal ancillary resource, will earn a financial benefit (i.e. profit) for providing the respective A/S.

** A "low to high" ranking of the offer prices for each participating resource.*

# Procuring Ancillary Services

## Method 2: Reimbursement of Offer Price

The Reimbursement of Offer Price is an alternative that could potentially be leveraged between two contracting parties seeking to enter into a bilateral agreement for A/S. It is a logical compromise between the "market clearing price" and "make-whole compensation" approach.

- Instead of a "clearing price" for the ancillary service, each resource is compensated on an individual basis for providing the service.
- The offer price for each resource would likely be derived in a similar fashion to the Market Clearing Price methodology. Specifically, the resource's "cost to provide + margin" (including opportunity costs) would serve as a rational basis for the offer price. If the agreement is between a utility and IPP, the offer price could be based on the anticipated production cost savings for the utility. The final ancillary service price would be based on a negotiated value between the respective parties.
- The period for which this contractually agreed to price is valid could be varied (i.e. hourly, daily, monthly, annually, or simply set at a constant rate for contract period, etc.)
- Similar to the Market Clearing Price approach, it is recommended that the Reimbursement of Offer Price incentivize participation by providing a "no-risk" contract architecture through the reimbursement of "actual incurred" costs (i.e. if incurred costs are higher than the compensation that would be derived via the offer-price).
- Due to the fact that resources are compensated on an individual basis, profitability (for the resource providing the service) is limited to the margin included in the offer price.

# Procuring Ancillary Services

## Method 3: Make-whole Compensation

The Make-whole Compensation approach is another alternative that could potentially be leveraged between two contracting parties seeking to enter into a bilateral agreement for A/S. Most wholesale markets include "make-whole compensation" provisions in their architecture. This method extracts the "spirit & intent" of those provisions.

- At its core, the rationale for "Make-whole Compensation" is to explicitly compensate participating resources for their costs (including opportunity costs) associated with providing A/S. This method is designed to make the participating resource indifferent toward providing ancillary services.
- Instead of negotiating an offer-price, the resource-specific cost structure would be shared between the contracting parties so that an accurate assessment of incurred costs could be obtained.
- Due to the fact that resources are compensated on an individual basis, and only for their cost to provide the service, there is no additional profitability potential for participating in A/S. For the three approaches discussed thus far, this method will typically result in the lowest overall production cost to reliably serve the load.
- It is important to note that while this approach adequately and explicitly compensates resources for their A/S participation, it does not incentivize that participation.

# Procuring Ancillary Services

## Method 4: Condition of Interconnection

It is important to note that all power systems (historical, existing, and future) require the use of certain interconnection requirements and ancillary services to ensure the system reliability is maintained. In many cases, such as with regulated utilities, the explicit compensation of resources for ancillary participation has not been required to maintain a reliable system. For this reason, the Condition of Interconnection approach was included in this list of options.

- The "Condition of Interconnection" approach would simply require ancillary service capability and participation from interconnecting resources.
- Resources would not be explicitly remunerated for providing ancillary service capability or for the associated costs incurred.
- The incentive for resources to provide ancillary service capability would be driven by the accompanying right to participate in selling energy.
- For this type of agreement, it is implied that the participating resources would derive financial benefit from the sale of energy alone that was sufficiently large enough to cover both the cost to provide energy and the cost to provide A/S.
- Due to the lack of explicit compensation, the "Condition of Interconnection" approach has the potential to offer the lowest production cost of the four methods described.

# Procuring Ancillary Services

## Forward Planning Approach to Derive Rational Ancillary Service Contract Prices

Much attention has been focused on obtaining ancillary services from resources with the lowest offer price and/or lowest "cost to provide" (including opportunity costs).

One potential method for assessing the basis of a "rational" ancillary service offer price would be to leverage a production cost simulation with the capability to co-optimize energy and ancillary services. For a given future scenario, with a known resource mix, the simulation could be exercised and evaluated at both a resource-level and a system-level to draw conclusions about a rational offer price for the respective resource:

- At a resource-level, the results of the simulation could be interrogated to identify the perceived cost (including opportunity cost) for each resource to provide a given ancillary service. To develop an offer price, the hourly observations for each resource could then be aggregated and averaged over a period that aligned w/ the desired contractual period.
- At a system-level, the simulation could be exercised by individually enabling / disabling the respective ancillary service capability for each resource under consideration. The resulting benefit (i.e. "reduction") in the overall annual production cost could be used as a basis for assessing the ancillary service offer price for each particular resource.

To adequately bound the offer price, it is recommended that both the resource-level and system-level assessments be conducted.

# Hawaii-Specific Ancillary Service Procurement

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# Procuring Ancillary Services

## Methods for Obtaining Ancillary Services in Hawaii

On Hawaii, ancillary services are presently obtained from dispatchable resources through a method which is similar to the previously mentioned "Condition of Interconnection" approach. Specifically, the utilities have the ability to dispatch resources to provide ancillary services without explicit compensation to the respective resources.

Going-forward, there will be a continued desire to increase the penetration of renewable resources on the Hawaiian system which has the potential to increase the system-level ancillary service requirements.

As the system-need for ancillary services increases, it may be necessary to incentivize new resources to provide (or existing resources to expand upon) their ancillary service capability. This incentive would likely come in the form of explicit financial compensation and include aspects of either the "make-whole compensation" or "reimbursement of offer price" methods. However, it should be noted the use of these methods has the potential to increase the overall production cost as a result of the explicit compensation for [some of/all of] the ancillary services. Careful consideration is required before integrating such remuneration methods.

# Procuring Ancillary Services

## Methods for Obtaining Ancillary Services in Hawaii

As outlined in the technology table (Part I, Task 2), renewable resources (i.e. wind/solar) are capable of providing many ancillary services. The use of these resources for providing A/S may help to facilitate their increased penetration and potentially reduce production costs as it introduces another degree of freedom for commitment & dispatch. Current RFP's and draft PPA's are seeking to leverage this capability from VG resources.

Relative to the current environment, in which resources are not explicitly compensated for fulfilling the system-level ancillary obligations, requiring the wind/solar to provide ancillary services via the "Condition of Interconnection" approach would certainly be an equitable option.

Due to the fact that wind/solar resources are presently compensated based on their energy contract price, which likely includes some fixed and capital cost recovery, there are periods when wind/solar are *more expensive* to operate than some non-renewable resources on the system *(i.e. periods where the energy contract price is higher than the marginal system cost)*. During these periods, it may result in a system level production cost savings to curtail wind/solar to provide ancillary services. However, the existing wind/solar contracts have provisions which preclude the curtailment of these resources for economic reasons. Therefore, during periods where wind/solar are curtailed exclusively for the purposes of providing ancillary services (i.e. up-reserves), the use of "Make-whole Compensation" would be recommended.

# Procuring Ancillary Services

## Methods for Obtaining Ancillary Services in Hawaii

It should be noted that the existing wind/solar contracts purposefully prevented curtailment for economic reasons in an effort to maximize renewable penetration. Therefore, to adopt the previous recommendation, an adjustment to the existing contracts would likely be required.

Energy storage devices have the potential to enhance penetration of renewable resources and/or lower the overall production cost. The process for "Evaluating and Selecting a Potential Resource Mix" could be leveraged to help quantify these potential benefits.

Due to the fact that energy storage resources are energy-neutral and operate exclusively for the purposes of providing ancillary services, the use of "make-whole compensation" is not applicable (i.e. storage resources have no opportunity costs). Therefore, an explicit remuneration method, such as "Reimbursement of Offer Price" may be required to incentivize the development & participation of energy storage resources to supply ancillary services.

To obtain a value for the ancillary services offered by the energy storage resources, it is likely that the previously mentioned "system-level" use of a production cost simulation would be required. Specifically, the simulation could be exercised by individually enabling / disabling the respective ancillary service capability for each resource under consideration. The resulting benefit (i.e. "reduction") in the overall annual production cost could be used as a basis for assessing the ancillary service offer price.

# Procuring Ancillary Services

## Methods for Obtaining Ancillary Services in Hawaii

Ancillary service participation from DR, transmission, and retrofit options have the potential to reduce production costs, improve renewables penetration, and avoid/defer/attenuate major capital expenditure.

Similar to energy storage resources, an explicit compensation method would likely be required to incentivize participation from DR and/or transmission-related technologies.

To incentivize the modification (i.e. retrofit) of existing resources to provide, or expand upon, their ancillary service capability, further use of explicit compensation may be required to cover upgrade costs.

# Procuring Ancillary Services

## Methods for Obtaining Ancillary Services in Hawaii

It should be noted that some resources have the potential to increase (or decrease) the required amount of ancillary services on the system. Further, some resources have the potential to provide more ancillary capability than other resource types.

In some cases, such as wind/solar, an individual resource has the potential to increase the required amount of ancillary services on the system. However, these resources also have [typically] low variable operating cost and have the have the potential to reduce the overall production cost for the system.

As a result, it is not recommended that individual resources, which induce additional ancillary obligations on the system, be additionally penalized.

Instead, it is recommended that the impact on overall production cost (including total ancillary services costs), coupled with other policy-related directives such as renewable penetration targets, be used as the metric to assess the viability of a particular resource.

# Risk Assessment and Other Considerations

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# Risk Considerations

## Outline considerations for specifying and acquiring ancillary services

- Hawaii specific resource costs
- New/emerging technology availability
- Ability to uprate/upgrade existing resources
- Fuel availability and fuel infrastructure
- Wind and solar forecasting process
- Interconnection costs
- Inter-Island transmission connections
- Challenges associated with monitoring / controlling Demand Response participation on a centralized basis
- Load shaping programs
- Inadequate response from renewables due to instantaneous availability
- Available down-reserves and stable operating region of thermal units during loss of load events
- Voltage/VAR support sufficiency
- Reductions in inertial response capability
- Unfavorable impacts to "system-level" variable cost of operation
- Impact to existing utility / IPP contracts may require modifications to accommodate schedule changes

Risks are highlighted in the "Observations" column of the scenario workbooks for each system

# Technology Risks

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# Generation Technology Risks

- **Wind Turbines:**
  - Variable generation
  - Unstable incentive structures (i.e. government tax credits)

- **Gas Turbines / Combined Cycles:**
  - Volatile fuel prices
  - Fuel transport costs

- **Simple Cycles:**
  - Volatile fuel prices
  - Fuel transport costs

- **Reciprocating Engines:**
  - To be added

# Generation Technology Risks

- **Solar Thermal:**
  - Unstable incentive structures (i.e. government tax credits)
  - Potential negative environmental impact - large installations can disrupt ecosystems/Permitting can be a major issue in Hawaii

- **Solar PV:**
  - Variable generation
  - Unstable incentive structures (i.e. government tax credits)

- **Hydropower:**
  - Potential negative environmental impact - large installations can disrupt ecosystems/Permitting can be a major issue in Hawaii

- **Geothermal:**
  - Potential negative environmental impact - large installations can disrupt ecosystems/Permitting can be a major issue in Hawaii

# Generation Technology Risks

- **Biomass:**
  - Unstable incentive structures (i.e. government tax credits
  - Cost of collecting biomass

- **Coal:**
  - Negative environmental impact
  - Fuel transport costs

# Storage Technology Risks

- **PHS:**
  - Energy naturally wants to spread out, so compressing water behind a dam creates the risk of an uncontrolled energy release
  - High costs/market liquidity/market price uncertainty (revenues from ancillary services hugely volatile)
  - Arbitrage revenue - after efficiency is taken into account this is not a huge money spinner at some market prices
  - Market risk (i.e. change in ISO rules)
  - Potential negative environmental impact - large installations can disrupt ecosystems/Permitting can be a major issue in Hawaii
  - There is a real option value that may not be captured unless risk is explicitly identified and quantified - plant operations decisions must incorporate these risks
  - A serious disadvantage is dependence on specific geological formations or man-made reservoirs
  - Difficult construction – depends on topography

# Storage Technology Risks (Comments)

Comments from HREA:

- Risk of Structural Failure: We understand with proper design and installation, the risks of dam or reservoir failures are very low. In addition, a Pumped Storage facility using advanced Roller-Compacted Concrete ("RCC") technology would mitigate structural risk with a design that incorporates a deep reservoir with most of its capacity below ground level. See also the Division of Safety of Dams ("DSOD"), Department of Water Resources in California for additional information (http://www.water.ca.gov/damsafety/).
- High costs/market liquidity/market price uncertainty: All renewable projects in Hawaii face similar costs/market risks. Re Pumped Storage, we understand construction costs would be similar to those for a wind farm of similar MW capacity. We agree that there could be risks associated with Pumped Storage that operates in the "classic" duty cycle for pumping during off-peak hours and generating during peak hours. However, we believe additional revenues for a number of ancillary services, such as load following, frequency response, spinning reserve, inertial stability (Wr2), voltage support, VAR generation/control, and black start capability, can reduce that risk significantly. The key will be ability to negotiate a PPA that helps meet system needs and provides an adequate revenue stream such that investors can make an acceptable return on their investment.
- Arbitrage revenue: As discussed previously, Pumped Storage may not be able to accomplish the primary goal of energy arbitrage, i.e., buy low, sell high or higher, in Hawaii. However, we believe a Pumped Storage facility with PPA that includes appropriate payment for generation and ancillary services can be financially viable.

# Storage Technology Risks (Comments)

Comments from HREA:

- Environmental Impacts: All projects have this risk, especially in Hawaii. We understand that FERC has revised its licensing requirements for "low impact hydro," which includes Pumped Storage. This revision is believed to reduce the time required to obtain a FERC license. In parallel, the developer of a Pumped Storage facility will need to prepare an EIS as part of the overall permitting process, just like any major renewable project. In addition, the reservoirs could be designed to be a source of fresh water.
- Risk of geological formations or man-made reservoirs: We do not believe Pumped Storage facilities will need to use existing geological formations in Hawaii, and in many instances the use of existing geological formation is not ideal due to soil stability and porosity concerns. The risk associated with man-made reservoirs can be mitigated through design and implementation approaches as discussed above. Furthermore, the FERC licensing review and approval process is rigorous.
- Difficult Construction: We agree. Construction costs will be higher in remote areas and sites that present topographic challenges, e.g., remote, steep terrain, just as it would be with any construction project. For pumped-storage the "sweet spot" tends to be an elevation difference of 300 to 600 feet; otherwise equipment costs become prohibitive for pumping more than 600 feet and generation efficiencies and outputs do not provide the return on investment below 300 feet. We believe that there are numerous potential sites in Hawaii that meet this criteria as well as being in relatively accessible locations.

# Storage Technology Risks

- **CAES:**
  - Energy naturally wants to spread out, so compressing air underground creates the risk of an uncontrolled energy release
  - High costs/market liquidity/market price uncertainty (revenues from ancillary services hugely volatile)
  - Arbitrage revenue - after efficiency is taken into account this is not a huge money spinner at some market prices
  - Potential negative environmental impact - large installations can disrupt ecosystems/Permitting can be a major issue in Hawaii
  - Determining the appropriateness of an underground aquifer geological structure is always challenging - it is difficult to determine, with precision, the exact characteristics of what actually exists underground without core sampling (i.e., test wells)
  - Underground storage requires a special site with the appropriate geological characteristics (normally these are salt caverns but on the mainland depleted natural gas fields, or other types of porous rock formations could be used)
  - Above ground storage requires large pressure vessels or pipelines
  - Need a fuel for the gas turbine - the fuel could be biodiesel, ethanol, or hydrogen (fuel cost impacts exist)

# Storage Technology Risks

- **Batteries:**
  - Energy naturally wants to spread out, so packing it into a small space like a battery creates the risk of an uncontrolled energy release like a fire or explosion (lithium-ion batteries, sodium-sulfur batteries) -newer lithium-ion batteries store more electricity than other electrochemical storage systems
  - Cascading failure/thermal runaway happens when a cell fails and releases its energy as heat which can cause adjacent cells to fail and generate heat, as well, leading to melting materials and fires (water can't always be used to extinguish an electrical fire, since water can conduct electricity)
  - Limited lifetime - need to be replaced periodically
  - Maintenance requirements higher than competing technologies
  - Storage capacity is limited – cannot attain same capacity as pumped storage
  - Sensitive to heat: service life can be reduced considerably if operated above rated temperature
  - Battery life depends on cycle-depth
  - Flow batteries complicated compared to standard batteries as they require pipes (susceptible to leakage), valves, pumps, storage tanks sensors, control units, and secondary containment vessels
  - Energy densities in flow batteries are generally lower when compared to portable batteries such as Li-ion

# Storage Technology Risks

- **PEVs:**
  - The technology is still in its infancy
  - In a car, a battery is exposed to a wide range of humidities, temperatures and electrical loads, and all of these factors influence the battery's reliability, and if they get too extreme, they can cause a thermal runaway condition
  - Unstable incentive structures (i.e. government tax credits) limits PEV adoption
  - Leverages the existing electrical delivery system but additions to the existing system are necessary:
    - The "smart-grid" infrastructure must be installed to accept PEVs
    - Convenient outlets for households that lack them (e.g. high rise apartments, building without garages etc.) as well as outlets in parking lots and on parking meters
    - Fast chargers that refill a battery in minutes rather than hours (fast chargers can refill batteries in 10-15 minutes) - they require heavier wires than most households have and thus will at least be located at gas stations and other key places
    - Tariffs and monitoring equipment that discourages recharging during peak hours - need large disincentives to discourage filling up during peak hours
  - Uncertain ability of the electrical distribution system to manage bi-directional flow of power (what % of a feeder's load can be back fed through transformers?)
  - New demand may stress low voltage distribution lines
  - Storage degradation (= operating cost) if deep discharge of battery
  - Need to prioritize driving needs

# Storage Technology Risks

- **Flywheels:**
  - Energy naturally wants to spread out, so packing it into a small space like a flywheel creates the risk of an uncontrolled energy release like a fire or explosion (i.e. Beacon Power 20 MW flywheel systems in Stephentown, N.Y)
  - Material strength and safety concerns limit energy output
  - While very efficient in short duration response functions, flywheels are not currently designed for providing long-duration energy response
  - Flywheels are not well suited to provide spinning/non-spinning reserve - the limiting factor for flywheels is the duration of the response required

- **Fuel Cells:**
  - The technology is still in its infancy
  - Energy naturally wants to spread out, so packing it into a small space like a fuel cell creates the risk of an uncontrolled energy release like a fire or explosion

# Demand Response Program Risks

- **Fast Auto DR:**
  - Regulatory approval (if any)
  - Finding the appropriate DR resource – and sizing/speed for different A/S offerings (frequency control, load following, regulation up/down, spinning and non-spinning reserves)
  - DR resource qualification (meeting the strict requirements)
  - Technical complexity and readiness, system integration, and technical inter-operability
  - Determination of the right level of incentives and pricing scheme

- **Direct Load Control:**
  - Regulatory approval (if any)
  - Finding the right types of resources, resource mix, and resource size
  - Customer selection, agreement, and engagement
  - Determination of the right level of incentives
  - Lack of verification of system breakdowns and customer over-rides in DLC with one-way communication

- **Interruptible Load:**
  - Regulatory approval (if any)
  - Finding the right types of resources, resource mix, and resource size
  - Customer selection, agreement, and engagement
  - Determination of the right level of incentives and rate design
  - Potential for lack of response by customer in the event of instruction by the utility for customer action to interrupt the load

# Demand Response Program Risks (Continued)

- **Price Responsive Demand:**
  - Regulatory approval (if any)
  - Finding the right types of resources, resource mix, and resource size
  - Customer selection, agreement, and engagement
  - Technical system design and implementation (AMI, Communications, etc.)
  - Resource aggregation and system integration
  - Appropriate Dynamic Pricing Rate Design and determination of the right level of incentives (different approaches for different dynamic pricing type such as TOU, CPP, CPR/PTR and RTP require)
  - Degree and level customer response (which usually depends on the end-use resource type, impact on comfort and convenience, pricing rates and perceived level of savings, availability of enabling technologies such as in-home-displays, home energy management systems, smart thermostats, smart appliances, or automated, programmable, and communicable response systems, etc.)

# Methodology for Determining Operating Reserves

imagination at work

# Method for Determining Op Reserves

## Overview

This section outlines the methodology to determine the operating reserves requirement to counteract the intra-hour variability of renewable energy.

The methodology specifies a reliability level of 99.99%; implying that if the operating reserves are made available as per the specified requirement, the renewable variability can be effectively counteracted for 99.99% of the time.

Operating reserves, as defined, is a function of spinning and non-spinning resources that can be made available within an hour.

At a certain defined level of non-spinning resources, the process outlines the required commitment of spinning reserves to sustain the variability for the forecasted level of renewables.

# Definitions

Contingency Reserves

- MWs to cover for the loss of the largest unit

Operating Reserves

- MWs to cover for the variability of wind and solar
- Spinning Reserves + Non-spinning Reserves

  Spinning Reserves

  - Available headroom (MWs) from committed thermal units

  Non-Spinning Reserves

  - Available MW capacity from quick-start units
  - These units can be started in less than an hour

**Total Reserves = Contingency Reserves + Operating Reserves**

<u>Oahu</u>
Contingency Reserves = 185 MW
Spinning Reserves = Committed thermal units
Non-Spinning Reserves = W9,W10,DG,CT1 (if not already committed)

# Factors Impacting the MW Availability from Non-Spinning Resources

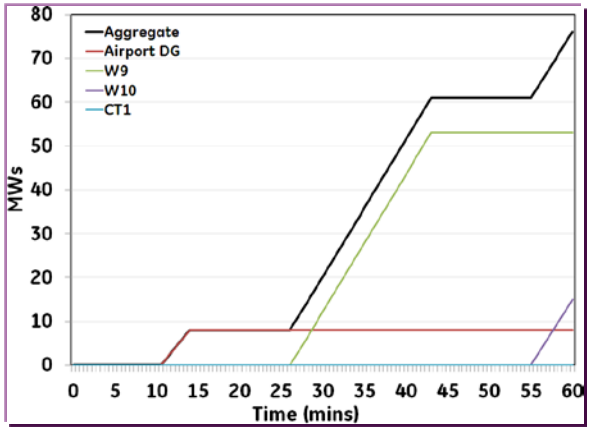
- Response time from the operator
  - Assumed to be 10-min
- Availability of the units
  - Assumed all units to be available
- Ramp rates of the units
  - We will show the extreme cases on the next slide
- Starting sequence of the units
  - We will show the extreme cases on the next slide
- Time delay between start of successive units
  - We will show the extreme cases on the next slide

# Non-Spinning Resource Contribution

We will use the following non-spin start-up sequences for Oahu and Maui

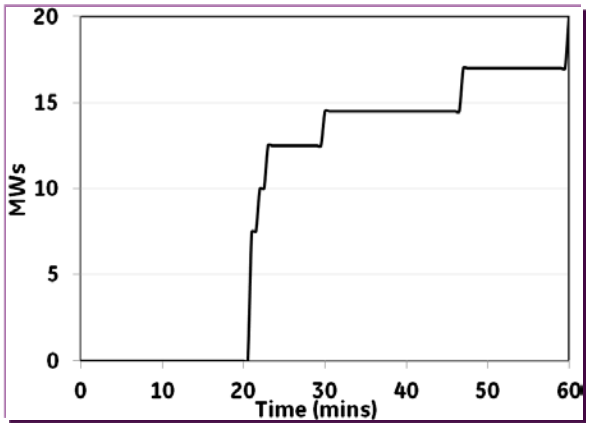
- This is assumes normal ramp rates of quick-start units
- Operator reaction time of 10-min is assumed

## Oahu Quick-starts




| Time Period | MWs |
|---|---|
| 0-10 min | 0 MW |
| 10-20 min | 6 MW |
| 20-30 min | 10 MW |
| 30-40 min | 35 MW |
| 40-50 min | 59 MW |
| 50-60 min | 64 MW |

## Maui Quick-starts




| Time Period | MWs |
|---|---|
| 0-10 min | 0 MW |
| 10-20 min | 0 MW |
| 20-30 min | 10.5 MW |
| 30-40 min | 14.5 MW |
| 40-50 min | 15 MW |
| 50-60 min | 17 MW |

# Operating Reserves on Oahu

Operating reserves are needed to sustain inter-hour (up to 60-min) variability

Spinning + Non-spinning reserves >= 10, 20min, 30min, ..... 60min $\Delta_{wind+solar}$

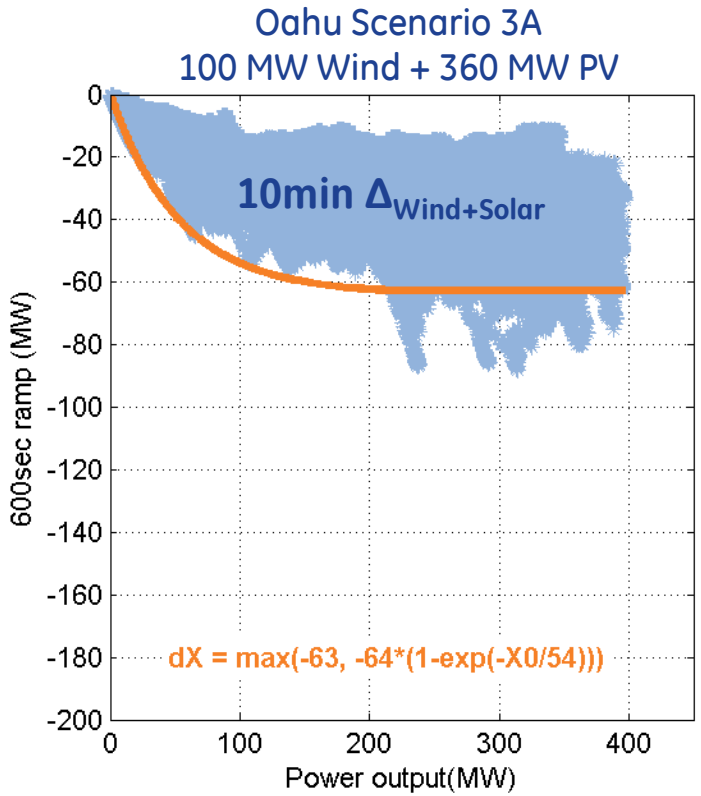
Operating reserves must satisfy the following (with operator action time = 10min):

1. Between 0-10min:
   - Spinning reserves + Non-spinning reserves>= 10min $\Delta_{wind+solar}$
   - Non-spinning cannot contribute
2. Between 0-20min:
   - Spinning reserve + Non-spinning>= 20min $\Delta_{wind+solar}$
   - Only airport DG may participate
3. This process is repeated for the remainder of the hour in 10-min increments, until we satisfy the following equations:
   - Spin Res + Non-spin Res >= 30min $\Delta_{wind+solar}$ , 40min $\Delta_{wind+solar}$ ,50min $\Delta_{wind+solar}$, 60min $\Delta_{wind+solar}$
   - While taking into account the quick-start (non-spin) availability in different time intervals

# How do we measure Variability?

## Analysis Using Scatter Plots

- Each dot corresponds to a drop in wind + solar power in a 10min period
- The orange curve encapsulates 99.99% events in two years
- If the operating reserves follow the orange curve, the system will be able to counteract 99.99% of such 10-minute events

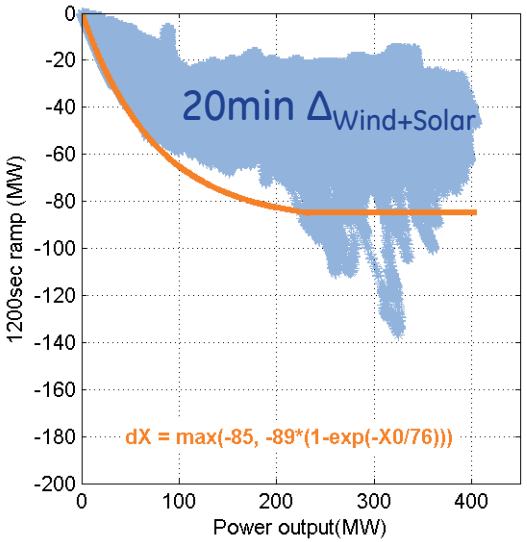


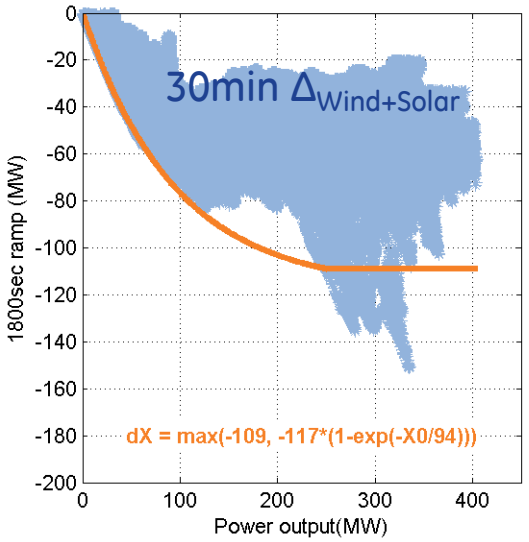

Scatter Plots – Rolling window with 2sec steps

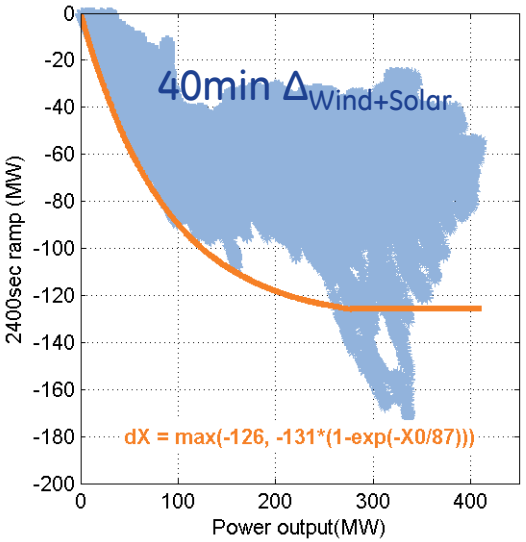
- There are 31.5M data points in 2 years (for full days)
- Only 0.01% of the points are outside the orange curve

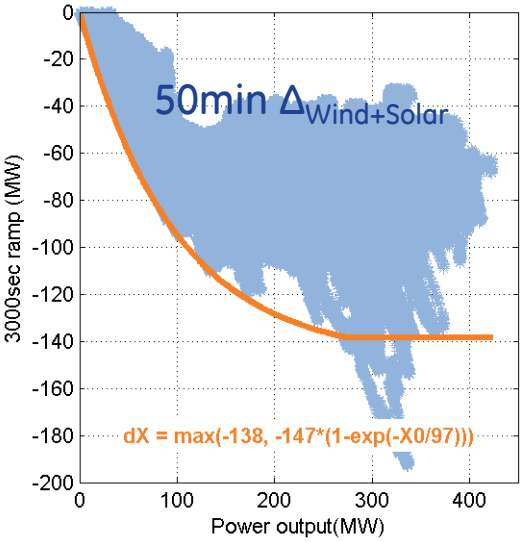
# Variability in Other Time Windows

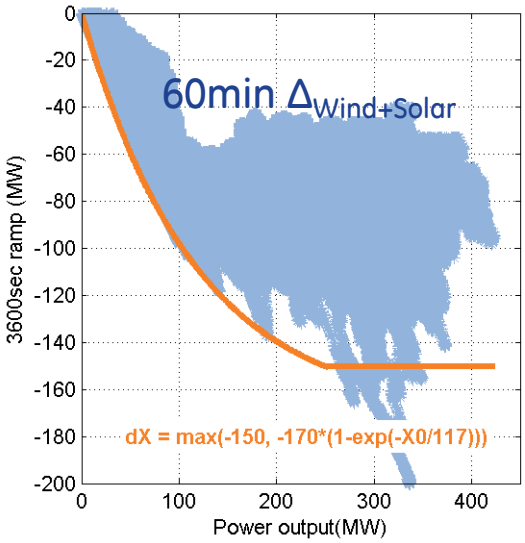
## Wthin an hour



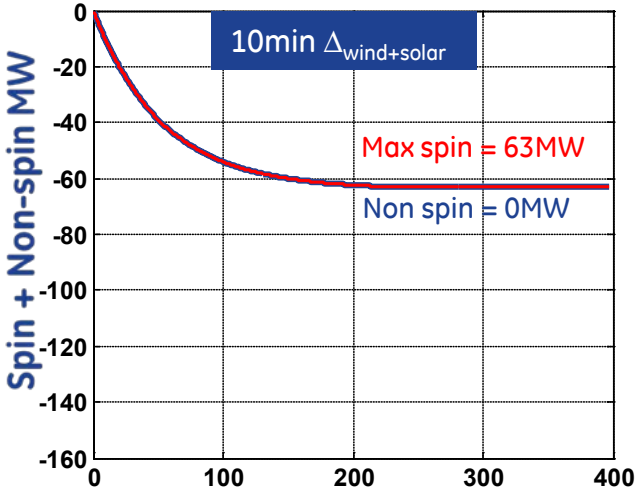



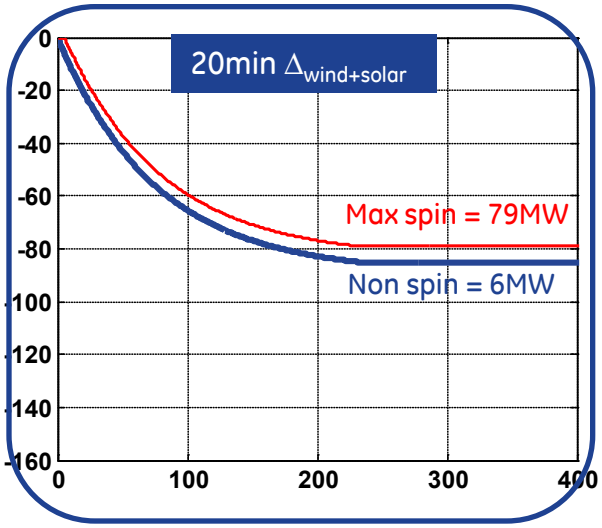



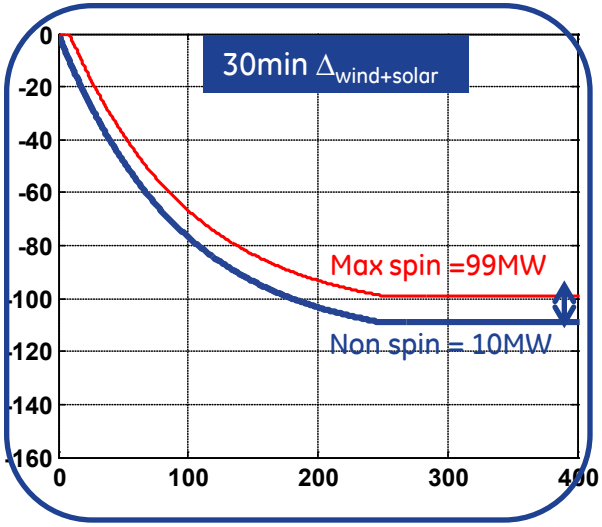



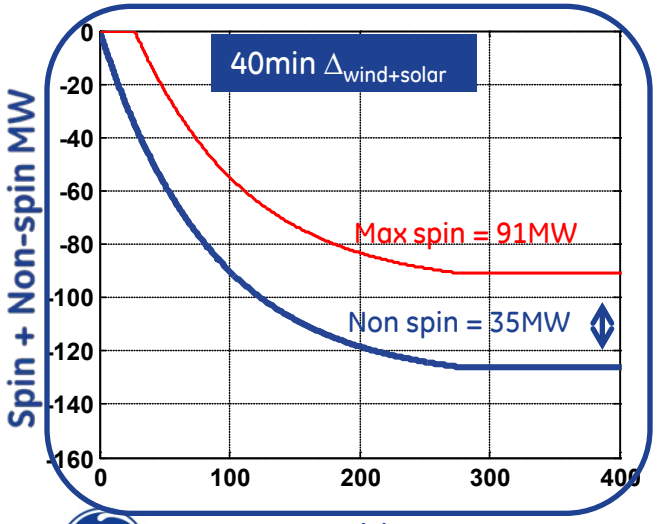
# Operating Reserves

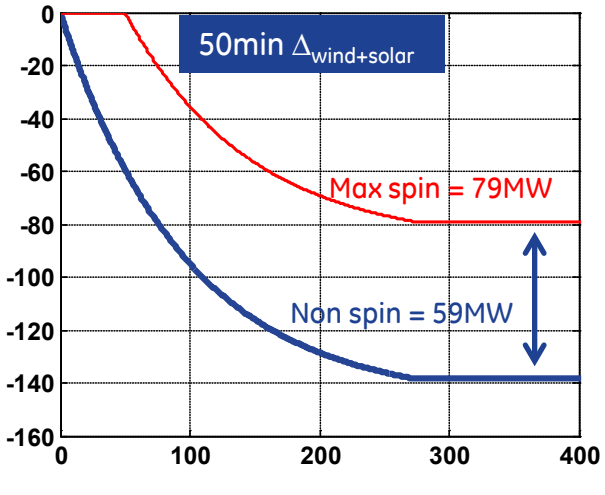
## Assuming MW availability from quick-starts to be the average within a 10-min time interval

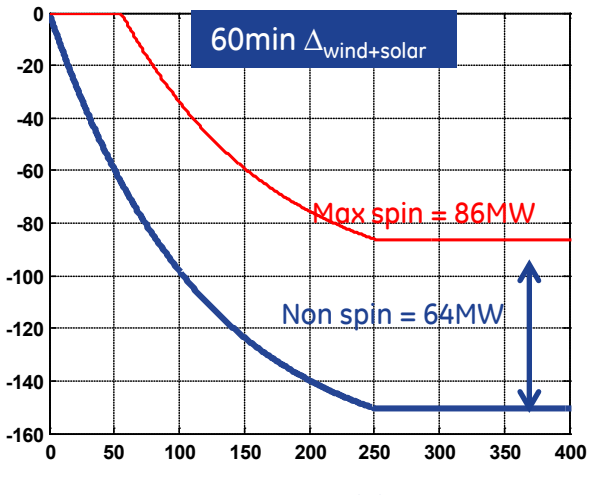


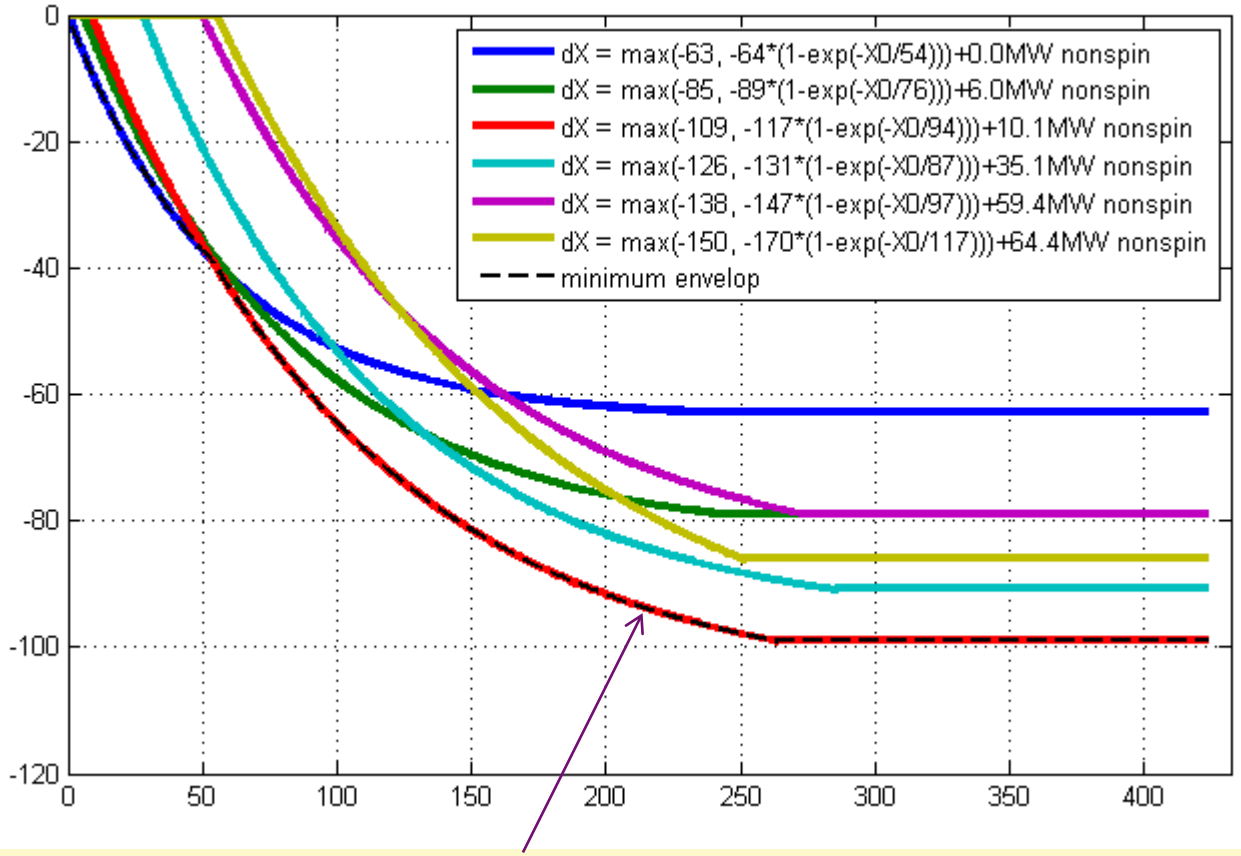



# Operating Reserves Requirement

## Envelope of the 6 previous curves




- The final spinning reserve is the envelop of all the 6 curves
- However, this assumes MW availability from quick-starts as the average in a given 10-min time period

# Final Operating Reserves Requirement

## Accounting for MW availability from quick-start units in finer time resolution

In the previous analysis, we used average MW availability in 10-min period from the quick-start units

Now we will be accounting the contribution of the quick-starts in more finer detail → every minute

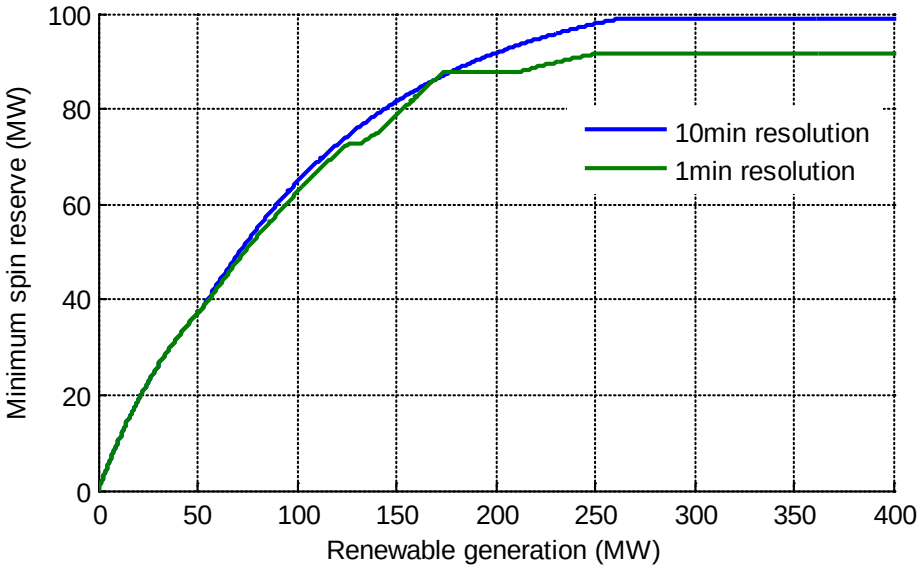
The operating reserves criteria remains the same:

- Spin + Non-spin reserves >= $\Delta_{Wind+Solar}$ in different time intervals (now moving in steps of 1-min) within an hour

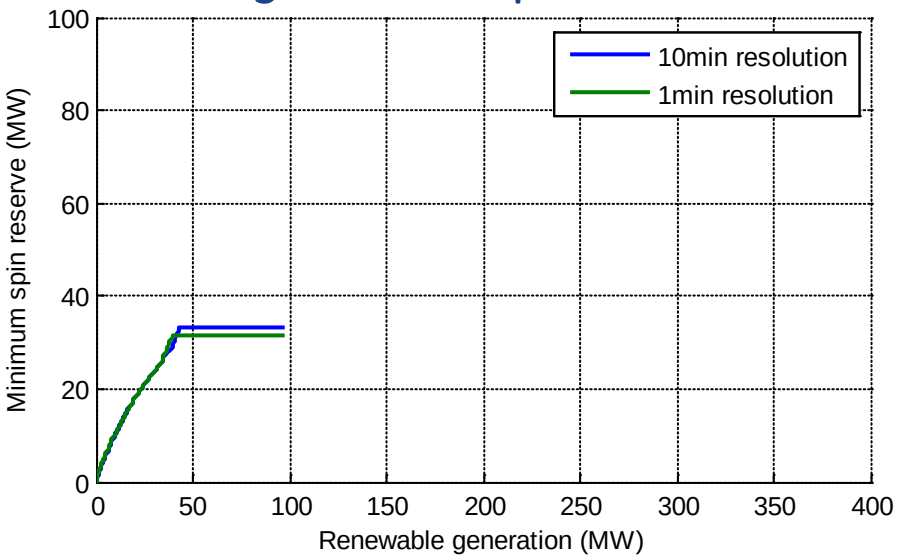
# Oahu Spinning Reserves

## Scenario 3A

### Day-Time (6am-8pm)




### Night-Time (8pm – 6am)



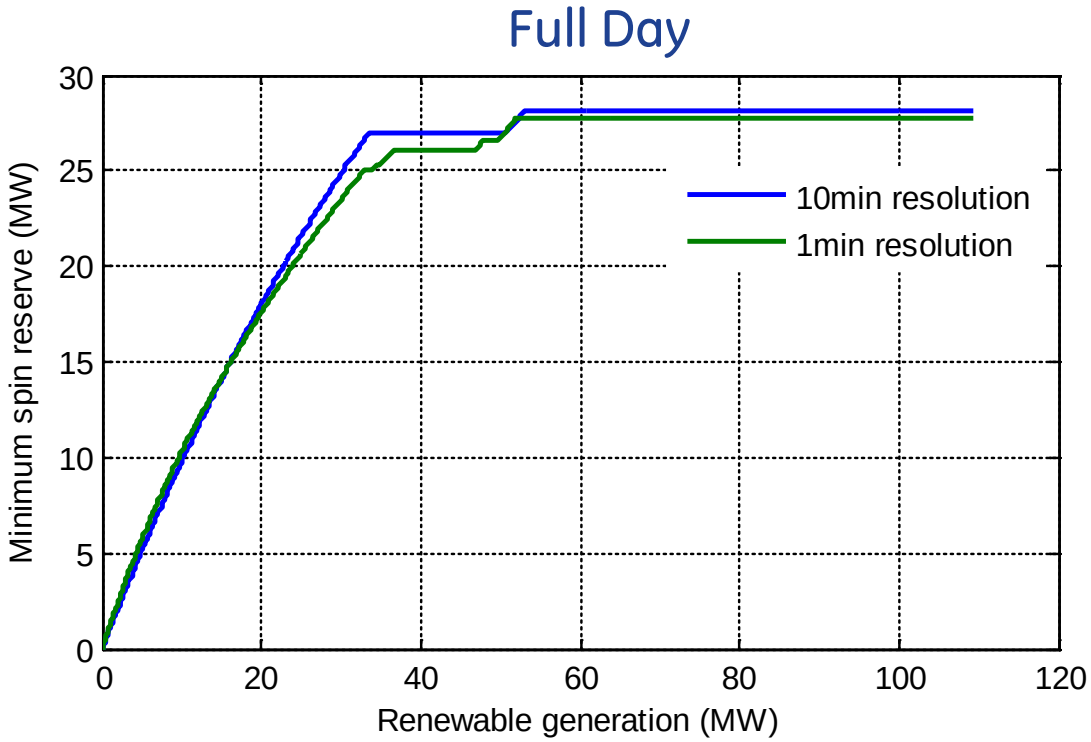

Spinning Reserves are very similar between the two strategies:

Blue → accounting MW availability from quick starts as average within 10-min

Green → accounting MW availability from quick starts every minute

# Maui Spinning Reserves

## Scenario 3




Spinning Reserves are very similar between the two strategies:

Blue → accounting MW availability from quick starts as average within 10-min

Green → accounting MW availability from quick starts every minute

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imagination at work

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# EXHIBIT 41-4

# *Optimizing Reserves*

## *Recommendations for the U.S. Department of Energy*

October 2019




EAC

ELECTRICITY ADVISORY COMMITTEE

# Optimizing Reserves

## Introduction

Operating reserves are needed to ensure that additional energy is available in response to numerous possible system events. "Spinning reserves" – one type of operating reserves – are the unloaded portion of generators that are online already and can quickly increase their output to their maximum ratings to meet changes in demand. Other operating reserves can be provided by offline generators that an operator can turn on when needed (known as 10-minute "quick start" units) but which cannot respond immediately as spinning reserves. Operating reserves help to restore balance to the system following large losses of resources, such as the balancing authority's largest single generating contingency. Both kinds of reserves are critical to reliability of the grid and should be optimized. (Note: Some regions allow other types of resources to provide operating reserves, such as demand response, storage, etc.)

While spinning reserves can respond rapidly to a sudden need for more power, this ability comes at a cost. Running a plant at levels below its maximum optimal operating point in order to provide spinning reserves can cause inefficiency in the provision of energy from individual resources, while increasing costs by requiring more plants to be online. The growing dependence on variable wind and solar power resources make it more necessary to balance reserves to cover minute-to-minute and hour-to-hour variability and uncertainty. Additionally, other power electronic interfaced resources (such as battery storage) and electronically-coupled load also can respond quickly if required after an event.

***The changing energy landscape, including the increased levels of variable energy resources and other emerging technologies, is driving the need to reconsider the industry's traditional approach to reserves.***

Operating reserves, including spinning reserves, have long been required by North American Electric Reliability Corporation (NERC) standards. All balancing area authorities in the United States require a minimum capacity of spinning reserves to be kept online at all times in case of sudden losses of generation or unexpected changes in net load. These spinning reserve requirements have become embedded within the grid codes of utilities, ISOs, and RTOs worldwide.

With traditional technologies, minimum spinning and operating reserves were necessary to prevent generation-load imbalances from leading to unstable drops in frequency and other issues. This helps avoid activation of under-frequency load shedding (UFLS) systems, which trip loads at predetermined low frequencies to prevent complete system collapses. Additionally, generator under-frequency protection systems are typically designed to trip generators offline if frequency approaches levels in which turbine blade resonance may damage equipment.

With more and more resources using power electronic interfaces and the retirement of some traditional synchronous generating resources, inertia on the system is being reduced. One characteristic of lower inertia is a more rapid and deeper decline in frequency (measured by the rate-of-change-of-frequency – RoCoF) after an event. However, with intelligent controls enabled, these power electronic interface resources can respond by injecting replacement energy more quickly and accurately than traditional synchronous generation, to arrest the frequency decline and recover frequency faster. It should be

noted that such response requires energy to be readily available to inject into the system from batteries, flywheels, or curtailed wind or solar resources.

At the same time, reserve requirements and definitions are changing globally as new types of services (such as fast frequency response) are being defined. These services also interact with each other. For example, an increase in quick-response reserves from inverter-based resources reduces the need for slower-acting reserves from traditional technologies. Significant economies may be realized by revising these reserve requirements and definitions. However, the tradeoffs and benefits of different technologies should likely be fully assessed.

Recent developments in new technologies—such as storage, load management, advanced predictive capability, and the demonstration of new inverter capabilities—have the potential to contribute to spinning and other reserve requirements.

Many ISOs and RTOs have expanded their definitions of reserves to allow some new technologies to provide reserve products that do not meet the historic definition of "spinning."[1] This allows new ancillary reserve services that complement the UFLS systems.[2] Though reserve requirements may not have been reduced, the effective amount of "spinning" reserves from online resources operating at non-optimal levels on their heat rate curves is less, and thus the economic efficiency is improved. These policies are inconsistent across the United States, potentially making reserve markets fragmented and less efficient.

## Approach

The Electricity Advisory Committee (EAC) hosted a panel discussion with experts on the topic at its June 2019 meeting. EAC Members and panelists engaged in a robust discussion after the topic was introduced and panelists gave their presentations. The panel explored the needs and costs of maintaining reserves, as well as the potential benefits and tradeoffs of replacing traditional spinning reserves with newer technologies while optimizing overall reserve requirements. The panelists addressed the following questions:

1. What are reserve requirements today, and in what ways can we challenge the traditional thinking given industry transformation with respect to data and technology?
2. What is the optimal level of reserves? (What variables must be considered in this determination and to what extent can new technologies and/or improved forecasts reduce the necessary level of reserves, and what are the benefits of doing so?) How do these reserve requirements change with larger penetrations of wind and solar?
3. What are reserve requirements for different regions across the United States? How do these requirements compare to the optimal levels described above?

[1] For example, see the Electric Reliability Corporation of Texas (ERCOT) standards for ancillary service quantities, http://www.ercot.com/content/wcm/libraries/188854/September_1__2019_Nodal_Protocols.pdf, and PJM's Balancing Operations Manual (https://www.pjm.com/-/media/documents/manuals/m12.ashx) and Emergency Operations Manual (https://www.pjm.com/-/media/documents/manuals/m13.ashx).

[2] This refers to the provision in some electricity markets of an ancillary service product allowing the sale of load shedding services in place of spinning reserves. These services are allowed only as long as they are guaranteed by placing the load to be shed behind automatic switching devices (high-set relays) which automatically shed the load at system frequencies well above the provisions described in NERC EOP-003.

4. If the reserve requirements are at other than an economically optimal level, what changes are appropriate to increase economic efficiency?
5. If changes are made to reserve requirements obligations across the United States, would these changes attract investment and increase economic efficiency?
6. What is the cost (in dollars, emissions, efficiency penalty, and/or opportunity cost) of maintaining traditional spinning reserves?

## Findings

Though the panel discussion provided many insights, the discussion concluded with more questions than answers. Below are key takeaways:

- Today's NERC standards will need to evolve with the changing nature of both the reserve and reliability needs of the grid.
- Markets were designed with the premise of reliability at least cost; however, new technologies and priorities (e.g., environmental considerations) might drive modified approaches to capacity and energy markets with respect to reserves.
- Primary contingency reserve calculations using N-1 might need to be supplemented with a greater focus on frequency response needed.
- The increased variability of resources within generation portfolios and uncertainty of events are beginning to drive reserve requirements.

## Recommendations

EAC Members developed recommendations to the Department of Energy (DOE) based on suggestions from the panelists and opinions of the EAC Members. The higher priority recommendations are provided below.

### *Recommendation 1: Defining Operating Reserve Requirements*

**DOE should consider (or expand/prioritize) efforts to quantify uncertainty and variability for the purposes of determining reserves requirements and initiate discussions with NERC regarding the appropriate risk and reserve methodology.**

DOE is in a unique position to expand existing efforts on determining uncertainty to additional markets and areas of the United States. Understanding that the N-1 approach does not effectively capture the growing uncertainty as a result of renewables and other technologies, this broader approach could help drive industry standards related to how reserves are calculated and valued in markets. This approach will help drive the reserve optimization that we seek across the industry.

While probabilistic efforts are underway to begin to address solar uncertainty and forecasting, there is an awareness that needs to vary by region. DOE should expand existing efforts and research to determine optimal reserves requirements.[3] Such expansion might include considerations that are more prevalent in certain areas of the country such as natural gas resource (pipeline) disruption, or potential susceptibility to weather-related contingencies (low wind or heavy cloud cover), and other variabilities or uncertainties.

[3] The Electric Power Research Institute (EPRI) has created a tool to quantify appropriate reserve levels, which could serve as a good starting point.

The North American Energy Resilience Model (NAERM) could also be used to model the three U.S. interconnections with respect to prospects of lower inertia and greater intermittency. Can the NAERM model the demand-side effects as well?

The accurate modeling of distributed power electronics (e.g., inverters) and controllable loads may support market mechanisms in pricing the reserve products provided by these devices.

NERC and other industry standards that drive reserve requirements should be modified to accommodate new determinations.

## *Recommendation 2: Performance Requirements for New Resources*

**DOE should consider analysis defining technological and operating requirements for new resources that might reduce the dependency on operating reserves.**

Generating units were historically designed to operate in a different performance mode from what is needed for the modern grid. Traditional governors, for example, may have a 3 to 6-second response time when a 1 to 3-second response is required to arrest frequency declines for events with very high RoCoF. Performance metrics could also help drive a more optimal operating reserve requirement. For example, is it worthwhile to create a requirement for governor-like droop settings on inverter-based resources and storages devices of 5% to 4% during normal operations? Other suggestions from the panel discussion were:

- Ensure that renewable resources—including storage devices—provide essential reliability services, including voltage control, frequency control and response, and ramping capability.
- Impose a steady-state ramp rate of 10% of the maximum capability of the unit (P max) to help manage variability in real-time.
- Reduce governor deadbands on resources from 0.036 hertz to 0.01667 hertz.

Various interconnections meet the reliability need to respond to frequency disturbances on the grid with additional mechanisms, including but not limited to fast-acting, frequency-responsive load response and quick-starting resources. DOE could identify limitations in the grid rules of the three major interconnections, which are creating sub-optimal limitations in responding to grid disturbances. What can be done to investigate and support the development of inertial response from the demand side?

## *Recommendation 3: Valuing Operating Reserve Needs for Optimization*

**DOE should explore market designs to appropriately value operating reserves once an optimal amount is determined.**

Existing market designs were not created with variable generation or renewable resources in mind. They were designed for controllable supply and dependable demand. With the large amount of renewables on the grid—especially during midday on weekends, when loads are low and solar generation goes up—the excess generation can create performance issues.

Traditional markets need to be redesigned. Nothing in market design today allows units to reverse course after they are locked in for a time interval. How can we tie system frequency back into market operations and pricing?

### *Recommendation 4: Convening*

**DOE should host a federal-state effort to help inform the governance needed to advance industry-wide reliability and market changes related to reserves.**

With the current regulatory structure, it is difficult to drive change. This matter fits squarely within both state and federal jurisdiction, with states increasingly engaged in distribution resource matters and incentives. To reach an optimal solution, state and federal stakeholders will need to agree on the direction and then the solution.

For example, how can distribution-connected resources provide wholesale market services?

## Conclusion

Operating reserves and how they are thought about must evolve with the industry. The amount of operating reserves required should consider the increasing rate of intermittent and natural gas resources on the grid. It also should accommodate the electrification and increased demand-side management efforts. Technology is changing and the optimizing operating requirements dictate that we rethink how we determine the future needs and values of this requirement.

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| 2024-12-10 | 105500 | 4691623 |
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| 2024-12-13 | 109400 | 4675969 |
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| 2024-12-29 | 75600 | 5040988 |
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| 2025-01-18 | 84200 | 5105462 |
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| 2025-01-23 | 94900 | 5024910 |
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| 2025-02-13 | 97000 | 4412823 |
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| 2025-02-16 | 66400 | 4336445 |
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| 2025-03-07 | 62300 | 4359311 |
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| 2025-11-08 | 79900 | 5049033 |
| 2025-11-09 | 69900 | 5073192 |
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| 2025-11-11 | 77600 | 5081254 |
| 2025-11-12 | 81100 | 5081254 |
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| 2025-11-20 | 94200 | 5008849 |
| 2025-11-21 | 92600 | 5000824 |
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| 2025-11-23 | 73600 | 5008849 |
| 2025-11-24 | 91000 | 4992803 |
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| 2025-12-14 | 89800 | 5016877 |
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| 2025-12-23 | 135200 | 5129707 |
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| 2025-12-26 | 124000 | 5057082 |
| 2025-12-27 | 121400 | 5049033 |
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| 2025-12-29 | 120800 | 5065135 |
| 2025-12-30 | 136100 | 5016877 |

# EXHIBIT 41-6

An official website of the United States government Here's how you know

MENU

# Washington water conditions

IMPORTANT

Temporary service issues may result in latest value reported as unknown for some locations. Visit the Monitoring Location Page to see the latest data.

DID YOU KNOW After customizing the filter settings, you can bookmark this page in your browser to return to your custom State Page? ×

Current water condition data available from
**704** monitoring locations with
**43** types of continuously collected data.

Select a different State or Territory

Select a state

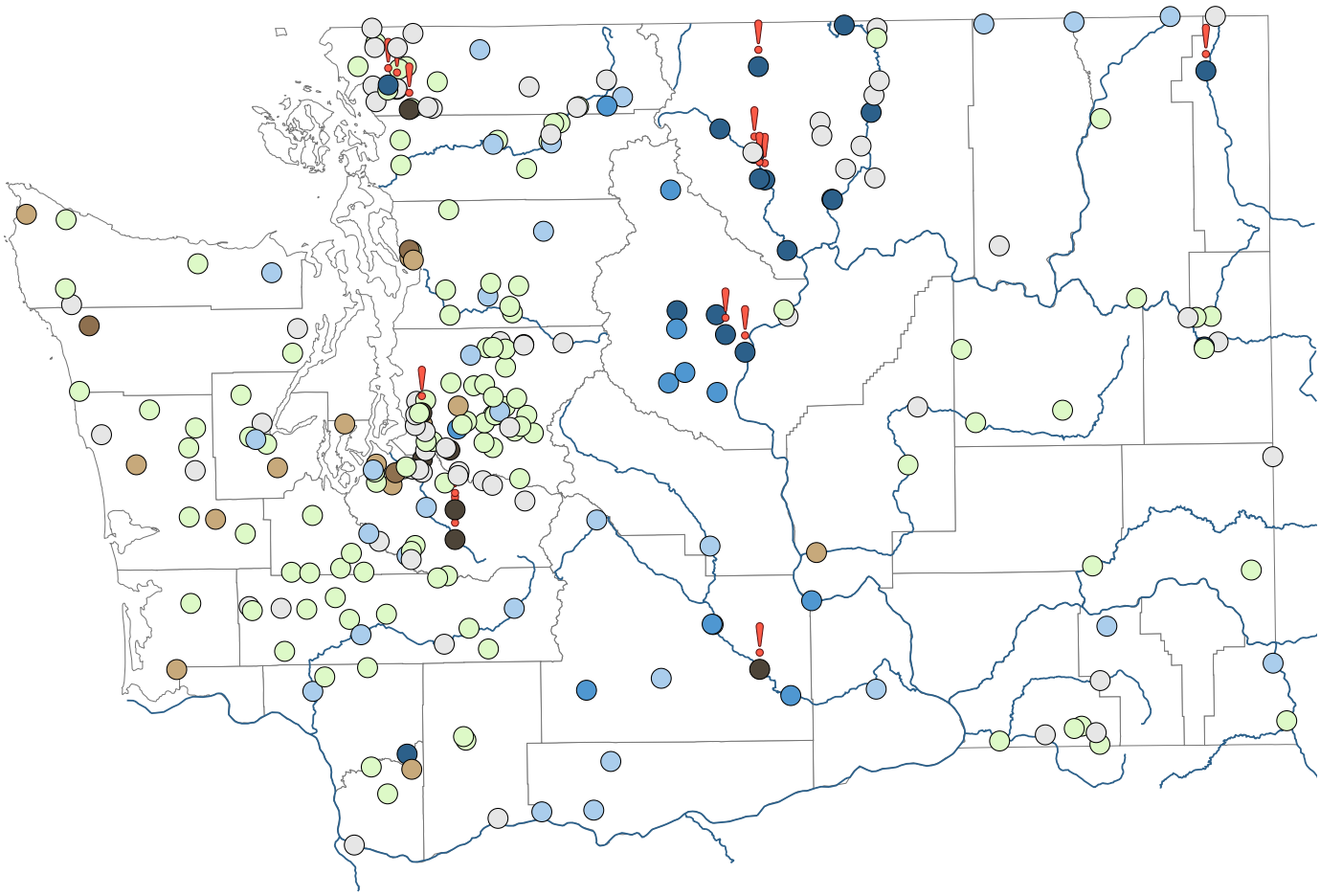
IMPORTANT Data are provisional

Customize filters

Get more information

Hide map

## Washington



Click a monitoring location or zoom map for more details.

## Legend

○ Monitoring location with Discharge, cubic feet per second
! Extreme conditions

For an explanation of dot color shading and extreme conditions please see the *Current condition estimate* section below.

## Current condition estimate

The condition estimate is based on the latest continuous data value recorded in relation to historic daily averages expressed as percentiles. The percentiles show how a value relates to all the other values for a given day of the year and indicate what percentage of days have an average (mean) value less than the latest recorded value. Extreme conditions are indicated when the latest continuous data value is outside of the percentile range of historic daily averages, meaning current conditions are above the highest or below the lowest daily average ever recorded for this day of the year.

| 0-5 | 5-10 | 10-25 | 25-75 | 75-90 | 90-95 | 95-100 |
|---|---|---|---|---|---|---|
| Extremely below | Much below | Below | Normal | Above | Much above | Extremely above |

No estimate available
Less than 20 years of data

Generation of meaningful percentile distributions requires daily data for the selected data type to have been collected by automated processes for at least 20 years at a location. Locations with less than 20 years of daily data

for the selected data type are shown in gray.

View statistics documentation

**261** monitoring locations
Data collection - **Continuous**

Using filters for
Data collection duration - **The last 120 days**

Showing locations with
**- Discharge, cubic feet per second**

Show only locations with

- (●) Discharge
- ( ) Gage height
- ( ) Depth to water level
- ( ) Water temperature
- ( ) Any data

**Hide map**

## My Favorites

0 Locations selected

**Show My Favorites options**

### Washington monitoring locations

Hide details for all locations

**261** monitoring locations
Data collection - **Continuous**

Using filters for
Data collection duration - **The last 120 days**

Showing locations with
**- Discharge, cubic feet per second**

**Group monitoring locations by**

- (●) County
- ( ) HUC-06 basin

**Select the order monitoring locations are shown**

- (●) Location Name - Ascending (A-Z)

Location Name - Descending (Z-A)

Location ID - Ascending

Location ID - Descending

Showing 31 of 38 counties

**Asotin County**
0 of 2 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Asotin Creek at Asotin, WA - USGS-13335050 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 79.5 Above normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

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Snake River Near Anatone, WA - USGS-13334300 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 25000 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

**Benton County**
0 of 1 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Yakima River at Kiona, WA - USGS-12510500 Hide details

| Latest value | Data type | Time |
|---|---|---|

| | | | |
|---|---|---|---|
| 6540<br>Above normal | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

**Chelan County**
0 of 11 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Chelan R at Habitat 4 Channel at Chelan Falls, WA - USGS-12452550 Hide details

| Latest value | Data type | Time |
|---|---|---|
| Seasonal | Discharge, cubic ... | Dec 01, 2025<br>12:00 AM PST |

Select for My favorites

View Monitoring location page

Chelan River at Chelan, WA - USGS-12452500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1120<br>Normal | Discharge, cubic ...<br>SPILLWAY | Dec 31, 2025<br>10:45 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Chiwawa River Near Plain, WA - USGS-12456500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 382<br>Extremely above | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Entiat River Near Ardenvoir, WA - USGS-12452800 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 373 Extremely above | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Entiat River Near Entiat, WA - USGS-12452990 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 476 Extremely above | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Icicle Creek Above Snow Creek Near Leavenworth, WA - USGS-12458000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 648 Much above | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Mad River at Ardenvoir, WA - USGS-12452890 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 104 Extremely above | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Stehekin River at Stehekin, WA - USGS-12451000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 680<br>Much above | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Wenatchee River at Monitor, WA - USGS-12462500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3390<br>Much above | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Wenatchee River at Peshastin, WA - USGS-12459000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3210<br>Much above | Discharge, cubic ... | Dec 31, 2025<br>11:15 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Wenatchee River at Plain, WA - USGS-12457000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 2180<br>Much above | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

**Clallam County**
0 of 6 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Bogachiel River Near Forks, WA - USGS-12042800 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 946 | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Calawah River Near Forks, WA - USGS-12043000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1200 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Dungeness River Near Sequim, WA - USGS-12048000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 442 Above normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Elwha River at Mcdonald BR Near Port Angeles, WA - USGS-12045500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1720 Normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Hoko River Near Sekiu, WA - USGS-12043300 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 331<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Tsoo-yess River Blw Miller Creek Near Ozette, WA - USGS-12043163 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 113<br>Below normal | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

**Clark County**
0 of 3 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Canyon Creek Near Amboy, WA - USGS-14219000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 284<br>Below normal | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Columbia River at Vancouver, WA - USGS-14144700 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 205000 | Discharge, cubic ...<br>Upstream | Dec 31, 2025<br>11:00 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

East Fork Lewis River Near Heisson, WA - USGS-14222500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 670 Normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

**Columbia County**
0 of 2 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Touchet River at Gallaher RD Near Waitsburg, WA - USGS-14016820 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 206 | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Tucannon River Near Starbuck, WA - USGS-13344500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 202 Above normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

**Cowlitz County**
0 of 5 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Cowlitz River at Castle Rock, WA - USGS-14243000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 19700<br>Above normal | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Lewis River at Ariel, WA - USGS-14220500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 4370<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>11:15 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

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NF Toutle River Below Srs Near Kid Valley, WA - USGS-14240525 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 930<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>11:00 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Speelyai Creek Near Cougar, WA - USGS-14219800 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 794<br>Extremely above | Discharge, cubic ... | Dec 31, 2025<br>10:15 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Toutle River at Tower Road Near Silver Lake, WA - USGS-14242580 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 2260 | Discharge, cubic ... | Dec 31, 2025 | View 7 day graph |

Normal | 10:45 AM PST | View statistical graphs

Select for My favorites

**Ferry County**
0 of 3 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Kettle River Near Ferry, WA - USGS-12401500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 339 Above normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Kettle River Near Laurier, WA - USGS-12404500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1010 Above normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Sanpoil River Above Jack Creek at Keller, WA - USGS-12434590 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| Ice af ... | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph |

Select for My favorites

**Grant County**

0 of 4 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Columbia River Below Priest Rapids Dam, WA - USGS-12472800 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 142000 Much above | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

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Crab Creek Near Beverly, WA - USGS-12472600 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 113 Below normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Crab Creek Near Moses Lake, WA - USGS-12467000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 20.8 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Crab Creek Near Stratford, WA - USGS-12466015 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 0.00 | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph |

Select for My favorites

**Grays Harbor County**
0 of 9 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Chehalis River at Porter, WA - USGS-12031000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 5970 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Humptulips River Below Hwy 101 NR Humptulips, WA - USGS-12039005 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1120 Below normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Quinault River Near Taholah, WA - USGS-1203951610 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 4500 | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Quinault River at Quinault Lake, WA - USGS-12039500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 2980 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Satsop River Near Satsop, WA - USGS-12035000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1700 Below normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Schafer Creek Near Grisdale, WA - USGS-12036400 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 49.1 | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph |

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View Monitoring location page

Wynoochee River Above Black Creek NR Montesano, WA - USGS-12037400 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1270 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Wynoochee River Above Save Creek Near Aberdeen, WA - USGS-12036000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 802 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Wynoochee River Near Grisdale, WA - USGS-12035400 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 424 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

**Jefferson County**
0 of 4 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Big Quilcene River Below Diversion NR Quilcene, WA - USGS-12052210 Hide details

| Latest value | Data type | Time |
|---|---|---|
| 144 | Discharge, cubic ... | Dec 08, 2025 05:30 PM PST |

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View Monitoring location page

Duckabush River Near Brinnon, WA - USGS-12054000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 380 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Hoh River at US Highway 101 Near Forks, WA - USGS-12041200 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1160 Much below | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Queets River Near Clearwater, WA - USGS-12040500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3660 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

**King County**
0 of 49 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Big Soos Creek Above Hatchery Near Auburn, WA - USGS-12112600 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 168 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Boise Creek at 252ND Ave NE NR Buckley, WA - USGS-12099550 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 32.5 | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph |

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View Monitoring location page

Boulder Creek Near Cedar Falls, WA - USGS-12115700 Hide details

| Latest value | Data type | Time |
|---|---|---|
| 0.01 | Discharge, cubic ... | Dec 22, 2025 |

01:45 AM PST

Select for My favorites

View Monitoring location page

Boxley Creek Near Cedar Falls, WA - USGS-12143700 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 30.6 Above normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Boxley Creek Near Edgewick, WA - USGS-12143900 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 52.8 Much above | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Canyon Creek Near Cedar Falls, WA - USGS-12116100 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 23.3 Above normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Cedar River Below Bear Creek Near Cedar Falls, WA - USGS-12114500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 116 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Cedar River Below Diversion Near Landsburg, WA - USGS-12117600 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 844 Normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Cedar River Near Cedar Falls, WA - USGS-12115000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 178 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Cedar River Near Landsburg, WA - USGS-12117500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 785 Normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Cedar River at Cedar Falls, WA - USGS-12116500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 389 Normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Cedar River at Powerplant at Cedar Falls, WA - USGS-12116400 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 71.0 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Cedar River at Renton, WA - USGS-12119000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1290 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Duwamish River at Golf Course at Tukwila, WA - USGS-12113390 Hide details

| Latest value | Data type | Time |
|---|---|---|
| Equipm ... | Discharge, cubic ... | Dec 09, 2025 10:00 AM PST |

Select for My favorites

View Monitoring location page

Green River Above S 277TH ST at Kent, WA - USGS-12113150 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 2110 | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Green River Below Crisp Creek NR Black Diamond, WA - USGS-12108800 Hide details

| Latest value | Data type | Time |
|---|---|---|

| | | | |
|---|---|---|---|
| 1530 | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Green River Below Howard a Hanson Dam, WA - USGS-12105900 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1260<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Green River Below Meeker ST at Kent, WA - USGS-12113310 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 2160 | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Green River Near Auburn, WA - USGS-12113000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 2090<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>10:45 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Green River at 200TH Street at Kent, WA - USGS-12113344 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 2170 | Discharge, cubic ... | Dec 31, 2025<br>10:15 AM PST | View 7 day graph |

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View Monitoring location page

Green River at Purification Plant Near Palmer, WA - USGS-12106700 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1150 Normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Greenwater River at Greenwater, WA - USGS-12097500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 269 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Issaquah Creek Near Hobart, WA - USGS-12120600 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 41.6 Below normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Issaquah Creek Near Mouth Near Issaquah, WA - USGS-12121600 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 130 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Middle Fork Snoqualmie River Near Tanner, WA - USGS-12141300 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 711 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Mill Creek Near Mouth at Orillia, WA - USGS-12113349 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 17.5 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Mill Creek at Earthworks Park at Kent, WA - USGS-12113347 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 2.63 Below normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

NF Snoqualmie River Near Snoqualmie Falls, WA - USGS-12142000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 380 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

NF Tolt River Above Yellow Creek NR Carnation, WA - USGS-12147470 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 312 | Discharge, cubic ... | Dec 31, 2025 | View 7 day graph |

10:30 AM PST

Select for My favorites

View Monitoring location page

Newaukum Creek Near Black Diamond, WA - USGS-12108500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 18.1 Extremely below | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Phelps Creek Blw Unnamed Trib NR Index, WA - USGS-12147680 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 27.3 | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Raging River Near Fall City, WA - USGS-12145500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 156 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Rex River Near Cedar Falls, WA - USGS-12115500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 58.6 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Rock Creek at Highway 516 Near Ravensdale, WA - USGS-12118400 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 40.2 Much above | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

SF Snoqualmie River AB Alice Creek Near Garcia, WA - USGS-12143400 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 257 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

SF Snoqualmie River at Edgewick, WA - USGS-12143600 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 508 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

SF Snoqualmie River at North Bend, WA - USGS-12144000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 540 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

SF Tolt River BL Regulating Basin NR Carnation, WA - USGS-12148300 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 219<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>11:00 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Snoqualmie River Near Carnation, WA - USGS-12149000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| Unknown | Discharge, cubic ... | Unknown<br>Unknown | View statistical graphs |

Select for My favorites

View Monitoring location page

Snoqualmie River Near Snoqualmie, WA - USGS-12144500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 2000<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

South Fork Skykomish River at Skykomish, WA - USGS-12131500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1240 | Discharge, cubic ... | Dec 31, 2025<br>11:15 AM PST | View 7 day graph |

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South Fork Tolt River Near Carnation, WA - USGS-12148000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 63.3<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph<br>View statistical graphs |

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View Monitoring location page

South Fork Tolt River Near Index, WA - USGS-12147600 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 22.8 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Springbrook Creek at Orillia, WA - USGS-12113346 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3.88 Extremely below | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Taylor Creek Near Selleck, WA - USGS-12117000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 133 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Tolt River Near Carnation, WA - USGS-12148500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 626 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

White River Above Boise Creek at Buckley, WA - USGS-12099200 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 842 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

White River Below Clearwater River NR Buckley, WA - USGS-12097850 Hide details

| Latest value | Data type | Time |
|---|---|---|
| 2690 | Discharge, cubic ... | Dec 08, 2025 12:45 PM PST |

Select for My favorites

View Monitoring location page

White River at R Street Near Auburn, WA - USGS-12100490 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1980 | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph |

Select for My favorites

**Kittitas County**
0 of 1 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Yakima River at Umtanum, WA - USGS-12484500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 2020 Above normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

**Klickitat County**
0 of 2 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Klickitat River BL Summit Creek Near Glenwood, WA - USGS-14111400 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1410 Above normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Klickitat River Near Pitt, WA - USGS-14113000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1770 Above normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

**Lewis County**
0 of 14 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Chehalis River Near Adna, WA - USGS-12021800 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1400 | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Chehalis River Near Doty, WA - USGS-12020000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 520 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Cispus River AB Yellowjacket Creek Near Randle, WA - USGS-14231900 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 989 Normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Cowlitz River Below Mayfield Dam, WA - USGS-14238000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 13400 Above normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Cowlitz River Near Kosmos, WA - USGS-14233500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 855 | Discharge, cubic ... | Sep 30, 2009 11:45 PM PDT | |

Select for My favorites

View Monitoring location page

Cowlitz River at Packwood, WA - USGS-14226500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1560<br>Above normal | Discharge, cubic ... | Dec 31, 2025<br>11:00 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Cowlitz River at Randle, WA - USGS-14231000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3410<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>11:15 AM PST | View 7 day graph<br>View statistical graphs |

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View Monitoring location page

Elk Creek Below Deer Creek Near Doty, WA - USGS-12020525 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 258 | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Mineral Creek Near Mineral, WA - USGS-12083000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 303<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>11:00 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

NF Newaukum River Above Bear Creek Near Forest, WA - USGS-12024400 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 162<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>11:00 AM PST | View 7 day graph |

View statistical graphs

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View Monitoring location page

Newaukum River Near Chehalis, WA - USGS-12025000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 623 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

South Fork Chehalis River Near Wildwood, WA - USGS-12020800 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 167 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

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South Fork Newaukum River Near Onalaska, WA - USGS-12024000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 409 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Tilton River AB Bear Canyon Creek Near Cinebar, WA - USGS-14236200 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 918 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

**Lincoln County**
0 of 3 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Coal Creek at Mohler, WA - USGS-12464800 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 0.81 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Crab Creek at Irby, WA - USGS-12465000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1.49 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Wilson Creek Below Corbett Draw Near Almira, WA - USGS-12465400 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 0.07 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

**Mason County**
0 of 6 selected for My Favorites

Select for My Favorites

All None

View Monitoring location page

Goldsborough Creek Above 7TH Street at Shelton, WA - USGS-12076800 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 118 Below normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

NF Skokomish R BL Staircase Rpds NR Hoodsport, WA - USGS-12056500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 486 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

NF Skokomish R NR Lwr Cushman Dam NR Potlatch, WA - USGS-12058790 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 306 | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

North Fork Skokomish River Near Potlatch, WA - USGS-12059500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 341 Above normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Skokomish River Near Potlatch, WA - USGS-12061500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1530<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph<br>View statistical graphs |

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View Monitoring location page

South Fork Skokomish River Near Union, WA - USGS-12060500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 557<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>10:45 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

**Okanogan County**
0 of 20 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Andrews Creek Near Mazama, WA - USGS-12447390 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 13.9<br>Extremely above | Discharge, cubic ... | Dec 31, 2025<br>10:45 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Antoine Creek at US Hwy 97 Near Ellisforde, WA - USGS-12444290 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 0.49 | Discharge, cubic ... | Dec 31, 2025<br>11:00 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Bonaparte Creek at Tonasket, WA - USGS-12444550 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| Ice af ... | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Chewuch River at Winthrop, WA - USGS-12448000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| Ice af ... | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Johnson Creek Near Riverside, WA - USGS-12445500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 8.88 | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Loup Loup Creek at Malott, WA - USGS-12447285 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| Ice af ... | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Methow River Above Goat Creek Near Mazama, WA - USGS-12447383 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 582 | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph |

Extremely above

View statistical graphs

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Methow River Near Pateros, WA - USGS-12449950 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1720 Extremely above | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Methow River at Twisp, WA - USGS-12449500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1350 Extremely above | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Methow River at Winthrop, WA - USGS-12448500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 994 Extremely above | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Ninemile Creek at Eastlake RD Near Oroville, WA - USGS-12438905 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| Equipm ... | Discharge, cubic ... | Dec 30, 2025 02:45 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

North Fork Salmon Creek Near Conconully, WA - USGS-12446150 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 8.57 | Discharge, cubic ... | Dec 31, 2025 10:15 AM PST | View 7 day graph |

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View Monitoring location page

Okanogan River Near Tonasket, WA - USGS-12445000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 2830 Extremely above | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Okanogan River at Malott, WA - USGS-12447200 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3220 Extremely above | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph<br>View statistical graphs |

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View Monitoring location page

Okanogan River at Oroville, WA - USGS-12439500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 330 Normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Omak Creek Near Omak, WA - USGS-12445900 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| Ice af ... | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Salmon Creek Above Diversion Near Okanogan, WA - USGS-12446995 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 10.3 | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Similkameen River Near Nighthawk, WA - USGS-12442500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 2380 Extremely above | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Twisp River Near Twisp, WA - USGS-12448998 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 422 Extremely above | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

West Fork Salmon Creek Near Conconully, WA - USGS-12446400 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| Ice af ... | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph |

Select for My favorites

**Pacific County**
0 of 2 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Naselle River Near Naselle, WA - USGS-12010000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 350<br>Below normal | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Willapa River Near Willapa, WA - USGS-12013500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 640<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>10:45 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

**Pend Oreille County**
0 of 2 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Pend Oreille River Below Box Canyon Near Ione, WA - USGS-12396500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 33000 | Discharge, cubic ... | Dec 31, 2025 | View 7 day graph |

| | | | |
|---|---|---|---|
| Extremely above | | 11:00 AM PST | View statistical graphs |

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View Monitoring location page

Pend Oreille River at International Boundary - USGS-12398600 Hide details

| Latest value | Data type | Time |
|---|---|---|
| 5290 | Discharge, cubic ... | Dec 01, 2025 12:00 AM PST |

Select for My favorites

**Pierce County**
0 of 26 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Carbon River Near Fairfax, WA - USGS-12094000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 75.3 Extremely below | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Chambers Creek BL Leach Creek Near Steilacoom, WA - USGS-12091500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 200 Above normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

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Clarks Creek at Stewart Avenue Near Puyallup, WA - USGS-12102078 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 41.0 | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Clearwater River Near Buckley, WA - USGS-12097820 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 119 | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Clover Creek Near Tillicum, WA - USGS-12090500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 59.6<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>11:15 AM PST | View 7 day graph<br>View statistical graphs |

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View Monitoring location page

Flett Creek at Tacoma, WA - USGS-12091100 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 28.4<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>10:45 AM PST | View 7 day graph<br>View statistical graphs |

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View Monitoring location page

Huckleberry Creek Near Greenwater, WA - USGS-12096865 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3.74 | Discharge, cubic ... | Dec 31, 2025<br>11:00 AM PST | View 7 day graph |

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View Monitoring location page

Huge Creek Near Wauna, WA - USGS-12073500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 7.53 Below normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

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Lake Tapps Diversion at Dieringer, WA - USGS-12101100 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 0.74 Extremely below | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Leach CR at Meadow Park GC at University Place, WA - USGS-12091290 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 8.31 Below normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Leach Creek Near Fircrest, WA - USGS-12091200 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 2.47 Below normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

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Mashel River Near LA Grande, WA - USGS-12087000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 208 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Nisqually River Near National, WA - USGS-12082500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 843 Normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Nisqually River at LA Grande Dam, WA - USGS-12086000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 36.6 | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Nisqually River at LA Grande, WA - USGS-12086500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 2520 Above normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

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North Fork Clover Creek Near Parkland, WA - USGS-12090400 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 6.03<br>Below normal | Discharge, cubic ... | Dec 31, 2025<br>11:15 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Ohop Creek Near Eatonville, WA - USGS-12088000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 63.0<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph<br>View statistical graphs |

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View Monitoring location page

Puyallup River Near Electron, WA - USGS-12092000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 136<br>Extremely below | Discharge, cubic ... | Dec 31, 2025<br>11:15 AM PST | View 7 day graph<br>View statistical graphs |

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View Monitoring location page

Puyallup River Near Orting, WA - USGS-12093500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 947<br>Above normal | Discharge, cubic ... | Dec 31, 2025<br>11:15 AM PST | View 7 day graph<br>View statistical graphs |

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Puyallup River at 5TH ST Bridge at Puyallup, WA - USGS-12101470 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3730 | Discharge, cubic ... | Dec 31, 2025 | View 7 day graph |

10:30 AM PST

Select for My favorites

View Monitoring location page

Puyallup River at Alderton, WA - USGS-12096500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1720 | Discharge, cubic ... | Dec 31, 2025<br>10:45 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Puyallup River at E Main Bridge at Puyallup, WA - USGS-12096505 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 2380 | Discharge, cubic ... | Dec 31, 2025<br>10:30 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Puyallup River at Puyallup, WA - USGS-12101500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3790<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>10:45 AM PST | View 7 day graph<br>View statistical graphs |

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South Prairie Creek at South Prairie, WA - USGS-12095000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 330<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>08:45 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Swan Creek at 80TH ST East Near Tacoma, WA - USGS-12102190 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1.19 Much below | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

White River Flume at Buckley, WA - USGS-12098920 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 0.99 | Discharge, cubic ... | Dec 28, 2025 08:30 AM PST | View 7 day graph |

Select for My favorites

**Skagit County**
0 of 10 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Bacon Creek Below Oakes Creek Near Marblemount, WA - USGS-12179900 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 319 Normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Baker River at Henry Thompson BR at Concrete, WA - USGS-12193400 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3490 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Cascade River at Marblemount, WA - USGS-12182500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 912 Above normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Diobsud Creek Near Marblemount, WA - USGS-12180500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 112 | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph |

Select for My favorites

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Samish River Near Burlington, WA - USGS-12201500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 371 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Sauk River Near Sauk, WA - USGS-12189500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3740 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Skagit River Above Alma Creek Near Marblemount, WA - USGS-12179000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 5520 Normal | Discharge, cubic ... | Dec 30, 2025 01:30 PM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Skagit River Near Concrete, WA - USGS-12194000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 16600 Above normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Skagit River Near Mount Vernon, WA - USGS-12200500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 18100 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Skagit River at Marblemount, WA - USGS-12181000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 5160 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

**Skamania County**
0 of 4 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Lewis River Above Muddy River Near Cougar, WA - USGS-14216000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1280 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Muddy River Below Clear Creek Near Cougar, WA - USGS-14216500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 697 Normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

White Salmon River Near Underwood, WA - USGS-14123500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1520 Above normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Wind River Near Carson, WA - USGS-14128500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1580 | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph |

Select for My favorites

**Snohomish County**
0 of 13 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

East Fork Tulalip Creek Near Mouth NR Tulalip, WA - USGS-12158032 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3.20 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Mission Creek Near Tulalip, WA - USGS-12157250 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 5.14 Below normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

NF Stillaguamish River Near Arlington, WA - USGS-12167000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1750 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Pilchuck River Near Snohomish, WA - USGS-12155300 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 572 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Sauk River AB White Chuck River NR Darrington, WA - USGS-12186000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1340 Above normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Skykomish River Near Gold Bar, WA - USGS-12134500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3110 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Snohomish River Near Monroe, WA - USGS-12150800 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 9510 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

South Fork Sultan River Near Sultan, WA - USGS-12137290 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 63.8 Normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Sultan River Below Diversion Dam Near Sultan, WA - USGS-12137800 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 108 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Sultan River Below Powerplant Near Sultan, WA - USGS-12138160 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1550 Above normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Tulalip Creek Near Tulalip, WA - USGS-12158040 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 11.5 Below normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Wallace River at Gold Bar, WA - USGS-12135000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 169 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

West Fork Tulalip Creek Near Tulalip, WA - USGS-12158010 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 4.61 | Discharge, cubic ... | Dec 31, 2025 | View 7 day graph |

Much below

11:00 AM PST

View statistical graphs

Select for My favorites

**Spokane County**
0 of 6 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Hangman Creek at Spokane, WA - USGS-12424000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 140 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Little Spokane River Near Dartford, WA - USGS-12431500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 537 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Little Spokane River at Dartford, WA - USGS-12431000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 229 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Spokane River Below N Greene ST at Spokane, WA - USGS-12422000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 14900 | Discharge, cubic ... | Dec 31, 2025<br>11:00 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Spokane River Below Nine Mile Dam at Spokane, WA - USGS-12426000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 15300 | Discharge, cubic ... | Dec 31, 2025<br>11:15 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Spokane River at Spokane, WA - USGS-12422500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 14900<br>Extremely above | Discharge, cubic ... | Dec 31, 2025<br>11:00 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

**Stevens County**
0 of 3 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Chamokane Creek Below Falls Near Long Lake, WA - USGS-12433200 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 32.0<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>10:15 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Columbia River at International Boundary - USGS-12399500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 101000<br>Above normal | Discharge, cubic ... | Dec 31, 2025<br>11:00 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Colville River at Kettle Falls, WA - USGS-12409000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 127<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>11:20 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

**Thurston County**
0 of 8 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Centralia Power Canal Near Mckenna, WA - USGS-12089208 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 296 | Discharge, cubic ... | Dec 31, 2025<br>11:00 AM PST | View 7 day graph |

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View Monitoring location page

Chehalis River Near Grand Mound, WA - USGS-12027500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3730<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>11:00 AM PST | View 7 day graph<br>View statistical graphs |

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View Monitoring location page

Deschutes River Near Rainier, WA - USGS-12079000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 288 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Deschutes River at E ST Bridge at Tumwater, WA - USGS-12080010 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 504 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Nisqually River at Mckenna, WA - USGS-12089500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3070 Above normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Skookumchuck River BL Bldy Run CR NR Centralia, WA - USGS-12026150 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 352 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Skookumchuck River Near Bucoda, WA - USGS-12026400 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 569<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>10:45 AM PST | View 7 day graph<br>View statistical graphs |

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View Monitoring location page

Skookumchuck River Near Vail, WA - USGS-12025700 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 250<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>11:00 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

**Walla Walla County**
0 of 6 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Blue Creek Near Walla Walla, WA - USGS-14013500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| Rating ... | Discharge, cubic ... | Dec 31, 2025<br>11:15 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Mill CR at Last Chance RD BR NR College Place, WA - USGS-14015350 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 108 | Discharge, cubic ... | Dec 31, 2025<br>11:15 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Mill Creek Near Walla Walla, WA - USGS-14013000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 87.0 Normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Mill Creek at Five Mile RD BR NR Walla Walla, WA - USGS-14013700 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 184 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Mill Creek at Walla Walla, WA - USGS-14015000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 98.1 Normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Walla Walla River Near Touchet, WA - USGS-14018500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 822 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

**Whatcom County**
0 of 26 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Anderson Creek Near Bellingham, WA - USGS-12201950 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 16.1 Normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Anderson Creek at Smith Road Near Goshen, WA - USGS-12210900 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 20.2 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

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View Monitoring location page

Baker River AB Blum Creek Near Concrete, WA - USGS-12190400 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 71.3 | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph |

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View Monitoring location page

Big Beaver Creek Near Newhalem, WA - USGS-12172000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 235 | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph |

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View Monitoring location page

Brannian Creek at S Bay DR NR Wickersham, WA - USGS-12201960 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 0.60<br>Extremely below | Discharge, cubic ... | Dec 31, 2025<br>11:15 AM PST | View 7 day graph<br>View statistical graphs |

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View Monitoring location page

Carpenter Creek Near Bellingham, WA - USGS-12202310 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| Equipm ... | Discharge, cubic ... | Dec 31, 2025<br>11:15 AM PST | View 7 day graph<br>View statistical graphs |

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View Monitoring location page

Chuckanut Creek Near Bellingham, WA - USGS-12201700 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 15.2 | Discharge, cubic ... | Dec 31, 2025<br>11:15 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Euclid CR at Euclid Ave at Bellingham, WA - USGS-12202400 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 0.94<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>10:45 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Fishtrap Creek at Front Street at Lynden, WA - USGS-12212050 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 87.8<br>Normal | Discharge, cubic ... | Dec 31, 2025<br>11:00 AM PST | View 7 day graph |

View statistical graphs

Select for My favorites

View Monitoring location page

MF Nooksack River Near Deming, WA - USGS-12208000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 675 Normal | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

NF Nooksack River BL Cascade Creek NR Glacier, WA - USGS-12205000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 790 Above normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Newhalem Creek at Newhalem, WA - USGS-12178150 Hide details

| Latest value | Data type | Time |
|---|---|---|
| Rating ... | Discharge, cubic ... | Dec 10, 2025 04:45 PM PST |

Select for My favorites

View Monitoring location page

Nooksack River Near Lynden, WA - USGS-12211500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3820 | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Nooksack River at Everson, WA - USGS-12211200 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3750 | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Nooksack River at Ferndale, WA - USGS-12213100 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 4010 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Nooksack River at North Cedarville, WA - USGS-12210700 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 3940 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Olsen Creek Near Bellingham, WA - USGS-12202300 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 0.47 Extremely below | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph<br>View statistical graphs |

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View Monitoring location page

Ruby Creek Below Panther Creek Near Newhalem, WA - USGS-12173500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 574 Above normal | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

SF Nooksack River at Saxon Bridge, WA - USGS-12210000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 553 | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Silver Beach CR at Maynard PL at Bellingham, WA - USGS-12202450 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 5.90 Extremely above | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Skagit River at Newhalem, WA - USGS-12178000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 4740 Normal | Discharge, cubic ... [Primary] | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Skookum Creek Above Diversion Near Wickersham, WA - USGS-12209490 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 179 | Discharge, cubic ... | Dec 23, 2025 02:00 PM PST | |

Select for My favorites

View Monitoring location page

Squalicum Creek Near Mouth at Bellingham, WA - USGS-12204010 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 30.1 | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Sumas River Near Sumas, WA - USGS-12214500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 89.3 | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Thunder Creek Near Newhalem, WA - USGS-12175500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 602 Much above | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

Unnamed Trib to Bertrand CR NR H ST NR Lynden, WA - USGS-12212430 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 1.41 | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph |

Select for My favorites

**Whitman County**

0 of 3 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Hangman Creek at State Line Road Near Tekoa, WA - USGS-12422990 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 38.3 | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph |

Select for My favorites

View Monitoring location page

Palouse River at Hooper, WA - USGS-13351000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 414 Normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

View Monitoring location page

South Fork Palouse River at Pullman, WA - USGS-13348000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 23.1 Normal | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph<br>View statistical graphs |

Select for My favorites

**Yakima County**

0 of 7 selected for My Favorites

Select for My Favorites All None

View Monitoring location page

Ahtanum Creek at Union Gap, WA - USGS-12502500 Hide details

| Latest value | Data type | Time |
|---|---|---|

| Latest value | Data type | Time | |
|---|---|---|---|
| 126 Much above | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

American River Near Nile, WA - USGS-12488500 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 237 Above normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Granger Drain at Granger, WA - USGS-12505450 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 12.7 Extremely below | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Klickitat River Above West Fork Near Glenwood, WA - USGS-14107000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 379 Much above | Discharge, cubic ... | Dec 31, 2025 11:15 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Toppenish Creek Near Fort Simcoe, WA - USGS-12506000 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 89.9 | Discharge, cubic ... | Dec 31, 2025 10:45 AM PST | View 7 day graph |

Above normal

View statistical graphs

Select for My favorites

View Monitoring location page

Yakima River Above Ahtanum Creek at Union Gap, WA - USGS-12500450 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 4250 Above normal | Discharge, cubic ... | Dec 31, 2025 10:30 AM PST | View 7 day graph View statistical graphs |

Select for My favorites

View Monitoring location page

Yakima River at Mabton, WA - USGS-12508990 Hide details

| Latest value | Data type | Time | |
|---|---|---|---|
| 6800 Much above | Discharge, cubic ... | Dec 31, 2025 11:00 AM PST | View 7 day graph View statistical graphs |

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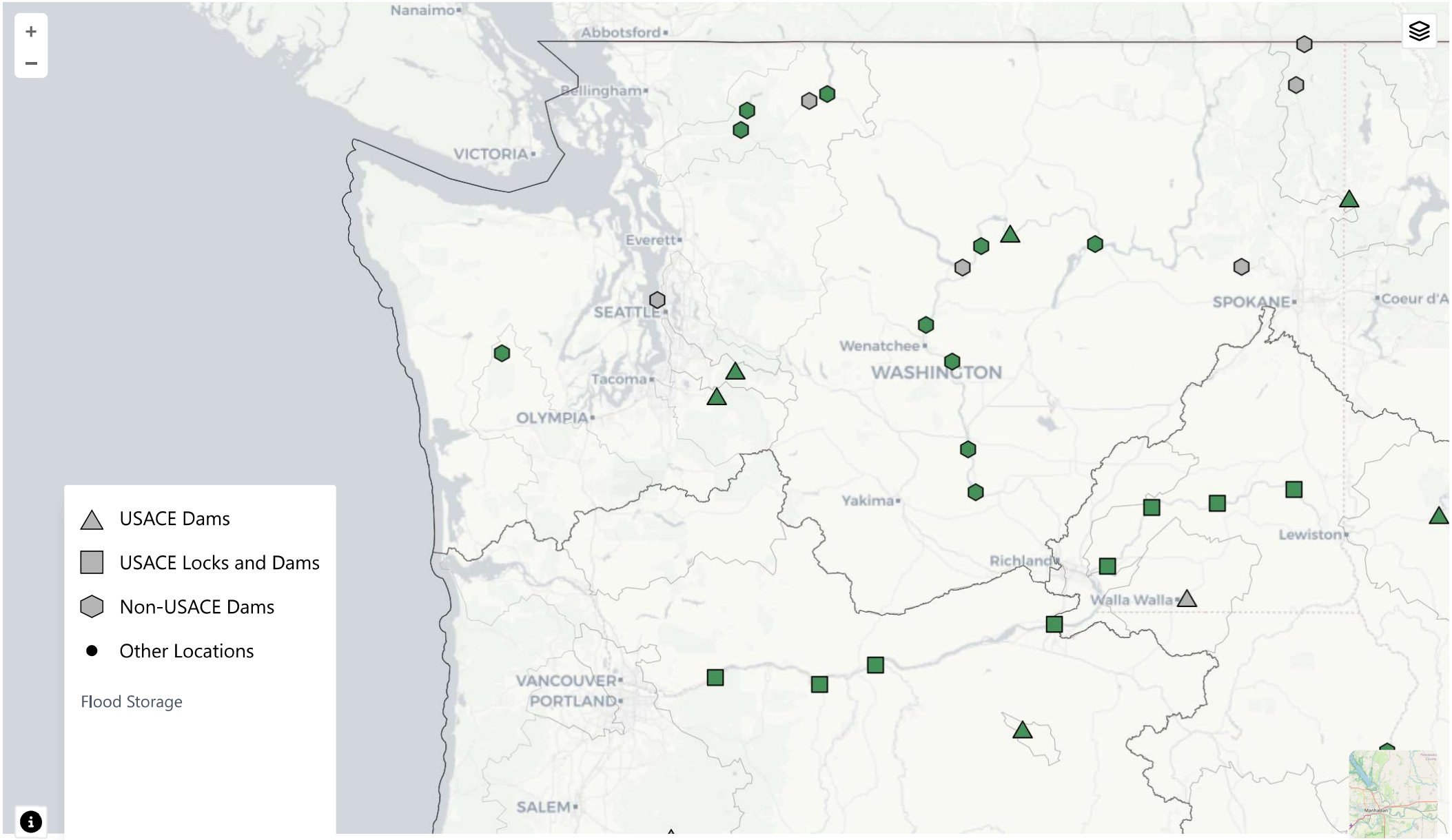
U.S. Department of the Interior | DOI Inspector General | White House | No Fear Act | FOIA

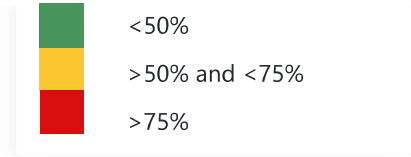
# EXHIBIT 41-7

An official website of the United States government Here's how you know

Home Map Locations Help Active Flooding Events Search

**US Army Corps of Engineers** Water Management Data




<50%
>50% and <75%
>75%

# EXHIBIT 41-8

An official website of the United States government Here's how you know



# Grand Coulee Dam

Pacific Northwest Region

Details Map

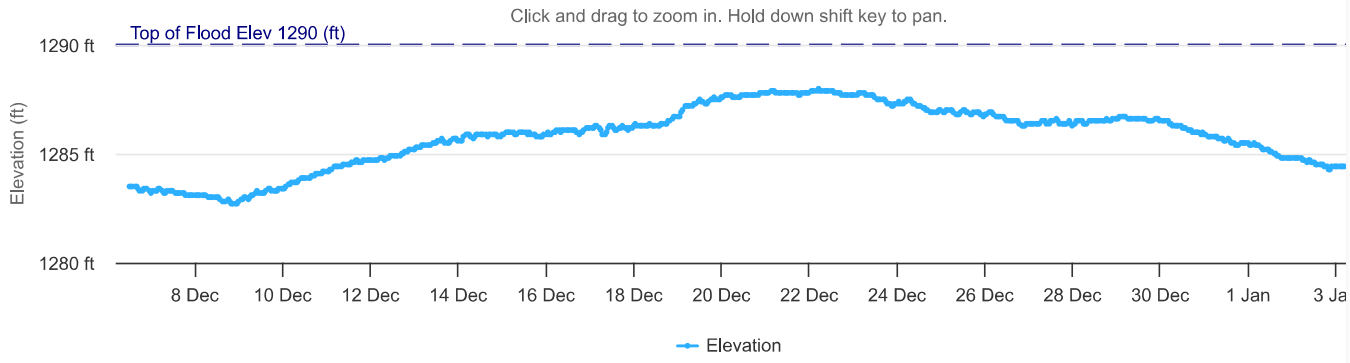
| | |
|---|---|
| Current Values | 5 |
| Metadata | |
| Links | 1 |
| Levels | 14 |

| Flood Storage Utilized | Conservation Storage Utilized | Total Storage Utilized |
|---|---|---|
| 0% | N/A | 90% |

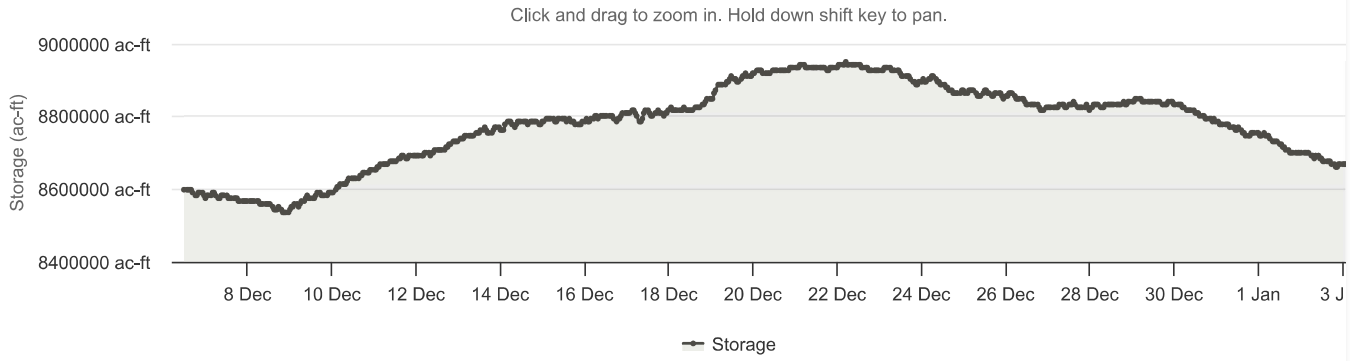
Dam Profile Timeseries 5

last 7 days last 14 days last month

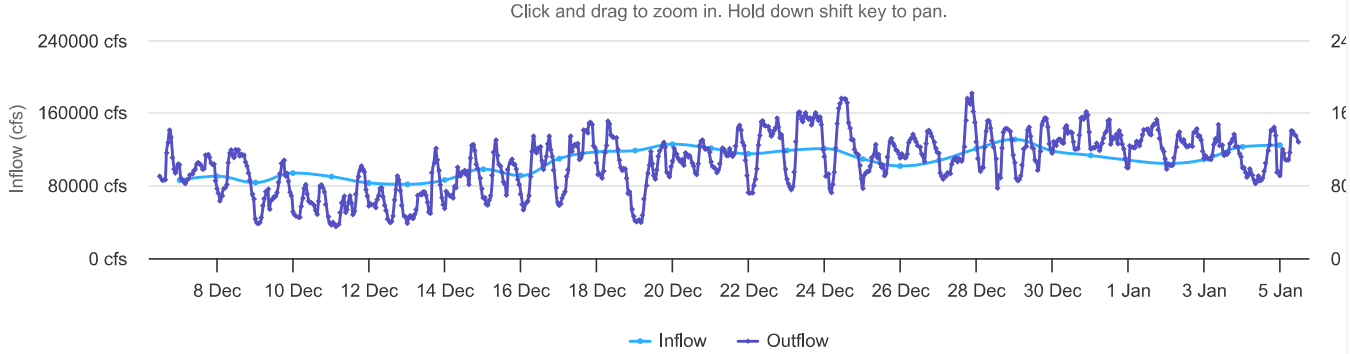
## Elevation



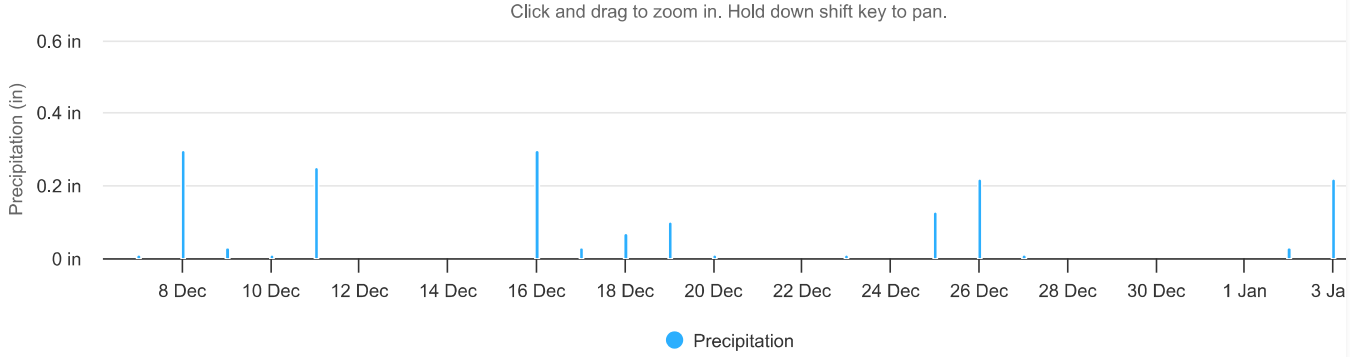
## Storage




## Inflow / Outflow




## Precipitation




| Label | Parameter | Value | Units |
|---|---|---|---|
| 0 | Elev | 920 | ft |
| Bottom of Flood | Elev | 1,290 | ft |
| Bottom of Normal | Elev | 1,208 | ft |
| Spillway Crest | Elev | 1,260 | ft |
| Streambed | Elev | 977.26 | ft |
| Top of Dam | Elev | 1,290 | ft |
| Top of Flood | Elev | 1,290 | ft |
| Top of Normal | Elev | 1,290 | ft |
| Bottom of Flood | Stor | 9,107,500 | ac-ft |
| Bottom of Normal | Stor | 4,365,786 | ac-ft |
| Spillway Crest | Stor | 7,446,416 | ac-ft |
| Top of Dam | Stor | 9,715,346 | ac-ft |
| Top of Flood | Stor | 9,715,346 | ac-ft |
| Top of Normal | Stor | 9,715,346 | ac-ft |

Data Sources 5

| Parameter | JSON | CSV |
|---|---|---|
| Outflow | | |
| Precipitation | | |
| Elevation | | |
| Inflow | | |
| Storage | | |
| Documents | 1 | |

## Our Mission

Deliver vital engineering solutions, in collaboration with our partners, to secure our Nation, energize our economy, and reduce disaster risk.

## About this Website

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Locations by Office
Interactive Map
Data Resources
Help Topics
Data Disclaimer
API Docs
Contact Us
USACE HQ
Privacy Policy

# EXHIBIT 41-9

An official website of the United States government Here's how you know



# Chief Joseph Dam

Pacific Northwest Region

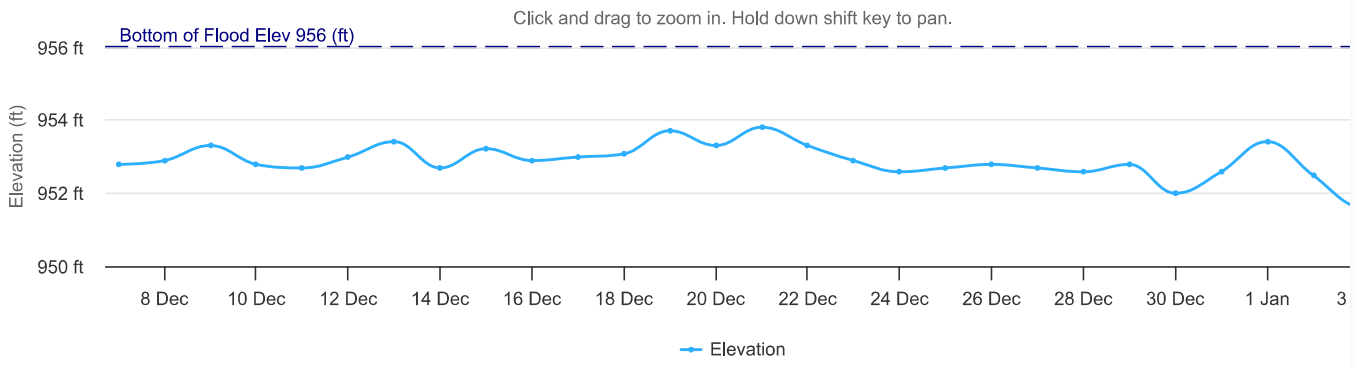
Details Map

| Flood Storage Utilized | Conservation Storage Utilized | Total Storage Utilized |
|---|---|---|
| 0% | N/A | N/A |

Dam Profile Timeseries 5

last 7 days last 14 days last month

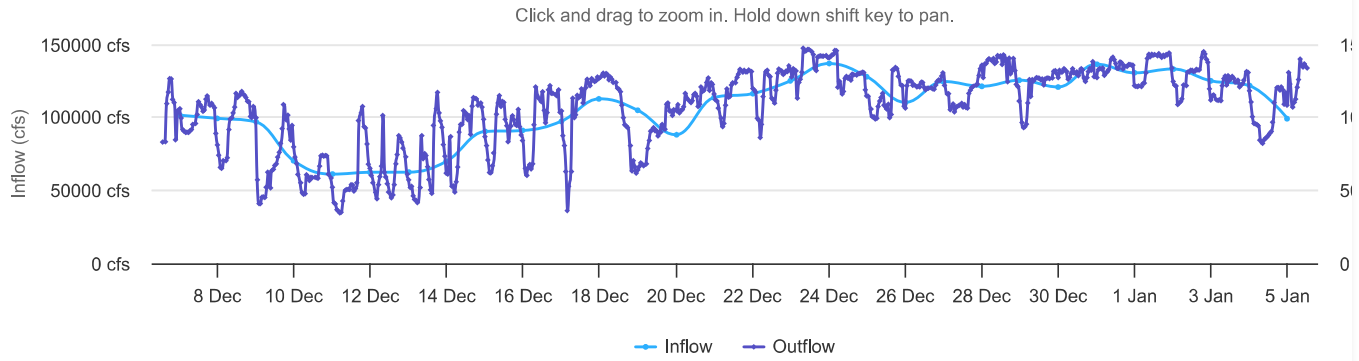
## Elevation




| | |
|---|---|
| Current Values | 5 |
| Metadata | |
| Links | 2 |
| Levels | 10 |

| Label | Parameter | Value | Units |
|---|---|---|---|
| Spillway Crest | Elev-Forebay | 901.5 | ft |
| Streambed | Elev-Forebay | 775 | ft |
| Top of Dam | Elev-Forebay | 970 | ft |
| Top of Normal | Elev-Forebay | 956 | ft |
| Bottom of Flood | Elev | 956 | ft |
| Top of Flood | Elev | 958.8 | ft |
| Bottom of Flood | Stor | 593,100 | ac-ft |
| Streambed | Stor | 0 | ac-ft |
| Top of Flood | Stor | 615,220 | ac-ft |
| Top of Normal | Stor | 1,000 | ac-ft |

## Inflow / Outflow




- Data Sources 5
- Nearby Locations 1
- Documents 1

### Our Mission

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Locations by Office
Interactive Map
Data Resources
Help Topics
Data Disclaimer
API Docs
Contact Us
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Privacy Policy

# EXHIBIT 41-10

An official website of the United States government Here's how you know



# Lower Granite Lock and Dam

Walla Walla District

Details Map

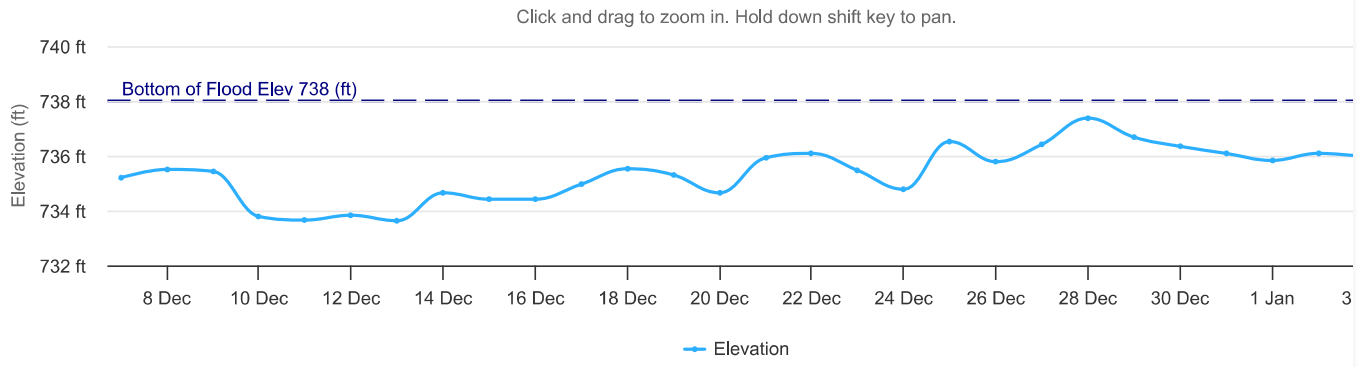
| | |
|---|---|
| Flood Storage Utilized | 0% |
| Conservation Storage Utilized | 94% |
| Total Storage Utilized | 74% |

| | |
|---|---|
| Current Values | 5 |
| Metadata | |
| Links | 3 |
| Levels | 16 |

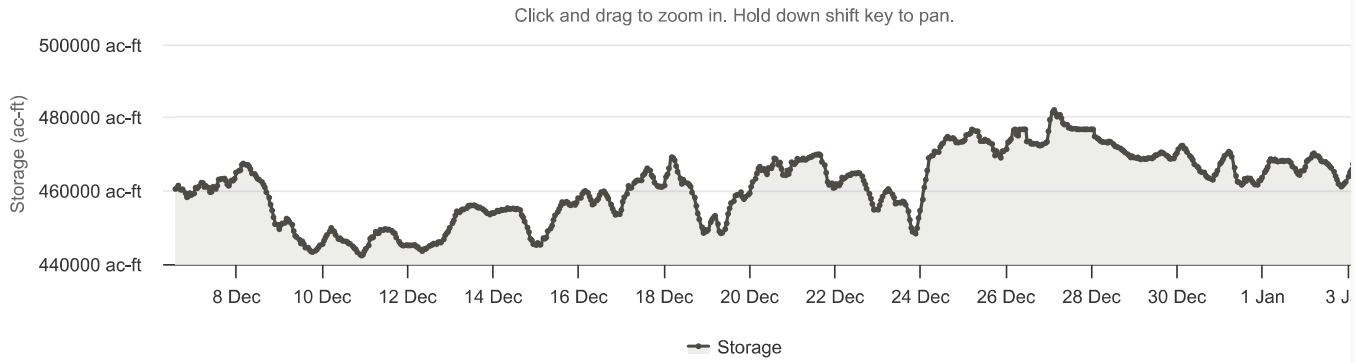
Dam Profile Timeseries 5

last 7 days last 14 days last month

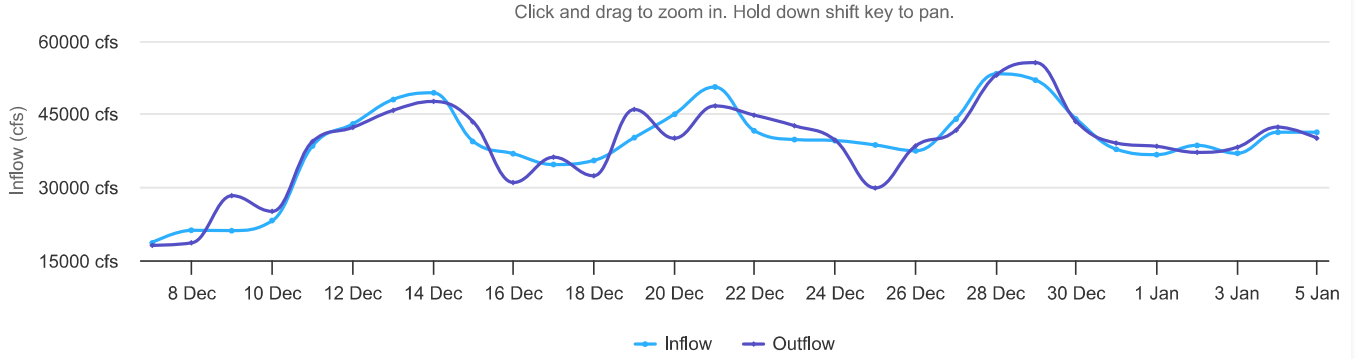
## Elevation



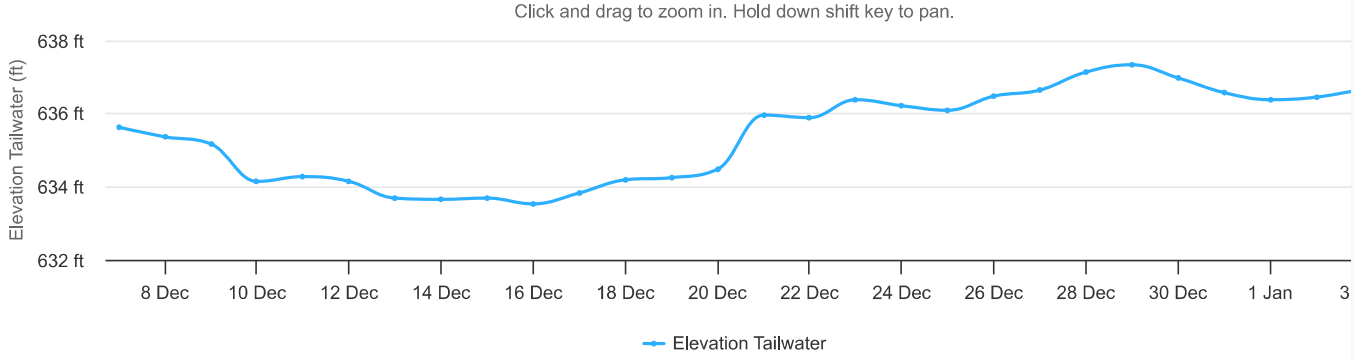
## Storage




## Inflow / Outflow




## Elevation Tailwater




| Label | Parameter | Value | Units |
|---|---|---|---|
| Bottom of Flood | Elev | 738 | ft |
| Bottom of Normal | Elev | 733 | ft |
| Spillway Crest | Elev | 681 | ft |
| Streambed | Elev | 590 | ft |
| Top of Dam | Elev | 751 | ft |
| Top of Flood | Elev | 746.5 | ft |
| Top of Inactive | Elev | 680 | ft |
| Top of Normal | Elev | 738 | ft |
| Bottom of Flood | Stor | 483,800 | ac-ft |
| Bottom of Normal | Stor | 440,200 | ac-ft |
| Spillway Crest | Stor | 140,000 | ac-ft |
| Streambed | Stor | 0 | ac-ft |
| Top of Dam | Stor | 621,600 | ac-ft |
| Top of Flood | Stor | 573,900 | ac-ft |
| Top of Inactive | Stor | 139,800 | ac-ft |
| Top of Normal | Stor | 483,800 | ac-ft |

Data Sources 5 ›

Nearby Locations 2 ›

Documents 1 >

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Locations by Office
Interactive Map
Data Resources
Help Topics
Data Disclaimer
API Docs
Contact Us
USACE HQ
Privacy Policy

# EXHIBIT 41-11

An official website of the United States government Here's how you know



# Little Goose Lock and Dam

Walla Walla District

Details Map

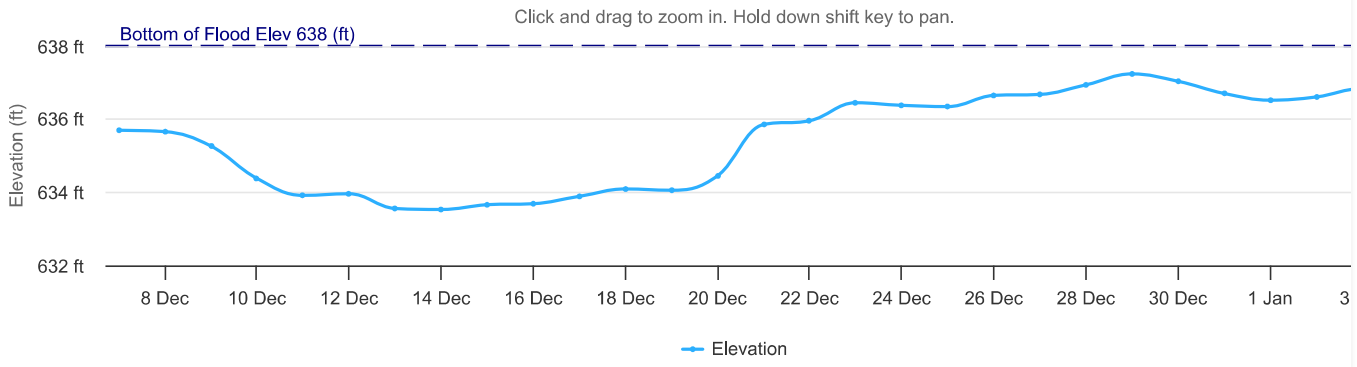
| | |
|---|---|
| Flood Storage Utilized | 0% |
| Conservation Storage Utilized | 70% |
| Total Storage Utilized | 70% |

| | |
|---|---|
| Current Values | 5 |
| Metadata | |
| Links | 1 |
| Levels | 16 |

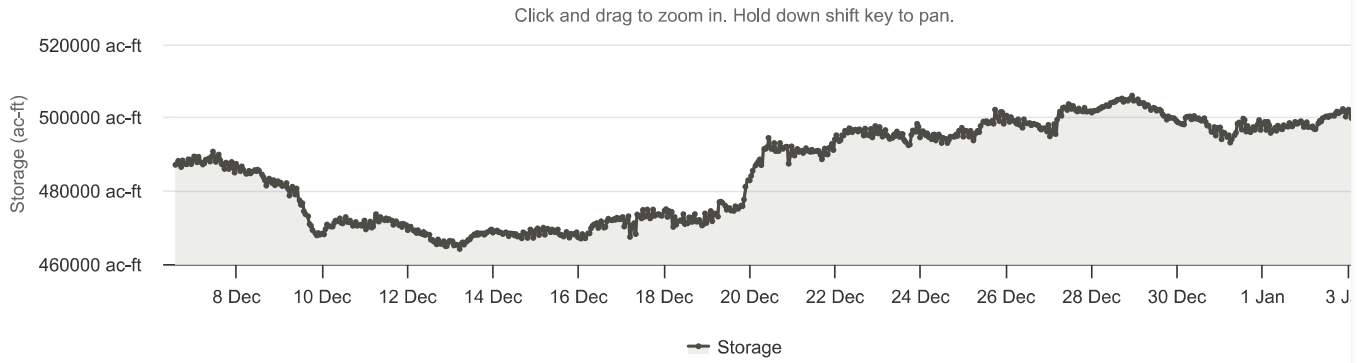
Dam Profile Timeseries 5

last 7 days last 14 days last month

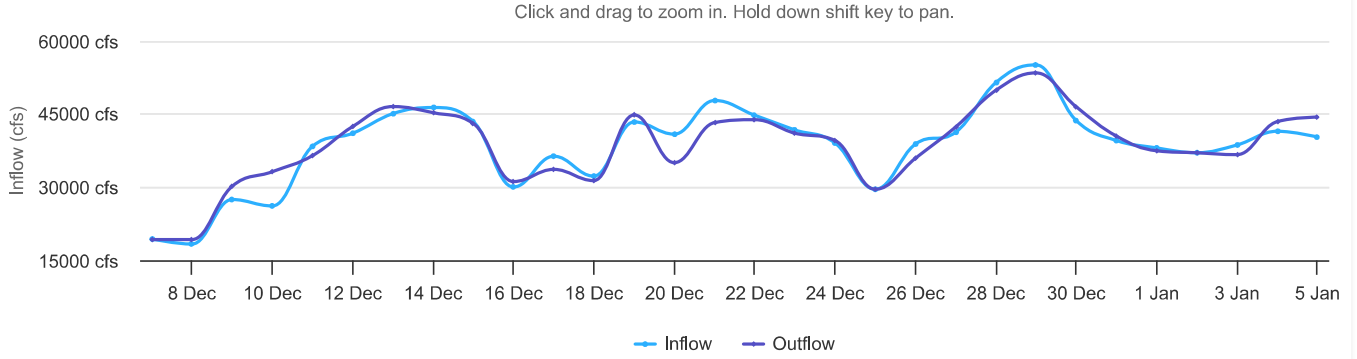
## Elevation



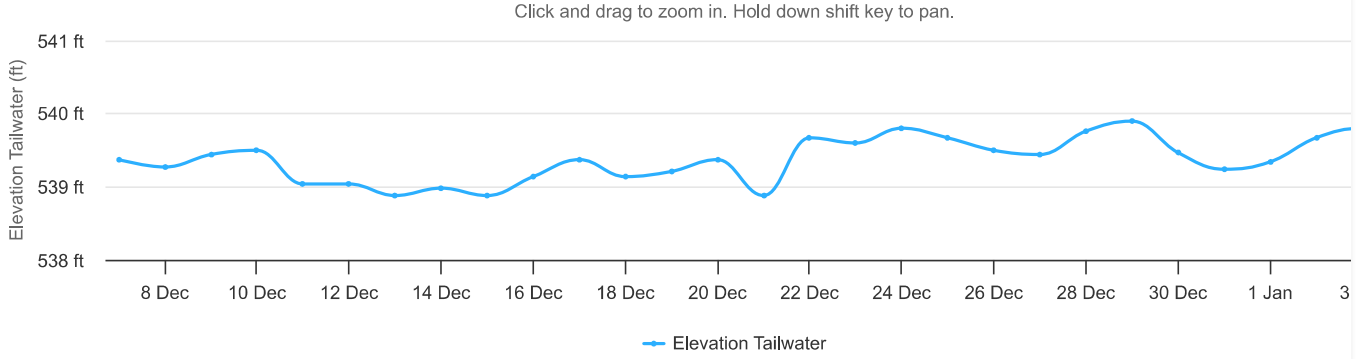
## Storage




## Inflow / Outflow




## Elevation Tailwater




| Label | Parameter | Value | Units |
|---|---|---|---|
| Bottom of Flood | Elev | 638 | ft |
| Bottom of Normal | Elev | 633 | ft |
| Spillway Crest | Elev | 581 | ft |
| Streambed | Elev | 500 | ft |
| Top of Dam | Elev | 651 | ft |
| Top of Flood | Elev | 646.5 | ft |
| Top of Inactive | Elev | 580 | ft |
| Top of Normal | Elev | 638 | ft |
| Bottom of Flood | Stor | 565,200 | ac-ft |
| Bottom of Normal | Stor | 516,300 | ac-ft |
| Spillway Crest | Stor | 307,600 | ac-ft |
| Streambed | Stor | 0 | ac-ft |
| Top of Dam | Stor | 693,900 | ac-ft |
| Top of Flood | Stor | 649,400 | ac-ft |
| Top of Inactive | Stor | 307,400 | ac-ft |
| Top of Normal | Stor | 565,200 | ac-ft |

Data Sources 5 ›

Nearby Locations 2 ›

Documents 1 >

## Our Mission

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## About this Website

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Locations by Office
Interactive Map
Data Resources
Help Topics
Data Disclaimer
API Docs
Contact Us
USACE HQ
Privacy Policy

# EXHIBIT 41-12

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# Lower Monumental Lock and Dam

Walla Walla District

Details Map

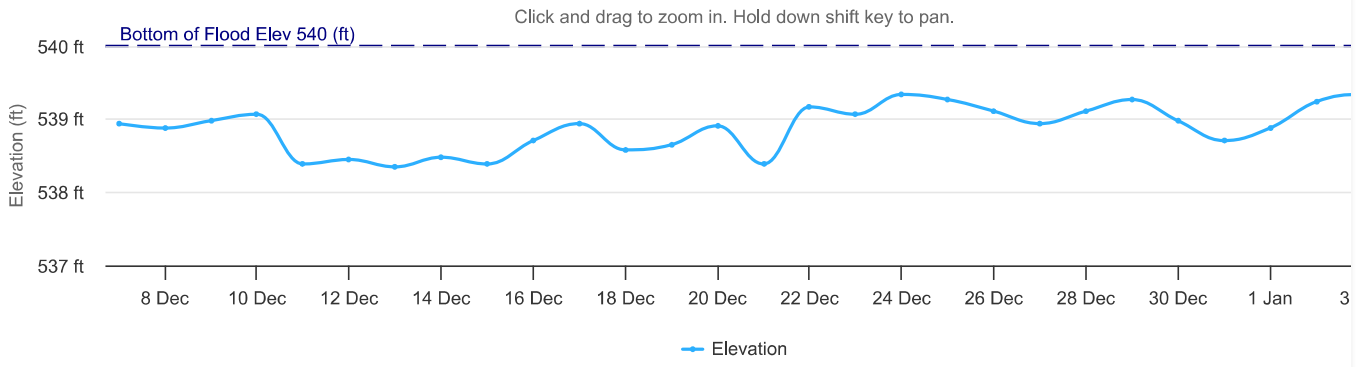
| Flood Storage Utilized | Conservation Storage Utilized | Total Storage Utilized |
|---|---|---|
| 0% | 80% | 74% |

| | |
|---|---|
| Current Values | 5 |
| Metadata | |
| Links | 2 |
| Levels | 16 |

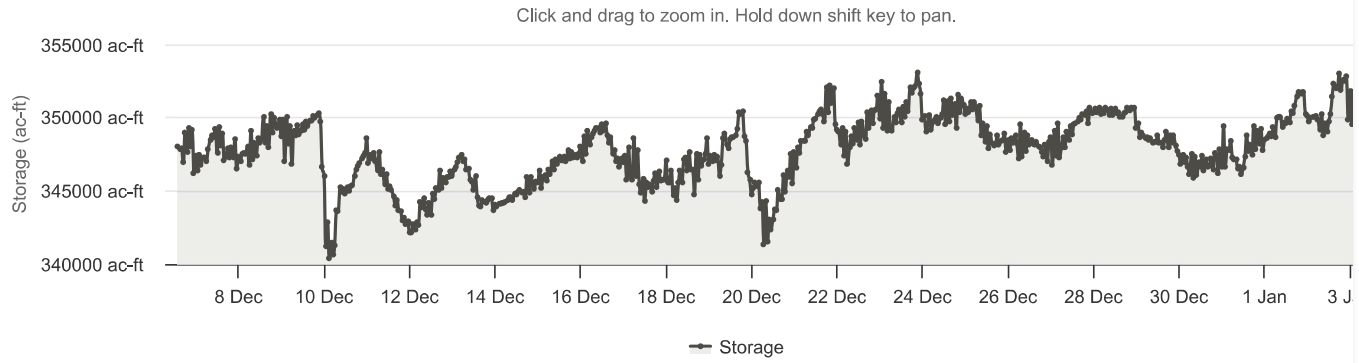
Dam Profile Timeseries 5

last 7 days last 14 days last month

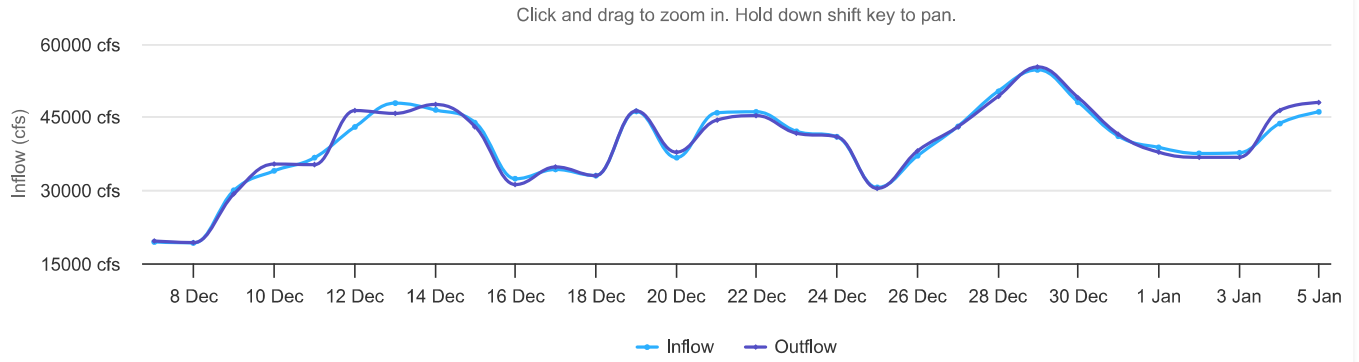
## Elevation



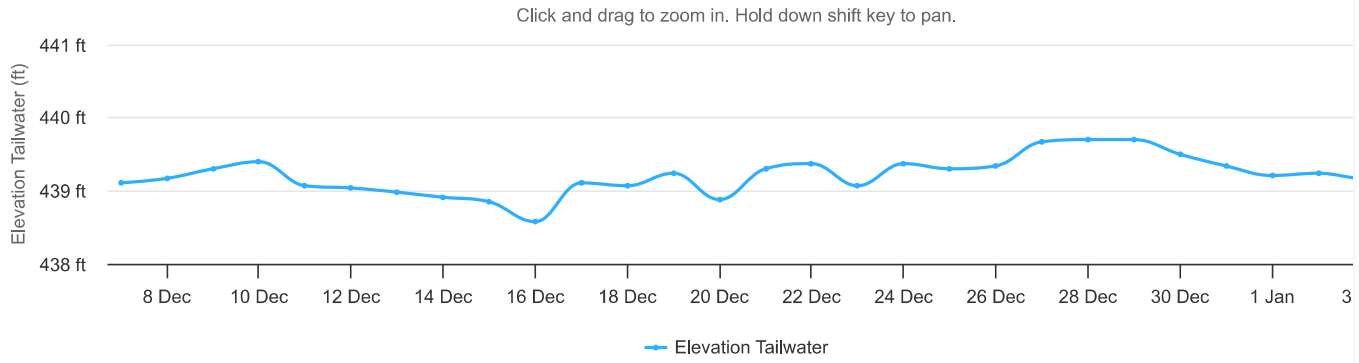
## Storage




## Inflow / Outflow




## Elevation Tailwater




| Label | Parameter | Value | Units |
|---|---|---|---|
| Bottom of Flood | Elev | 540 | ft |
| Bottom of Normal | Elev | 537 | ft |
| Spillway Crest | Elev | 483 | ft |
| Streambed | Elev | 406 | ft |
| Top of Dam | Elev | 553 | ft |
| Top of Flood | Elev | 548.3 | ft |
| Top of Inactive | Elev | 482 | ft |
| Top of Normal | Elev | 540 | ft |
| Bottom of Flood | Stor | 376,300 | ac-ft |
| Bottom of Normal | Stor | 356,200 | ac-ft |
| Spillway Crest | Stor | 209,400 | ac-ft |
| Streambed | Stor | 0 | ac-ft |
| Top of Dam | Stor | 465,100 | ac-ft |
| Top of Flood | Stor | 433,000 | ac-ft |
| Top of Inactive | Stor | 209,200 | ac-ft |
| Top of Normal | Stor | 376,300 | ac-ft |

Data Sources 5 ›

Documents 1 ›

## Our Mission

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Locations by Office
Interactive Map
Data Resources
Help Topics
Data Disclaimer
API Docs
Contact Us
USACE HQ
Privacy Policy

# EXHIBIT 41-13

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# Ice Harbor Lock and Dam

Walla Walla District

Details Map

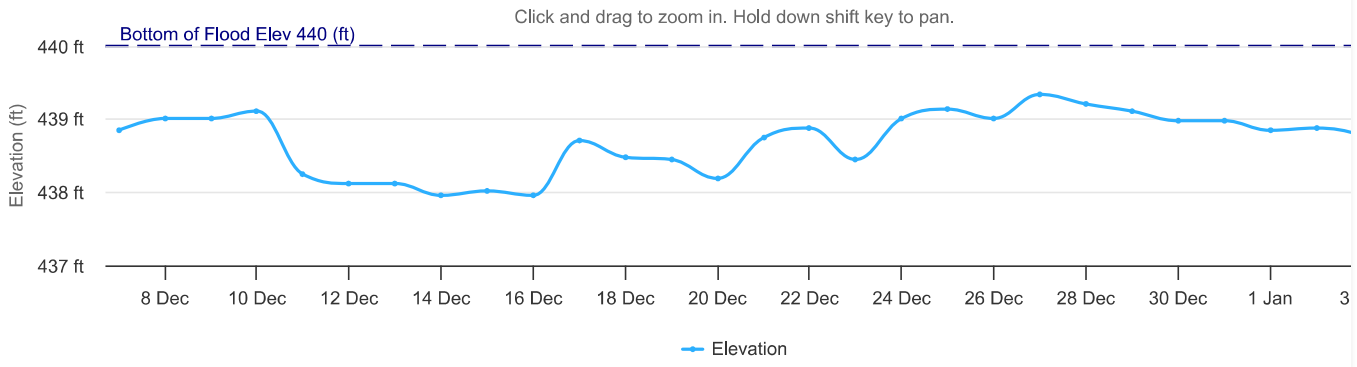
| Flood Storage Utilized | Conservation Storage Utilized | Total Storage Utilized |
|---|---|---|
| 0% | 93% | 82% |

| | |
|---|---|
| Current Values | 6 |
| Metadata | |
| Links | 1 |
| Levels | 17 |

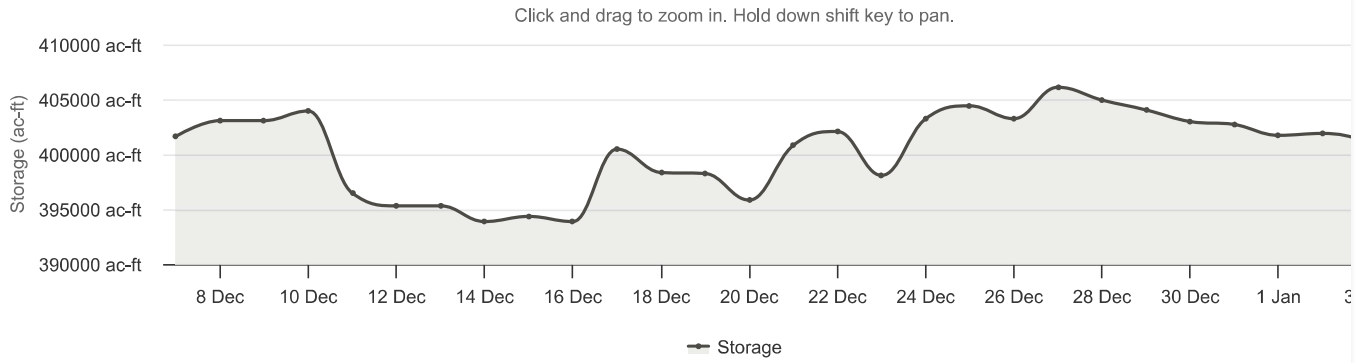
Dam Profile Timeseries 6

last 7 days last 14 days last month

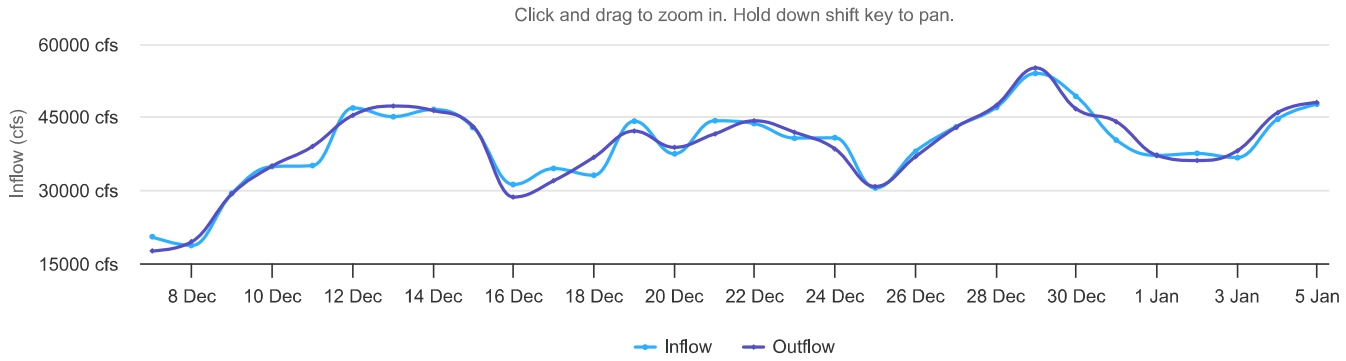
## Elevation



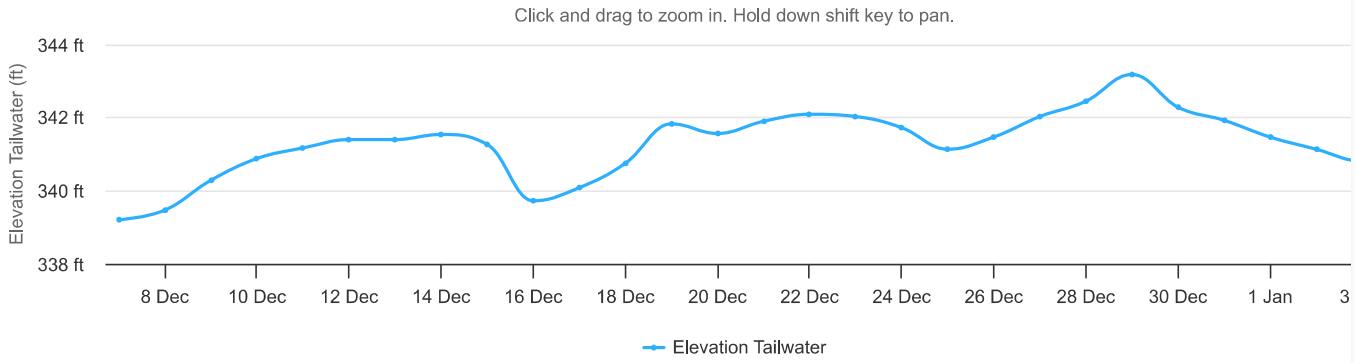
## Storage




## Inflow / Outflow



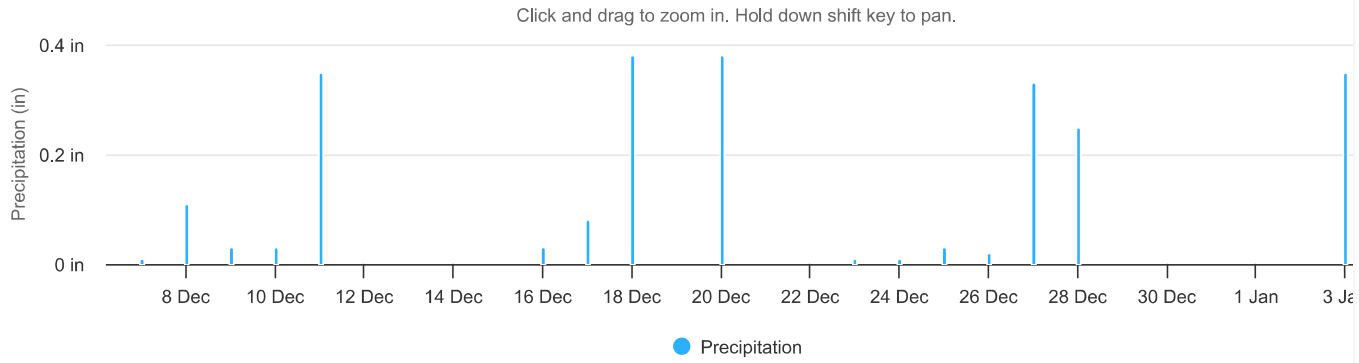

## Elevation Tailwater




| Label | Parameter | Value | Units |
|---|---|---|---|
| 0 | Elev | 388 | ft |
| Bottom of Flood | Elev | 440 | ft |
| Bottom of Normal | Elev | 437 | ft |
| Spillway Crest | Elev | 391 | ft |
| Streambed | Elev | 310 | ft |
| Top of Dam | Elev | 453 | ft |
| Top of Flood | Elev | 446.4 | ft |
| Top of Inactive | Elev | 390 | ft |
| Top of Normal | Elev | 440 | ft |
| Bottom of Flood | Stor | 406,300 | ac-ft |
| Bottom of Normal | Stor | 381,600 | ac-ft |
| Spillway Crest | Stor | 243,400 | ac-ft |
| Streambed | Stor | 0 | ac-ft |
| Top of Dam | Stor | 484,400 | ac-ft |
| Top of Flood | Stor | 459,400 | ac-ft |
| Top of Inactive | Stor | 243,200 | ac-ft |
| Top of Normal | Stor | 406,300 | ac-ft |

Data Sources 6 ›

## Precipitation




Documents 1 ›

### Our Mission

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### About this Website

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Locations by Office
Interactive Map
Data Resources
Help Topics
Data Disclaimer

API Docs
Contact Us
USACE HQ
Privacy Policy

# EXHIBIT 41-14

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# McNary Lock and Dam

Pacific Northwest Region

Details Map

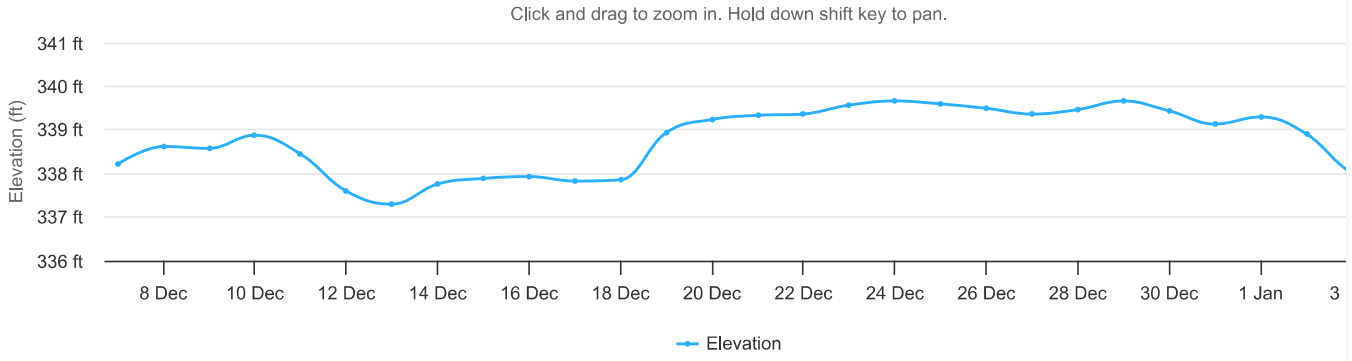
| Flood Storage Utilized | Conservation Storage Utilized | Total Storage Utilized |
|---|---|---|
| 0% | N/A | 59% |

| | |
|---|---|
| Current Values | 7 |
| Metadata | |
| Links | 1 |
| Levels | 14 |

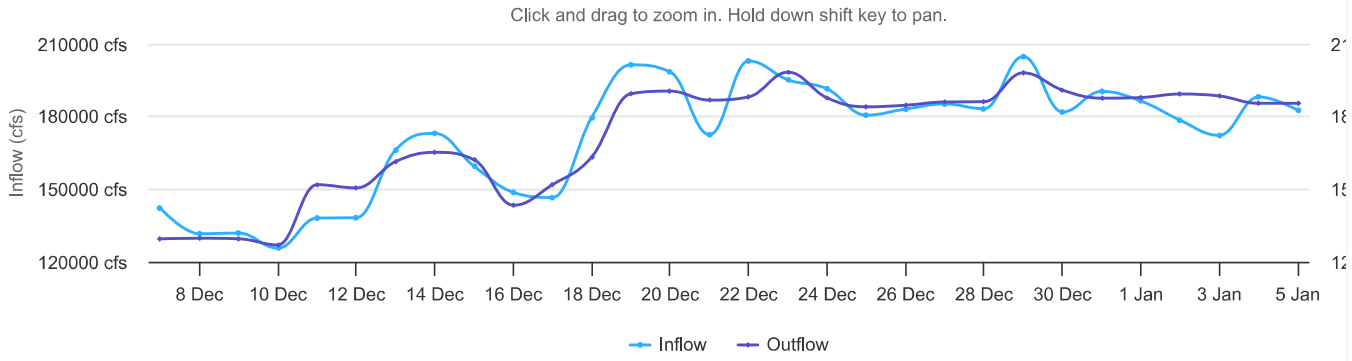
Dam Profile Timeseries 7

last 7 days last 14 days last month

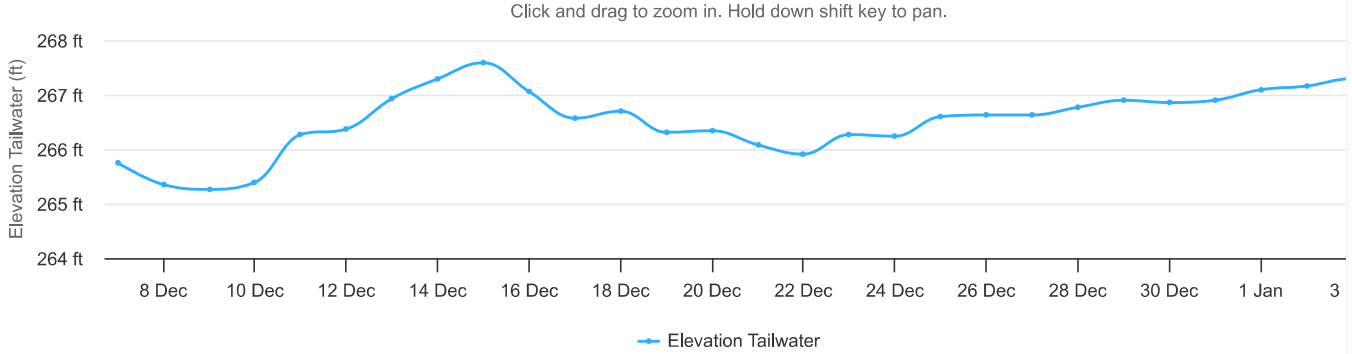
## Elevation



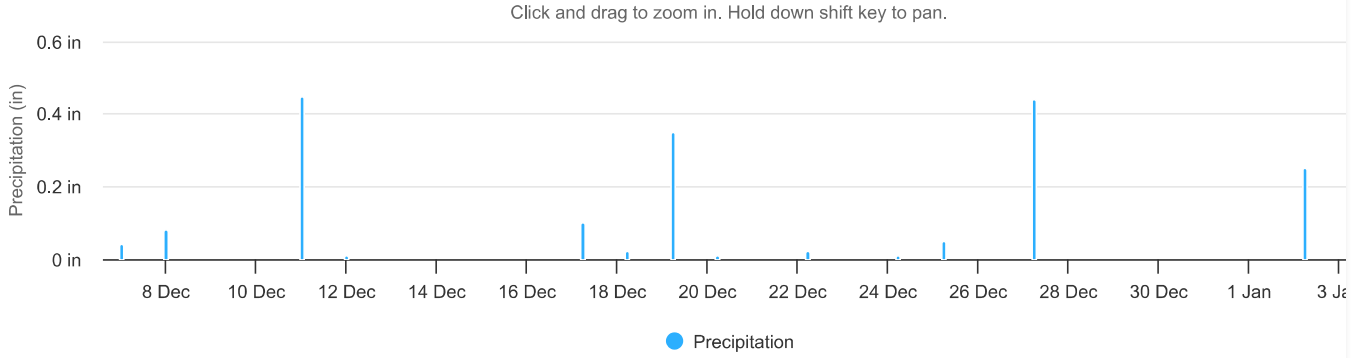
## Inflow / Outflow




## Elevation Tailwater




## Precipitation




| Label | Parameter | Value | Units |
|---|---|---|---|
| Bottom of Normal | Elev | 337 | ft |
| Spillway Crest | Elev | 291 | ft |
| Streambed | Elev | 250 | ft |
| Top of Dam | Elev | 361 | ft |
| Top of Flood | Elev | 356.5 | ft |
| Top of Inactive | Elev | 290 | ft |
| Top of Normal | Elev | 340 | ft |
| Bottom of Normal | Stor | 1,165,000 | ac-ft |
| Spillway Crest | Stor | 206,400 | ac-ft |
| Streambed | Stor | 0 | ac-ft |
| Top of Dam | Stor | 2,151,800 | ac-ft |
| Top of Flood | Stor | 1,980,000 | ac-ft |
| Top of Inactive | Stor | 206,200 | ac-ft |
| Top of Normal | Stor | 1,350,000 | ac-ft |

**Data Sources** 7 ›

**Nearby Locations** 1 ›

**Documents** 1 ›

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Locations by Office
Interactive Map
Data Resources
Help Topics
Data Disclaimer
API Docs
Contact Us
USACE HQ
Privacy Policy

# EXHIBIT 41-15

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# John Day Lock and Dam

Pacific Northwest Region

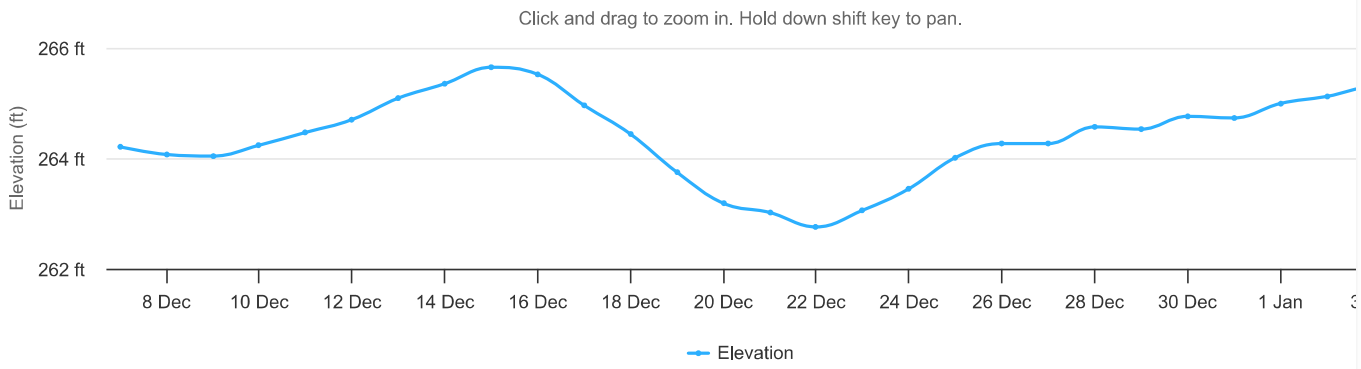
Details Map

| Flood Storage Utilized | Conservation Storage Utiliz... | Total Storage Utilized |
|---|---|---|
| 0% | N/A | N/A |

Dam Profile | Timeseries 5

last 7 days | last 14 days | last month

## Elevation




| | |
|---|---|
| Current Values | 5 |
| Metadata | |
| Links | 2 |
| Levels | 8 |

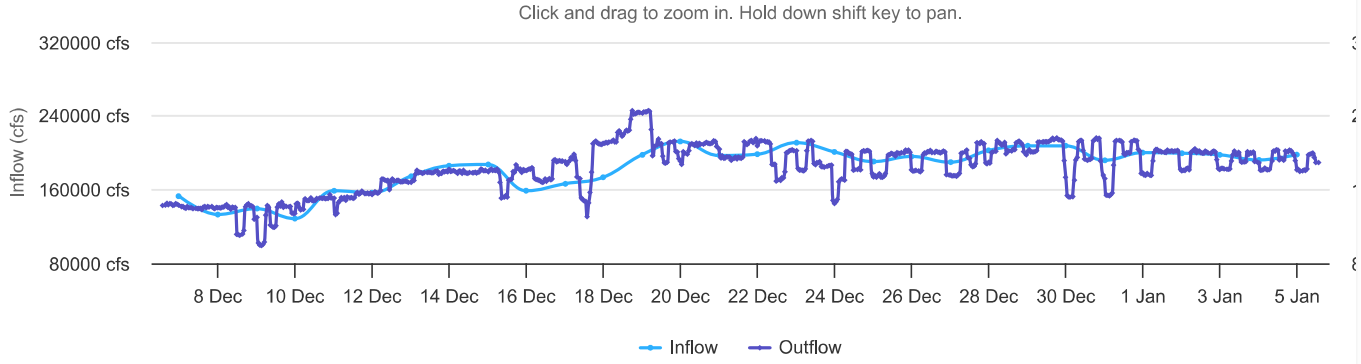
| Label | Parameter | Value | Units |
|---|---|---|---|
| Bottom of Flood | Elev | 268 | ft |
| Spillway Crest | Elev | 210 | ft |
| Streambed | Elev | 161 | ft |
| Top of Dam | Elev | 281 | ft |
| Top of Flood | Elev | 276.5 | ft |
| Top of Normal | Elev | 268 | ft |
| Bottom of Flood | Stor | 534,000 | ac-ft |
| Top of Flood | Stor | 976,000 | ac-ft |

| | |
|---|---|
| Data Sources | 5 |
| Documents | 1 |

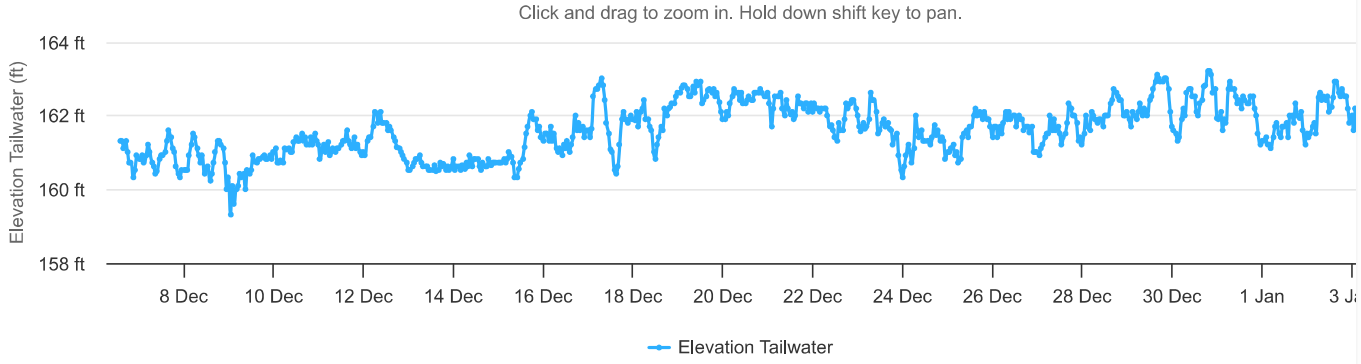
## Storage




## Inflow / Outflow




## Elevation Tailwater



## Our Mission

Deliver vital engineering solutions, in collaboration with our partners, to secure our Nation, energize our economy, and reduce disaster risk.

## About this Website

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Locations by Office
Interactive Map
Data Resources
Help Topics
Data Disclaimer
API Docs
Contact Us
USACE HQ
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# EXHIBIT 41-16

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# The Dalles Lock and Dam

Pacific Northwest Region

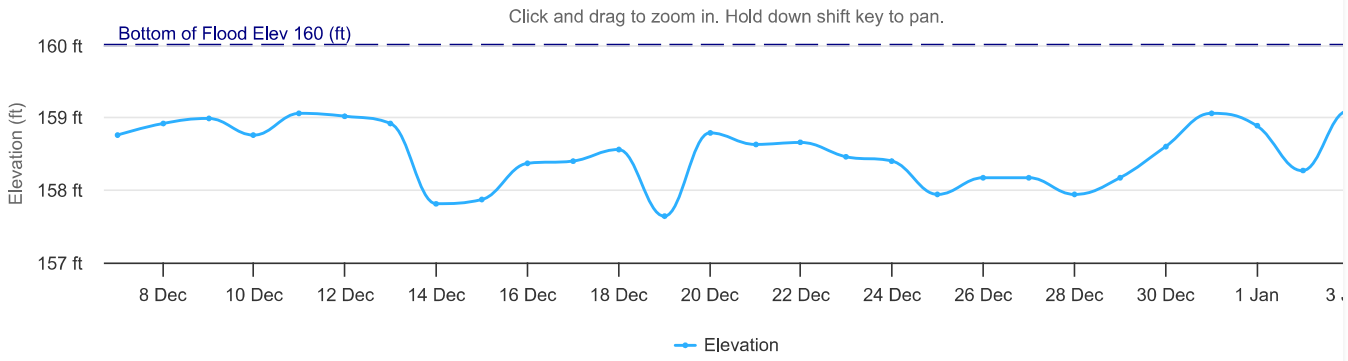
Details Map

| Flood Storage Utilized | Conservation Storage Utilized | Total Storage Utilized |
|---|---|---|
| 0% | N/A | N/A |

Dam Profile | Timeseries 4

last 7 days | last 14 days | last month

## Elevation

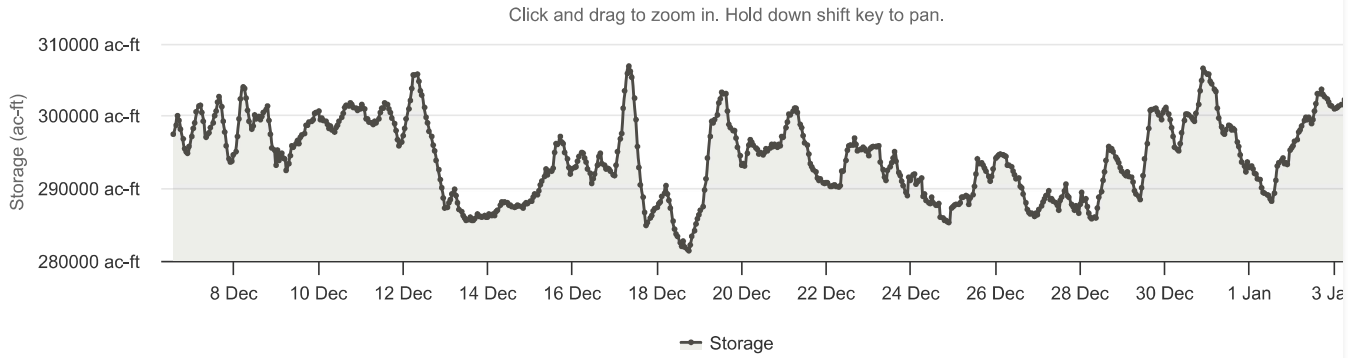



| | |
|---|---|
| Current Values | 4 |
| Metadata | |
| Links | 2 |
| Levels | 8 |

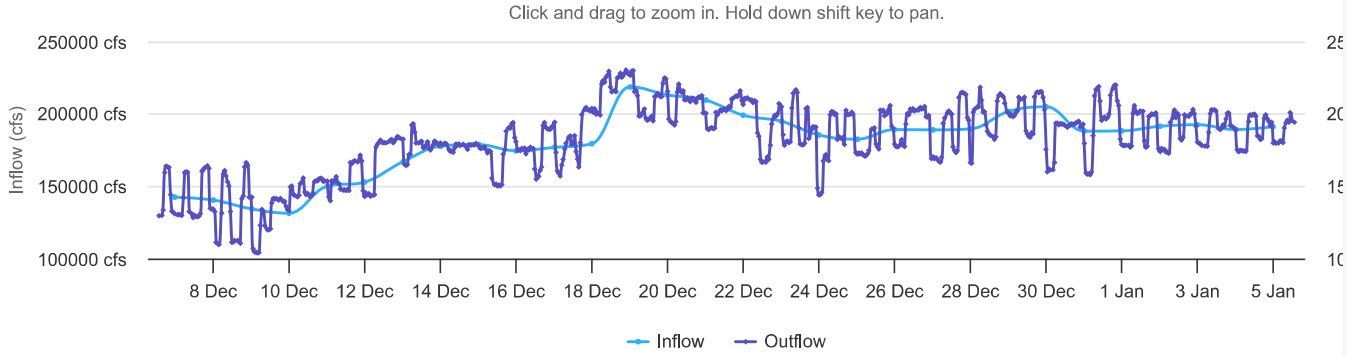
| Label | Parameter | Value | Units |
|---|---|---|---|
| Bottom of Flood | Elev | 160 | ft |
| Spillway Crest | Elev | 121 | ft |
| Streambed | Elev | 55 | ft |
| Top of Dam | Elev | 185 | ft |
| Top of Flood Control | Elev | 182.3 | ft |
| Top of Normal | Elev | 160 | ft |
| Bottom of Flood | Stor | 310,000 | ac-ft |
| Top of Flood | Stor | 554,900 | ac-ft |

| | |
|---|---|
| Data Sources | 4 |
| Nearby Locations | 1 |
| Documents | 1 |

## Storage




## Inflow / Outflow




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Interactive Map
Data Resources
Help Topics
Data Disclaimer
API Docs
Contact Us
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# EXHIBIT 41-17

An official website of the United States government Here's how you know



# Bonneville Lock and Dam

Pacific Northwest Region

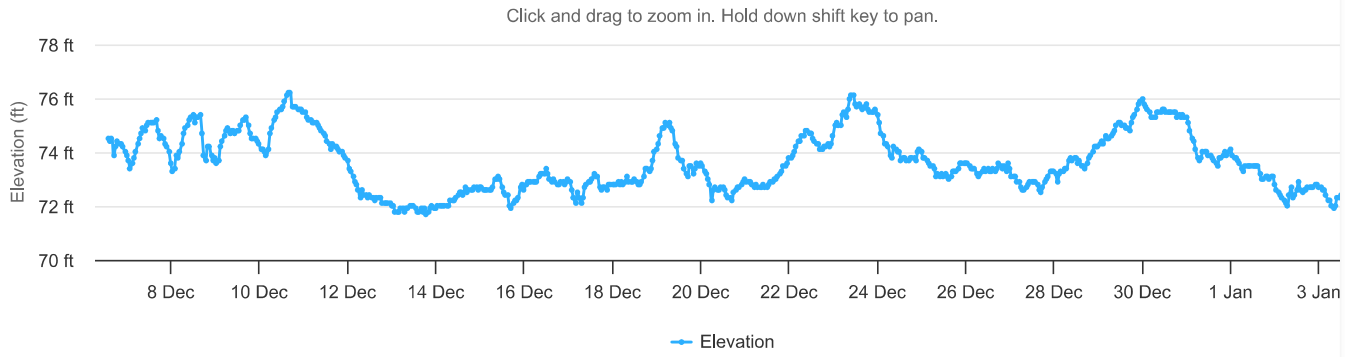
Details Map

| Flood Storage Utilized | Conservation Storage Utilized | Total Storage Utilized |
|---|---|---|
| 0% | N/A | N/A |

Dam Profile | Timeseries 7

last 7 days | last 14 days | last month

## Elevation

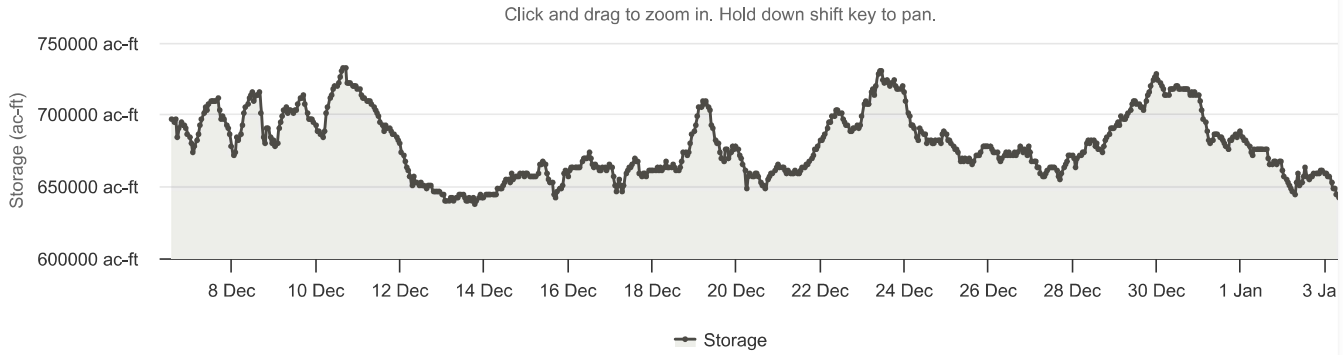



| Current Values | 7 |
|---|---|
| Metadata | |
| Links | 2 |
| Levels | 10 |

| Label | Parameter | Value | Units |
|---|---|---|---|
| Bottom of Operating | Elev | 71.5 | ft |
| Spillway Crest | Elev | 24 | ft |
| Streambed | Elev | 15 | ft |
| Top of Dam | Elev | 97 | ft |
| Top of Normal | Elev | 77 | ft |
| Top of Operating | Elev | 76.5 | ft |
| Bottom of Flood | Stor | 739,000 | ac-ft |
| Bottom of Operating | Stor | 739,000 | ac-ft |
| Top of Flood | Stor | 2,471,500 | ac-ft |
| Top of Operating | Stor | 739,000 | ac-ft |

Data Sources 7

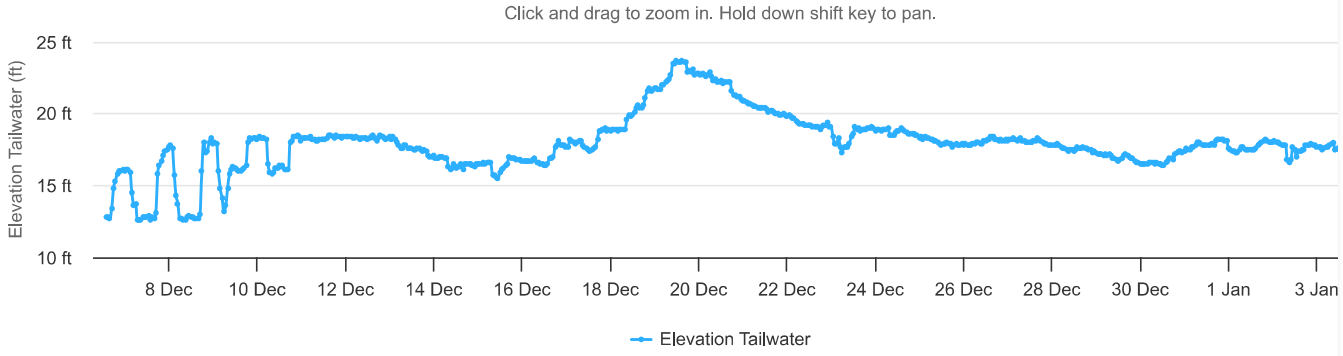
## Storage




## Inflow / Outflow

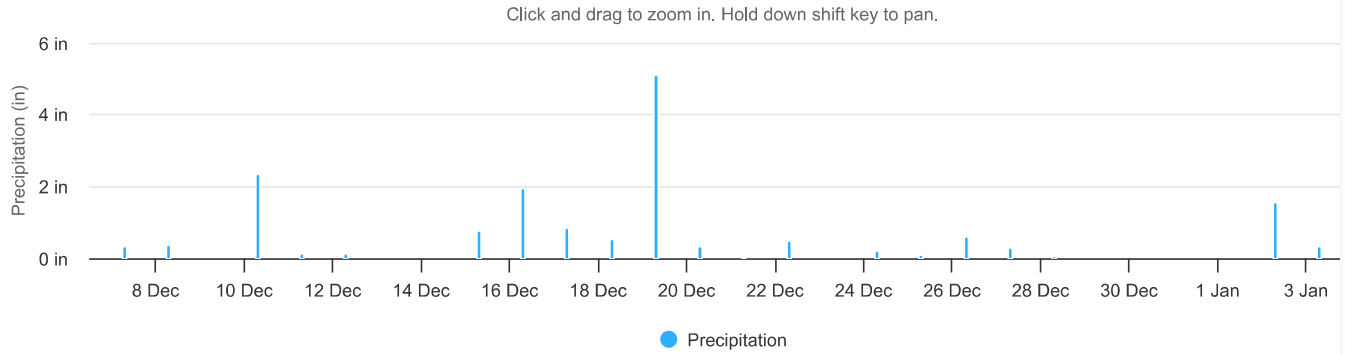



## Elevation Tailwater

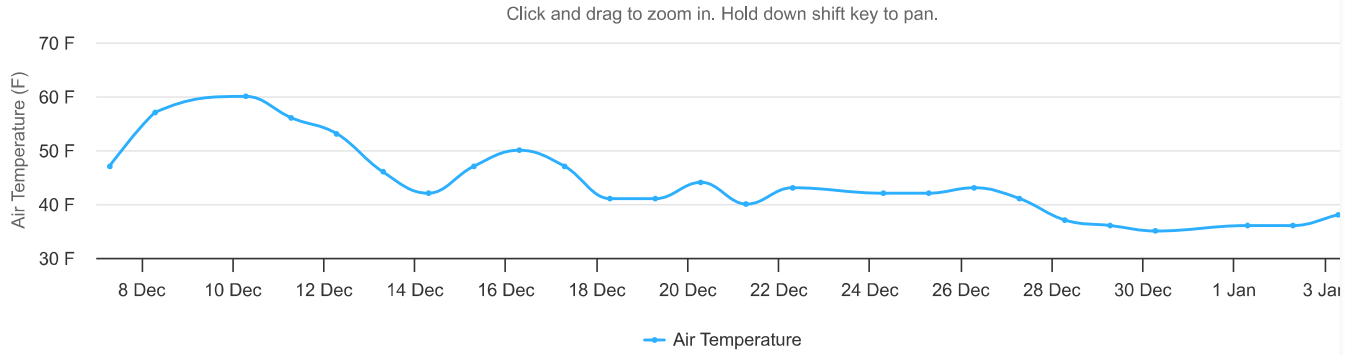



Documents 1

## Precipitation




## Air Temperature




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### About this Website

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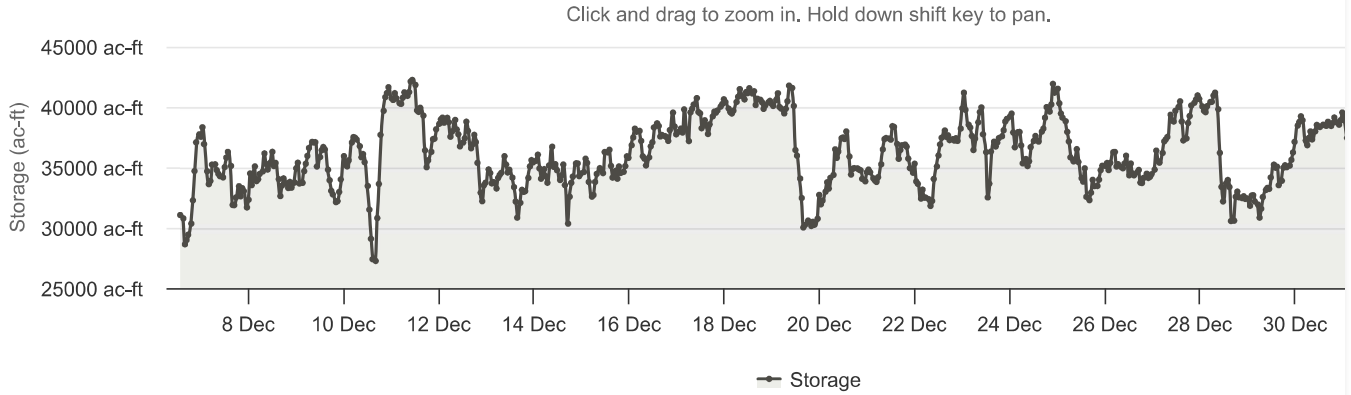
v1.0.1

Locations by Office
Interactive Map
Data Resources
Help Topics
Data Disclaimer
API Docs
Contact Us
USACE HQ
Privacy Policy

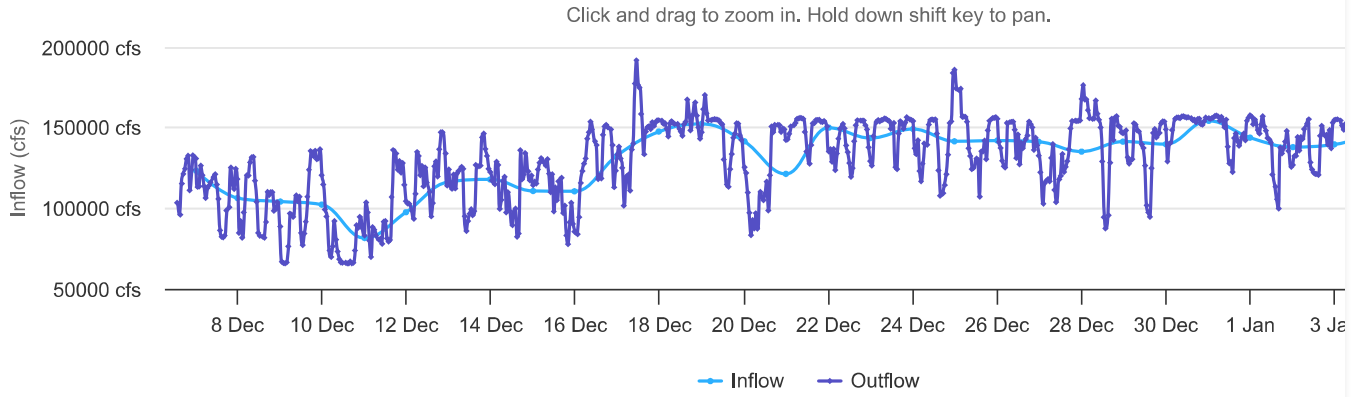

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# EXHIBIT 41-18

## Storage




## Inflow / Outflow




### Our Mission

Deliver vital engineering solutions, in collaboration with our partners, to secure our Nation, energize our economy, and reduce disaster risk.

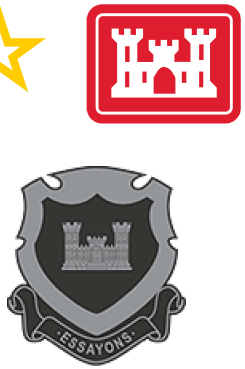
### About this Website

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Locations by Office
Interactive Map
Data Resources
Help Topics
Data Disclaimer
API Docs
Contact Us
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# EXHIBIT 41-19

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# Wanapum Dam

Pacific Northwest Region

Details Map

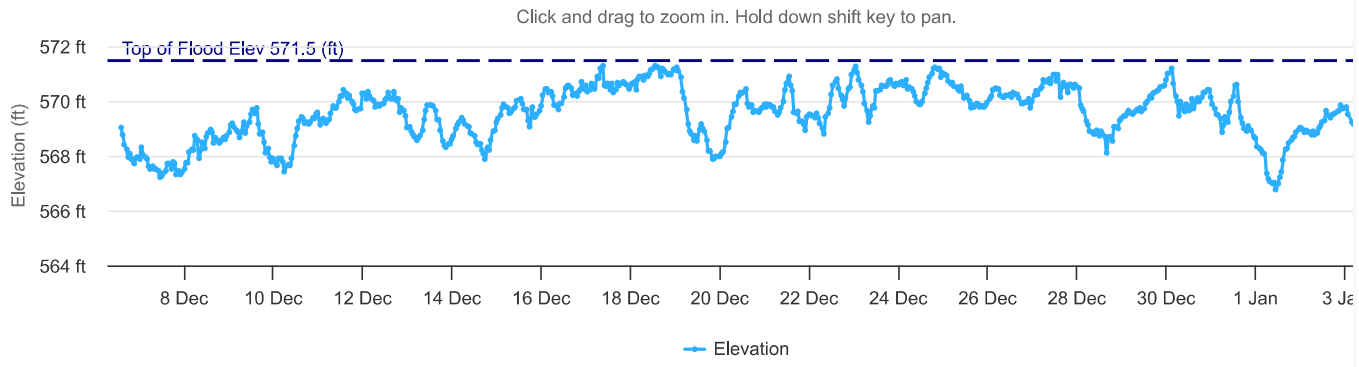
| Flood Storage Utilized | Conservation Storage Utilized | Total Storage Utilized |
|---|---|---|
| 0% | N/A | 11% |

| | |
|---|---|
| Current Values | 4 |
| Metadata | |
| Links | 1 |
| Levels | 13 |

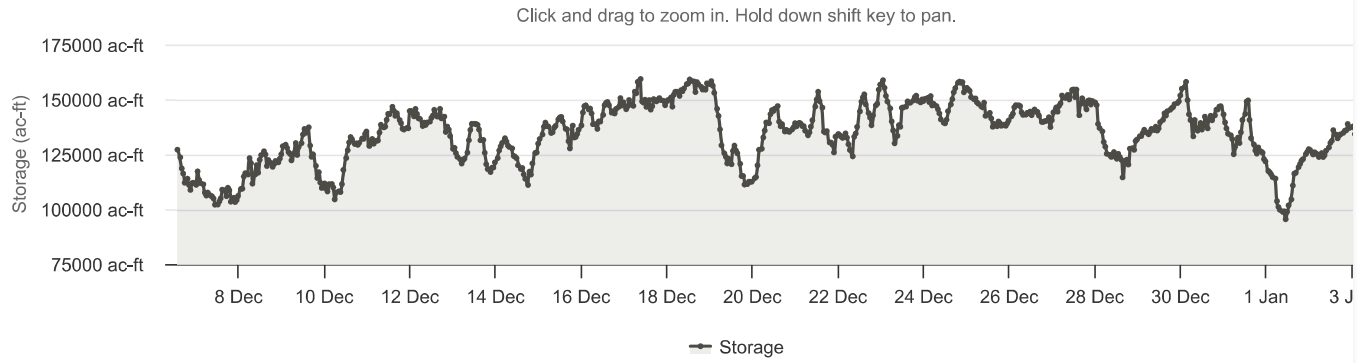
Dam Profile Timeseries 4

last 7 days last 14 days last month

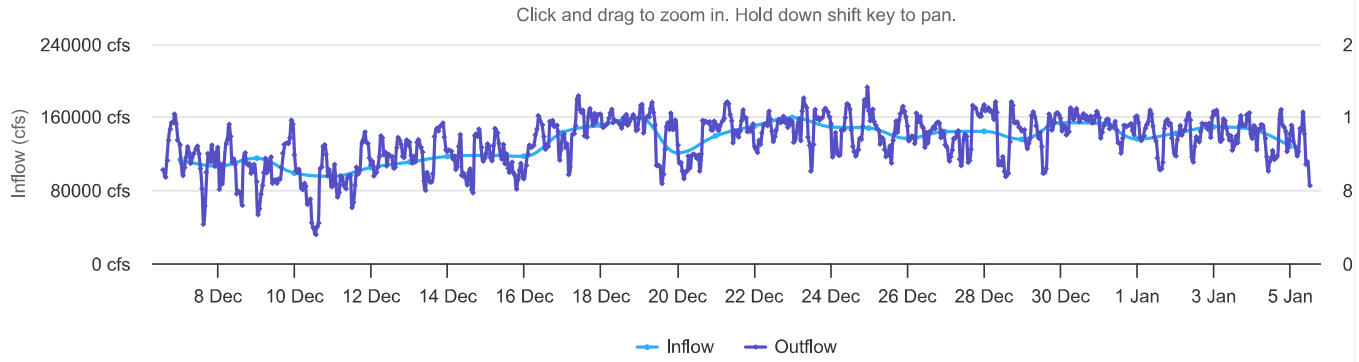
## Elevation



## Storage




## Inflow / Outflow




| Label | Parameter | Value | Units |
|---|---|---|---|
| Bottom of Flood | Elev | 571.5 | ft |
| Bottom of Normal | Elev | 571.5 | ft |
| Spillway Crest | Elev | 505 | ft |
| Streambed | Elev | 450 | ft |
| Top of Dam | Elev | 575.5 | ft |
| Top of Flood | Elev | 571.5 | ft |
| Top of Normal | Elev | 571.5 | ft |
| Bottom of Flood | Stor | 673,000 | ac-ft |
| Bottom of Normal | Stor | 760,000 | ac-ft |
| Spillway Crest | Stor | 300,000 | ac-ft |
| Top of Dam | Stor | 850,000 | ac-ft |
| Top of Flood | Stor | 673,000 | ac-ft |
| Top of Normal | Stor | 790,000 | ac-ft |

**Data Sources** 4 ›

**Documents** 1 ›

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About this Website

Locations by Office
Interactive Map
Data Resources
Help Topics

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# EXHIBIT 41-20

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# Rock Island Dam

Pacific Northwest Region

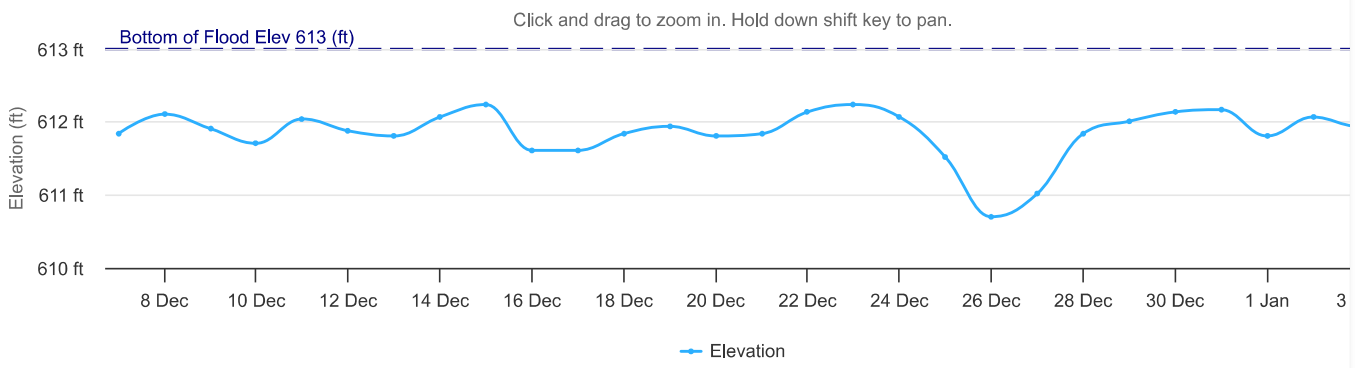
Details Map

| Flood Storage Utilized | Conservation Storage Utilized | Total Storage Utilized |
|---|---|---|
| 0% | N/A | N/A |

Dam Profile | Timeseries 4

last 7 days | last 14 days | last month

## Elevation

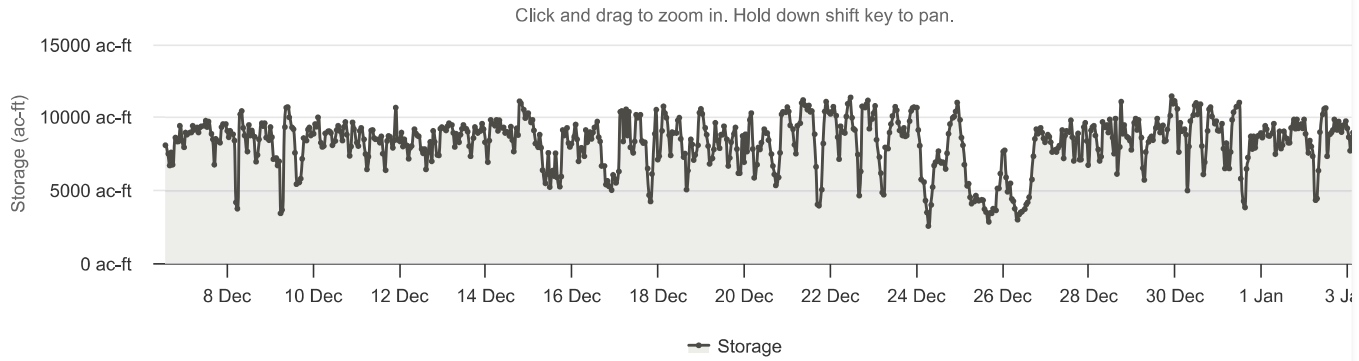



| | |
|---|---|
| Current Values | 4 |
| Metadata | |
| Links | 1 |
| Levels | 8 |

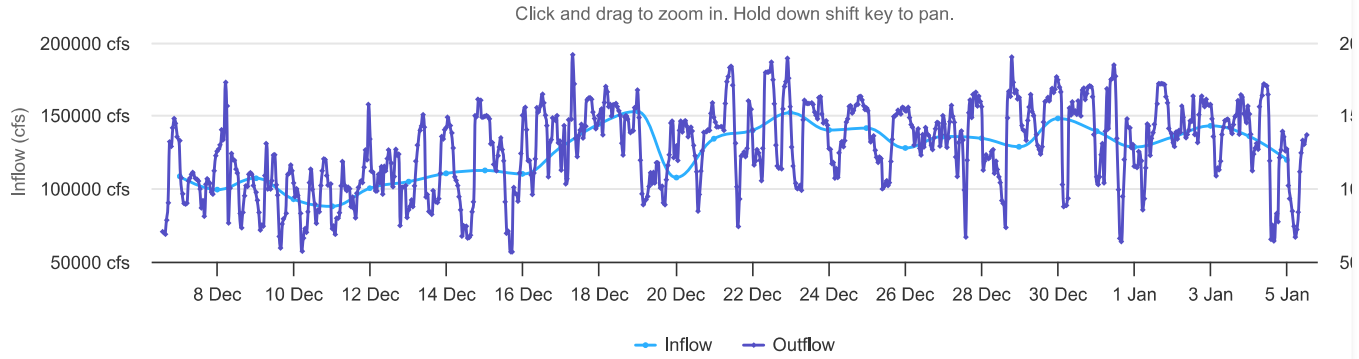
| Label | Parameter | Value | Units |
|---|---|---|---|
| Spillway Crest | Elev-WAN-RIS | 609 | ft |
| Streambed | Elev-WAN-RIS | 570 | ft |
| Top of Dam | Elev-WAN-RIS | 619 | ft |
| Top of Normal | Elev-WAN-RIS | 613 | ft |
| Bottom of Flood | Elev | 613 | ft |
| Top of Flood | Elev | 619 | ft |
| Bottom of Flood | Stor | 11,600 | ac-ft |
| Top of Flood | Stor | 29,000 | ac-ft |

| | |
|---|---|
| Data Sources | 4 |
| Documents | 0 |

## Storage




## Inflow / Outflow




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Interactive Map
Data Resources
Help Topics
Data Disclaimer
API Docs
Contact Us
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# EXHIBIT 41-21

CPC Search
CPC search Go

Map Explanations
Official Fcsts
Fcst Tools

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Who We Are

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CPC Information
CPC Web Team

Official 90-day Outlooks are issued once each month near mid-month at 8:30am Eastern Time. Please consult the schedule of 30 & 90-day outlooks for exact release dates.

USA.gov Government Made Easy

# Three-Month Outlooks

# OFFICIAL Forecasts

## Jan-Feb-Mar 2026

Click here for information about the three-month outlook

**Text-Format Discussions**

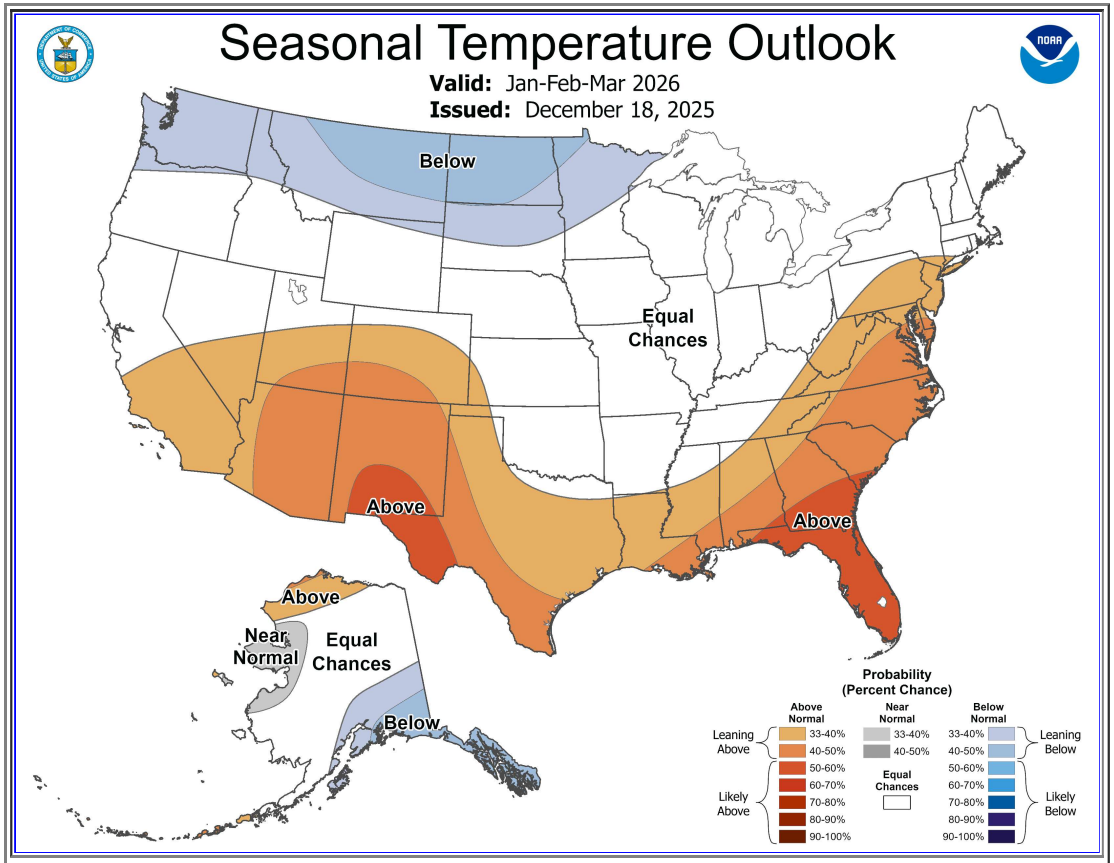
Monthly
Long Lead
30-& 90-Day Hawaiian

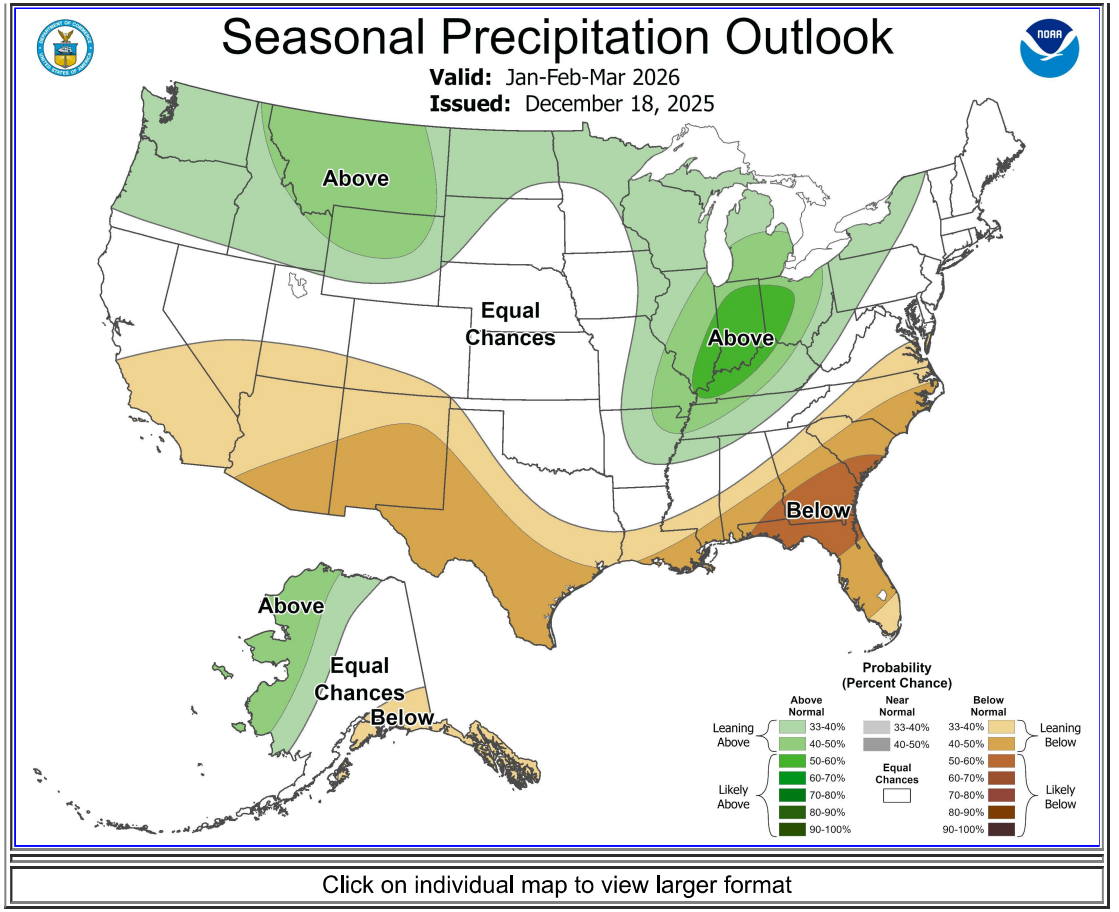
**More Outlooks**

JFM 2026
FMA 2026
MAM 2026
AMJ 2026
MJJ 2026
JJA 2026
JAS 2026
ASO 2026
SON 2026
OND 2026
NDJ 2026 - 27
DJF 2026 - 27
JFM 2027
0.5mn Jan 2026

Climatological Values (1991-2020) for JFM

**Tools Used** (see Discussion for explanation)
Tools Discussion (updated as new tools are implemented)
Canonical Correlation Analysis
Ensemble Canonical Correlation Analysis
Optimal Climate Normals
Climate Forecast System
Screening Multiple Linear Regression Tool
Probability of Exceedence






Click on individual map to view larger format

| Email to Forecasters | Email to Webmasters |
|---|---|

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NOAA Center for Weather and Climate Prediction
Climate Prediction Center
5830 University Research Court
College Park, Maryland 20740
Page Author: Climate Prediction Center Internet Team
Page last modified: September 03, 2015

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# EXHIBIT 41-22

**(Native Format)**

# EXHIBIT 41-23

**(Native Format)**