BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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Independent System Operator	)
(MISO)	)
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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 51

2023 Energy Innovation Coal Cost Report

Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment

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EXECUTIVE SUMMARY

The cost of operating existing coal power plants in the United States continues to increase while coal jobs, generation, and mining all decrease.[i] New coal retirement announcements seem to happen faster, even as natural gas prices skyrocket, and renewable energy prices keep dropping.

The Inflation Reduction Act (IRA), which extended and expanded clean energy tax credits, along with new funding to guarantee loans for refinancing fossil assets and reinvesting in clean energy infrastructure, has shifted the economic scale even further toward wind and solar. But it also creates thoughtful new investment opportunities in areas burdened by existing coal plants with a 10 percent tax credit boost for projects located in nearby communities.

These factors underpin the third iteration of our Coal Cost Crossover analysis, which shows wind and solar energy are unequivocally cheaper than coal-fired generation across the country. This study finds 99 percent of all coal-fired power plants in the U.S. are more expensive to operate on a forward-

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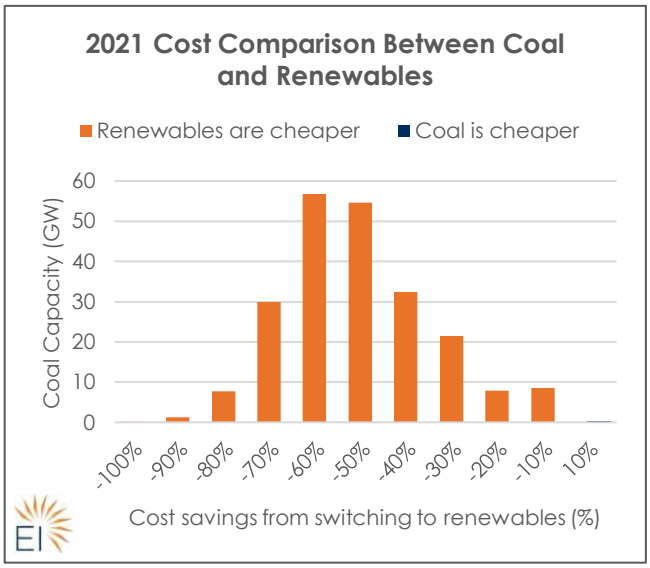
looking basis than the all-in cost of replacement renewable energy projects, and 97 percent are more expensive than renewable energy projects sited within 45 kilometers (approximately 30 miles), a significant acceleration from our two previous analyses. For more than three quarters of U.S. coal capacity, the all-in cost per MWh of the cheapest renewable option is at least a third cheaper than the going-forward costs for the coal it would replace.

In this report we compare the cost of operating each continental U.S. coal plant in 2021, totaling 220 gigawatts (GW) of coal capacity across the country, to the estimated costs of building new wind and solar generation. We consider the wind and solar costs within two geographic scopes: local to the coal plants (within 45 kilometers) and regionally (roughly within the utility balancing area), finding that nearly all existing coal plants have multiple lower-cost clean energy replacement options.



This research shows all but one of the country's 210 coal plants are more expensive to operate than either new wind or new solar. If the IRA's new energy community tax credit is included in the equation, 199 of the 210 plants are more expensive to operate compared to local solar resources sited within 45 kilometers of the plant. Local wind resources are also cost-effective and readily available, with 104 plants having cheaper wind resources within 45 kilometers.

Altogether, 205 plants have local renewable options that would be cheaper than coal-fired electricity. This potential to replace existing coal plants with cheap, local clean energy generation creates significant economic benefits for community transition. Our analysis finds replacing these plants with local solar or wind would drive $589 billion in local capital investment that could support economic diversification, job creation, and tax revenue.

These local wind and solar resources could also help solve the problem of long interconnection queues—a significant barrier to renewables deployment. Renewable projects built near a retiring coal plant could use the existing plant's interconnection, helping to further lower costs. If more policymakers consider this dynamic, they can streamline economic replacement and anticipate coal retirements, which are accelerating due to the cost dynamics analyzed in this report.

While solar and wind replacement resources provide significant low-cost energy and reliability value to the grid, savings generated by switching from more expensive coal to cheaper clean energy can finance other resources to provide additional energy and reliability value.

We find that the savings generated by shifting to local solar could fund the addition of 137 GW of four-hour batteries across all plants, and 80 percent or more of the capacity at a third of existing coal plants – the economics of replacing coal with renewables are so favorable that they could fund a massive battery storage buildout to add reliability value along with emissions reductions. However, it is important to remember reliability is a system attribute—replacement renewable

portfolios need not bear sole responsibility for replacing the reliability services of individual coal plants.

While the economic case is clear and virtually universal, barriers remain to replacing coal with clean energy, and policymakers must act to unlock the cost savings and human health benefits for coal communities while reducing climate pollution.

Several policies can enable a faster coal-to-clean transition. Specifically:

- To prepare the way for coal transition, regulators and system operators should:
  - Improve methods to assess reliability and resource adequacy reflecting the reliability value of renewable portfolios and valuing the reliability attributes of a high-renewables grid.
  - Update interconnection study rules to leveraging existing coal plant interconnection rights to speed grid connection processes for local renewable replacement resources.
- To proactively pursue the transition, regulators should:
  - Encourage utilities to utilize IRA financing programs available through the Departments of Energy and Agriculture to remove financial barriers to coal community economic transition and investment.
  - Enable competitive resource procurement.
  - Require re-assessment of any utility investment plan, including integrated resource plans and market-based solicitations for renewable supply, completed prior to IRA as renewables costs are now out of date.
- To create a just transition for affected communities, state legislatures and energy offices should:
  - Plan for and fund a coal community-centered economic transition, where local clean energy resources are the anchor for a more expansive economic transition plan.

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INTRODUCTION

The U.S. power sector is in transition, with coal-fired power generation falling to 55 percent of its 2007 peak in 2021. This transition is also decreasing the number of coal mines, power plants, and workers. Over the same period, utility-scale solar and wind generation have increased more than

18,000 percent and 1,000 percent, respectively, as costs declined by 90 percent for solar and 72 percent for wind.[1,ii]

In 2019, Energy Innovation Policy & Technology LLC® partnered with Vibrant Clean Energy to compile and analyze a 2018 dataset of capital, operations and maintenance, and fuel costs for coal, wind, and solar. Our first Coal Cost Crossover report found that 62 percent of existing coal capacity was uneconomic compared to producing the same amount of energy with new local wind or solar. To make this comparison, we evaluated the marginal cost of running each coal plant with the levelized cost of new wind and solar, where the levelized cost of energy (LCOE) is the cost of building and operating a new resource divided by its energy production over its lifetime. The analysis projected that by 2025, more than 80 percent of the coal fleet would be unable to compete against new renewables or would be retired, even without federal incentives.[2]

In 2021, we completed a similar analysis of 2019 data that considered the National Renewable Energy Laboratory's (NREL) 2018 Annual Technology Baseline (ATB) forecast showing steep cost declines for solar and wind energy, as well as an extension of the federal investment tax credit for solar coupled with a continued production tax credit for wind. The Coal Cost Crossover 2.0 report found that the coal crossover had significantly expanded, with 72 percent of coal capacity and 80 percent of plants already more expensive to run compared to either new solar or wind, including tax credits in effect.[3]

This Coal Cost Crossover 3.0 report uses new 2021 data to reevaluate the coal crossover economic dynamic. Since our 2.0 report, solar and wind costs continued fall, coal prices kept rising, and coal plant capacity factors continued decreasing, all continuing the trends observed between 2017-2019.[iii]

Now, new federal tax credits in the IRA make the economic case for replacing coal with clean energy unequivocal. IRA incentive bonuses for clean energy projects located near retired coal infrastructure offer new, additional savings and reinvestment opportunities. This report combines elements of the previous two studies, analyzing both regional and local renewable resources, but now accounts for the new incentives.[4] Given the IRA's expanded tax credits, we find all coal plants but one are more costly to run compared to new wind and solar energy, and all but five are more expensive than wind or solar sited within a 45 kilometer (km) radius.

Of course, examining relative economics using levelized cost faces limitations. The overall value of these power plants depends on much more than just cost. While the coal cost crossover describes a scenario in which renewable resources replace coal generation on a one-to-one basis, the reality is that coal retirement is a complex process that depends on the reliability needs of the local and

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[ii] Coal generation decreased from 2,016,455 gigawatt-hours (GWh) in 2007 to 875,885 GWh in 2021. Solar generation increased from only 612 GWh in 2007 to 115,258 GWh in 2021. Wind generation increased from 34,449 GWh in 2007 to 378,196 GWh in 2021. In total, coal generation was still higher in 2021 than wind and solar in the U.S. by 382 GWh.
[iii] Renewable costs continued to fall through 2021, the year we used for this analysis. Costs across the energy industry rose in 2022 due to supply chain constraints but are expected to fall again as supply issues ease.

regional electricity grid, which in turn, depends on the entire resource portfolio's dynamics. For example, in some regions one-to-one replacement with a combination of wind and solar resources may not adversely affect reliability. In others it may, depending on what other resources are serving the power grid.

Many communities also depend on coal plants for jobs and tax revenue. In addition to reliability value, policymakers must consider the potential of replacement energy resources to provide similar economic value. The new IRA incentives to locate replacement resources in the same communities where coal plants sit can contribute to a sustainable, economic transition. As we show in this report, these incentives fundamentally improve the prospect for coal communities to benefit from new clean energy resource development.

This report traces the shifting role of coal in the U.S. power sector and identifies key changes in the economics of coal-fired electricity generation due to the IRA's passage. We explain our coal cost crossover calculations, including how we compiled the coal dataset using publicly available data, and how we calculated the LCOE for both local and regional wind and solar using open-source modeling tools developed by NREL.

Four scenarios compare new renewable generation costs to marginal coal costs: regional wind, regional solar, local wind, and local solar, effectively assessing the replacement of every unit of energy produced by the coal plants. For the local solar scenario, we also analyze the economics of adding four hours of battery storage capacity to the solar resources. This analysis demonstrates a clean alternative to coal generation with added reliability value and an opportunity for local investment and economic diversification.

Finally, we provide policy recommendations to help policymakers successfully transition away from polluting, higher cost coal power to cheaper, clean energy. Because the IRA aligns the aims of least-cost electricity planning and procurement with an economic transition for coal communities, we highlight the opportunity for gradual economic transition centered around replacing coal generation with local renewables and storage. Local replacement also has the advantage of potentially being able to leverage existing grid interconnection rights. We describe how utilities can directly take advantage of key IRA provisions, as well as how policymakers can ensure utilities account for the changing economic landscape in their planning and procurement. We also explain how just transition planning, accurate reliability assessments, and transmission buildout can speed up and smooth out coal's phaseout in the U.S.

COAL'S ROLE IN THE U.S. POWER SECTOR

Coal-fired power was the bedrock of a reliable, affordable U.S. power sector for nearly a century. But since 2010, coal generation has declined 52 percent, and renewable power generation exceeded coal generation for the first time in 2020. In 2011, the U.S. had 317.6 GW of coal-fired

electricity generation capacity,[5] but that number fell to 221 GW in 2021. Nearly a quarter of the remaining fleet is slated for retirement by 2029.[6]

Several factors explain this decline, including pollution control standards requiring costly retrofits, cheap natural gas and renewable power, state clean energy policies, and improved building and industrial efficiency.[7] Coal's decline has been accompanied by a precipitous fall in coal industry employment.[8] But even as employment fell, reduced pollution from coal plants dramatically improved public health. Annual deaths attributed to air pollution from coal plants fell from 30,000 deaths in 2000 to less than 3,000 in 2019.[9]

Coal's role in electricity system reliability has shrunk considerably. Coal-fired power plants operate as part of an integrated power system where supply and demand must remain in constant balance. The decline in coal-fired generation and capacity, and replacement by a more diverse portfolio of gas and renewable power plants with vastly different operational characteristics indicates that coal is not necessary for reliable power systems. For example, the United Kingdom reliably operated its grid without any coal generation for two straight months in 2020.[10]

The role of coal plants and their operation in the electricity system has also changed over time. Historically, coal plants operated as "baseload" power plants, relying on a relatively low-cost fuel supply to run at a constant, high output. But now markets are pushing coal plants to operate more variably, ramping up and down as the economics and availability of renewable energy fluctuate throughout the day and over a season.[11] Coal plants in our dataset had an average capacity factor of 46 percent, which means they ran, on average, only 46 percent of the time. This on-again, off-again operation increases wear and tear on coal plants designed for a different operating paradigm.

Displacement by cheaper gas and renewables means baseload operation is increasingly unprofitable for existing coal—operating at high output when plentiful clean energy resources operate at zero marginal cost is a waste of fuel. According to RMI, since 2012 utilities could have saved customers $1–$2 billion per year by turning down coal and relying on lower-cost, less polluting resources. This is partially due to self-scheduling, a practice through which monopoly utilities uneconomically run their coal plants in wholesale markets and charge captive customers the difference.[12]

Replacing coal with clean energy is not a one-to-one exercise. System operators and utilities only gain confidence that coal retirements won't adversely affect system reliability by evaluating the reliability of the entire energy portfolio. A recent North American Electric Reliability Corporation (NERC) assessment highlighted the need to build new generation before retiring old generation when reliability risks are present.[13] But recent studies such as the 2030 Report, which found an 80 percent clean, coal-free electricity system to be both reliable and affordable, confirm we can maintain a dependable electricity system without coal.[14]

The U.S. will continue relying on coal plants for reliability until we add enough new clean resources (including demand-side resources and transmission) to replace their reliability and energy services.

The Coal Cost Crossover 3.0 analysis highlights opportunities to economically displace coal-fired generation and replace those services in part. With the IRA's passage, the economic case for shifting from coal to renewables is stronger than ever.

INFLATION REDUCTION ACT IMPACTS ON U.S. ENERGY ECONOMICS

The IRA will significantly affect the relative economics of coal and clean power in the U.S. In this analysis, the IRA's extended and improved tax credits, along with a pair of refinancing programs, have the greatest effect on the cost of coal compared to renewables.

Tax Credits

Clean energy tax credits have arguably been the most important federal climate policies to date, driving nationwide solar and wind growth. The IRA builds upon this successful policy to make the clean energy transition cost effective for the long term, with earlier Energy Innovation® analysis finding the credits to be the most impactful IRA provision for electricity sector decarbonization.[15]

The production tax credit (PTC) and investment tax credit (ITC) are the IRA's two key tax credits for new clean electricity resources. Historically, the PTC has primarily supported wind energy resources, and at its full value paid approximately $26 per megawatt-hour (MWh) in 2022 dollars over the first 10 years of a wind project's commercial operations.[16] The ITC has largely supported solar resources, and at its full value offered a tax credit for 30 percent of total system cost, paid out when it is first placed in service. Prior to the IRA's passage, the PTC had expired, and the ITC had begun phasing out with a value of 26 percent for projects starting construction in 2022.[17] The IRA created long-term certainty for these tax credits, with the extension lasting through 2032 or until electricity sector greenhouse gas (GHG) emissions fall 75 percent below 2022 levels, whichever is later.

The IRA also immediately revived a long-expired option for solar projects placed in service in 2022 or later to elect the PTC instead of the ITC, which ensures that tax credits will stay impactful as solar capital costs continue to fall. In addition, the IRA provides an ITC for stand-alone energy storage technologies placed in service in 2022 or later, removing prior restrictions that required storage to be co-located with and charged primarily from solar energy resources.

Beyond the extension and increased flexibility, the IRA created several human impact bonuses that increase the value of the tax credit. To qualify for the full credit, a project must meet prevailing wage and apprenticeship requirements. Additionally, a project can earn a 10 percent boost for meeting domestic content requirements and an additional 10 percent for locating the project in an energy community (which includes census tracts in which coal-fired power plants have been retired since 2009 and adjacent census tracts, as defined by the IRA, see Figure 1).[iv]

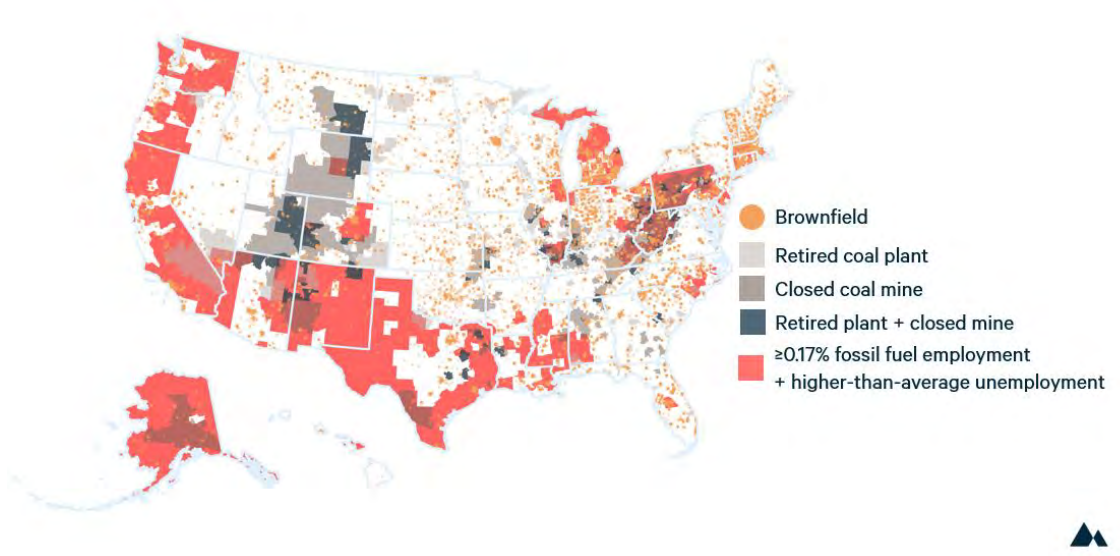

Figure 1. Map of probable energy communities, as defined by the IRA. Source: Resources for the Future.[18]

The combined impacts of energy community, labor, and domestic content bonuses reshape solar economics in coal communities. The median cost of new solar in these communities is about $24/MWh with low variance, while the median marginal cost of coal is $36/MWh with higher variance (see Figure 2). As discussed later in this report, this cost differential provides significant headroom for additional battery storage, which can also qualify for energy community bonuses.

[iv] The 10 percent credit boost for siting projects in energy communities works slightly differently for the ITC and PTC, providing a 10-percentage point ITC bonus and a 10 percent bonus on the PTC credit value.

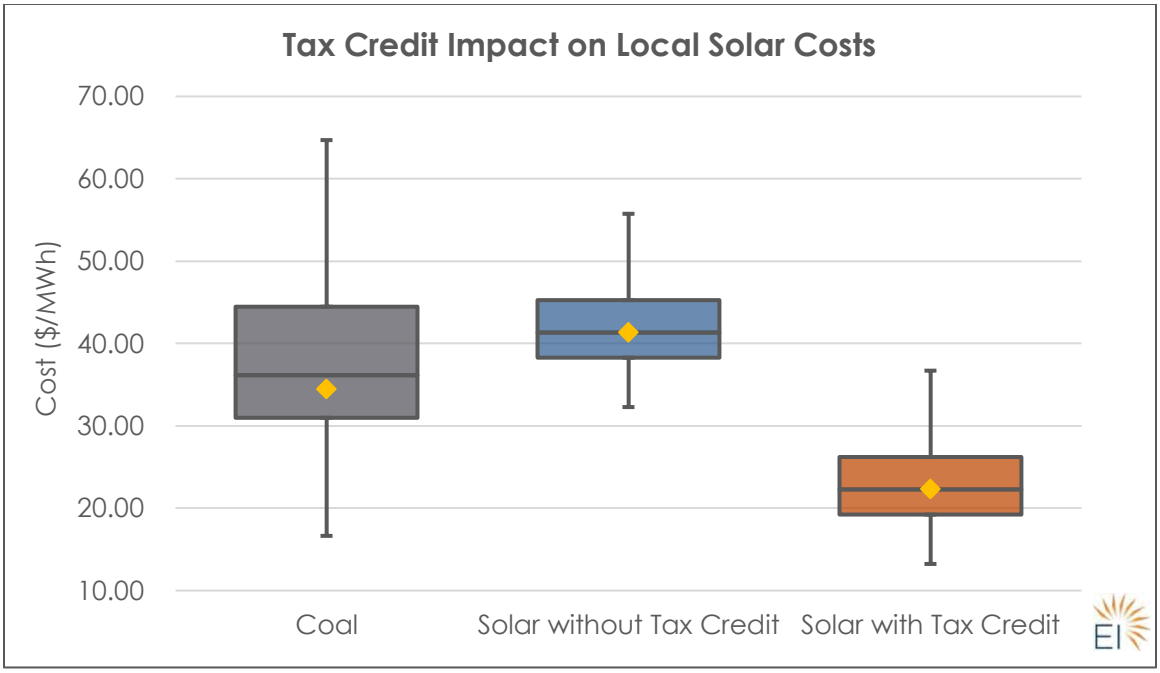

Figure 2. Impact of tax credits on local solar LCOEs in our analysis, including the energy community bonus. The yellow diamond indicates the average cost of each resource (weighted by generation). With the IRA, the economic case for local solar becomes unequivocal.

Revinvestment Financing

The PTC and ITC play the crucial role of decreasing the cost of developing clean electricity resources, but upfront cost is far from the only barrier to moving from coal generation to clean alternatives. One of the biggest hurdles to this transition is the rate impacts of adding large capital investments to utility rates when billions are still owed to debtors and investors on uneconomic coal assets. But a new IRA financing program to invest in clean energy infrastructure in current or former coal communities can overcome this hurdle. As the program only lasts until 2026, time is of the essence.

Most U.S. coal capacity is owned and operated by monopoly utilities, which collectively hold at least $176 billion in unpaid fossil plant balances[v]—accounting ledgers that represent the debt and equity capital structures utilities used to finance these plants over time. Utilities include this capital cost in electricity rates, typically recovered over the plant's entire lifetime in a financial arrangement somewhat similar to a conventional 30-year mortgage (albeit one that is continuously extended as new capital is invested at coal plants). As long as the plant remains in operation or

until the investment is fully depreciated, customers are generally obligated to continue to cover these costs, which include substantial returns for utility shareholders. Without a change to this structure, monopoly utilities have little to gain from early coal plant retirement and they may perceive retirement or partial replacement as putting cost recovery at risk.

New IRA programs provide flexible, low-cost financing to clean up utility balance sheets by reducing the cost of investing in new local clean energy infrastructure, including wind, solar, batteries, transmission infrastructure, and reuse of the coal plant itself. Utilities and other power plant operators, such as independent power producers, can access low-cost government-backed loans to reduce the rate impacts associated with large capital expenditures required to transition from coal to clean and stimulate local economic development. The IRA created two novel programs to support utilities in transition:

First, the IRA appropriated $5 billion to the U.S. Department of Energy's (DOE) Loan Programs Office (LPO) via the Energy Infrastructure Reinvestment (EIR) program to support $250 billion in loan-making authority to facilitate refinancing and reinvestment in capital projects at fossil infrastructure sites, using below-market interest rates. Funds can be used flexibly to "re-tool, re-power, re-purpose, or replace" fossil infrastructure across the entire energy industry (including non-utilities), reducing the cost of replacement resources and creating numerous pathways for community diversification and redevelopment. The financing provisions are flexible enough to work for all parties—utilities, consumers, and communities. These stakeholders can use the financing to reduce the near-term rate impacts of capital transition, allowing new investment to arrive sooner in these communities that sorely need it as aging fossil plants ramp down.

Second, the IRA authorized a $9.7 billion program specifically for rural electric cooperatives through the U.S. Department of Agriculture (USDA). Rural electric cooperatives provide electricity to more than 40 million people. Their power supply is particularly coal-heavy, with coal accounting for 28 percent of generation in 2020 compared to 19 percent nationwide.[19] This means surrounding rural communities bear a disproportionate burden of coal-related pollution, while member-owned cooperative customers remain tethered to coal debt. While members may want to transition to clean energy to capture pollution and cost savings, this debt holds them back. Furthermore, simply shutting down cooperative coal plants could impact communities that rely on relatively high-paying jobs where economic opportunities are sparse. To address these challenges, the IRA funds USDA to provide direct grants or loans for rural electric cooperatives to procure clean energy, with an express purpose of reducing GHG emissions.

METHODOLOGY

As in the previous two coal cost crossover studies, this report compares the marginal cost of energy (MCOE) for existing coal plants across the U.S. with the LCOE for solar and wind. We compare the same coal costs to four different cost scenarios for renewables. Scenarios vary by resource type

(wind or solar) and by geographic scope (regional or local). For the first two scenarios, regional solar and regional wind, we separately examine the costs of solar and wind located within the same region as a given coal plant, calculating the LCOE to replace each plant's annual generation within a nearby region that corresponds roughly to the utility's service territory.[vi]

For the last two scenarios, local solar and local wind, we look at local costs for solar and wind separately, calculating the cost if all replacement renewables are sited within a 45 km radius of the existing coal plant. Local solar and wind projects get the additional energy community tax credit bonuses in the IRA, which helps to offset losses in power resource quality due to the local siting constraint. A more detailed explanation of our methodology is available in this report's Appendix.

Coal Economics

To calculate the MCOE at each coal plant, we sum three cost components: the cost of fuel, the fixed and variable costs of operations and maintenance, and the going-forward routine capital expenditure costs, each calculated on a per-MWh basis. Using 2021 U.S. Energy Information Administration (EIA) data, we calculate the total going-forward marginal cost for all coal plants operated by utilities or independent power producers in the continental U.S., excluding plants that are used for co-generation of heat. These costs appropriately comprise marginal cost because they would not be paid if the coal plant retired. By contrast, we do not include unpaid capital balances as part of the MCOE because their payment does not depend on whether the plant retires.[vii]

Renewable Economics

We used NREL's Regional Energy Deployment System (ReEDS) model to calculate solar and wind LCOE values, which are all-in estimates of the cost of energy output in MWh, taking into account all capital expenditure, operations, and maintenance costs. We used the 2021 actual cost values from the 2022 NREL ATB.

The ReEDS model uses solar and wind resource potential values at around 50,000 sites across the country, accounting for comprehensive exclusion criteria, including land cover, elevation, slope, environmentally sensitive areas, and local siting regulations. The model also provides annual capacity factors at each of these sites. The site-specific LCOE is then calculated based on capacity factor, as well as a comprehensive list of parameters including capital costs, fixed operation and maintenance costs, equity costs, interest rates, construction costs by location, construction period,

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[vi] We use regions defined by NREL's Regional Energy Deployment System model, explained in detail in the appendix.
[vii] These remaining balances are the primary target of the reinvestment programs created by the IRA. Though we don't include the balances in our cost calculations, the potential to refinance and replace with clean energy is another path toward reducing coal generation beyond operating costs.

IRA tax credits, and depreciation. We calculate the LCOE after accounting for both the ITC and PTC 2022 tax credit values, using the cheaper of the two.

Renewables key assumptions

Across the four renewable scenarios, we make several key assumptions:

- Regional solar and wind costs include new grid interconnection costs, while local resources do not.
- All renewable resources qualify for the prevailing wage and apprenticeship hour tax credit bonus.
- All wind resources qualify for the full domestic content bonus, while 42 percent of solar resources qualify for the domestic content tax credit bonus based on current domestic content levels.[20]
- Storage does not qualify for the domestic content credit bonus.
- All tax credits are reduced by 10 percent to account for transfer losses.

Regional renewables scenarios

For the two regional renewable cost scenarios, regional wind and regional solar, we start by finding the LCOE for regional wind and solar that could replace each plant's 2021 annual generation. The region we study for each plant is based on the ReEDS balancing area (of which there are 134, see Appendix) in which the plant is located, corresponding roughly to the utility territory. For each coal plant, we sort the wind and solar sites available in that region by LCOE and choose the best sites based on capacity factor to replace the coal generation. For selected sites within each region, we capacity-weight the site-level LCOEs to estimate the weighted average regional LCOE. Interconnection costs associated with transmission lines that connect the project to the grid are also added into these LCOEs, while we make no assumption about broader grid impacts.

Local renewables scenarios

For the local wind and local solar scenarios, we first determine the viability of the local wind or solar replacements for each coal plant. Using the plant's latitude and longitude as the center, we create concentric circles around each coal plant, starting with a radius of 5 km and moving up to 45 km in 5 km increments. We identify the solar and wind sites that fall within each of these concentric circles and separately estimate the site-level capacity and annual generation potential for solar and wind resources. We then estimate the minimum radius needed to replace the annual generation from each coal power plant with solar or wind resources.

If there is enough generation found within the 45 km radius, we then determine the local LCOE by capacity-weighting the site-level LCOEs for the maximum radius needed to match the existing

plant's generation. For solar, nearly all plants meet the generation requirement within a 20 km radius while for wind, the average radius is much larger and there are many plants without enough wind generation within 45 km because of the more site-specific nature of wind energy potential and the larger land footprint (see Figure 3).

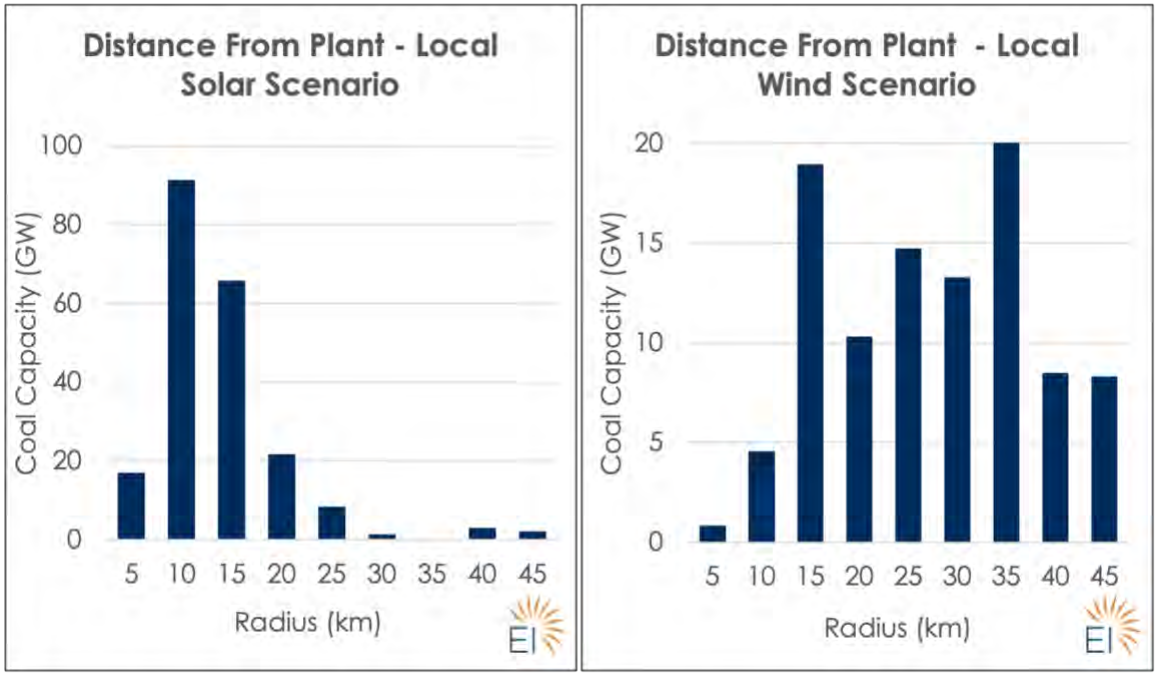

Figure 3. This figure plots the radius needed to match each plant's generation, while still being cheaper than coal, for both local solar and local wind. The majority of coal capacity has enough solar potential within a 20 km radius to meet the plant's entire annual generation in our local analysis and still provide cheaper energy than coal. While many plants have sufficient and cost-effective local wind nearby, less potential is available in close proximity for local wind.

For the local scenarios, we assume that all projects sited within 45 km of the plant will receive the IRA's 10 percent energy community bonus tax credit, given that both the census tract and neighboring census tract to any retiring coal plant fit the IRA's definition of an energy community. For these scenarios, interconnection costs are not included in the LCOEs as we assume that the new resources can utilize the existing plant's interconnection infrastructure.

Storage analysis

For the local solar scenario, we also analyze the economic feasibility of installing four-hour battery storage capacity along with the solar to provide additional reliability services to the grid. For this analysis, we start with a $330 per kilowatt-hour (kWh) price for the storage,[viii] and we include a 36

[viii] This price is based on the 2021 actual storage costs in the NREL 2022 ATB.

percent ITC (the full credit plus the energy community bonus, minus transferability losses). After calculating the savings from replacing the coal generation with local solar generation, we then determine how much battery capacity those cost savings would fund. Due to uncertainty in the battery price going forward, we calculate the battery capacity funded for storage prices ranging from $100 to $400/kWh.

RESULTS & DISCUSSION

Main findings:

1. >99 percent of plants studied are more expensive to run than to replace with new renewable wind or solar energy.
2. >97 percent of plants studied are more expensive to run than to replace with either local solar or local wind energy within 45 km (approximately 30 miles) of the coal plant.
3. Replacing coal generation with local solar resources could drive up to $589 billion in clean energy investment in energy communities across the U.S.
4. Replacing coal generation with local renewable resources could save enough to finance installation of 137 GW of four-hour battery storage—62 percent of the coal fleet's nameplate capacity.

Overall comparison between coal and renewable costs

For this report we combined elements of the two previous Coal Cost Crossover reports: We looked at replacing coal power with regional wind or solar resources *and* at replacing coal power with local wind or solar resources close enough to a plant to take advantage of its transmission connection and the energy community bonus tax credit. Across these four scenarios, we found that:

- 199 plants are more expensive to run than to replace with regional wind.
- 190 plants are more expensive to run than to replace than regional solar.
- 104 plants are more expensive to run than to replace than local wind.
- 199 plants are more expensive to run than to replace than local solar.

Analyzing these scenarios together, we found all but a single coal plant[ix] in the dataset of U.S. coal plants to be more expensive (lower renewable LCOE than coal MCOE) compared to replacement by at least one of these renewable options. Between local solar and local wind, 205 out of 210 plants had at least one cost-effective local renewable option. Of these, 98 had *both* local solar and local wind options that were cheaper than coal (see Figure 4). This represents a sharp acceleration

[ix] The single coal plant is the Dry Forks Station in Wyoming. It is the newest and among the cleanest coal plants in the U.S. coal fleet and is still only $0.32/MWh cheaper to operate than available regional wind. It is also a testbed for carbon capture use and storage (see https://www.powermag.com/dry-fork-a-model-of-modern-u-s-coal-power/). A similar plant built today would include capital costs and would not be competitive with new renewables.

in the previously observed trend in our coal cost crossover reports (see Figure 5). The full results of all four scenarios can be viewed in the accompanying spreadsheet.

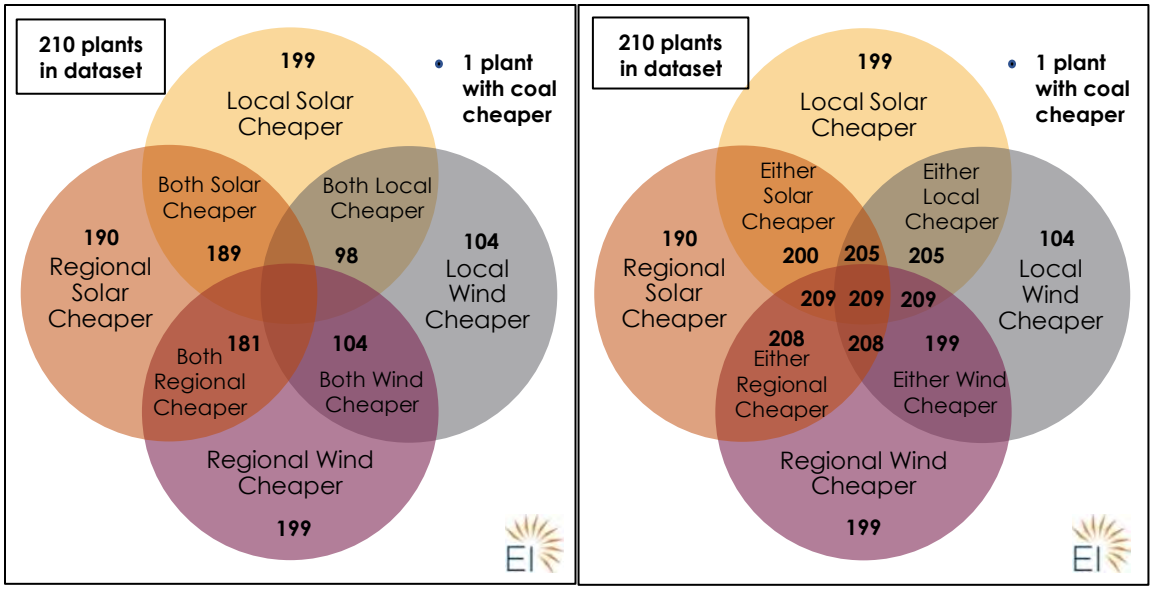

Figure 4. A closer look at the 210 coal plants in our data set based on the specific comparison with renewables that was made. The Venn diagram on the right looks at inclusive intersections (either resource is cheaper than coal) while the one on the left looks at exclusive intersections (both resources are cheaper than coal). We did not analyze any hybrid combinations of wind and solar, although this is clearly a possibility in the local context (98 plants) and the regional context (181 plants).

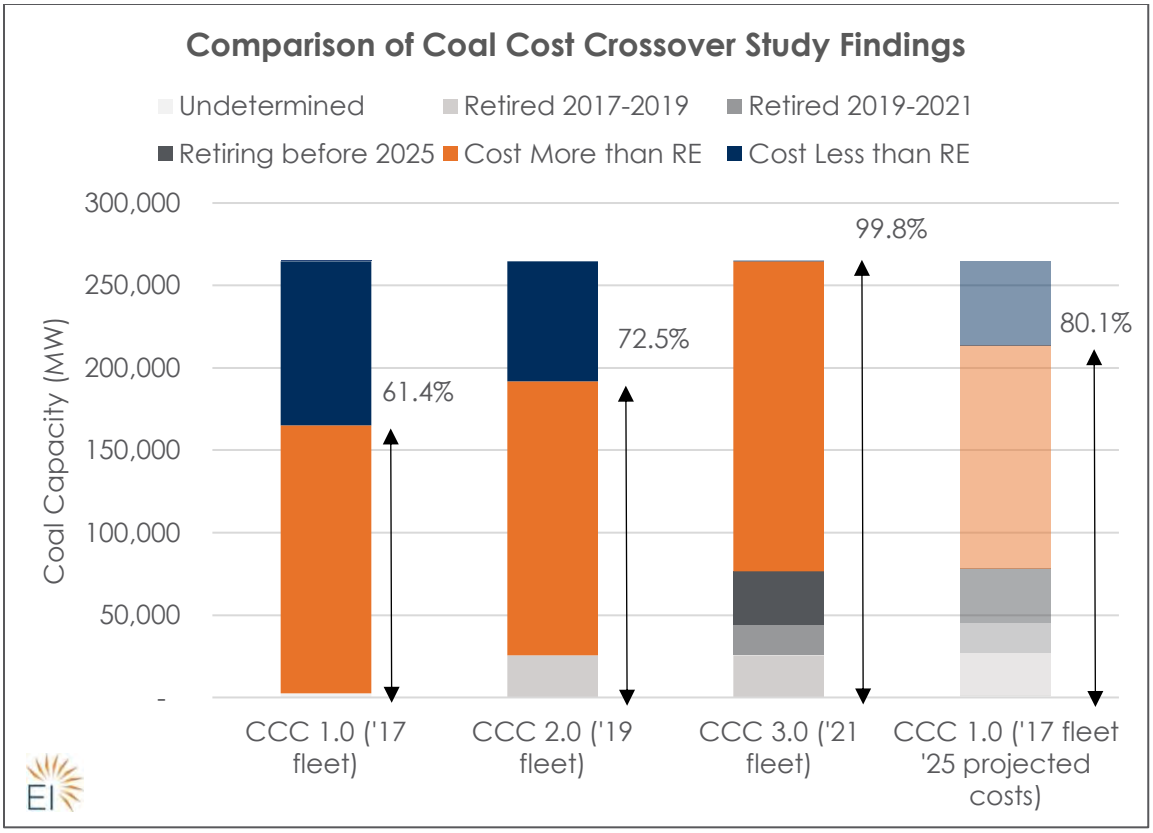

Figure 5. Comparison of our two original analyses of renewables and coal cost-competitiveness. The first included a 2025 projection for renewable costs to compare with 2017 coal going-forward costs. This comparison highlights how much the trend for coal being uneconomic compared to replacement by renewables has accelerated since the first report published in 2019.

Comparison between coal and cheapest available wind or solar resource

For the plants that were uneconomic, multiple renewable options were less expensive than coal generation, but regional wind and local solar were most frequently the cheapest overall resources (see Figure 6 and Figure 7). Regional wind was the cheapest option for 117 plants, while the most economic resource was local solar for 75 plants, local wind for 13, and regional solar for only four.

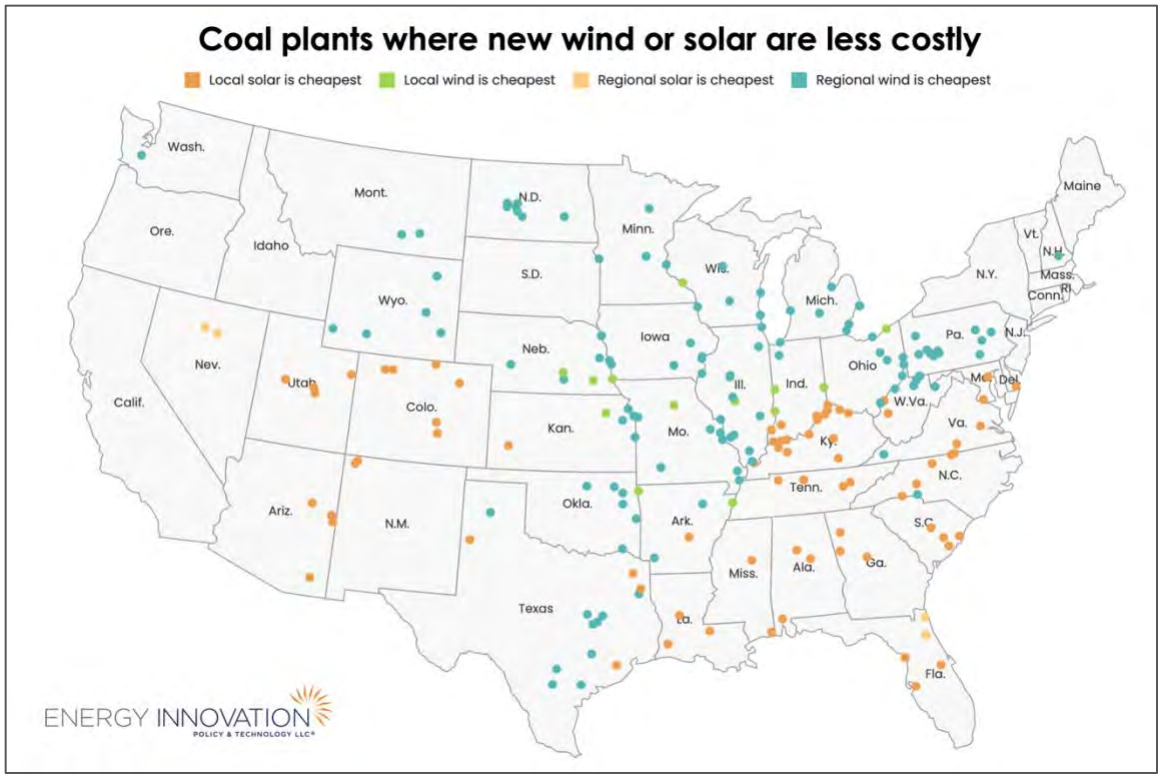

Figure 6. While most plants have multiple cheaper renewable options, the overall cheapest renewable resource varies by geography.

Notably, for solar, local replacement is cheaper than regional replacement in many cases due to low regional cost variability, lower transmission spur line costs,[x] and IRA energy community bonuses. For regional versus local wind, however, regional resources tend to be cheaper even with the added costs due to higher variation in resource quality for wind—going further from the plant often yields significantly better wind energy sites.

[x] A "spur line" is the transmission line that connects a renewable project to the bulk system at a point of interconnection. In this analysis, we do not make assumptions about interconnection costs beyond the cost of building the spur line. In this limited respect, we anticipate that local wind and solar costs would be lower than regional renewables, because local renewables are adjacent to the coal plant's point of interconnection. We recognize that interconnection costs for renewables have been increasing for a variety of reasons as they sit in ever-growing interconnection queues around the country, but also hypothesize that some renewables could reuse existing coal plant interconnection rights with very low interconnection costs. See https://emp.lbl.gov/news/pjm-data-show-substantial-increases.

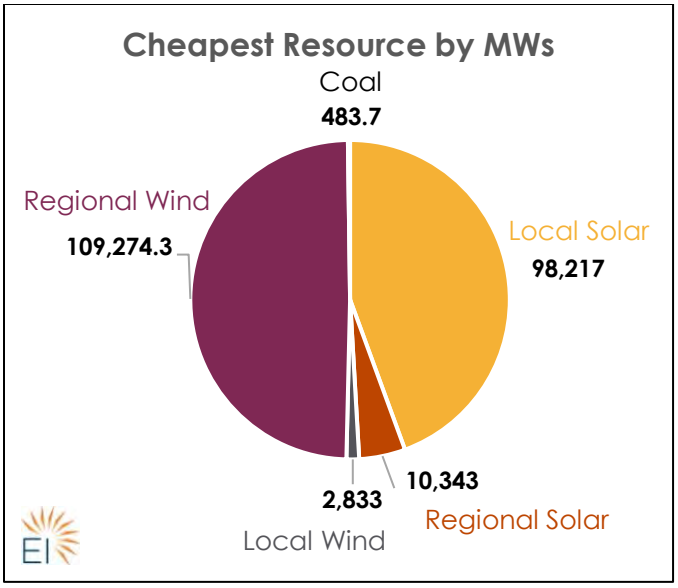

Figure 7. This chart shows the cheapest renewable resource option for each MW of coal capacity studied in this report. Local solar and regional wind are the cheapest renewable resources for nearly all plants.

We still see a wide range in the relative economics between existing coal and new wind or solar, with the all-in costs for the cheapest renewable option anywhere from zero (for one plant) up to 80 percent cheaper than the going-forward costs for coal, absent a few edge cases. Typically, the least economic plants have low capacity factors that result in very high fixed marginal costs per MWh or very high fuel costs.

For more than three-quarters of U.S. coal capacity, the all-in cost per MWh of the cheapest renewable option is at least a third cheaper than the going-forward costs for the coal it would replace (see Figure 8).

The substantial cost savings from replacing coal with renewables indicates the potential to invest in additional resources that provide complementary services like flexibility and transmission, without raising costs. Policymakers should consider a portfolio of clean resources that together provides adequate value and any needed reliability services. These resources could include storage,

regional or interregional transmission upgrades, demand-side resources, and complementary portfolios of wind and solar.

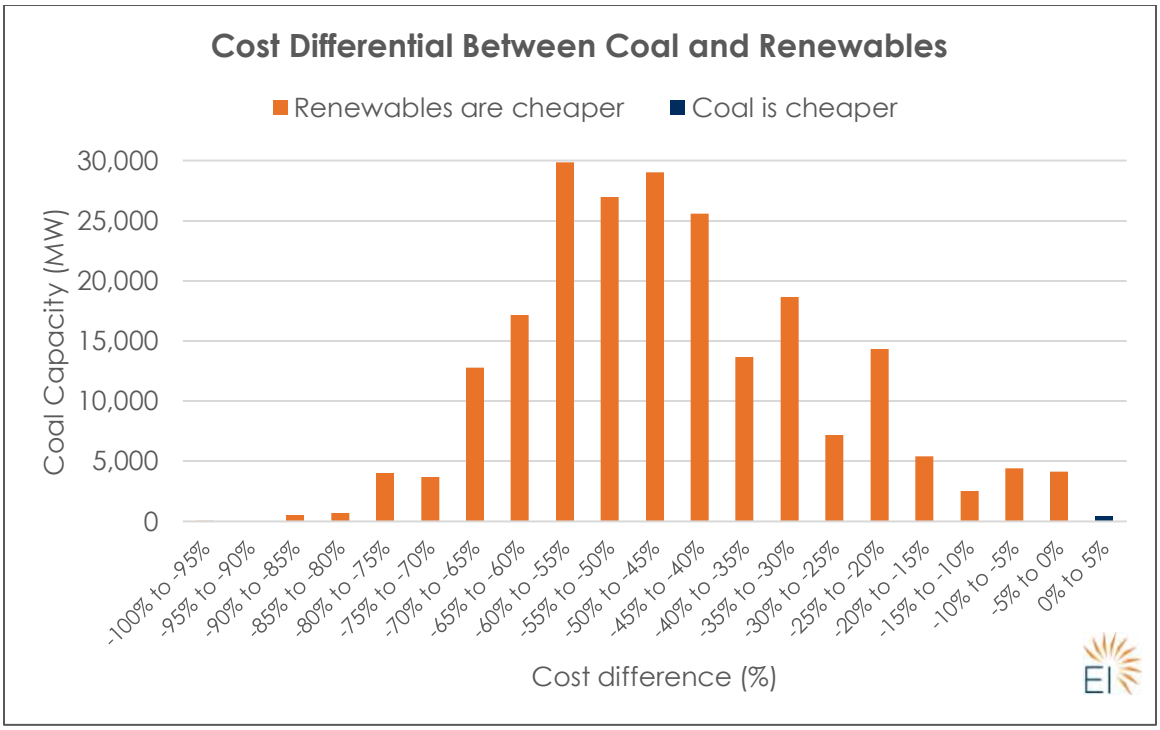

Figure 8. Aggregated plant capacity shown as percent difference between renewables LCOE and coal going-forward cost. The orange bars indicate capacity where renewables are cheaper than coal and coal is deemed "uneconomic." The one blue bar indicates the sole plant that is still cheaper to operate than replace with renewables.

Local replacement of coal

Local solar and wind

For 199 of the 210 plants studied we find that local solar replacement is more economic than coal, based on energy generation alone, and for 75 plants it is the cheapest option entirely. Local wind is also a viable option for many plants, with 104 plants having cost-effective local wind resources and 13 having local wind as the cheapest option. For 98 plants, both local wind and local solar were

cheaper than coal. While we did not study any combinations of the two, this result indicates that a portfolio that includes both local wind and local solar would likely be a viable option with additional reliability value near many plants.

In these local replacement scenarios, we looked at replacing all the annual electricity generated by a given coal plant with either local wind or local solar within 45 km of the plant. This allowed us to assume lower interconnection costs[xi] (a significant barrier for new projects)[21] while taking advantage of the IRA's energy community tax credit bonus. In nearly all cases we studied, the reduced interconnection costs and added tax credit compensates for potentially lower resource quality when restricting site selection in areas close to the plant. We find particularly good resource quality in the local solar scenario, where 191 plants have sufficient sites nearby such that their generation can be replaced within 20 km.

Solar plus storage stepping in at North Valmy

In Nevada, NV Energy has already realized the cost and community benefits of using solar plus storage in place of the 567 MW North Valmy Generating Station, near Winnemucca. Two new solar plus storage facilities located within the same county will replace this plant when they are completed by 2025. The two replacement projects will provide 250 MW solar capacity plus 200 MW of storage, and 350 MW of solar plus 280 MW of storage. These projects will also create several hundred construction jobs, and the storage will help shift the solar generation to the times of day it is most needed, serving the reliability needs of the area. This is consistent with our analysis, which finds that it would be cheaper to use solar plus storage up to the full plant's capacity than to continue to run the coal plant. Plants across the country can now follow Valmy's example and effectively decarbonize with solar plus storage.

Local replacement offers three other benefits. First, local replacement can help preserve livelihoods and tax revenue for surrounding communities through the energy transition.[xii] Second, local resource replacement falls into the category of projects that can qualify for loans via the DOE's

[xi] In our modeling, we use ReEDS spur line costs as a proxy for interconnection costs of regional renewables. For local renewables, we assume no interconnection costs because the point of interconnection already exists at the coal plant. This is a simplification—each site will be different and will require an interconnection study or transmission plan to ascertain the interconnection costs.

[xii] New renewable energy installations are only one piece of the puzzle when it comes to community transition as they typically do not provide as many jobs or as much tax revenue as a coal plant. While local energy replacement can contribute, further community re-development and economic diversification is needed, as discussed further in the policy recommendations section.

EIR program, as the projects would be a direct reinvestment in energy infrastructure. Our analysis shows investment in local solar resources could drive $589 billion in capital investment to energy communities across the country (see Figure 9).

Third, siting renewables in proximity to plants creates the possibility that these new resources could use the existing plant's grid interconnection. Recent analysis of PJM's interconnection process shows that the median interconnection cost from 2020 to 2022 grew ten-fold over the costs from 2017 to 2019, largely due to transmission network upgrade costs.[22] While we considered reduced interconnection costs for local resources, the advantage of local replacement could be even more considerable as the cost of the line is only a part of the problem. For clean energy projects across the country, long interconnection wait times are also a major hurdle to overcome.

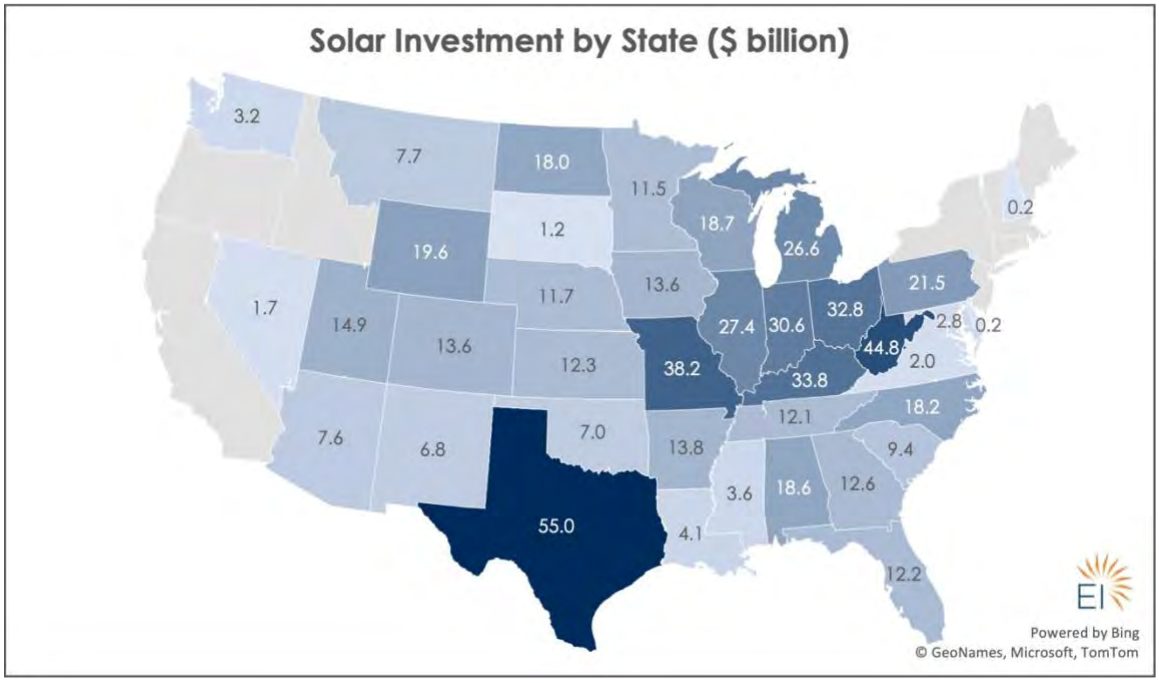

Figure 9. The solar capacity needed to provide enough energy to make up for coal generation across the country would drive hundreds of billions in investment. States with no investment number had no plants in our data set.

Local solar plus storage

We followed up on our local solar scenario by looking at a solar plus storage replacement option for each plant that includes local solar energy plus four-hour batteries to provide additional capacity value and higher market profitability in some cases. We find that the savings available from switching from coal generation to local solar generation can finance 137 GW of four-hour battery capacity at a price of $330/kWh across the coal fleet.

For more than a third of the coal capacity studied, we find that in addition to energy generation replacement with local solar, 80 percent or more of the plant's capacity can be replaced with four-hour batteries at a combined levelized cost that is still less than the going forward cost of the plant. For the remaining plants, the percentage of capacity that can be economically replaced is still quite significant: We find that savings from renewable generation could fund storage at more than 50 percent plant capacity at 136 plants.

Renewable options cheaper than expensive upgrades at Mitchell plant

In 2021, American Electric Power determined it would likely be more cost-effective to retire West Virginia's Mitchell Power Plant than pay for expensive pollution control upgrades required by the U.S. Environmental Protection Agency (EPA). However, the West Virginia Public Service Commission (PSC) ruled that the utility had to keep the plant open, and that WV ratepayers must pay for the upgrades. At the same time, in Kentucky and Virginia, who were also receiving power from the plant declined to make their state's customers pay, leaving West Virginians to shoulder a $448 million price tag. Our analysis shows taking advantage of regional wind resources would be 48 percent cheaper than continuing to run this polluting plant. Replacement with local solar and battery storage would be 50 percent cheaper and would provide the reliability the PSC seeks while saving ratepayers hundreds of dollars every year.

This local solar plus storage arrangement has at least three advantages:

First, solar plus storage provides resources with a significant capacity and ancillary service value at the same place on the power grid, addressing in part possible reliability concerns that may be associated with coal plant retirement.

Second, the new storage ITC means batteries do not need to be co-located with renewables to take advantage of the tax credit. This means that while local renewables may need to be sited a short distance from the plant, storage can be placed directly at the coal plant site and use existing electrical infrastructure to act as a central collection site for renewables. This arrangement also bolsters economic development opportunities in coal communities.

Third, combining solar and storage empowers a gradual coal phase-out, benefiting communities and grid reliability. Electricity generated from coal can be reduced, while keeping the coal boiler and generator available for emergencies. If needed, the generator can eventually be transformed into a piece of grid regulation hardware requiring no boiler, and batteries can store and release renewable energy to make the whole system available at times of highest grid demand. Renewable energy can

be a part of an economic diversification package that may include other re-purposing of the site, such as a plant in Michigan that was re-developed into an insurance company's headquarters.[23]

The reliability implications of coal plant retirement should be evaluated for each specific plant. A one-to-one replacement is often not necessary given the capabilities of the remaining power plant fleet. For example, the battery capacity necessary to take over the reliability burden of any given coal plant is varied, depending on the role of the plant and broader resource mix, and it is not needed at all in many cases. Wind and solar (especially in a complementary combination) already tend to provide a measure of capacity value to the regional grid. Other assets like faster, more flexible gas units or behind-the-meter resources may already be carrying more of the regional reliability burden, and transmission expansion can help reduce the need for dispatchable generation for resource adequacy as well. Therefore, coal capacity is not always necessary for reliability depending on the resource adequacy in each region as determined by the balancing authority.[24]

Figure 10 shows the percentage of battery capacity at each plant that can be funded by coal replacement with local solar, providing a range of options for combining renewables with storage.

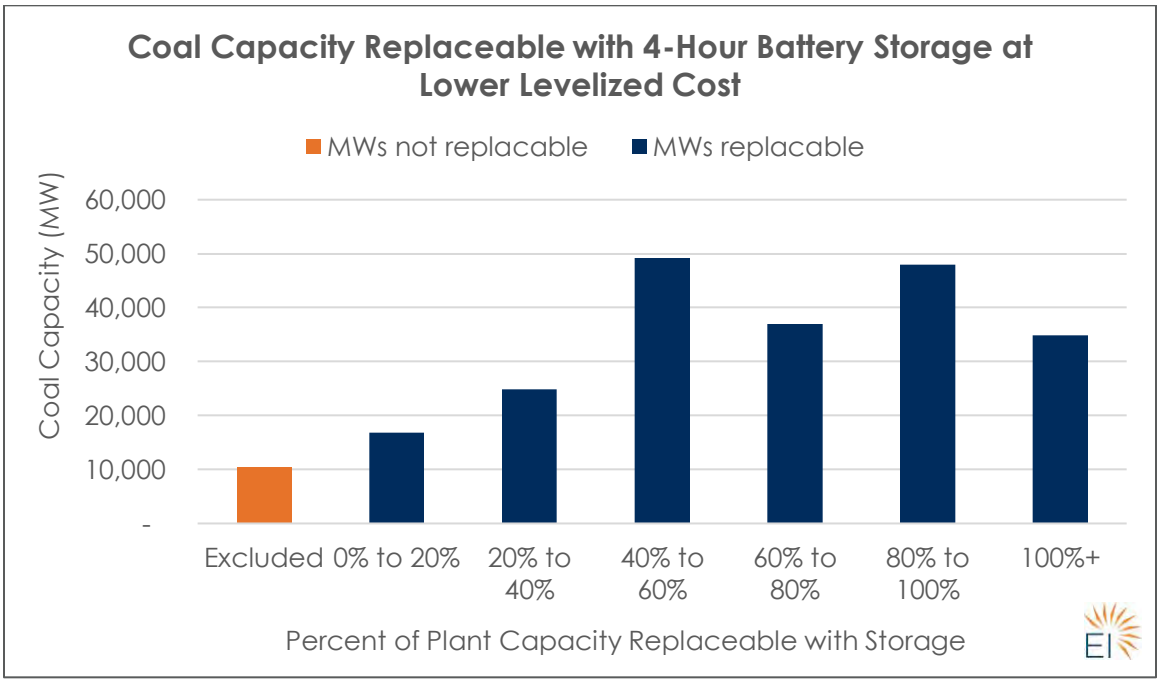

Figure 10. Coal plant capacity (in MW) by the percentage that can be replaced using only coal crossover savings. "Excluded" indicates plants for which local solar generation was available but was not cheaper than coal.

The economics of battery replacement for capacity are highly dependent on battery costs. For the analysis above, we used $330/kWh as the cost of storage, which is the 2021 cost for storage in the NREL 2022 ATB.[25] Our cost accounted for the new standalone storage ITC and energy community tax credit. To study the sensitivity of these findings to battery prices, we evaluated the potential for capacity replacement across prices ranging from $100/kWh to $400/kWh (see Figure 10).

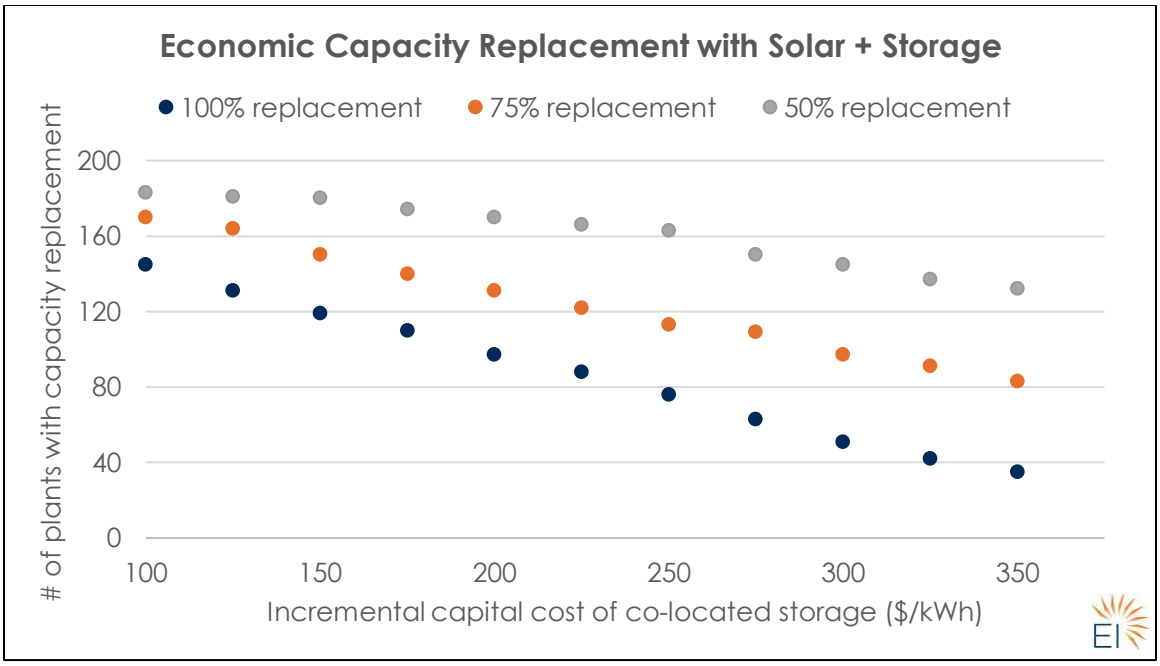

Figure 11. Economic battery capacity relative to battery price by percent capacity that can be replaced at each plant.

Utilizing additional financing to fund local resources: Ameren's Rush Island Plant

It is important to note, however, that fuel savings are not the only source of savings that could help finance replacement batteries in a coal-to-local renewables swap.

For example, Ameren's Rush Island power plant in Missouri is not a strong candidate for financing batteries solely with savings from switching to local renewables. Yet by also accounting for needed upgrades, the plant's remaining balance, and reliability concerns, the case for financing batteries for reliability value becomes stronger.

Ameren was planning to retire the 1,195 MW coal plant in September 2022 partially due to the expense of adding court-ordered selective catalytic reduction (SCR) to address air pollution

noncompliance, with a price tag of $310 million[xiii] to $1 billion.[26] Unfortunately, because early retirement could cause severe voltage stability problems leading to cascading power outages, the Midcontinent Independent System Operator (MISO) sought to keep the plant online and received Federal Energy Regulatory Commission (FERC) approval for a 12-month system support resource agreement to be renewed annually.[xiv] According to the grid operator, potential renewable energy additions or possible demand-response programs wouldn't adequately address the location-specific voltage problem. However, due to the geographic nature of the potential voltage instability, local renewables coupled with batteries could go a long way toward mitigating this concern without waiting for the transmission upgrades MISO deemed necessary.

Our initial analysis finds that switching to renewables could generate savings to pay for replacing replacement of only 4 percent of the plant's capacity with batteries. However, the IRA now creates new possibilities. Because Ameren faces capital expenditures in the $300 million to $1 billion range, and already holds an estimated $600 million for the plant in its rate-base (interest on which is paid by its customers at standard utility rate of return), existing state public utility commission securitization authority could be used to refinance this obligation in combination with the EIR program, generating much greater customer savings.[xv] Investing these savings in four-hour battery storage could match 85 to 165 percent of the plant's capacity. Furthermore, batteries would only be necessary if the local renewables on their own were not sufficient to provide voltage support or if the proposed transmission solutions proved too slow or expensive.[xvi]

New IRA financing and tax credits make replacing coal plants with a combination of local wind and solar power supported by batteries an attractive option for most coal plants in the U.S. Such replacement can be done with a minimum of disruption to the grid while keeping jobs in affected communities—not to mention the great improvements to public health from reduced pollution.

POLICY RECOMMENDATIONS

Our analysis makes it clear the comprehensive the IRA tax incentives have created a favorable policy environment for the coal-to-clean transition. However, the transition can be made even more cost-effective if utilities harness the IRA's loan and grant programs and use best practices to assess cost-saving replacement options.

[xiii] Assuming $250/kW all-in costs. See https://www.powermag.com/estimating-scr-installation-costs/.

[xiv] MISO identified four transmission upgrades that are needed to maintain voltage on the grid, with the last one expected online by June 2025, according to the grid operator. See https://www.utilitydive.com/news/ameren-missouri-coal-rush-island-miso-ferc/630226/.

[xv] The interest rate on the securitized loans or government-backed loans through EIR are assumed to be 2.95 percent, or the average of the 20-treasury yield across the last 10 years plus 0.375 percent. Missouri law already allows for coal plant securitization.

[xvi] While MISO investigated replacement of the plant with renewable energy, it does not appear that MISO considered renewables in geographic proximity to the plant.

Planners and policymakers should make sure they are not caught unprepared by a wave of retirements, and that replacement renewables and complementary flexible resources can be deployed in a timely manner. Advocates and policymakers interested in capturing the economic and public policy benefits of shifting away from coal can take several actions to ensure that power plant operators take advantage of the moment by requiring utilities to account for IRA incentives and funding programs in planning and procurement. Finally, our analysis suggests that IRA provisions designed to encourage a just transition for coal communities are well positioned to spur new investment in generation and grid balancing resources in the immediate vicinity of existing plants, but experience has shown that a just transition will only happen with the careful attention of legislators and regulators alongside local communities.

Reliability assessment keeping expensive Indian River plant online

Delaware's only remaining coal plant, Indian River Generating Station, was planned for retirement by June 2022—until the grid operator, PJM, requested it remain open until 2026. PJM had determined that transmission upgrades would be needed to stabilize the grid before the plant could be taken offline. The plant, which only has one remaining unit, is historically the worst polluter in Delaware and also the eighth most expensive plant we analyzed due to low capacity factor and high estimated fuel costs. Local replacement of this plant could assuage reliability concerns by providing generation and capacity needs at the same location on the grid. Our local analysis finds that 246 MW of storage could be funded via savings. At over 50 percent of the plant's capacity, this is a good candidate for re-assessment of reliability needs.

Preparing the way for coal transition

Improving interconnection and transmission processes

The Rush Island Power Station example discussed above is not unique and blocking retirement of uneconomic plants due to broader system stability concerns and transmission requirements harms customers. To move forward while maintaining reliability, independent system operators (ISOs) and regional transmission organizations (RTOs) should proactively study solutions that can enable plant retirements. The alternative—overriding utility retirement plans and requiring FERC approval for expensive stopgap payments to keep high-cost plants running—is not good for utilities or their customers.

Our analysis shows that post-IRA, almost every coal plant has reached its economic tipping point. As pollution standards and clean energy policies continue to worsen coal plant economics, ISO/RTOs will increasingly encounter situations where innovative resource

portfolios will be needed to economically and reliably replace coal plants, including transmission. As neutral arbiters of just and reasonable rates, system operators must be ready to enable cheaper electricity and public policy goals by allowing utilities to retire uneconomic plants. Proactive transmission planning and deployment, alongside improvements to interconnection processes are both crucial to prepare for uneconomic plant replacement.

Absent regulators stepping in, retiring a plant is much easier than building a new renewable project. Price signals may induce coal retirements before new renewable projects can be approved and built to take their place. The growing interconnection queue backlog is of particular concern here. As of 2022, the two largest power markets in the U.S., MISO and PJM, had about three times more renewables capacity waiting in the queue than they had existing coal capacity.

For PJM, this backlog was deemed insurmountable. While PJM works through its existing interconnection requests, it will not review new requests until early 2026. It is clear that additional measures to improve the interconnection process, including better regional transmission planning, are needed to avoid similarly extreme measures in the future.[27] FERC is currently considering interconnection policy changes, but state public utility commissions can also help by examining their state's queue and assessing whether proactive transmission buildout could connect cost-effective clean energy. In states outside an ISO/RTO, states hold sole responsibility for proactive transmission and planning process reform to reduce wait times and hasten the pace of in-state clean energy investment.

Building local: accelerating deployment while maintaining reliability

Action from FERC and other policymakers on interconnection reform and transmission buildout cannot come too soon. A recent brief from Lawrence Berkeley National Lab (LBNL) analyzing interconnection costs in the PJM region finds that, alongside the tremendous lengthening of the interconnection queue, interconnection costs have increased substantially in recent years.[28] The main driver behind these increases has been broader network upgrade costs, reflecting system changes due to the influx of renewables and the fact that optimal renewable sites are often far from the coal they might replace.

There is no doubt that variable renewable resources are fundamentally different from dispatchable fossil generators, but variability does not imply unreliability. Studies are clear: A coal-free U.S. electricity system can be dependable.[29] Yet renewables do require a different resource adequacy framework, which makes resource diversity, energy sufficiency, regional and interregional transmission, and demand response more important. As system operators design new resource adequacy metrics, regulators should support them by defining minimum resource adequacy requirements and soliciting cost information.[30]

In a high-renewables environment, interregional electricity transfer can help manage local weather variation, providing higher reliability at lower cost. RTOs and regulators can enable interregional

coordination by expanding planning areas or subsidizing transmission lines that provide for specific reliability needs. Finally, regulators and state legislatures can require resources that bolster reliability like energy storage has become a cost-effective way to integrate renewables, as this report shows. However, storage still lags in investment. A legislative storage mandate, like the one passed in California in 2013 can help accelerate storage deployment.[31]

Ultimately, building out the network to include and adapt to some of the best available renewable resources, evolving the bulk power system's resource adequacy framework, and improving inter-regional coordination supports a least-cost, reliable electricity system given the new IRA incentives. But, as is evidenced by the delays described above, all this takes time. Building local resources closer to or at the same site as coal plants could dramatically accelerate clean energy deployment while providing significant incremental reliability value.

Prior to the IRA, local replacement was not always economic on an annual generation cost basis relative to the cost of maintaining a coal plant. However, to support a just transition, the IRA includes additional incentives for building new clean resources near coal plants or "energy communities." Our analysis shows that local wind or local solar plus storage could create a cheaper electricity portfolio than nearly every plant, while delivering the same amount of electricity and providing significant reliability value. Even if a coal plant weren't completely shut down, it could work in tandem with cleaner, cheaper resources fed through the same point of interconnection to deliver cheaper, cleaner electricity without materially affecting the transmission system and system operations (it might even improve these). Utilities, ISO/RTOs, and state and federal regulators should move swiftly to develop standard templates that allow for coal plant hybridization or replacement with clean portfolios. These templates would have to be generically robust enough to satisfy system reliability and stability concerns under a variety of conditions to replace coal without a lengthy interconnection process.[xvii]

Proactively pursuing transition

Re-evaluation of integrated resource plans and improving competitive procurement

While measures to proactively plan for and better accommodate new renewable projects are necessary to capture the huge economic benefits of transitioning expensive coal plants to cheaper renewables, they are not sufficient. Utility integrated resource plans routinely overestimate new renewable costs, and the IRA programs will likely make these overestimations even higher. Any

[xvii] There may be concerns about undermining competition if some resources are allowed to skip ahead of the line, but presumably standard templates will involve costlier investments than what might be proscribed in a more specific interconnection study. In any case, it makes sense to recognize that providing replacement resources at or near an existing resource is easier and simpler for the network, and the benefits of just transition and accelerated deployment should be balanced against competition concerns.

investment plan or market-based solicitation for renewable contracts completed before August 2022 is now out of date. Regulators can expect independent power producers to offer lower bids for just about any clean energy technology. Under their authority to set just and reasonable rates, PUCs should insist that utilities redo integrated resource plans and resource solicitations, despite the procedural complexity. For example, advocates have already submitted evidence to the North Carolina Utility Commission that such a re-examination would be prudent for Duke Energy's Integrated Resource Plan and Carbon Plan.[32]

In addition to cost updates, integrated resource plans should account for the benefits of location-based procurement to replace coal generation. In New Mexico, the Energy Transition Act required the Public Service Company of New Mexico to site some of the replacement resources for the San Juan Generating Station in the nearby school district to replace lost tax revenue.[33] Because of location-specific tax credit bonuses, traditional regulatory requirements to minimize consumer costs now require an examination of local investment in replacement wind, solar, and battery resources.

FERC and NERC should work with the ISO/RTOs to create standardized approaches to gradual replacement with local resources and eventual development of reliable resource portfolios that include renewables, transmission, and emerging technologies like power electronics and synchronous condensers.

In addition to accurately assessing renewables during planning processes, enabling competitive procurement is crucial to getting steel in the ground. Even before the IRA, unsubsidized renewables were the cheapest new resource in most of the country. However, regulators can have difficulty discerning the true cost of clean energy or comparing variable clean resources with dispatchable fossil power providing different services. Such assessments generally depend on limited utility information.

All-source procurement is a way around this—it is a well-established but underutilized process that requires the utility to provide assessments of resource need, then bid these services to the market. For example, Xcel Energy Colorado achieved record-low wind, solar, and storage prices that shocked the electricity world with an all-source procurement in 2018, avoiding costly investments in gas and accelerating coal retirement.[34] PUCs should establish all-source procurement rules that link these solicitations as inputs to integrated resource planning processes that ultimately result in resource procurement—a key part of the Colorado planning process.[35] These solicitations also provide the opportunity to assess and define needed system reliability attributes after coal plants retire and allow supply-side, demand-side, transmission expansion, and regional market resources all compete to fill that need.[36]

Utilizing IRA funding and financing programs

Our comparison of the going-forward costs of existing coal plants with regional or local renewables doesn't capture all the economic advantages of such a transition. The IRA also includes measures that facilitate savings from lower cost financing.

First, the IRA created a $9.7 billion fund for rural electric cooperatives to reduce GHG emissions via a myriad of methods. With cooperative assets highly tied up in coal and without the same access to capital as investor-owned utilities, the transition to cheaper clean resources can be particularly challenging. To take advantage of these funds as soon as possible, co-ops should develop clear plans that use new clean energy and coal generation replacement to achieve deep GHG emissions reductions, in accordance with the IRA's statutory language.[37] For their part, states should provide resources to support the planning and application processes. With nearly 18 GW of plants in this analysis majority-owned by cooperatives, this program, if used to its greatest potential, could spur billions in rural economic development.

In addition to rural cooperative funding, the IRA provides substantial debt refinancing potential, when paired with reinvestment in new clean energy infrastructure. While we find all but one plant are uneconomic when compared to replacement with new wind and solar, many plants have large debt burdens that hamper the customer savings available from clean energy replacement. Some states have explicitly allowed utilities to refinance these remaining balances via securitization, but now all power plant owners have access to flexible low-cost capital to finance new clean energy projects reusing coal-

Cleaning up coal ash at the G G Allen Steam Plant

In 2014, the now-retired Dan River Power Station leaked 39,000 tons of coal ash into the Dan River—leaving residents without drinking water for years and requiring a $3 million clean-up. It also kicked off an investigation of Duke Energy in North Carolina that found all 14 coal plants in the state were leaking coal ash. G G Allen has the largest amount of coal ash on site out of all the plants with 19 million tons of that need to be removed. In addition to this high pollution impact, it is also the second most expensive coal plant to run in the U.S. according to our analysis. But it needn't be this way. North Carolinians can have clean air and water with cheaper clean energy. All four renewable scenarios in our analysis were cheaper than running the G G Allen plant. In addition to clean energy replacement, the use of a DOE loan guarantee could save ratepayers even more by using low-cost financing for replacement infrastructure including the coal ash remediation.

plant infrastructure via the DOE's new loan program.[38] PUCs should require utilities to update prior investment and coal retirement plans to reflect the low-cost capital now available for reinvestment in communities.

Particularly for independent power producers, which own 23 percent of the coal capacity we studied, these DOE loans will be significantly cheaper than those without government backing. The loan guarantee must be used to reduce GHG emissions and reinvest in that same community.[39] Funds can be used for a wide range of applications including partial or full coal replacement with renewable resources, transmission and storage, and even remediation of former fossil fuel sites, improving environmental conditions and serving as another source of job creation for the local community. Given the flexibility of the program, this is far from an exhaustive list.To smooth community transition, loans need not require immediate plant retirement, but instead could support projects that gradually reduce coal while increasing renewable generation and diversifying the community's economy.[40] The local renewable replacement plus storage scenario we study fits this approach.

Just transition in Colorado

In 2019, the Colorado legislature passed a bill creating the first Office of Just Transition (OJT), and just in time. With six coal mines and seven coal-fired power plants still operating, small communities, particularly in Western Colorado, risked near-total economic collapse. Since the legislation passed, the OJT created a Just Transition Action Plan to support economic diversification and job retraining. The town of Nucla illustrates how this plan can work. When their coal plant shut down three years ahead of schedule, it was the largest employer. The plant also provided nearly half the tax revenue that supported the whole region—including the fire department and school district. Residents were rightfully concerned, but Nucla has worked with OJT to transition their economy to focus on tourism and small businesses. Nucla still has a way to go and more funding is needed, but Nucla shows how pre-emptive planning can help ease the sting of coal closures. Now, newly appropriated OJT funds will continue to help Nucla restructure while preparing other Colorado coal communities.

Just transition for affected communities

State PUCs, legislatures, and state energy offices all have a role to play ensuring a just transition for coal communities. New IRA funding mechanisms mean traditional, least-cost utility planning practices now require reinvestment in communities whose economic prosperity depends on coal plants and coal mining. Assessing and including reinvestment in

these places is now essential to "least cost, best fit" resource planning.

Of course, the nuances of community needs are more complex than simple economics, and fully considering viable transition strategies in integrated resource plans is not possible unless state regulators and utilities seek input from affected communities at the beginning of the planning process. Seeking community input is not typically part of existing integrated resource planning processes, and it can be challenging for resource-constrained PUCs or utilities to incorporate new, innovative approaches to stakeholder engagement and ultimately community transition.[41]

State legislation should require PUCs and utilities to plan for community transition and assess the value of federal loan guarantees and tax credits for community transition, starting with outreach in an investigatory proceeding that provides access by holding commission forums in those communities. With this input, utility investment plans can better meet community economic needs, which can include tax revenue, workforce development, infrastructure investment, pollution clean-up, and community ownership models like community solar.

While the IRA has several reinvestment programs, energy communities cannot rely on clean energy alone to fully replace coal jobs and tax revenue. However, local clean energy can provide the opportunity for additional industrial development if new data centers or industrial facilities like synthetic fuel producers seek direct on-site access to low-cost clean energy. Proactive diversification of local economies is another path for success, which would benefit from state resources. The transition can even begin before the plant retires—gradual replacement and interconnection could ramp up in anticipation of the plant's eventual retirement, growing jobs and reducing pollution along the way.

Legislators should consider creating and funding a just transition office, following Colorado's example, to help coal communities develop transition plans. In addition to these legislative actions, PUCs can consider putting community transition funding into rates or creating ratepayer and shareholder cost sharing arrangements, similar to the arrangement made following closure of the coal plant in Colstrip, Montana.[42]

CONCLUSION

The economic case for replacing highly polluting and expensive coal-fired generation with clean energy is stronger than ever. Our new analysis, based on 2021 data, already surpasses our previous projection for 2025, finding that 99 percent of all U.S. coal plants are more expensive to run compared to new clean energy generation. Local replacement is more attractive than ever due to the IRA's new incentive and funding programs. Including battery storage along with local renewable generation can be an economic way to bolster the reliability value that these renewable projects provide to the grid. Building new wind or solar before completely retiring existing coal can be a recipe for success, a paradigm supported by the DOE's new loan authority. The near-complete crossover of coal economics versus renewables makes the imperative to transition clearer than

ever before, but policymakers, utilities, consumers, and coal-dependent communities must recognize the benefits and seize this moment.

APPENDIX: DETAILED METHODOLOGY

Coal Costs

Our goal was to develop an accurate estimate of the going-forward cost of running U.S. coal plants using publicly available data from EIA, FERC, and EPA. In assembling a master list of U.S. coal plants, we restricted ourselves to plants running mostly coal (excluding wood waste and petroleum coke burning units) operated by utilities and independent power-producers (sectors 1 and 2, in EIA parlance), excluding plants used for combined heat and power, for which the economics are more complicated because these plants receive other revenues from providing heat.

As a matter of convenience, we limited ourselves to coal plants in the lower 48 states and excluded a few plants for various practical reasons like corrupted or unavailable data. The companion spreadsheet to this report lists these in detail. In any case, these cuts did not materially reduce the number of GWs of capacity we covered. Finally, we grouped boilers and generating units together at one location as single plants, while excluding boilers and generating units fueled mostly with natural gas. The final master list of 210 coal plants is available in the companion spreadsheet to this report.

The going-forward cost for each coal plant in our master list comprises three principal components

- The cost of fuel on a per MWh of coal generation basis.
- The operation and maintenance cost of each plant levelized over the total generation from each included boiler and generating unit.
- The average annual going-forward costs for capital investments needed to replace and upgrade part of the power plant levelized over the total generation from each included boiler and generating unit.

This Appendix reviews our methodology for each of these three elements in more detail.

Cost of Fuel

Our principal method for calculating fuel cost for any given coal plant comes from first computing its cost of energy inputs in dollars per million British Thermal Units ($/mmBTU). We need a heat rate in mmBTU/MWh to convert this input into a cost of delivered energy in $/MWh. The heat rate is a number particular to any given plant that varies according to any number of contextual factors (e.g., fuel-type, technology, age, outside temperature, capacity factor). As a matter of simple expediency, we use a heat rate for each power plant defined by the sum of BTUs from all non-

natural gas fuels burned at that plant in 2021 divided by all the net-generation from these fuels as defined in the first page of EIA Form 923. We used this to convert input fuel costs into output electricity fuel costs.

We then used EIA data on fuel contracts paid by the plant; listed on page 5, "Fuel Receipts and Costs," of EIA Form 923. The EIA 923 spreadsheet lists fuel contracts with heat contents (mmBTU per fuel unit) and price paid in cents per mmBTU. From these contracts we can establish an mmBTU-weighted cost per mmBTU for coal, which we use as an input cost for that plant. Note that this does not include fuel processing costs that might be covered in values reported to FERC. Probably the most important example of fuel processing comes from plants that report burning so-called "refined coal" on one part of Form 923 while at the same time reporting direct purchases of other coal, e.g., bituminous coal, on another part of the form. This discrepancy is due to the fact that "refined coal" involves processing purchased coal (usually by spraying it with certain chemical agents) to reduce emissions from the smokestack. It is hard to know how much this extra processing costs on a per mmBTU basis, but we understand that the economic rationale for doing so is driven mostly by a tax credit. Historical trend analysis of some plants that burn "refined coal" shows that they sometimes choose to apply this processing and sometimes not reflecting, in our opinion, the likelihood that there is only a small impact on fuel costs to "refining" after netting out processing costs and tax credit income.

For plants that do not report input fuel costs to a regulator, however, other less plant-specific sources of information were required. In these cases, instead of specifically reported plant data, we used state-based data on the average cost of coal from EIA. To accurately reflect the diversity of coal types and relative mix of types that various plants consume, we used a combination of total plant coal consumption and state average coal costs from EIA as well as historical fuel consumption trends at the plant to estimate source coal type and marginal fuel costs. We used the following procedure:

Step 1: Extract the various mmBTU quantities of coal by type used by the boilers in each coal plant of interest from the 2021 EIA Form 923.

Step 2: Link each coal type with a state benchmark input fuel price in $/mmBTU. We establish that benchmark price by combining information on electric power sector coal prices by coal type and plant state from EIA's Coal Data Browser with coal heat content (mmBTU/ton) by state and coal type, also from EIA's Coal Data Browser (if heat content for a given coal type was unavailable for the 2021 reporting year, we used the most recent year).

Step 3: Tag "refined coal." One type of coal that appears in boiler consumption figures but not price tables is "refined coal." To price this type of consumption, we assigned each instance of "refined coal" to a coal sub-type. Depending on the plant, the source coal for "refined coal" might be bituminous, sub-bituminous, or lignite. With some painstaking work, we were able to infer from other nearby plants and historical fuel consumption trends at the plant which coal type was being refined with high confidence.

Step 4: Combine coal types to get a plant fuel cost. We combined price and consumption levels at each plant to get a weighted fuel input cost in $/mmBTU. We then converted this to $/MWh using the heat rate—just like the plants that report their input fuel costs.

Operation and Maintenance Costs

We used plant-by-plant operation and maintenance estimates obtained from the Electricity Market Module (EMM) in EIA's North American Energy Modeling Systems (NEMS). For some plants, no NEMS value for operation and maintenance was available and we used a national average value.

Going forward capital costs — National Energy Modeling System (NEMS)

The third element in our overall coal going-forward cost estimate is the going-forward capital cost. For this element we used a fairly simple method. We started by taking the average age (weighted by generator capacity) of a given coal power plant and compared it to the EIA NEMS table found in Figure 12. From this NEMS table and the average age of the plant, we obtained a per kW-year going-forward cost, which we multiplied by the overall capacity of the plant. We then divided by the total net MWh output from the plant (defined by the included set of generators) as reported on EIA Form 923. This includes any natural gas-fueled generation and results in a $/MWh, which then factors into the complete coal going-forward cost.

Age	Annual Capital Investment Requirement ($/kW-yr)
0 - 10 years	$ 17.16
10 - 20 years	$ 18.42
20 - 30 years	$ 19.68
30 - 40 years	$ 20.94
40 - 50 years	$ 22.20
50 - 60 years	$ 23.46
60 - 70 years	$ 24.72
70 - 80 years	$ 25.98

Figure 12. NEMS estimates of going forward capital costs by age of plant.

Renewables Costs

Identifying Renewable Energy Sites

We use NREL's ReEDS model that provides high spatial resolution solar and wind potential datasets in the U.S. The solar and wind potential numbers in ReEDS are, in turn, taken from the Renewable Energy Potential (ReV) model, which assesses the wind and solar energy potential at 11.2 km x 11.2 km spatial resolution after applying comprehensive exclusion criteria, including land cover, elevation, slope, environmentally sensitive areas, local siting regulations, etc. Across the continental U.S., ReV and ReEDS identify nearly 50,000 individual solar sites totaling a potential of 96,000 GW, and around 50,000 individual wind sites totaling a potential of 6,600 GW. The ReEDS model also provides annual capacity factors at each of these sites, which are estimated using the wind speed, solar irradiance, temperature, and other weather parameters from the Wind

Integration National Dataset (WIND) and National Solar Radiation Database (NSRDB). More information on this can be found in ReEDS documentation.

Technology Costs

We run the ReEDS model using technology costs from ATB 2022 and IRA incentives and estimate the wind and solar LCOE at each of the 50,000 sites. ReEDS uses a comprehensive list of parameters to estimate a site-specific LCOE including capital costs, fixed operation and maintenance costs, equity costs, interest rates, construction costs differentiated by location across the U.S., construction period, ITC and PTC incentives per IRA, tax equity haircuts, depreciation, and taxes (see Figure 13). Additional details on LCOE estimation could be found in ReEDS documentation.

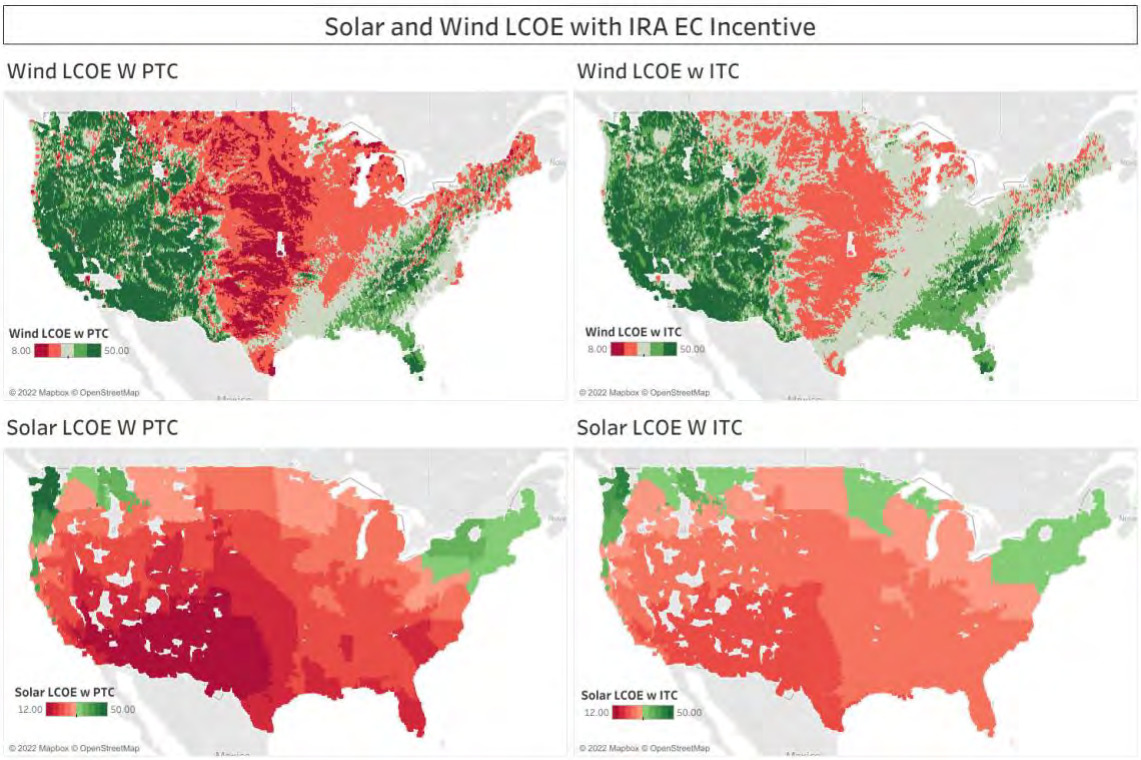

Figure 13. Wind and Solar LCOE including IRA incentives (including energy community) at each of the individual 50,000 sites across the U.S.

Assessing Hyperlocal Potential and LCOEs

The objective of this exercise is to assess the physically closest (hyperlocal) solar or wind resources that could replace the generation from each coal power plant in the country. We start with the location (latitude and longitude) of each of the 210 coal plants in the US. We then create concentric circles around each coal plant with radiuses starting from 5 km up to 45 km in increments of 5 km. Within each of these concentric circles, we identify the solar and wind sites that fall within that circle and estimate the site-level capacity and annual generation potential for solar and wind resources separately, using the high-resolution solar and wind datasets available from ReEDS, as described earlier. We then estimate the minimum circle radius ("hyperlocal circle") needed to replace the annual generation from each coal power plant with solar or wind resources. Within each hyperlocal circle, we assume that the solar and wind projects get the Energy Community Tax Credit per IRA and will not incur any interconnection costs since they could continue using the coal plant interconnection. We weight the site-level LCOEs within each hyperlocal circle by the site-level capacity potential to arrive at a weighted average hyperlocal LCOE to replace the generation from each coal power plant.

We find that annual generation at almost all coal power plants can be cost-effectively replaced by solar resources within a 20 km radius. The minimum radius for wind is much higher.

Regional LCOEs

In addition to the hyperlocal LCOEs, we also estimate the regional LCOEs in the regions where coal plants are located. The ReEDS model divides the contiguous U.S. into 134 regions which are generally aligned with the utility territories (see Figure 14). These regions never cross state boundaries

The rationale for estimating the regional LCOEs in addition to the hyperlocal LCOEs is that the higher-quality resources might not be available in the near vicinity of the coal plants but slightly farther away, and so from the perspective of the developer, it might make sense to move further from the coal plants to access the higher quality resource. This is more important for wind as wind speeds can vary significantly over short distances. As compared to wind, solar is more energy dense, as we can get almost 10 times the capacity of solar in the same amount of land as wind.

The methodology used for estimating regional LCOEs is very similar to that of hyperlocal LCOEs. For each coal plant, we sort the wind and solar sites available in that region (i.e., ReEDS balancing area) by LCOE and choose the best sites to replace the coal generation. For selected sites within each region, we capacity-weight the site-level LCOEs to estimate the weighted average regional LCOE. For the regional LCOE, we do not account for the Energy Community tax credit available in IRA. We also add the interconnection costs to the LCOEs as we assume that these sites may not be able to access the existing coal power plant interconnection.

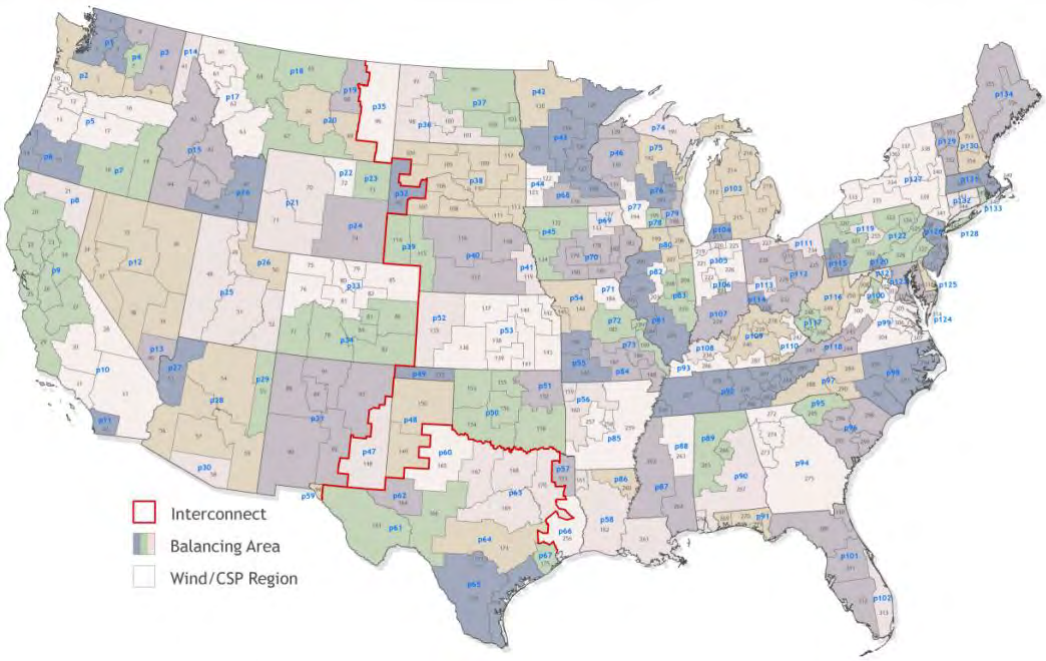

Figure 14. ReEDS balancing areas, used for our regional analysis and roughly corresponding to utility service territories, are highlighted by the different colors in this map. Source: National Renewable Energy Laboratory.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Midcontinent	)
Independent System Operator	)
(MISO)	)
	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 52

MI State Energy Profile

U.S. Energy Information Administration

Michigan State Energy Profile

Michigan Quick Facts

- Michigan has 44 natural gas storage fields with almost 1.1 trillion cubic feet of underground storage capacity, which is the most capacity of any state and almost one-eighth of the nation's total natural gas storage capacity.
- The share of Michigan's total electricity generation from natural gas-fired plants increased from 12% in 2013 to 46% in 2023.
- Renewables provided 11% of Michigan's electricity net generation in 2023, with wind energy providing 64% of that power. Michigan ranks 16th among the states in the amount of electricity generated by wind energy.
- Michigan ranks fifth among the states in residential sector petroleum use and is first in residential sector consumption of propane.
- Michigan’s second-largest power plant by capacity is the 2,186-megawatt Ludington pumped-storage plant on the shores of Lake Michigan. It is one of the 10 largest pumped-storage power plants in the world.

Last Updated: October 17, 2024

- Consumption by Source
- Consumption by Sector
- Production
- Electricity
- Prices

Data

Last Update: May 15, 2025 | **Next Update:** June 20, 2025

Energy Indicators

Demography	Michigan	Share of U.S.	Period
Population	10.1 million	3.0%	2024
Civilian Labor Force	5.1 million	3.0%	Mar-25
Economy	**Michigan**	**U.S. Rank**	**Period**
Gross Domestic Product	$ 659.0 billion	14	2023
Gross Domestic Product for the Manufacturing Sector	$ 107,736 million	7	2023
Per Capita Personal Income	$ 59,714	40	2023
Vehicle Miles Traveled	98,289 million miles	10	2023
Land in Farms	9.4 million acres	30	2024
Climate	**Michigan**	**U.S. Rank**	**Period**
Average Temperature	48.9 degrees Fahrenheit	37	2024
Precipitation	34.4 inches	35	2024

Prices

Petroleum	Michigan	U.S. Average	Period	find more
Domestic Crude Oil First Purchase	$ 64.24 /barrel	$ 70.11 /barrel	Feb-25	
Natural Gas	**Michigan**	**U.S. Average**	**Period**	find more
City Gate	$ 4.00 /thousand cu ft	$ 4.83 /thousand cu ft	Feb-25	find more
Residential	$ 9.55 /thousand cu ft	$ 12.94 /thousand cu ft	Feb-25	find more
Coal	**Michigan**	**U.S. Average**	**Period**	find more
Average Sales Price	--	$ 54.04 /short ton	2023	
Delivered to Electric Power Sector	W	$ 2.41 /million Btu	Feb-25	
Electricity	**Michigan**	**U.S. Average**	**Period**	find more
Residential	18.91 cents/kWh	16.44 cents/kWh	Feb-25	find more
Commercial	14.05 cents/kWh	13.09 cents/kWh	Feb-25	find more
Industrial	8.54 cents/kWh	8.23 cents/kWh	Feb-25	find more

Reserves

Reserves	Michigan	Share of U.S.	Period	find more
Crude Oil (as of Dec. 31)	46 million barrels	0.1%	2022	find more
Expected Future Production of Dry Natural Gas (as of Dec. 31)	1,302 billion cu ft	0.2%	2022	find more
Expected Future Production of Natural Gas Plant Liquids	11 million barrels	*	2022	find more
Recoverable Coal at Producing Mines	--	--	2023	find more
Rotary Rigs & Wells	**Michigan**	**Share of U.S.**	**Period**	find more
Natural Gas Producing Wells	1,308 wells	0.3%	2020	find more
Capacity	**Michigan**	**Share of U.S.**	**Period**	
Crude Oil Refinery Capacity (as of Jan. 1)	140,000 barrels/calendar day	0.8%	2024	
Electric Power Industry Net Summer Capacity	31,538 MW	2.6%	Feb-25	

Supply & Distribution

Production	Michigan	Share of U.S.	Period	find more
Total Energy	562 trillion Btu	0.6%	2022	find more
Crude Oil	11 thousand barrels per day	0.1%	Feb-25	find more
Natural Gas - Marketed	68,132 million cu ft	0.2%	2023	find more
Coal	--	--	2023	find more
Total Utility-Scale Net Electricity Generation	**Michigan**	**Share of U.S.**	**Period**	find more
Total Net Electricity Generation	10,281 thousand MWh	3.0%	Feb-25	
Utility-Scale Net Electricity Generation (share of total)	**Michigan**	**U.S. Average**	**Period**	
Petroleum-Fired	0.1 %	0.4 %	Feb-25	find more
Natural Gas-Fired	35.6 %	39.0 %	Feb-25	find more
Coal-Fired	27.5 %	18.4 %	Feb-25	find more
Nuclear	22.6 %	18.2 %	Feb-25	find more
Renewables	12.4 %	23.6 %	Feb-25	

Supply & Distribution

Stocks	Michigan	Share of U.S.	Period	find more
Motor Gasoline (Excludes Pipelines)	9 thousand barrels	0.1%	Feb-25	
Distillate Fuel Oil (Excludes Pipelines)	1,641 thousand barrels	1.8%	Feb-25	find more
Natural Gas in Underground Storage	599,933 million cu ft	9.6%	Feb-25	find more
Petroleum Stocks at Electric Power Producers	157 thousand barrels	0.8%	Feb-25	find more
Coal Stocks at Electric Power Producers	2,054 thousand tons	1.9%	Feb-25	find more
Fueling Stations	**Michigan**	**Share of U.S.**	**Period**	
Motor Gasoline	3,539 stations	3.2%	2022	
Propane	87 stations	3.3%	Apr-25	
Electric Vehicle Charging Locations	1,606 stations	2.3%	Apr-25	
E85	247 stations	5.6%	Apr-25	
Biodiesel, Compressed Natural Gas, and Other Alternative Fuels	9 stations	0.2%	Apr-25	

Consumption & Expenditures

Summary	Michigan	U.S. Rank	Period	
Total Consumption	2,707 trillion Btu	10	2022	find more
Total Consumption per Capita	270 million Btu	28	2022	find more
Total Expenditures	$ 46,032 million	9	2022	find more
Total Expenditures per Capita	$ 4,588	41	2022	find more
by End-Use Sector	**Michigan**	**Share of U.S.**	**Period**	
Consumption				
» Residential	754 trillion Btu	3.9%	2022	find more
» Commercial	579 trillion Btu	3.5%	2022	find more
» Industrial	664 trillion Btu	2.1%	2022	find more
» Transportation	711 trillion Btu	2.6%	2022	find more
Expenditures				
» Residential	$ 11,064 million	3.3%	2022	find more

Consumption & Expenditures

» Commercial	$ 7,148 million	2.9%	2022	find more
» Industrial	$ 6,267 million	2.2%	2022	find more
» Transportation	$ 21,553 million	2.5%	2022	find more
by Source	**Michigan**	**Share of U.S.**	**Period**	
Consumption				
» Petroleum	163 million barrels	2.2%	2023	find more
» Natural Gas	1,048 billion cu ft	3.2%	2023	find more
» Coal	14,516 thousand short tons	3.4%	2023	find more
Expenditures				
» Petroleum	$ 21,905 million	2.4%	2023	find more
» Natural Gas	$ 7,382 million	3.7%	2023	find more
» Coal	$ 979 million	4.1%	2023	find more
Consumption for Electricity Generation	**Michigan**	**Share of U.S.**	**Period**	find more
Petroleum	13 thousand barrels	0.6%	Feb-25	find more
Natural Gas	25,619 million cu ft	2.7%	Feb-25	find more
Coal	1,558 thousand tons	4.4%	Feb-25	find more
Energy Source Used for Home Heating (share of households)	**Michigan**	**U.S. Average**	**Period**	
Natural Gas	74.0 %	46.0 %	2023	
Fuel Oil	0.8 %	3.7 %	2023	
Electricity	12.7 %	41.7 %	2023	
Propane	9.1 %	5.0 %	2023	
Other/None	3.4 %	3.5 %	2023	

Environment

Renewable Energy Capacity	**Michigan**	**Share of U.S.**	**Period**	find more
Total Renewable Energy Electricity Net Summer Capacity	5,826 MW	1.6%	Feb-25	
Ethanol Plant Nameplate Capacity	346 million gal/year	1.9%	2024	
Renewable Energy Production	**Michigan**	**Share of U.S.**	**Period**	find more

Environment				
Utility-Scale Hydroelectric Net Electricity Generation	101 thousand MWh	0.5%	Feb-25	
Utility-Scale Solar, Wind, and Geothermal Net Electricity Generation	1,004 thousand MWh	1.8%	Feb-25	
Utility-Scale Biomass Net Electricity Generation	169 thousand MWh	4.6%	Feb-25	
Small-Scale Solar Photovoltaic Generation	23 thousand MWh	0.4%	Feb-25	
Fuel Ethanol Production	7,903 thousand barrels	2.2%	2022	
Renewable Energy Consumption	**Michigan**	**U.S. Rank**	**Period**	find more
Renewable Energy Consumption as a Share of State Total	7.4 %	28	2022	
Fuel Ethanol Consumption	10,287 thousand barrels	9	2022	
Total Emissions	**Michigan**	**Share of U.S.**	**Period**	find more
Carbon Dioxide	154.0 million metric tons	3.1%	2022	
Electric Power Industry Emissions	**Michigan**	**Share of U.S.**	**Period**	find more
Carbon Dioxide	50,018 thousand metric tons	3.3%	2023	
Sulfur Dioxide	31 thousand metric tons	3.7%	2023	
Nitrogen Oxide	43 thousand metric tons	3.8%	2023	

Analysis

Last Updated: October 17, 2024

Overview

Known as the Great Lakes State, Michigan's shores touch and include portions of four of the five Great Lakes.[1] The northern ends of two Great Lakes—Lake Michigan and Lake Huron—divide Michigan into the Upper and Lower Peninsulas. The northern shore of the Upper Peninsula is bordered by Lake Superior and a small portion of the southeastern shore of the Lower Peninsula touches Lake Erie.[2,3] The state‘s geologic history includes ancient broad shallow seas in a basin that was centered in Michigan's Lower Peninsula.[4] That basin was ringed by reefs that, now deeply buried, contain most of the state's crude oil and natural gas reserves.[5] In addition to Michigan's natural gas and crude oil, the state has many renewable energy resources. Winds that sweep across the Great Lakes provide the state with substantial offshore wind energy resources and moderate onshore ones.[6] Forests cover more than half of the state's land area and many cities and large towns provide municipal solid waste and landfill gas, giving Michigan considerable biomass resources.[7,8] Dams on the state's rivers generate hydroelectric power, despite the generally level terrain.[9] Most of those dams, including all of the largest ones, are in the Lower Peninsula, where Michigan's largest and longest rivers are located.[10,11]

Most of Michigan's population and all of the major cities, manufacturing industries, commercial agriculture, crude oil production, and natural gas production are located in the state's Lower Peninsula.[12,13] The Upper Peninsula is lightly populated, heavily forested, and contains valuable iron and copper deposits.[14,15,16] With 40,000 square miles of the Great Lakes and thousands of smaller inland lakes and ponds within Michigan's borders, the state's total area is more than two-fifths water—the largest land-to-water ratio among all states.[17,18] As a result, Michigan has one of the longest shorelines in the United States. Vessels that move through the Great Lakes-Saint Lawrence Seaway deliver coal and refined petroleum products at several of the state's Great Lakes ports.[19,20,21]

Michigan consumes almost five times more energy than it produces and ranks 10th among the states in both population and total energy consumption.[22,23,24] Although the Great Lakes moderate Michigan's temperatures, extremes occur in the interior of the Lower Peninsula. However, snowfalls are greatest on the Upper Peninsula and along the Lake Michigan shoreline of the Lower Peninsula.[25] In part because of its cold winters, Michigan is among the top 10 states in per capita residential energy use, but the state's total energy use per capita is below the U.S. average.[26] The residential sector is the leading energy-consuming sector, accounting for 28% of the state's total energy use, followed closely by the transportation sector at 26%, the industrial sector at 25%, and the commercial sector at 21%.[27] Detroit is known as Motor City, and Michigan employs the largest number of workers in the motor vehicles and parts manufacturing sectors in the nation.[28,29] This sector accounts for nearly two-fifths of the state's manufacturing GDP. Other important contributors to the state's GDP include the manufacture of machinery, fabricated metal products, chemicals, food and beverage products, and plastics.[30] Michigan does not have any significant critical mineral deposits, but is a major producer of cement, construction sand, and gravel.[31]

Michigan ranks 10th among the states in total energy use.

Natural gas

The Antrim Shale formation sweeps along a narrow arc in the northern portion of the Lower Peninsula and contains most of Michigan's natural gas reserves, and the state holds about 0.2% of U.S. total proved reserves.[32,33,34] Michigan's natural gas production has declined from its 1997 peak of nearly 312 billion cubic feet to 68 billion cubic feet in 2023, making up 0.2% of total U.S. production.[35,36]

Several interstate pipelines cross Michigan, as well as five U.S.-Canadian natural gas pipeline border crossings, but the state does not have any natural gas market hubs.[37] Natural gas enters Michigan from Ohio, Wisconsin, and Indiana. While some natural gas also arrives by pipeline from Canada, the bulk of the natural gas flowing across the border goes to Canada, most of it at St. Clair, located northeast of Detroit. Smaller volumes of natural gas also intermittently enter Canada at the Detroit, Sault St. Marie, and Marysville border crossings.[38,39,40] More natural gas enters Michigan than is consumed in the state, and most of the excess is exported to Canada.[41,42]

Some of the natural gas that Michigan receives or produces is injected into underground natural gas storage fields. Michigan has the largest underground natural gas storage capacity in the nation at nearly 1.1 trillion cubic feet, which is almost one-eighth of the U.S. total. The state has 44 natural gas storage fields, the second-largest number after Pennsylvania.[43,44] During high demand periods, typically between November and April, natural gas is withdrawn from storage to meet increased demand for space heating. Much smaller volumes of natural gas are withdrawn from storage in the summer months when natural gas-fueled power generation increases to meet cooling demand.[45,46]

Michigan has the largest underground natural gas storage capacity in the nation.

In 2023, Michigan's total natural gas consumption was 15 times greater than the state's natural gas production.[47,48] The electric power sector became the largest consumer of natural gas in the state in 2023, surpassing the residential sector for the first time and making up two-fifths of total natural gas use. The residential

sector, where almost 8 out of 10 Michigan households use natural gas as their primary source for home heating, accounted for about three-tenths of the state's natural gas consumption.[49,50] Michigan routinely ranks among the top 5 states in residential use of natural gas and in the top 10 for total natural gas consumption.[51,52] The commercial and the industrial sectors each account for about 16% of the state's natural gas consumption.[53]

Petroleum

Michigan's crude oil reserves and production are modest. The state's crude oil reserves and production each account for 0.1% of the nation's total.[54,55] Commercial quantities of crude oil were first found in Michigan in 1925.[56] The state's oil production substantially increased in the 1970s when oil was produced from the deeply buried reefs that ringed the Michigan Basin millions of years ago. Those reefs accounted for 29 million of the 35 million barrels of crude oil recovered in Michigan's peak production year of 1979.[57,58,59] Since then, Michigan's crude oil output has generally declined and was about 4.8 million barrels in 2023.[60]

Michigan has one crude oil refinery, located near Detroit. It can process about 140,000 barrels per calendar day of light sweet and heavy sour crude oils into gasoline, asphalt, propane, and other petroleum products.[61,62] Crude oil produced from wells in western Canada enters Michigan by pipelines through Wisconsin and Indiana. Crude oil produced in western Michigan is delivered by an intrastate pipeline to Lewiston, Michigan, where it is added into the Enbridge pipeline system that enters the state through northern Wisconsin. The Enbridge pipeline delivers crude oil to a Canadian refinery in Ontario and also has a branch that enters the state from Indiana and delivers crude oil to Michigan on its way to Ontario.[63,64,65] Michigan's governor revoked the pipeline's permit in May 2021 because of safety concerns about a potential leak where an underwater section of the pipeline crosses the Mackinac Strait between the state's Upper and Lower Peninsulas. Enbridge has refused to shut down the pipeline and the legal dispute remains. There have been discussions around building a tunnel to house the pipeline.[66,67,68] The Mid-Valley Pipeline, another crude oil pipeline that originates in the U.S. Gulf Coast states, enters Michigan through Ohio.[69] Port Huron on the Lower Peninsula receives additional crude oil imports from Canada.[70] Much of the crude oil that enters Michigan exits into Canada at a border crossing between Marysville, Michigan, and Sarnia, Ontario.[71]

Petroleum product pipelines bring refined products from the Chicago, Illinois, area to the southwest and from the Toledo, Ohio, area to the southeast of Michigan in the Lower Peninsula. The Upper Peninsula has no petroleum product pipelines, and trucks transport most petroleum products from terminals in Wisconsin.[72,73] The Lower Peninsula port cities of Port Huron and Detroit receive almost all the state's petroleum product imports from Canada. Some Canadian petroleum products also arrive at the Sault St. Marie port on the Upper Peninsula.[74]

Michigan ranks 11th among the states in total petroleum consumption. Four-fifths of the state's petroleum use is in the transportation sector, and motor gasoline accounts for 62% of that transportation petroleum consumption.[75,76] Federal regulations allow conventional motor gasoline without ethanol to be sold in most of the state year-round. However, to reduce emissions that contribute to ground-level ozone, eight southeastern Michigan counties around Detroit regulate the vapor pressure of motor gasoline sold during the summer.[77,78] The industrial sector accounts for one-tenth of the state's petroleum use. Although the residential sector accounts for only about 6% of the state's petroleum consumption, Michigan is among the top five states in residential sector petroleum consumption.[79] About 1 in 10 Michigan households heat with petroleum products, mostly propane.[80,81] Total consumption of hydrocarbon gas liquids (HGLs), such as propane, is greater in Michigan than in all but seven other states, and the state has the largest residential sector HGL consumption in the nation.[82] The commercial sector accounts for most of the rest of the state's petroleum consumption. A small amount of petroleum is used intermittently for electricity generation.[83]

Michigan has the largest residential sector consumption of hydrocarbon gas liquids, such as propane, in the nation.

Electricity

In 2023, natural gas fueled the largest share of Michigan's electricity generation at 46%, followed by nuclear power at 23%, and coal at 19%. Up until 2020, coal had provided the largest share of the state's electricity net generation.[84] Coal-fired plants make up 3 of the 10 largest power plants by generating capacity in the state, including the largest, and 4 of the top 10 were natural-gas fired.[85] Since 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned. The state's most recent operating coal-fired generating unit came online in 1990.[86] Michigan's electricity net generation from natural gas is more than four times greater in the last decade.[87] Two new natural gas-fired power plants are expected to come online by 2025, adding 1,000 megawatts of generating capacity.[88]

Michigan's in-state electricity net generation from natural gas is more than four times greater in the last decade.

Typically, 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. The state's Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022.[89,90,91] However, the new owners of the Palisades nuclear power plant are seeking to restart the plant.[92] The state currently has two operating nuclear power plants, Fermi with one reactor and Donald C. Cook with two reactors.[93]

Wind energy accounts for a small but increasing share of Michigan's electricity generation and accounted for 7% of the state's total generation in 2023. This was a slight decline from 2022, due to below normal wind speeds, despite 337 megawatts of new wind power generating capacity that came online in 2023.[94,95,96] Biomass, solar energy, gases created as byproducts of industrial processes, petroleum coke, and hydroelectric power provided most of the rest of the state's net generation.[97] Most of Michigan's power plants are located in the Lower Peninsula, where electricity demand is greatest.[98]

In 2023, Michigan ranked 11th among the states in the amount of electricity generated. Because consumption was less than generation, Michigan sent its surplus electricity out of state via the regional grid.[99,100] The commercial sector is the state's largest electricity consumer, accounting for 37% of the state's total electricity sales, followed very closely by the residential sector, with 34%. The industrial sector accounts for 29% of power sales.[101] Residential electricity sales per capita are less than in three-fourths of the states and less than the national average.[102,103] Only about 1 in 8 Michigan households rely on electricity as their primary source of energy for home heating.[104]

Electricity net generation from utility-scale solar in Michigan increased by 53% in 2023.

In July 2024, Michigan had about 1,500 public electric vehicle charging locations.[105] The majority of charging stations are located on the Lower Peninsula around Detroit, Grand Rapids, Lansing, and Kalamazoo.[106] The Charge Up Michigan Program provides grants to private and public organizations to help expand the state's electric vehicle charging network.[107]

Renewable energy

Renewable energy provided 11% of Michigan's total in-state electricity net generation in 2023, most of it from wind. In 2013, wind energy surpassed hydropower and biomass and became Michigan's largest source for renewable generation. In 2023, wind energy supplied 64% of the state's renewable electricity and about 7% of Michigan's total net generation from all sources.[108] The state's strongest onshore winds are along its curving Lake Huron and Lake Michigan coastlines.[109,110] Michigan ranks 12th in the nation in wind generation capacity and 16th in actual generation from wind energy.[111] The state has 34 wind farms with a total generating capacity of nearly 3,800 megawatts.[112] Many of

Michigan's wind farms are located between Saginaw Bay and Lake Huron in the eastern part of the state's Lower Peninsula.[113]

In 2023, biomass provided 15% of Michigan's renewable electricity generation and about 2% of the state's total generation from all sources.[114] Michigan has 35 biomass power plants with a combined generating capacity of 490 megawatts. A municipal solid waste plant in the Detroit area is one of the largest on the Lower Peninsula. The biomass plants that are fueled with wood and wood waste are primarily in more heavily forested northern Michigan, including on the Upper Peninsula. Several biomass facilities generate electricity using methane recovered from landfills.[115,116] Additionally, the state has anaerobic digesters that convert animal and food waste into biogas (methane) that is used as fuel for electricity generation.[117,118,119] Michigan's forests also provide the feedstock for the state's three wood pellet manufacturing plants that have a combined production capacity of 173,000 tons of pellets per year.[120] Wood pellets are used as fuel for electricity generation and for space heating. Wood is used for space heating by 2% of households in Michigan.[121]

Michigan has about four dozen conventional hydroelectric dams that accounted for about 1% of the state's total generation from all sources in 2023. However, the state's largest hydroelectric facility by capacity is a pumped-storage plant on the shores of Lake Michigan on the Lower Peninsula.[122,123,124] Built in 1973, Michigan's Ludington pumped storage plant has a nameplate generating capacity of about 2,200 megawatts and is one of the ten largest pumped storage power plants in the world.[125,126] During periods of low power demand, which are usually at night, less costly electricity is used to pump water from a lower reservoir to an upper reservoir. Then, during periods when power demand and electricity prices are higher, the water is released from the upper reservoir and flows down through generating turbines on its way back to the lower reservoir, producing electricity. Although the plant uses more power than it generates, it supplies power in periods of peak demand when electricity prices are highest.[127]

Michigan produces and consumes biofuels. It has four fuel ethanol production plants, all located in the southern half of the Lower Peninsula.[128] Those plants have a combined capacity of about 350 million gallons each year and produced 330 million gallons of fuel ethanol in 2022.[129,130] Michigan is among the nation's top 10 fuel ethanol-consuming states and uses more than it produces. In 2022, the state consumed about 430 million gallons of fuel ethanol.[131] Michigan's two biodiesel plants are also located on the Lower Peninsula.[132] These plants can produce 16 million gallons of biodiesel fuel each year, less than the 28 million gallons consumed in the state annually.[133,134]

In 2023, utility-scale (1 megawatt or larger) solar installations generated 1% of Michigan's total in-state electricity. The state's first utility-scale solar power facility, the 1-megawatt Domino Farms Solar, came online in 2015. In 2023, electricity net generation from utility-scale solar in Michigan increased by 53%.[135] Eleven solar farms came online in 2023, adding nearly 270 megawatts of generation capacity, including the 100-megawatt Cereal City Solar Energy Center project. An additional 1,280 megawatts of solar power capacity are expected to be added in the state by 2025.[136,137] Customer-sited, small-scale (less than 1 megawatt) solar photovoltaic (PV) generating systems, most of which are on residential and business rooftops, provided 19% of the state's total solar power.[138]

Michigan enacted a renewable energy standard (RES) in 2008 that required the state's retail electricity providers, including investor-owned electric utilities, alternative retail suppliers, electric cooperatives, and municipal electric utilities, to have at least 10% of the electricity they sold be generated by renewable energy resources by 2015. The RES goal was met, and, in December 2016, the state's RES requirement increased to 15% of electricity sales by 2021.[139] In 2020, all of Michigan's electric providers met the 15% RES.[140] Acceptable renewable energy resources for generating electricity include solar power, biomass, wind, geothermal energy, municipal solid waste, landfill gas, existing hydroelectricity, and tidal, wave, and river currents. Utilities are allowed to use energy efficiency to meet a portion of their requirements. In 2023, Michigan expanded the RES requirements, with an aim to use 100% clean energy by 2040.[141]

Coal

Michigan has a small amount of economically recoverable coal reserves, but no active coal mines.[142] However, Michigan ports, including the Port of Detroit, handled 31% of all Great Lakes coal shipments in 2023.[143] The electric power sector uses 92% of the coal consumed in Michigan to generate electricity. The industrial and commercial sectors use the other 8% to produce coke for steelmaking and for electricity and heat.[144] Most of the coal consumed in Michigan comes by rail from the West, primarily from Wyoming and Montana. Small amounts of coal also arrive from nearby states, including West Virginia, Pennsylvania, Colorado, Kentucky, Virginia, Indiana, and Illinois.[145]

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States:Electricity Transmission Lines - Ventyx, Velocity Suite;Grey Base:National

0 25 50 100 Miles

Mask	Hydroelectric Power Plant	Pumped Storage Power Plant
Surface Coal Mine	Natural Gas Power Plant	Solar Power Plant
Underground Coal Mine	Nuclear Power Plant	Wind Power Plant
Biomass Power Plant	Other Power Plant	Wood Power Plant
Coal Power Plant	Other Fossil Gases Power Plant	Petroleum Refinery
Geothermal Power Plant	Petroleum Power Plant	Strategic Petroleum Reserve

http://www.eia.gov/state/

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Midcontinent	)
Independent System Operator	)
(MISO)	)
	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 53

Consumers News Release

A key regulatory decision today cleared the way for Consumers Energy to stop burning coal to generate electricity by 2025 — 15 years faster than previously planned — and provide reliable electricity for Michigan.

The Michigan Public Service Commission (MPSC) approved Consumers Energy's agreement with a diverse group of stakeholders on updates to its Clean Energy Plan, a 20-year blueprint to meet Michigan's energy needs while protecting the environment for future generations.

A broad coalition of supporters for the plan includes customer groups, environmental organizations, MPSC staff, energy industry representatives and the Michigan Attorney General.

Consumers Energy is one of the first utilities in the nation to go coal-free.

"This is a historic moment in Michigan's clean energy transformation journey," said Garrick Rochow, President and CEO of Consumers Energy. "The Clean Energy Plan is a sea change that positions our company as a national leader and empowers us to deliver reliable energy while protecting the planet for decades to come."

The updates to Consumers Energy's Clean Energy Plan — first approved in 2019 — include:

- **COAL PLANT RETIREMENTS BY 2025:** closes all three units at the J.H. Campbell coal plant in West Olive in 2025 in addition to two units at the D.E. Karn coal plant in 2023 (as per the 2018 Clean Energy Plan) and will be among the first utilities in the nation to go coal-free by 2025.

- **SYSTEM RELIABILITY:** ensures supply reliability through the purchase of the Covert Generating Station in Van Buren County, a natural gas-fired power plant. Additionally, we plan to purchase 700 megawatts of electric capacity — roughly the equivalent of a power plant — from a variety of sources through a one-time request for proposal (RFP).

- **RISE OF SOLAR:** continues the rapid transition to clean, renewable sources by adding nearly 8,000 megawatts (MW) of solar power by 2040 ensuring 90 percent of our capacity comes from clean sources. Learn more at ConsumersEnergy.com/MiSolar (https://www.consumersenergy.com/company/electric-generation/renewables/solar-generation/farmers)

- **BATTERY DEPLOYMENT**: accelerates energy storage with a total of 75 MW of energy storage by 2027, achieving 550 MW by 2040.

- **AFFORDABLE ENERGY:** creates price stability and helps customers save an estimated $600 million dollars through 2040 compared to the current plan. Consumers Energy would also continue its successful energy waste reduction programs that have saved customers nearly $5 billion since 2009. In addition, the company has committed to continue to fund utility bill assistance programs for low-income customers.

"Together, we've created the best Clean Energy Plan for Michigan," Rochow said. "We're building a dramatically different energy landscape in which customers won't have to choose between protecting the planet and their pocketbooks. We will do both while making sure our state has the reliable power it needs."

Consumers Energy, Michigan's largest energy provider, is the principal subsidiary of CMS Energy (NYSE: CMS), providing natural gas and/or electricity to 6.8 million of the state's 10 million residents in all 68 Lower Peninsula counties.

# # #

Media Contacts: Katie Carey, 517-740-1739, or Brian Wheeler, 517-740-1545

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Federal Power Act Section 202(c)	)
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Exhibit 54

NARUC Coal Report

Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices

National Association of Regulatory Utility Commissioners | January 2020

Phillip Graeter, Energy Ventures Analysis, Inc.

Seth Schwartz, Energy Ventures Analysis, Inc.

EXHIBIT 15: TYPICAL STARTUP AND CYCLING COSTS FOR A MEDIUM-SIZED COAL-FIRED POWER PLANT ($2019)[19]

Type of Start	Cost category	Cost estimates ($/MW)		
		Expected	Low	High
Hot Start (1–23 h offline)	Maintenance and capital	$ 128	$ 102	$ 162
	Forced outage	$ 60	$ 48	$ 76
	Start-up fuel	$ 20	$ 14	$ 30
	Auxiliary power	$ 11	$ 8	$ 13
	Efficiency loss from low and variable load operation	$ 5	$ 4	$ 8
	Water chemistry cost and support	$ 1	$ 1	$ 2
	Total cycling cost	**$ 225**	**$ 178**	**$ 291**
Warm Start (24 - 120 h offline)	Maintenance and capital	$ 137	$ 109	$ 170
	Forced outage	$ 65	$ 51	$ 80
	Start-up fuel	$ 43	$ 30	$ 57
	Auxiliary power	$ 23	$ 18	$ 28
	Efficiency loss from low and variable load operation	$ 6	$ 5	$ 9
	Water chemistry cost and support	$ 6	$ 4	$ 9
	Total cycling cost	**$ 277**	**$ 217**	**$ 351**
Cold Start (> 120 h offline)	Maintenance and capital	$ 205	$ 162	$ 255
	Forced outage	$ 96	$ 76	$ 120
	Start-up fuel	$ 64	$ 45	$ 24
	Auxiliary power	$ 29	$ 23	$ 36
	Efficiency loss from low and variable load operation	$ 6	$ 5	$ 10
	Water chemistry cost and support	$ 17	$ 13	$ 21
	Total cycling cost	**$ 417**	**$ 325**	**$ 465**
Load follow down to 36% of Capacity	Maintenance and capital	$ 20	$ 12	$ 31
	Forced outage	$ 9	$ 6	$ 15
	Efficiency loss from low and variable load operation	$ 1	$ 1	$ 2
	Mill cycle gas	$ 2	$ 19	$ 50
	Total cycling cost	**$ 32**	**$ 19**	**$ 50**

As shown in **Exhibit 15,** expected costs for cold starts can be almost double the startup cost for a hot start when the remaining temperature in the boiler and turbine system are still significantly higher. However, even hot starts can range from $89,000 to $145,500 per start for a 500 MW coal-fired EGU. These costs can also vary significantly between coal units based on differences in boiler size and design (subcritical vs. supercritical). The highest cost

19 Source: Lefton S A, Hilleman D (2011). *Make your plant ready for cycling operations.* http://www.powermag.com/make-your-plant-ready-for-cycling-operations/

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Federal Power Act Section 202(c)	)
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Exhibit to
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Exhibit 55

IEA Flexibility Report

Increasing the flexibility of coal-fired power plants

Colin Henderson

September 2014

© IEA Clean Coal Centre

4 Increasing flexibility – turbine and water-steam systems

There is much that can be done to make these areas of a plant more durable, able to respond faster and suffer less efficiency losses. Examples are given in this chapter.

4.1 Reducing stresses during start-up

Start-up, especially from cold, places particularly large stresses on many parts of a coal-fired plant. The turbine is no exception in this regard. Very rapid temperature changes need to be kept to the minimum, while component designs can be adapted to suit. Lindsay and Dragoon (2010) have collected together data from published sources on start-up times for different plant conditions. They found that, generally, coal plants required approximately 12 hours to cold start, 4 hours to warm start, and 1 hour to hot start. There was considerable variation, and this was believed to stem from how hot, warm, and cold starts were defined, and whether those times were actually equipment-limited or not.

One of the requirements for flexibility in the turbine is that the very small clearances between stationary and moving components remain almost constant during output changes. This requires careful design, advanced sealing (*see also* Henderson, 2013) and measures for ensuring uniform thermal loading and applies especially during cold start-up operations (Quinkertz and others, 2008).

Turbine bypass systems are a necessity in plants designed for two-shift (on/off) and other flexible forms of operation. They allow all or part of the steam to bypass the HP turbine or LP turbine so that the rate of steam temperature change in the turbine can be managed as the boiler is starting up and shutting down. This allows thermal stresses in the turbine to be reduced (Lindsay and Dragoon, 2010). This is not to be confused with another type of bypass (HP stage bypass), that can be installed for frequency control in new plants and is described later.

The very high temperature and pressure conditions of USC systems necessitate use of thick-walled components so that they possess adequate strength. Unfortunately, this can limit the rate of temperature change consistent with reducing thermal fatigue to acceptable levels. In the turbine, one means used to counter this is steam cooling of the outer casing to keep its temperature 30–40°C lower than that of the inner casing at the corresponding position along the turbine during load changes. The steam for this is bled radially from points along the inner casing. The steam reduces temperature extremes in the outer casing and allows its thickness to be reduced. The result is that cold start-up time is reduced by almost 50% (Almstedt and others, 2007).

4.2 Load following using sliding pressure operation

While, traditionally, throttling has been used to vary output from a turbine while keeping the pressure constant (Lindsay and Dragoon, 2010), sliding pressure operation has become a commonly applied system in modern supercritical once-through systems (Henderson, 2004). A critical constraint on ramping operation is matching steam and turbine metal temperatures, and more rapid output changes can be achieved using sliding pressure. Sliding pressure also offers advantages over throttle control

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
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(MISO)	)
	)

Exhibit to
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Exhibit 56

Blumenstock 2021 Second Rebuttal Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
CONSUMERS ENERGY COMPANY for Case No. U-21090
approval of an Integrated Resource
Plan under MCL 460.6t, certain Volume 10
accounting approvals, and other relief.

_____/

CROSS-EXAMINATION (Settlement Agreement)

Proceedings held via Microsoft Teams in the above-entitled matter before Sally L. Wallace, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Friday, May 20, 2022, at 9:06 a.m.

APPEARANCES:

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P.O. Box 30755
Lansing, Michigan 48909

On behalf of Michigan Attorney General

(Continued)

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

SECOND REBUTTAL TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2022

Q. Please state your name and business address.

A. My name is Richard T. Blumenstock, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director of Electric Supply.

Q. Are you the same Richard T. Blumenstock that submitted direct and rebuttal testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your second rebuttal testimony?

A. My second rebuttal testimony will provide an overview of the Settlement Agreement filed in this matter on April 20, 2022 and explain how the Settlement Agreement represents the most reasonable and prudent means of meeting the Company's energy and capacity needs, pursuant to MCL 460.6t(8). In the contested settlement portion of this proceeding, direct testimony was filed by Michigan Public Service Commission ("Commission" or "MPSC") Staff ("Staff") witness Paul A. Proudfoot; Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board ("MNS-CUB") witness Douglas B. Jester; Environmental Law and Policy Center, Vote Solar, Ecology Center, Union of Concerned Scientists, Urban Core Collective (collectively the Clean Energy Organizations ("CEOs")) witness James Gignac; Energy Michigan, Inc. ("Energy Michigan") witness Alexander J. Zakem; Wolverine Power Supply Cooperative, Inc. ("Wolverine") witness Thomas King, Jr.; and Cadillac Renewable Energy, LLC, Genesee Power Partners Limited Partnership, Decker Energy-Grayling, LLC, Tondu Corporation,

National Energy of Lincoln, LLC, and National Energy of McBain, LLC (collectively the Biomass Merchant Plants ("BMPs")) witness Richard A. Polich. My second rebuttal testimony will respond to portions of the testimony filed by the aforementioned witnesses but will particularly focus on responding to the assertions raised by the parties contesting approval of the Settlement Agreement, namely, Energy Michigan, Wolverine, and the BMPs.

Q. Have you prepared any exhibits in conjunction with your second rebuttal testimony?

A. Yes. I am sponsoring Exhibit A-150 (RTB-5), the April 20, 2022 Settlement Agreement.

Q. Was this exhibit prepared by you or under your direction?

A. Yes.

I. THE SETTLEMENT AGREEMENT

Q. On page 1 of his contested settlement direct testimony, BMP witness Polich alleges that there are "inconsistencies, failures and risks presented by the proposed Settlement." Furthermore, on page 1 of his contested settlement direct testimony, Energy Michigan witness Zakem indicates that "Energy Michigan is objecting to the Settlement" and on page 9 of his testimony, Wolverine witness King recommends that the Settlement Agreement be rejected. Please describe the proposed Settlement Agreement which the BMPs, Energy Michigan, and Wolverine are contesting.

A. The Settlement Agreement, as provided in Exhibit A-150 (RTB-5), is the result of extensive negotiations and represents a compromise on the positions filed by the parties in this case. The Settlement Agreement proposes to completely resolve this matter and the signing parties have agreed that the resolution is in the public interest. Numerous other

parties have also agreed not to object to the Settlement Agreement. The Settlement Agreement also generally provides for the following:

- The approval of the Company's Proposed Course of Action ("PCA"), as modified by the Settlement Agreement, as the most reasonable and prudent means of meeting the Company's energy and capacity needs over the 5-year, 10-year, and 15-year time horizons. The Company will file its next Integrated Resource Plan ("IRP") consistent with the requirements of MCL 460.6t;
- The approval of the purchase of the New Covert Generating Facility ("Covert Plant") and of investments in, and the capacity value of, resources which the Company will commence within the next three years;
- The approval of a battery deployment program which will accelerate the deployment of batteries in the PCA through an additional 75 MW of batteries being added between 2024 and 2027;
- The retirement of the entire J.H. Campbell ("Campbell") coal plant in 2025, approximately 15 years sooner than planned, and accounting mechanisms to recover the unrecovered book balance and decommissioning costs of the Campbell Plant. D.E. Karn ("Karn") Units 3 and 4 will continue operating until 2031, consistent with the design lives of those units, and will continue to provide capacity and reliability for the Company and its customers as the PCA is implemented;
- A one-time solicitation which will seek to acquire: (i) up to 500 Zonal Resource Credits ("ZRCs") of capacity through power purchase agreements ("PPA") with dispatchable, nonintermittent generation and (ii) up to

200 ZRCs from unaffiliated third-party intermittent resources and dispatchable, nonintermittent clean capacity resources;

- Accounting approval to defer expenses related to the Campbell site severance and retention agreement. The Settlement Agreement also provides for community transition activities related to the Campbell and Karn sites;
- The extension of the annual competitive solicitation process used to acquire the supply-side resource technologies specified in the PCA and the 50%/50%, Company ownership to third-party ownership construct, as initially approved in Case No. U-20165, with certain modifications. Among other things, those modifications provide greater flexibility for the Company to pursue the most economic projects in each solicitation. Through the annual solicitation process the Company will continue the solar glidepath, as outlined in the PCA, which provides for the addition of approximately 8,000 MWs of solar resources by 2040;
- The extension of the Financial Compensation Mechanism ("FCM") approved in Case No. U-20165, with certain modifications to the new PPAs for which the FCM applies;
- The extension of the Company's Public Utility Regulatory Policies Act of 1978 ("PURPA") avoided cost construct, as approved in Case No. U-20165, with certain modifications which include modifications impacting eligibility for avoided cost rates and the Standard Offer Tariff and PPA;

- Ongoing Company donations, which will not be recovered from customers, to a low-income fund that provides bill assistance to Consumers Energy's electric customers; and
- Finally, the Settlement Agreement includes numerous actions that the Company must implement and items that the Company must evaluate and consider in the Company's next IRP. That includes modeling and analysis related to distributed resources and generation, emissions analysis, combined heat and power resource analysis, and new processes to implement in the Company's public outreach efforts.

Q. What parties to this matter signed the Settlement Agreement?

A. On April 20, 2022, Consumers Energy entered into the Settlement Agreement with the following parties: the Michigan Public Service Commission Staff, Michigan Environmental Council, National Resource Defense Council, Sierra Club, Michigan Attorney General Dana Nessel ("Attorney General"), Environmental Law and Policy Center, Vote Solar, Ecology Center, Union of Concerned Scientists, Urban Core Collective, Citizens Utility Board of Michigan, Hemlock Semiconductor Operations, LLC, Michigan Energy Innovation Business Council, Institute for Energy Innovation, Clean Grid Alliance, Michigan Electric Transmission Company, LLC, and Great Lakes Renewable Energy Association.

Q. What parties to this matter indicated that they do not object to the approval of the Settlement Agreement?

A. The following parties signed a statement of non-objection: Michigan Public Power Agency, Midland Cogeneration Venture, LP, Association of Businesses Advocating Tariff Equity, and Residential Customer Group.

Q. What positions did the remaining parties to the proceeding take with respect to the filing of the Settlement Agreement?

A. On May 3, 2022, Energy Michigan filed Objections to the Settlement Agreement. On May 4, 2022, the following parties filed Objections to the Settlement Agreement: the Mackinac Center for Public Policy, Wolverine, and the BMPs. Only Energy Michigan, Wolverine, and the BMPs have filed direct testimony in this contested case proceeding.

Q. On page 4 of his contested settlement direct testimony, Wolverine witness King alleges that the outcome of the Settlement Agreement "not the 'most reasonable and prudent plan to meet the utility's energy and capacity needs'" under MCL 460.6t. BMP witness Polich makes similar allegations on page 4 of his contested settlement direct testimony. Furthermore, on page 7 of his direct testimony supporting the Settlement Agreement, Staff witness Proudfoot asserts that the PCA, as modified in the Settlement Agreement, meets the statutory requirements of MCL 460.6t. Does the Settlement Agreement meet the statutory requirements of MCL 460.6t?

A. Yes. As discussed in more detail below, the Settlement Agreement should be approved by the Commission because it results in the most reasonable and prudent plan to meet the energy and capacity needs of the Company's customers.

Q. Please explain the requirements for approval of an IRP under MCL 460.6(t)?

A. As indicated in my direct testimony filed in this matter, Subsection (8) of MCL 460.6t requires the Commission to approve an IRP, if it determines the plan represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. To make this determination, the Commission shall consider whether the plan appropriately balances all of the following factors:

i. Resource adequacy and capacity sufficient in quantity to serve anticipated peak electric load plus applicable Planning Reserve Margin Requirement ("PRMR") and Local Clearing Requirement ("LCR");

ii. Compliance with applicable state and federal environmental regulations;

iii. Competitive pricing;

iv. Reliability;

v. Commodity price risks;

vi. Diversity of generation supply; and

vii. Whether the proposed levels of peak load reduction and Energy Waste Reduction ("EWR") are reasonable and cost effective.

Q. Does the Settlement Agreement meet the requirements for approval of an IRP under MCL 460.6t?

A. Yes. One of the over-arching objectives in developing the IRP PCA, and the resulting Settlement Agreement, was to create the most reasonable and prudent means of meeting short- and long-term energy and capacity needs. In the Settlement Agreement, the intent and focus of the Company's original PCA were maintained, ensuring the Company's clean energy transition, as initially set forth in the Company's 2018 IRP. The PCA, as modified by the Settlement Agreement, will help lead a faster clean energy transformation by accelerating the Company's exit from coal-fired generation while increasing electric

reliability and providing resource adequacy for customers. The Settlement Agreement satisfies the planning objectives set forth by the Commission in Subsection (8) of MCL 460.6t.

Q. Please explain how the Settlement Agreement ensures resource adequacy and capacity that is sufficient in quantity to serve anticipated peak electric load plus applicable PRMR and LCR.

A. The PCA, as modified in the Settlement Agreement, has maintained a balance of resource additions and retirements—backfilling capacity lost to accelerated retirement with the addition of new baseload resources, expansion of demand-side resources, expansion of renewable resources, and deployment of battery storage resources. The Settlement Agreement continues the annual solicitation process which will procure the supply-side resource technologies specified in the PCA. The Settlement Agreement also provides for the purchase of the Covert Plant, which is a resource that will move into the Midcontinent Independent System Operator, Inc. ("MISO") Zone 7 from PJM Interconnection, LLC ("PJM"), the continued operation of Karn Units 3 and 4 (with retirement on or before May 31, 2031), consistent with the design lives of those units, and the one-time solicitation which will procure 700 Zonal Resource Credits ("ZRCs") of capacity and associated energy. The Settlement Agreement also provides for numerous mechanisms for the Company to procure capacity if it is needed, such as the flexibility to procure additional MWs in the annual solicitation process and the ability to make short-term capacity additions to address capacity shortfalls which cannot reasonably be addressed through the annual solicitation process. All of these items provided for in the Settlement Agreement

ensure resource adequacy and capacity that is sufficient in quantity to serve anticipated peak electric load plus applicable PRMR and LCR.

Q. Please explain how the Settlement Agreement ensures compliance with applicable state and federal environmental regulations.

A. The PCA, as modified in the Settlement Agreement, is in full compliance with all environmental regulations and mitigates future financial risks of potential environmental regulation on fossil fuel generation. The PCA also specifies retirement of Campbell Units 1, 2, and 3 by 2025, approximately 15 years sooner than planned, aggressively reduces waste, and continues to increase solar generation; all consistent with the Company's evolved Clean Energy and decarbonization goals. As indicated in my direct testimony in this case, the Company's Clean Energy Goal calls for reducing carbon emissions to achieve net zero by 2040 and exit coal by 2025. The Settlement Agreement keeps the Company on a path to achieving these goals and also would put Michigan on track to achieve the Governor's Michigan Healthy Climate Plan which calls for reducing carbon emissions by 52% by 2030 and ending coal-fired generation. This is further confirmed in the testimony of CEO witness Gignac and MNS-CUB witness Jester as filed in this contested settlement proceeding. See CEO witness Gignac's Testimony in Support of Settlement Agreement, page 3; MNS-CUB witness Jester's Testimony in Support of Settlement Agreement, pages 6-9.

Q. Please explain how the Settlement Agreement ensures competitive pricing.

A. The PCA, as modified in the Settlement Agreement, provides competitive pricing in numerous ways. First, the Settlement Agreement PCA provides for customer savings of nearly $600 million. These savings are achieved through accelerated retirement of existing

assets, acquisition of the Covert Plant, and continuing the strategy of modular deployment of new generation and demand-side sources. The plan provides for balancing retirements and additions along a glide path that provides flexibility to adjust plans in the future should lower-cost technologies become available. The resources identified in the PCA are also supported by the Company's extensive modeling performed in this case which identified least-cost resources. The Company also agrees with MNS-CUB witness Jester that "[e]xtensive modeling conducted by Consumers and by MNS-CUB in this case demonstrated that retiring Campbell in 2025 is economic for customers." MNS-CUB witness Jester's Testimony in Support of Settlement Agreement, page 6. Additionally, competitively bidding new supply-side generation in the one-time solicitation and annual solicitation processes provides an opportunity to identify and take advantage of the best implementation opportunities while limiting cost to customers.

Q. Please explain how the Settlement Agreement ensures reliability.

A. The PCA, as modified in the Settlement Agreement, allows the Company to maintain sufficient capacity resources to meet the expected PRMR. Additionally, the Company plans to secure resources within the lower peninsula of Michigan that will be transferred to MISO Zone 7 through the purchase of the Covert Plant and are located in MISO Zone 7 through the solicitations provided for in the Settlement Agreement, ensuring that the LCR is also met. MNS-CUB witness Jester correctly noted in his testimony filed in this contested settlement proceeding that the acquisition of the Covert Plant supports reliability because "Covert will add 1,114 Zonal Resource Credits or ZRCs to MISO Zone 7." See MNS-CUB witness Jester's Testimony in Support of Settlement Agreement, page 10.

Further, the PCA, as modified in the Settlement Agreement, provides electric reliability assurance consistent with the PCA as filed. The Company provided a capacity sufficiency analysis and stochastic risk assessment that highlighted the electric reliability benefits of the PCA and the PCA, as modified by the Settlement Agreement, is expected to provide similar reliability benefits. Finally, the flexibility of phased-in modular resources provides the Company adequate time to mitigate cost, assess reliability within the reconfigured portfolio, and to modify as necessary.

Q. Please explain how the Settlement Agreement addresses commodity price risks.

A. The PCA, as modified in the Settlement Agreement, provides for a diverse portfolio of pumped storage and hydro generation, gas generation, wind and solar generation, energy efficiency, demand response, emerging technologies such as grid modernization and battery storage, and PPAs with numerous technology types. This represents a balanced and modular supply plan which provides flexibility to adjust to changes in fuel costs, technology cost, electric demand, or the business environment and insulates the Company and its customers from commodity price risks. The Settlement Agreement also continues the Clean Energy Plan which provides for a modular and scalable supply portfolio which will provide further opportunities for the utilization of diverse supply resources and protects against high customer rates.

Q. Please explain how the Settlement Agreement ensures diversity of generation supply.

A. As explained above, the PCA, as modified in the Settlement Agreement, provides for a diverse portfolio of pumped storage and hydro generation, gas generation, wind and solar generation, energy efficiency, demand response, emerging technologies such as grid modernization and battery storage, and PPAs with numerous technology types. In addition,

the Company intends to keep its gas- and oil-fired peaking resources (i.e. Karn Units 3 and 4) operational, to ensure customer reliability needs are met. This blend of resources provides a significant diversity of generation supply. The modular nature in which many of these resources are added to the generation supply ensures future agility in response to changing technology or market conditions.

Q. Please explain whether the proposed levels of peak load reduction (Demand Response ("DR"), Conservation Voltage Reduction ("CVR"), and EWR), in the Settlement Agreement are reasonable and cost effective.

A. The proposed levels of peak load reduction (DR, CVR, and EWR) in the PCA, as modified in the Settlement Agreement, are aligned with the Company's testimony in this proceeding, the DR and EWR potential studies conducted in support of the Company's IRP and are reasonable and cost effective. The implementation of demand-side resources ensures consistent and effective marketing can be developed and deployed. Also, as detailed in the Settlement Agreement, the Company will continue reporting any changes to the approved demand-side projects, thereby ensuring that cost will be continuously assessed as the Company's implementation of its PCA moves forward.

Q. Please explain other benefits of the Settlement Agreement that the Commission should consider.

A. As explained above, the Settlement Agreement continues the annual solicitation process for procuring capacity through competitive bids originally approved in Case No. U-20165, with certain modifications, and provides for a one-time solicitation process for procuring 700 ZRCs of capacity and energy. These solicitations provide an orderly process for the acquisition of capacity and energy and provide customers with the benefit of competitively

priced energy and capacity. Furthermore, the modifications to the annual solicitation process provide the Company with greater ability to pursue the most economic projects in each solicitation. The Settlement Agreement also continues the Company's PURPA avoided cost construct, as approved in Case No. U-20165, with certain modifications. Among other things, those modifications will provide Qualifying Facilities ("QFs"), which the Company has obligation to purchase from under PURPA, with greater access to the Standard Offer PPA.

The Settlement Agreement provides that approximately 50% of the new capacity that the Company intends to procure through the PCA in each annual solicitation will be from PPAs and other third-party agreements that do not result in Company ownership and approximately 50% will be owned by the Company, as acquired through a competitive bidding process. This approach, which is similar to what was approved in Case No. U-20165, provides opportunities for third-party resources and resources which will ultimately be owned by the Company to participate in the annual solicitation process.

The Settlement Agreement also provides for an extension of the FCM approved in Case No. U-20165, and FCM cap, on PPA payments, which appropriately incentivizes the Company to proceed with the PCA instead of the traditional utility regulatory model which encourages utilities to build owned assets and discourages pursuit of PPAs due to imputed debt concerns. This important incentive was correctly acknowledged by MNS-CUB witness Jester in his testimony filed in this contested settlement proceeding. See, MNS-CUB witness Jester's Testimony in Support of Settlement Agreement, page 17. The continued approval of such compensation is critical to creating a stable, sustainable

regulatory and financial model that drives utilization of PPAs that benefit the Company's customers and the state of Michigan.

The Settlement Agreement also provides for the approval of accounting mechanisms to recover the unrecovered book balance and decommissioning costs of the Campbell Plant. The recovery of these costs in a manner which helps ensure the financial health of the utility, as provided for in the Settlement Agreement, is critical to the Company's ability to retire the Campbell Plant in 2025.

The Settlement Agreement further provides for the accelerated deployment of battery storage in advance of when these resources were planned to be deployed in the originally proposed PCA. The battery deployment program will accelerate the deployment of battery storage in the PCA through an additional 75 MW of batteries being added between 2024 and 2027 and the one-time solicitation will provide an additional opportunity for battery storage resources to be procured and deployed.

The Settlement Agreement provides that the Company will donate $5 million in 2022 to a low-income fund that provides bill assistance to Consumers Energy's electric customers and will donate $2 million annually to the same low-income fund in future years. These donations will not be recovered in rates and Consumers Energy will consult with the Attorney General and Staff on the low-income fund receiving the donations.

The collaboration agreed to as part of the Settlement Agreement is also extensive and important to note. This includes: (i) stakeholder engagement prior to the initiation of the battery deployment program; (ii) stakeholder engagement related to the one-time solicitation process; (iii) consultation with organizations and community members regarding the Campbell Plant community transition plan; (iv) consultation with the settling

parties regarding the bid evaluation criteria in the annual solicitation process; (v) stakeholder outreach to develop a simplified agreement, tariff-based program, or other mechanism which will allow QFs 150 kWac and below to receive full avoided cost rates; and (vi) stakeholder outreach related to a distributed generation as a resource modeling approach. The Settlement Agreement also provides for greater public accessibility during the public outreach process implemented by the Company prior to its next IRP.

Q. Does the Company's evidence, as bound into the record in this matter, support the Settlement Agreement?

A. Yes. The Company's direct testimony, rebuttal testimony, second rebuttal testimony, and exhibits support approval of the PCA and the Settlement Agreement. The testimony and exhibits of many other parties, including that of Staff, also support the compromise positions reached in the Settlement Agreement. Therefore, the evidence submitted in this matter establishes that the Settlement Agreement is based on substantial record evidence.

II. RESPONSE TO ENERGY MICHIGAN WITNESS ZAKEM

Q. Beginning on page 1 of his contested settlement direct testimony, Energy Michigan witness Zakem indicates that Energy Michigan objects to the Settlement Agreement because of "impacts on resource adequacy and impacts on the competitive markets." Do you agree with Mr. Zakem's concerns?

A. No. Company witness Thomas P. Clark addresses and refutes Mr. Zakem's alleged "impacts on resource adequacy and impacts on the competitive markets." However, there are other foundational flaws in Mr. Zakem's arguments which the Commission should consider in rejecting Energy Michigan's objections. In this contested settlement proceeding, Energy Michigan is continuing to rely on its direct testimony as previously submitted in this case before the Settlement Agreement was reached. See Energy Michigan

witness Zakem's Contested Settlement Direct, page 2. The problem with that approach is that Mr. Zakem's direct testimony was focused on the Company's purchase of the Dearborn Industrial Generation ("DIG"), the Kalamazoo River Generating Station ("Kalamazoo"), and the Livingston Generating Station ("Livingston") plants (see 8 TR 3171-3178) and the Settlement Agreement no longer provides for the purchase of those plants in the manner initially proposed by the Company. Mr. Zakem has also made no adjustment to his initial position to account for the fact that the Settlement Agreement continues operation of Karn Units 3 and 4 until 2031, as opposed to 2023, as initially proposed by the Company. Therefore, while Mr. Zakem's assessment of the Company's PCA was incorrect from the outset, it is now also incorrect because it no longer accurately describes the elements of the PCA, as modified by the Settlement Agreement.

In an attempt to rehabilitate his direct testimony, Mr. Zakem claims that the one-time solicitation provided for in the Settlement Agreement may "already being counted toward MISO Zone 7's resource adequacy requirements" but this position is entirely speculative. Furthermore, for the reasons discussed by Company witness Clark, Mr. Zakem has failed to establish that the Company's procurement of resources already located in MISO Zone 7 is a valid reason to reject the Settlement Agreement.

III. RESPONSE TO WOLVERINE WITNESS KING

Q. What are the arguments discussed in the contested settlement direct testimony of Wolverine witness King that you will address in your second rebuttal testimony?

A. Mr. King's arguments focus on purported reliability issues that he claims are at risk in the Settlement Agreement. Mr. King attempts to suggest that the Company's PCA, as modified by the Settlement Agreement, leaves the Company capacity deficient in 2025 and recommends that "[t]he Commission should simply adjust the timeline for retirement of

Campbell 3." See Wolverine witness King's Contested Settlement Direct, page 9. Mr. King's claimed Company capacity deficiency is plainly incorrect. Wolverine has also failed to establish any reliability risks related to the PCA, as modified by the Settlement Agreement.

My second rebuttal testimony will discuss the fatal flaws of the calculations presented in Mr. King's exhibit regarding the Settlement Agreement capacity position. Company witness Clark will address Mr. King's incorrect assessment of reliability risks including: the Company's December 2021 capacity demonstration filing, Case No. U-21099, underlying load forecast assumptions, and solar capacity accreditation. See Wolverine witness King's Contested Settlement Direct, pages 4-9. Company witness Clark will also address other areas where Wolverine has incorrectly conveyed the reliability risks of the Settlement Agreement.

Finally, the Commission should reject Mr. King request to adjust the timeline for retirement of Campbell Unit 3, as proposed in the Settlement Agreement. As explained in response to the BMPs, the terms of the Settlement Agreement do not permit modification to the Settlement Agreement. Furthermore, proposed modifications to the Settlement Agreement or alternative settlement proposals are beyond the scope of this contested settlement proceeding.

Q. What are Mr. King's arguments regarding the Settlement Agreement capacity position?

A. Beginning on page 3 of his contested settlement direct testimony, Mr. King states that "Consumers will likely be capacity negative in 2025," and later discusses the basis for that opinion. However, Mr. King's arguments are philosophically and technically flawed.

Q. What are the flaws of Mr. King's arguments regarding the Settlement Agreement capacity position?

A. There are two initial flaws in Mr. King's representation of the Company's capacity position which undermine the credibility of Mr. King's position. First, the magnitude of Mr. King's (erroneously) calculated shortfall is insignificant (28 ZRC, as shown in Exhibit WPSC-7) for 2025. On page 3 of his contested settlement direct testimony, Mr. King references his own Exhibit WPSC-6, which states

> *The 2020-21 OMS-MISO survey projected a small surplus for planning year 2022-23, which was eroded by an increased load forecast, less capacity entering the auction as result of retirements, and the decreased accredited capacity of new resources.*

MISO's above statement is indicative of the fact that a small magnitude surplus *or* shortfall can shift over a relatively short period of time. This is why the Company implements a strategy of maintaining approximately 200 ZRCs of capacity surplus.

The second issue with Mr. King's argument is that he relies on the <u>exclusion</u> of capacity acquired through the one-time solicitation included in this Settlement Agreement. His claim that the Company could be capacity negative in 2025 would assume the Company is wholly unsuccessful in its one-time solicitation – that 0 ZRC of capacity are acquired through a Request for Proposals soliciting up to 700 ZRCs. That is highly unlikely. Properly including the addition of up to 700 ZRCs, even Mr. King's own exhibit shows capacity sufficiency in year 2025 above the Company's strategic surplus amount of 200 ZRC.

Q. What are the technical flaws of Mr. King's arguments regarding the Settlement Agreement capacity position?

A. Exhibit WPSC-7 is offered as evidence to support an alleged 28 ZRC capacity shortfall (disregarding any capacity acquired through a solicitation looking for up to 700 ZRCs) in 2025. The mechanics in the calculation supporting the shortfall for 2025 are incorrect.

The calculation is presented in Exhibit WPSC-7. The first column of data, "**Settlement 2022/23**" is taken directly from the Company's detailed calculations of capacity position. The value shown on the row labeled as "Surplus/Deficient" is the correct ZRC surplus level projected and presented in Figure 6 of my direct testimony in the initial filing of this case.

Mr. King's next step is to compare the filed capacity position of the 2021 IRP to the filed capacity position presented in the Company's December 2021 capacity demonstration filing, Case No. U-21099. This is summarized in Exhibit WPSC-7 in the column labeled as "**Cap Dem 2022/23**." Mr. King has generally populated this column with appropriate values from Case No. U-21099. He has then created an "Equalization Adjustment Factor," which accounts for the difference in final capacity position between the Capacity Demonstration and the IRP. Although Mr. King's testimony is not well-supportive of the calculation, the Company is able to confirm the accuracy of this value for planning year 2022/2023.

Next, in Exhibit WPSC-7, Mr. King calculates a planning year 2025 capacity position in the column labeled as "**Settlement 2025/26**." This is consistent with Figure 6 of my direct testimony, with modifications to (i) remove the DIG, Kalamazoo, and Livingston plant capacity; (ii) extend the capacity for Karn Units 3 and 4; and (iii) add

capacity that will be acquired through the one-time solicitation. I take no issue with these modifications; however, Mr. King has failed to add capacity provided by the battery deployment program, which would contribute approximately 14 ZRCs by 2025.

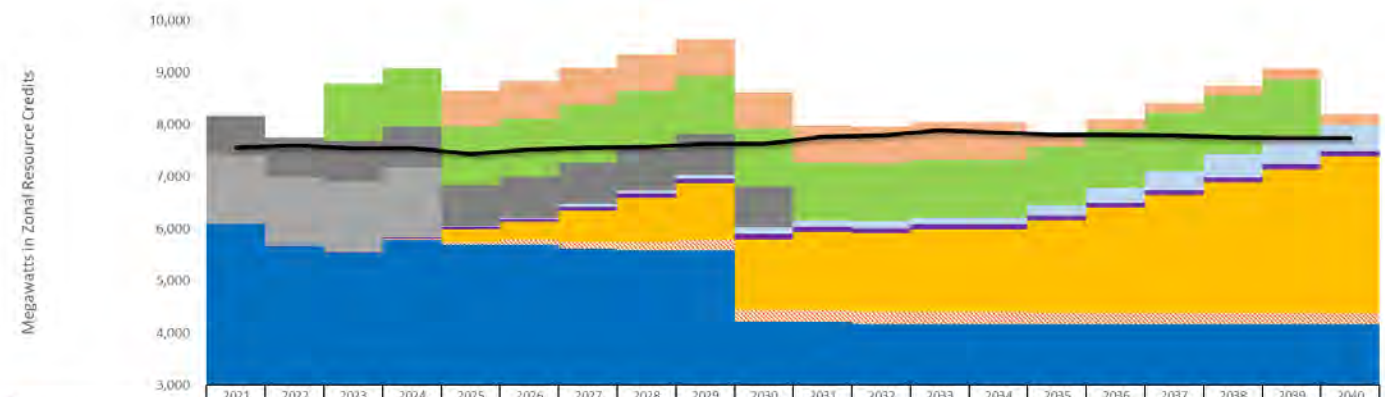
The flaw in the analysis, however, occurs in the final column of Exhibit WPSC-7 labeled as "**Cap Dem 2025/26**." While the lines of data through the row labeled as "PRMR" are generally accurate (though again, Mr. King fails to include 14 ZRC that will be provided by the battery deployment program), attention must be brought to the row "Equalization Adjustment Factor." While Mr. King referenced this row on page 4, line 21, of his testimony, he offers little in the way of explanation for it. While this section of my testimony addresses the Company's general acceptance of the -343 ZRC value *for planning year 2022/2023*, Mr. King's testimony fails to explain how this value is calculated or the appropriate use of this value. In fact, Mr. King offers no explanation whatsoever in his application of the -343 ZRC value to the final column of Exhibit WPSC-7, which is an accounting of *planning year 2025/2026* capacity and demand, not 2022/2023. An appropriate re-calculation of the "Equalization Adjustment Factor" for planning year 2025/26 would be required, but Mr. King failed to do so. In fact, Mr. King's "Equalization Adjustment Factors" are only included in his exhibit to calculate the capacity position filed in the capacity demonstration. That value is readily available in Case No. U-21099, Exhibit 2 of 11, line 35, column (d), shown to be a +25 ZRC surplus[1]. Application of a correct "Equalization Adjustment Factor" as well as inclusion of 14 ZRCs of battery deployment capacity would result in a positive "Surplus/Deficit" value of +39 ZRCs, a capacity <u>surplus</u>, not a -28 ZRC capacity shortfall, as mis-calculated in Exhibit WPSC-7.

[1] This is consistent with Mr. King's column "Cap Dem 2022/23," which is also presented in Case No. U-21099, Exhibit 2 of 11, line 33, column (a).

Combined with up to +700 ZRCs of capacity acquired through the one-time solicitation, it is abundantly clear that Mr. King's statement that the Company could be capacity negative in 2025 is disproven.

The prior discussion reconciled Mr. King's calculated capacity position from the Company's December 2021 capacity demonstration, Case No. U-21099. Figure 1, below, presents the capacity position of the PCA, as modified by the Settlement Agreement. While Figure 1 indicates a very small capacity shortfall in 2035 (34 ZRCs), the Company will have sufficient time between now and 2035 to address that shortfall. There are also numerous mechanisms provided for in the Settlement Agreement which will allow the Company to address that projected shortfall long before it may happen.

Figure 1: Proposed Course of Action, as Modified by the Settlement Agreement



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
One-time Solicitation					700	700	700	700	700	700	700	700	700	700	200	200	200	200	200	200
Covert	-	-	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	
Karn 3&4	767	769	787	785	784	787	789	789	789	789	-	-	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,144	1,346	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New Storage	-	-	-	5	14	33	71	71	71	126	127	128	130	131	208	286	364	441	514	507
New Demand Response	-	-	12	25	37	49	62	74	87	99	99	99	99	99	99	99	99	99	99	99
New Solar					250	352	602	852	1,102	1,352	1,488	1,513	1,591	1,591	1,759	2,009	2,259	2,509	2,759	3,009
New Energy Waste Reduction	-	-	-	20	57	91	123	157	187	216	231	232	229	229	225	222	220	218	215	213
Current Existing Portfolio	6,095	5,667	5,533	5,781	5,694	5,694	5,624	5,589	5,589	4,227	4,209	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168
PRMR	7,558	7,600	7,542	7,553	7,435	7,516	7,558	7,575	7,627	7,625	7,770	7,796	7,883	7,844	7,807	7,804	7,785	7,745	7,734	7,759
Capacity position	617	154	1,249	1,522	1,215	1,304	1,528	1,771	2,012	998	209	158	148	188	(34)	294	639	1,005	1,336	456

IV. RESPONSE TO BMP WITNESS POLICH, P.E.

A. CONSIDERATION OF BIOMASS PLANTS

Q. Beginning on page 2 of his contested settlement proceeding direct testimony, BMP witness Polich offers eight objections to the Settlement Agreement. Do you agree with Mr. Polich's objections?

A. No. I will address Mr. Polich's arguments in more detail below; however, the BMPs' foundational position in this case has not changed in this contested settlement proceeding from what the BMPs initially argued prior to settlement. The BMPs are continuing to claim that the Company did not appropriately consider biomass plants in this IRP and continue to push for PPA extensions for the individual BMP plants. See BMP witness Polich's Contested Settlement Direct Testimony, pages 4-6. The BMPs' positions are unreasonable, not supported in the record, and fail to provide a basis to reject the proposed Settlement Agreement.

As explained by Company witness Keith G. Troyer in his rebuttal testimony, the Company is not under any obligation to enter new PPAs with the BMPs or extend the BMPs' existing contracts. Each of the BMPs are above the Company's must-purchase obligation MW threshold under PURPA and therefore, the Company is not required under PURPA to continue purchasing from the BMPs once the current PPAs for those plants expire. Furthermore, while the BMPs concede that the Hillman Plant will retire in 2022 (see BMP witness Polich's Contested Settlement Direct, page 5), the BMPs fail to acknowledge that the prior owners of the National Energy of Lincoln and McBain plants contractually agreed to decommission those plants when their current PPAs expire. This means that the only BMPs which could conceivably enter a new PPA or PPA extension with the Company are TES Filer City Station (PPA expires in 2025), Grayling Generating

Station (PPA expires in 2027), Cadillac Renewable Energy (PPA expires in 2028), and Genesee Power Station (PPA expires in December 2030).

Moreover, the Company did consider biomass plants in the development of the IRP. The Company considered biomass plants as it began its modeling process, but due to the fact that those resources were not viable options on an economic or cost basis, biomass plants did not pass the Company's resource screen process. It should further be noted that the plants which make up the BMPs are included in the PCA through the end of their current PPA terms. Upon expiration of those contracts, those plants are eligible to participate in the MISO markets.

Through the litigation of this proceeding, it has become apparent that the BMPs take issue with the Company not considering the cost to extend or enter new PPAs with the existing plants which make up the BMPs. Beyond the fact that the Company has no obligation to do that, and the fact that the BMP PPAs are not set to expire for numerous years, the flaw in the BMPs' position is that the Company did not have adequate information to determine the cost of new PPAs or PPA extensions with the BMPs in the development of this IRP. And throughout this proceeding, the BMPs have failed to produce any evidence in the record establishing the costs that the BMPs could agree to in new PPAs or PPA extension. As explained in the rebuttal testimony of Company witness Troyer, the cost of current BMP PPAs have not been historically competitive with either market pricing or the Company's more-recent competitive procurement of new solar resources. Based on the cost of the BMPs' existing PPAs, the Company had no reason to

assume that the BMP suppliers were willing to accept lower rates than what is provided for in the current agreements during the development of this IRP.

Therefore, prior to addressing the individual objections offered by the BMPs, it is important to acknowledge that: (i) the Company has no obligation to enter new PPAs or extend existing PPAs with any of the BMPs; (ii) the Company did consider biomass plants in the development of its IRP and that type of resource was shown not to be a viable option on an economic or cost basis; (iii) the BMPs have failed to produce any evidence establishing the costs that the BMPs could agree to in new PPAs or PPA extension, and (iv) the existing BMP PPA cost information available to the Company establishes that the BMPs are not competitive with either market pricing or the Company's recent competitive procurement results.

Q. Beginning on page 17 of his contested settlement direct testimony, Mr. Polich recommends modifications to the proposed Settlement Agreement which would provide PPA extensions to the BMPs. Should the Commission adopt any changes to the proposed Settlement Agreement?

A. No. As explained on page 7 of Staff witness Proudfoot's direct testimony supporting the Settlement Agreement, Paragraph 22 of the Settlement Agreement provides that if the Commission rejects or modifies the Settlement Agreement or any provision of the Settlement Agreement, the Settlement Agreement shall be deemed to be withdrawn. See Exhibit A-150 (RTB-5), page 17, Paragraph 22. This is standard language which preserves

the bargain that the settling parties negotiated. Since the Settlement Agreement cannot be modified, the BMPs' requested modifications should be rejected by the Commission.

The BMPs' requested modifications to the settlement agreement are also beyond the scope of this contested settlement proceeding. As set forth in the Commission's June 7, 2019 Order Approving Settlement Agreement in Case No. U-20165, other proposed versions of settlements not adopted by the parties who signed the settlement agreement are not within the scope of issues to be decided by the Commission in a contested settlement proceeding:

> The Commission agrees with Consumers that SEIA's proposal is outside the scope of this contested settlement agreement. The issue to be decided in this case is whether the criteria set forth in Rule 431(5)(a) through (c) have been satisfied so that the Commission may approve of the settlement agreement at issue here. Other proposed versions of settlements not adopted by the parties who signed the settlement agreement are not properly before the Commission. Further, the Commission agrees with the Staff that SEIA's proposal should not be used to derail the settlement agreement in this case. Accordingly, the Commission rejects SEIA's recommendation to make approval of the settlement agreement contingent on SEIA's proposal. [MPSC Case No. U-20165, June 7, 2019 Order Approving Settlement Agreement, page 82.]

Since the BMPs' proposed Settlement Agreement modifications are beyond the scope of this contested settlement proceeding, they should be rejected by the Commission.

Furthermore, as set forth above, the BMPs have failed to produce any evidence in the record establishing that extended PPAs with the BMPs would be economic compared to other resource options. And the record establishes just the opposite. Based on historic information related to existing PPAs, the BMPs are not competitive with either market pricing or the Company's recent competitive procurement results. Therefore, even if the Settlement Agreement could be modified, which it cannot, and if the BMPs' proposal was

within the scope of this proceeding, which it is not, there is still no basis to adopt the BMPs recommended modifications to the Settlement Agreement because the record does not establish that the PPA extensions with the BMPs would be economic compared to other resource options.

B. CAPACITY POSITION

Q. Beginning on page 6 of his contested settlement direct testimony, Mr. Polich claims that the Settlement Agreement PCA will result in excess capacity between 2023 and 2030 and capacity shortages between 2031 and 2038. Do you agree?

A. I do not agree with Mr. Polich's generalizations regarding the Company's capacity position under the PCA, as modified by the Settlement Agreement. Specifically, I do not agree that the Settlement Agreement PCA results in capacity shortages. As explained in response to Wolverine witness King, under the PCA, as modified by the Settlement Agreement, the Company maintains sufficient capacity to serve customers. See Figure 1 of this second rebuttal testimony. Furthermore, below I discuss that Mr. Polich's own Exhibit BMP-7 (RAP-7) supports the capacity sufficiency of the Settlement Agreement.

With respect to the BMPs allegations of excess capacity, I also disagree with Mr. Polich that the capacity amounts in any year of the PCA is to the detriment of customers. I will discuss this in more detail below.

Q. On page 8, beginning on line 1 of his contested settlement direct testimony, Mr. Polich states the Settlement Agreement results in excess capacity, exposing customers to unreasonable expense. Mr. Polich opines that the addition of the Covert Plant in 2023 means customers will be paying for two years of "unnecessary costs for the Covert capacity that is unnecessary" and that one-time solicitation "is not needed until 2030." Do you agree with Mr. Polich's claims?

A. No. The record in this case demonstrates that the Company initially proposed to acquire the Covert Plant *and* the DIG, Kalamazoo, and Livingston plants to retire Karn Units 3 and 4, which are capacity resources, *and* Campbell Units 1, 2, and 3, which are capacity and energy resources. In other words, the acquisition of any particular unit was not assigned to the retirement of any particular unit. The acquisitions and retirements were considered as a whole based on the impact of the energy and capacity lost and the energy and capacity gained. Through the settlement process, the settling parties agreed that the Company would not purchase the DIG, Kalamazoo, and Livingston plants, as originally proposed. However, in order to retire Campbell Units 1, 2, and 3, the Company still needs to acquire the Covert Plant and the Purchase Sale Agreement ("PSA") for that plant provides for the purchase in 2023. Therefore, Mr. Polich is plainly incorrect in alleging that the Covert Plant capacity is "unnecessary." Nearly every party in this proceeding supported acquisition of the Covert Plant in 2023. This acquisition brings dispatchable baseload capacity into MISO and Zone 7 and will support the replacement of the energy and capacity of the units proposed for retirement in this IRP.

Mr. Polich has also not established that the Company has any ability to move the start date of the Covert Plant purchase. Since the PSA provides for the Covert Plant to be

purchased in 2023, attempting to move that date is not possible under the terms of the agreement. Furthermore, even if the Covert Plant does provide surplus energy and capacity for a short period, the Company can monetize the energy and capacity of the Covert Plant by selling it into the MISO markets and using the resulting revenue to lower power supply costs to the benefit of customers. The Company disagrees with Mr. Polich that customers will face economic harm as a result of the Company owning the Covert Plant.

Moreover, without the acquisition of the DIG, Kalamazoo, and Livingston units, as initially proposed by the Company, the one-time solicitation included in the proposed Settlement Agreement also supports the retirement of Campbell Units 1, 2, and 3. It is expected that the 500 ZRCs of dispatchable generation and the 200 ZRCs of intermittent and non-intermittent clean resources will provide sufficiency of supply to support retirement of the Campbell Units. However, until such resources are acquired and operational on behalf of customers, the Settlement Agreement provides for continued operation of Karn Units 3 and 4, which provide low-cost capacity for the benefit of customers. The continued operation of Karn Units 3 and 4 further addresses reliability concerns for customers. These low-cost capacity resources will continue to be evaluated in future IRPs, along with other existing assets, to identify if they continue to serve customer needs reliably and affordably. The Settlement Agreement identifies the plan to cease operations of these units by May 31, 2031, however, the Company intends to manage its capacity surplus position in the best interests of its customers. Because the one-time solicitation will support the retirement of Campbell Units 1, 2, and 3, and the need for continued operations of Karn Units 3 and 4 can be assessed in the future, the BMPs have

not established that the one-time solicitation is unnecessary or to the detriment of customers.

Q. Beginning on page 13 of his contested settlement direct testimony, Mr. Polich claims that the PCA, as modified in the Settlement Agreement, results in a capacity shortfall position in years 2031 through 2038. Do you agree with Mr. Polich's alleged capacity shortfall?

A. No. The calculation described by Mr. Polich and included as Exhibit BMP-9 (RAP-9) is misleading and inconsistent with the modeling presented in this case. Company witness Clark discusses the issue of solar accreditation itself, in further detail. Mr. Polich suggests that *if* a change to solar accreditation is made at MISO, the PCA would result in capacity shortfalls eight years into the future. This argument is not compelling for two primary reasons.

First, the PCA was developed using current MISO solar capacity accreditation practices. While discussions in MISO have raised the possibility of changes to solar capacity accreditation, it would be premature to adopt such changes ahead of MISO itself issuing the rule change. In fact, at the Company's existing solar facilities, capacity accreditation, based on actual performance, has been as high as 65%. While the possibility of lowering the accreditation is under consideration, actual performance will ultimately dictate the levels of capacity customers receive from these resources. Mr. Polich's Exhibit BMP-7 (RAP-7) actually presents a capacity position for the Company under a 50% solar accreditation and demonstrates that the Company has no capacity shortfall through 2040.

See Exhibit BMP-7 (RAP-7), line 24.[2] Table 1, below, which is pulled directly from the referenced line of Exhibit BMP-7 (RAP-7) illustrates the capacity position calculated by Mr. Polich.

Table 1: Capacity Position Presented in Exhibit BMP-7 (RAP-7)

Year	Settlement Agreement Net Capacity in Excess of PRMR (Line 24)
2021	617
2022	154
2023	1,249
2024	1,517
2025	1,201
2026	1,271
2027	1,457
2028	1,700
2029	1,942
2030	927
2031	138
2032	88
2033	78
2034	118
2035	396
2036	224
2037	568
2038	934
2039	1,270
2040	1,514

Since Mr. Polich's own exhibit clearly supports the sufficiency of capacity in the Settlement Agreement, as set forth above, his claim of a capacity shortfall should be rejected.

Second, Mr. Polich's alleged and miscalculated capacity shortfall is projected to occur eight years into the future. The Company will file at least one, if not multiple, IRPs

[2] Note that Figure 1 in my second rebuttal testimony provides the Company's actual PCA capacity position, as modified in the Settlement Agreement. The Company is only providing the purported "Settlement Agreement Net Capacity in Excess of PRMR," as provided in Exhibit BMP-7 (RAP-7), to demonstrate that Mr. Polich's own calculations show that the PCA has no capacity shortfalls. Exhibit BMP-7 (RAP-7) contains errors which include the omission of the battery storage deployment program beginning in planning year 2024/2025.

between now and that time. If changes to solar accreditation occur at MISO, the Company has ample time to respond and adjust the PCA. Furthermore, as set forth above, under the PCA, as modified by the Settlement Agreement, and the numerous mechanisms provided for in the Settlement Agreement which will allow the Company to address that projected shortfall long before it happens, the Company will maintain sufficient capacity to serve customers.

C. <u>ONE-TIME SOLICITATION</u>

Q. Beginning on page 9 of his contested settlement direct testimony, BMP witness Polich suggests that the one-time solicitation proposed in the Settlement Agreement is "deeply flawed." Do you agree with Mr. Polich's claims regarding the solicitation?

A. No. The first "flaw" Mr. Polich claims is that the one-time solicitation timing will favor existing generation facilities, and he cites engineering, financing, and construction time limitations, as well as delays in the MISO interconnection process. The Company disagrees that this is a flaw in the design of the solicitation. As explained above, the resources acquired in the one-time solicitation will help replace the capacity and energy lost by Campbell Units 1, 2, and 3 in 2025. Furthermore, beyond speculating what plants can participate, Mr. Polich fails to establish anything unreasonable about the solicitation. The solicitation will provide capacity and energy to meet the needs of the Company and its customers, and the characteristics of the resources sought in the solicitation are consistent with the results of the extensive modeling performed by the Company in this case. As explained by Company witness Sara T. Walz, the Company's modeling selected natural gas units to satisfy large capacity and energy needs, which is consistent with the characteristics sought in the 500 ZRC tranche. The Company's modeling also selected clean resources, like solar, which is consistent with the 200 ZRC tranche.

Mr. Polich's second claimed flaw relies on incorrect data assumptions. Specifically, Mr. Polich incorrectly states that MISO Zone 7 is projected to be 397.4 ZRCs short in 2023. See BMP witness Polich's Contested Settlement Direct, page 10. This is inaccurate. Mr. Polich has incorrectly interpreted page 13 of Exhibit BMP-8 (RAP-8), which provides the results of the Planning Year *2022/2023* Planning Resource Auction ("PRA"). The results presented in this summary are not indicative of any projection of Zone 7 in Planning Year 2023/2024, as stated in Mr. Polich's testimony. Further, the Company's addition of the Covert Plant results in an increase of capacity resources of over 1,100 ZRCs in Zone 7 in 2023.

Mr. Polich correctly stated that the MISO PRA for planning year 2022-2023 resulted in higher clearing prices than recent historical averages, as well as a shortfall position for Zone 7. However, the PCA, as presented in this Settlement Agreement, provides for long-term capacity sufficiency for customers. Mr. Polich has himself acknowledged that the Settlement Agreement will provide a capacity surplus for customers for years 2023 through 2030. See BMP witness Polich's Contested Settlement Direct, page 8. As has been discussed repeatedly in this case, Consumers Energy customers are not responsible for resource adequacy requirements for the entire Zone 7, which includes customers served by alternative energy suppliers ("AESs") as well as other utilities. The Settlement Agreement ensures PRMRs are met for Consumers Energy customers. Please see the testimony of Company witness Clark for additional discussion on this matter.

Mr. Polich's third claimed flaw suggests that the BMPs are precluded from participation in the one-time solicitation because of their existing contracts and dispatchability constraints. See BMP witness Polich's Contested Settlement Direct,

page 11. However, this limitation is untrue, and one created by the BMPs. At the outset, Mr. Polich's alleged flaw is a red herring because the Company was under no obligation to issue the one-time solicitation in a manner that would align sought PPA start dates with the expiration of the BMPs current PPAs. Because the current PPAs of the BMPs expire in different years between 2025 and 2030, it would not be possible to align the one-time solicitation with the expiration of every BMP PPA. Furthermore, while the solicitation is seeking bids which will provide the Company with capacity credit in the MISO Zone 7 starting in the 2025 Planning Year, this would not preclude certain BMPs from submitting bids which take into account current contractual commitments. Such contractual commitments could be evaluated in the solicitation when determining the overall economics of a bid.

Mr. Polich also suggests that the BMPs are excluded from the 500 ZRC tranche of the one-time solicitation because it "provides for hourly dispatch" and the BMPs are "dispatched on 24 hours-notice." BMP witness Polich's Contested Settlement Direct, page 11. However, Mr. Polich does not correctly represent the Settlement Agreement language which provides that "[t]his tranche will seek dispatchable, nonintermittent generation *capable* of dispatching up or down in every hour of the year in response to wholesale energy market signals." See Exhibit A-150 (RTB-5), page 6, Paragraph 6 (emphasis added). It is also notable that during this proceeding Mr. Polich has claimed that the BMPs "generation facilities can provide *around the clock*, renewable, *dispatchable* and reliable power generation." See 7 TR 2684 (emphasis added). Mr. Polich's statements in his contested settlement direct testimony are therefore inconsistent with his prior testimony in this proceeding which suggested that the BMPs are "dispatchable" "around

the clock."[3] It should also be noted that, under existing BMP PPAs, certain BMPs are offered into the MISO Day-Ahead Market as units which can dispatch on an hourly basis. Since the MISO Day-Ahead Market clears the day prior to operation, the plants are provided dispatch notice prior to actual operation.

Mr. Polich's fourth alleged flaw in the one-time solicitation suggests that the second tranche which seeks to procure 200 ZRCs does not define "clean capacity resources" and could mean any resources cleaner than "Consumers existing generation resources" and therefore "natural gas plants could offer proposals." BMP witness Polich's Contested Settlement Direct, page 11. This fourth alleged flaw is not an actual flaw in the one-time solicitation and instead represents Mr. Polich's interpretation of the second tranche of the one-time solicitation. The Settlement Agreement was entered by 18 parties and represents a compromise reached by those parties. The terms of the Settlement Agreement speak for themselves and Mr. Polich's observations are irrelevant. Nevertheless, Mr. Polich's interpretation of the second tranche simply does not make sense. The Company's generation portfolio includes fossil fuel and clean capacity resources such as solar and hydro generation. Since the Company already possesses clean capacity resources in its generation portfolio, Mr. Polich's interpretation that this tranche "can mean any generation resource *cleaner* that Consumers existing generation resources" (emphasis added) would produce absurd results because nothing could be "cleaner" than the clean capacity resources the Company already has.

[3] Mr. Polich has presented numerous claims in this proceeding that the BMPs are dispatchable and has not previously explained any of the limitations on dispatchability expressed in his contested settlement direct testimony. See, e.g., 7 TR 2684, 2689, 2691, 2698, 2703, 2714, 2715, 2721, 2722, 2728. Mr. Polich also compared the operation of the BMPs to the DIG gas plant, claiming that "[a]s with DIG, these plants are dispatchable and provide equivalent availability." 7 TR 2715.

Mr. Polich also fails to provide the full text describing the "clean capacity resources" that can participate in the second tranche of the one-time solicitation. The Settlement Agreement specifically provides that "[t]his tranche will seek intermittent resources and dispatchable, nonintermittent clean capacity resources *(including battery storage resources)* providing capacity which meets the Local Clearing Requirement of MISO Zone 7." Exhibit A-150 (RTB-5), page 6, Paragraph 6 (emphasis added). Since the Settlement Agreement provides "battery storage resources" as an example of the "dispatchable, nonintermittent clean capacity resources" that can participate in the second tranche, the Settlement Agreement is not "very ambiguous," as Mr. Polich claims. See BMP witness Polich's Contested Settlement Direct, page 11.

Mr. Polich's fifth alleged flaw in the one-time solicitation assumes that the "One-Time Solicitation will likely result in Consumers acquiring substantial amount of natural gas capacity in addition to the Covert capacity" and discusses "volatility of natural gas pricing." BMP witness Polich's Contested Settlement Direct, page 12. In making this argument, Mr. Polich is speculating on the outcome of the one-time solicitation for 500 ZRCs of dispatchable resources, which is unproductive. For the reasons set forth by Company witness Brian D. Gallaway in the record, Mr. Polich's discussion of gas price volatility should also be rejected. Mr. Gallaway established that gas price volatility is not expected to continue into the future. Furthermore, Mr. Polich's suggested "need for a more fuel diverse generation portfolio" (see BMP witness Polich's Contested Settlement Direct, page 12) ignores that the Company will have an incredibly diverse resource portfolio that includes: pumped storage and hydro generation, gas generation, wind generation, solar generation, energy efficiency, DR, and emerging technologies such as grid modernization

and battery storage to meet the future demand of its customers. The Company also maintains PPAs with numerous technology types.

Mr. Polich's sixth and final alleged flaw with the one-time solicitation suggests that it is flawed because it solicits "only intermittent generation because solar generation with battery storage will likely be too expensive to compete with solar generation without battery storage and due to shortages of materials." BMP witness Polich's Contested Settlement Direct Testimony, page 12. Here, again, Mr. Polich is speculating on the outcomes of the 200 ZRC tranche. The one-time solicitation is a competitive bidding process which will consider the value of the resources which are bid. If certain resources are "too expensive," as Mr. Polich claims, that issue will naturally be resolved through the evaluation and ranking of eligible bids.

D. <u>OTHER ISSUES</u>

Q. On page 14 of his contested settlement direct testimony, Mr. Polich states that the Settlement Agreement does not "meet the intent of being carbon neutral by 2040 as [sic] stated in Settlement Section 16." Do you agree?

A. No. First of all, Mr. Polich purported "intent of being carbon neutral by 2040" is not a term of the Settlement Agreement. Paragraph 16 of the Settlement Agreement merely reiterates that the Company's filed IRP "set forth a proposal to be Carbon Neutral by 2040 and retire all coal generation by 2025." See Exhibit A-150 (RTB-5), page 13, Paragraph 16. While the Company still aims to be carbon neutral by 2040, this is not a requirement in the Settlement Agreement. Still, there is nothing in the Settlement Agreement that will necessarily impede the Company's ability to meet its goal.

In an attempt to support his argument regarding not meeting carbon neutrality by 2040, Mr. Polich asserts that "Consumers is relying on Covert and 200 MW of generation

from PPAs originating under the One-Time Solicitation" and that "[t]hese are fossil generation resources and are not carbon neutral." BMP witness Polich's Contested Settlement Direct, page 14. However, Mr. Polich's assumptions are not accurate. First, as made clear in my direct testimony, the 20-year capacity plan provided by the Company in this IRP assumed cessation of operations of the Covert Plant by May 31, 2040. The final solution in 2040 will vary dependent upon the evolution of cleaner technologies, the possibility of carbon sequestration technologies, and potential for carbon offsets. Second, Mr. Polich is incorrect that the Company will acquire 200 MWs of "fossil generation resources" in the one-time solicitation that will operate beyond 2040. Mr. Polich implies that the 200 ZRC tranche, which can result in contracts up to 25 years, could result in fossil generation resources but that is inconsistent with the description of that tranche which provides that only "intermittent resources and dispatchable, nonintermittent clean capacity resources (including battery storage resources)" are eligible. See Exhibit A-150 (RTB-5), page 6, Paragraph 6. Mr. Polich has therefore not established that the Covert Plant purchase or the one-time solicitation will result in the Company not meeting its carbon neutrality goal.

Mr. Polich also suggests the resource mix included in the PCA will impact the Company's ability to meet its carbon neutrality goal. Specifically, Mr. Polich questions solar production levels, a lack of battery storage, and levels of energy market purchases. See BMP witness Polich's Contested Settlement Direct, page 14. These matters have all been extensively addressed and refuted by the evidence provided by the Company in this case. First, the Company utilized and successfully supported use of National Renewable Energy Laboratories ("NREL") projections for solar operating factors. Testimony

provided by Company witness Jeffrey E. Battaglia supports these projections from third-party and reputable sources. Secondly, the Settlement Agreement provides for an incremental 75 MW of battery storage capacity by 2027, as compared to the initial PCA. This brings the total capacity of battery storage to 550 MW installed throughout the study period on top of 1,170 MW of Ludington pumped storage capacity. Lastly, purchase of energy from MISO's energy market is a benefit to customers, to ensure the lowest-cost resources are used to meet their needs. The Company's Net Zero Carbon goal accounts for carbon emissions from those market purchases, as discussed in testimony presented by Company witness Heather A. Breining.

Q. On page 7 of his contested settlement direct testimony, Mr. Polich suggests that potential risk of capacity shortages in Zone 7 could prevent retirement of Karn Units 3 and 4. Specifically, Mr. Polich suggests that the units could be designated as a System Support Resource ("SSR") by MISO. Does this represent a significant risk to customers?

A. No. Mr. Polich's discussion of an SSR designation for Karn Units 3 and 4 does not represent a significant risk to customers because, as discussed above, Mr. Polich's position is based on a flawed interpretation of the Company's future capacity position. Mr. Polich has failed to establish that the Company will experience a capacity shortage between 2031 and 2038 and therefore has not established that there is a "likelihood that MISO will designate one or more of Consumers' fossil fuel Karn generating plants as System Support Resource and not allow their retirement." BMP witness Polich's Contested Settlement Direct, page 7.

Mr. Polich also fails to accurately represent the customer benefit of Karn Units 3 and 4 and what an SSR designation actually means for customers. An SSR designation would not be due to a capacity or energy shortfall. An SSR designation would result from an electric transmission system deficiency that must be mitigated before Karn Units 3 and 4 could be retired. Karn Units 3 and 4 will continue to operate to ensure near-term reliability for the benefit of Consumers Energy customers. These units may be operated through May 31, 2031, depending on the Company's capacity needs and the outcome of the Company's resource procurement efforts. The cost to maintain operations of Karn Units 3 and 4 is very low[4], compared to many alternatives available to meet load obligations which means that customers will not be required to pay high costs for extensive capacity and reliability benefits provided by these units. Moreover, even if Karn Units 3 and 4 were designated as SSR units, the cost burden associated with that designation would shift to all customers who benefit from the reliability assets, in this case, all customers in Zone 7. Moreover, the SSR period would only be in place while system improvements are made to accommodate retirement of Karn Units 3 and 4. At the time the Company submits an Attachment Y with MISO, to initiate the process of retirement, if MISO designates the units as SSR for Zone 7, <u>the entirety of the zone</u> would then financially support the

[4] See page 1 of Exhibit A-51 (NJK-2) Revised, page 1 of Exhibit A-52 (NJK-3) Revised, and page 1 of Exhibit A-53 (NJK-4) Revised.

continued operation of the units. Therefore, an SSR designation does not pose an increased risk to customers.

Q. Beginning on page 15 of his contested settlement direct testimony, Mr. Polich suggests that there are risks associated with the Company's proposal solar generation. Do you agree with Mr. Polich's assessment?

A. No. For the reasons discussed in the second rebuttal testimony of Company witness Clark, the Company disagrees with Mr. Polich's assessments of the risks of solar procurement and development.

Q. On page 6 of his contested settlement direct testimony, Mr. Polich suggests that the Settlement Agreement "fails to consider both the employment and tax benefits of the Biomass Plants as well as the full panoply of their environmental benefits as identified in my initial direct testimony." Do you agree with Mr. Polich's criticism of the Settlement Agreement?

A. No. The BMPs positions on these issues were extensively refuted by the Company's record evidence and briefs. The BMPs position regarding the consideration of the employment and tax benefits of the BMPs is also based on a flawed reading of MCL 6t(8)(b). See BMPs' May 4, 2022 Objections, page 6. The BMPs' reading of the requirements of Section 6t(8)(b) is also incorrect. That provision addresses what the Commission shall determine in approving an IRP. See MCL 460.6t(8). In relevant part, Section 6t(8)(b) provides "[t]o the extent practicable, the construction or investment in a new or existing capacity resource in this state is completed using a workforce composed of residents of this state as determined by the commission." MCL 460.6t(8)(b). Section 6t(8)(b) therefore only applies when a utility is proposing to construct a new resource or invest in an existing

resource and aligns with the cost approval provision of the IRP law which allows utilities to seek pre-approval of those construction and investment costs in an IRP. MCL 460.6t(11) ("the commission shall specify the costs approved for the construction of or significant investment in an electric generation facility..."). There is no reasonable interpretation of Section 6t(8)(b) which could link that provision to a required evaluation of the "instate employment and tax benefits" of the BMPs. The Company does not own the BMPs and is not proposing any construction or investment related to those plants.

V. CONCLUSION

Q. Based on the contested settlement direct testimony filed by Energy Michigan, Wolverine, and the BMPs, have those parties established any basis for the Commission to reject the Settlement Agreement?

A. No. For the reasons discussed above, Energy Michigan and Wolverine have failed to establish that there are detrimental reliability and resource adequacy impacts related to the Settlement Agreement. Wolverine's assertion that the Company will experience a capacity deficiency in 2025 was also shown to be incorrect. As explained by Company witness Clark, Energy Michigan and Wolverine have also refused to provide the capacity projections and future capacity plans for Energy Michigan's AES members and Wolverine. Therefore, beyond the fact that Energy Michigan's and Wolverine's claims are incorrect about the impact of the Settlement Agreement on Zone 7, Wolverine's and Energy Michigan's failure to provide capacity forecasts and future capacity plans also makes clear that their criticisms of the Settlement Agreement cannot be sustained. Wolverine and

Energy Michigan have failed to establish any basis for the Commission to not approve the Settlement Agreement.

The BMPs have also failed to establish any basis for the Commission to not approve the Settlement Agreement. The BMPs positions should be rejected because: (i) the Company has no obligation to enter new PPAs or extend existing PPAs with any of the BMPs; (ii) the Company did consider biomass plants in the development of its IRP and that type of resource was shown not to be a viable option on an economic or cost basis; (iii) the BMPs have failed to produce any evidence establishing the costs that the BMPs could agree to in new PPAs or PPA extension; and (iv) the existing BMP PPA cost information available to the Company establishes that the BMPs are not competitive with either market pricing or the Company's recent competitive procurement results. For the reasons detailed above, the BMPs have also failed to establish any real flaws in the Settlement Agreement which would prevent the Settlement Agreement from being approved by the Commission.

Q. Does this conclude your second rebuttal testimony?

A. Yes.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Midcontinent	)
Independent System Operator	)
(MISO)	)
	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 57

Jester 2021 Direct Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
CONSUMERS ENERGY COMPANY for Case No. U-21090
approval of an Integrated Resource
Plan under MCL 460.6t, certain Volume 10
accounting approvals, and other relief.

_____/

CROSS-EXAMINATION (Settlement Agreement)

Proceedings held via Microsoft Teams in the above-entitled matter before Sally L. Wallace, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Friday, May 20, 2022, at 9:06 a.m.

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(Continued)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	U-21090 ALJ Sally L. Wallace

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TESTIMONY OF DOUGLAS B. JESTER
IN SUPPORT OF SETTLEMENT AGREEMENT

ON BEHALF OF

THE MICHIGAN ENVIRONMENTAL COUNCIL,
NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB,
AND CITIZENS UTILITY BOARD OF MICHIGAN

May 9, 2022

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I. INTRODUCTION

Q. Are you the same Douglas Jester who previously filed testimony in this case?

A. Yes.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC), and Sierra Club (SC) (collectively, "MNS") and Citizens Utility Board of Michigan (CUB).

Q. What is the purpose of your testimony?

A. I am testifying on behalf of MNS and CUB to support the settlement agreement in this case.[1]

Q. Are you sponsoring any exhibits?

A. No.

Q. Please summarize your opinions regarding the settlement agreement.

A. The settlement agreement is in the public interest; represents a fair and reasonable resolution of this case; and is supported by substantial evidence. The settlement preserves the most beneficial aspects of Consumers' Proposed Course of Action, including the retirement of the entire Campbell plant and the permanent exit from coal generation in 2025; as well as the solar ramp-up and annual competitive solicitations for solar generation.

[1] Case No. U-21090, Settlement Agreement filed April 20, 2022.

The settlement also improves upon Consumers' initially-filed PCA by:

- Eliminating the purchase of certain gas plants from Consumers' affiliate CMS Enterprises;
- Providing for competitive solicitation of Power Purchase Agreements to backfill the retiring Campbell capacity, including a tranche of dispatchable, non-intermittent generation and a tranche of clean capacity (which includes battery storage resources);
- Maintaining Karn units 3-4 in operation to support resource adequacy;
- Reducing the return on equity for the proposed regulatory asset for the retiring Campbell plant;
- Providing additional support from Company shareholders to low-income customer bill assistance programs;
- Substantially maintaining the 50/50 procurement terms from the settlement in Case No. U-20165;
- Maintaining the Financial Compensation Mechanism methodology from the settlement in Case No. U-20165;
- Requiring further evaluation of transmission options to improve reliability and facilitate economic power imports;
- Advancing battery storage investments;
- Improving future analysis of line losses and avoided transmission and distribution costs in the evaluation of distributed resources, including residential demand response;

- Requiring environmental justice analysis in Consumers' next IRP;
- Providing for public filing of community transition plans for the Campbell and Karn sites; and
- Addressing issues under the Public Utility Regulatory Policies Act (PURPA) to the satisfaction of the parties who engaged on those issues.

The improvements to the PCA reflected in the settlement agreement resulted from extensive, arms-length negotiations between Consumers and the parties, and the settlement agreement is supported by the vast majority of the parties in this case. For these reasons, it is my opinion that the settlement is in the best interest of customers and the environment, and I wholeheartedly recommend that the Commission approve it.

II. OVERVIEW OF CONSUMERS' INITIAL PROPOSALS IN THIS CASE

Q. Please summarize the resource portfolio presented in Consumers' initial PCA in this case.

A. The PCA described in Consumers Energy's direct case included the following resource elements:

- Retire Karn units 3 and 4, which are oil/gas peakers, in May 2023;
- Retire coal-fired Campbell units 1, 2, and 3 in May 2025;
- Purchase the New Covert Generating Facility, a natural gas-fired plant, in May 2023;
- Purchase three gas plants owned by Consumers' affiliate, CMS Enterprises Company – Dearborn Industrial Generation (DIG), Kalamazoo, and Livingston – in May 2025;

- Continue procuring solar resources via annual competitive solicitations, with increases in projected utility-scale solar deployment throughout the 2020s and 2030s;
- Slow development of battery storage projects, with the first battery resources coming online in 2030;
- Make modest adjustments in Consumers' projected Energy Waste Reduction, Demand Response, and Conservation Voltage Reduction programs; and
- Pursue no new transmission projects or agreements to secure power imports from outside MISO Zone 7.

Q. Please summarize the principal financial requests that Consumers made in its direct case.

A. Apart from the gas plant acquisition costs, Consumers made two significant financial requests in its initial case.

First, Consumers proposed to establish a $1.5 billion regulatory asset for the unrecovered book balances of the Campbell plant and Karn units 3-4. Consumers also proposed to recover that asset through conventional ratemaking over the previously planned remaining life of the units, with recovery of depreciation expense and pre-tax weighted average cost of capital, or WACC, including return on equity.

Second, Consumers proposed to change the method by which its PPA Financial Compensation Mechanism, or FCM, is calculated. The settlement in Consumers' last IRP case, U-20165, provided the Company with an FCM calculated by multiplying the PPA

payments by Consumers' after-tax WACC using its total capital structure. In this case, Consumers proposed to increase the FCM by multiplying the PPA payments by Consumers' pre-tax WACC using its permanent capital structure. Using pre-tax WACC instead of after-tax WACC and using permanent capital structure instead of total capital structure would have increased Consumers' current PPA incentive by almost 50%.

Q. Did Consumers propose changing its solar procurement practices?

A. Yes. The most significant proposed change was to the allocation between Company-owned and PPA solar projects. In the settlement of Case No. U-20165, Consumers agreed to acquire at least 50% of its solar capacity acquired via PPAs and no more than 50% from company-owned projects or build-transfer agreements. In this case, the Company proposed to reverse that allocation and acquire at least 50% from company-owned resources and no more than 50% via PPAs.

III. REASONABLENESS OF THE SETTLEMENT AGREEMENT

Q. What does the settlement provide regarding the Campbell plant?

A. In paragraph 4(ii) of the settlement, the parties agree that Campbell units 1, 2, and 3 will retire on or before May 31, 2025.

Q. In your opinion, is retiring the Campbell plant a reasonable and beneficial settlement term?

A. Yes. First it should be noted that no party in this case opposed retirement of Campbell units 1 and 2. The Proposal for Decision (PFD) in this case also recommended approval of those retirements.

Further, retiring the entire Campbell plant will benefit both customers and the environment and is therefore in the public interest. After Karn 1 and 2 retire in 2023, Campbell 1-3 will be the last remaining coal units in Consumers' portfolio. The Campbell plant has a greater carbon impact than any other resource owned by the Company, and its retirement is critical to meeting state and federal climate goals, including the Michigan Healthy Climate Plan.[2] Because the Campbell plant emits other pollutants, such as SO_2, NO_x, and particulate matter, retiring Campbell is likely to also have health benefits in addition to those from reducing the Company's carbon output.

Extensive modeling conducted by Consumers and by MNS in this case demonstrated that retiring Campbell in 2025 is economic for customers. MNS witnesses Tyler Comings and Casey Roberts also explained that Campbell's continued operation poses regulatory risks due to Steam Electric Effluent Guidelines (SEEG) requirements and potential carbon costs. And witness Comings noted that retiring Campbell in 2025 will save customers more than $150 million of avoidable capital expenditures. In proposing Campbell's retirement, the Company also cited community and worker benefits of accelerated retirement over continued operation. The testimony, exhibits, and modeling regarding these issues provide substantial evidence to support the Campbell plant retirement.

Q. Please explain why Campbell's 2025 retirement is important for meeting the Michigan Healthy Climate Plan goals.

[2] Available at https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf?rev=d13f4adc2b1d45909bd708cafccbfffa&hash=99437BF2709B9B3471D16FC1EC692588, last checked May 6, 2022.

A. Governor Whitmer's Executive Directive, which initiated development of the Michigan Healthy Climate Plan, directed that the plan should result in 26-28% reduction in economy-wide greenhouse gas emissions from 2005 to 2025.[3] The following table displays Michigan's GHG emissions in 2005 and the associated goals of the Michigan Healthy Climate Plan as I compiled them from reports by the US Energy Information Administration:[4]

Michigan Energy GHG Emissions 2005 (million metric tons CO2 Equivalent)	Residential Sector	Commercial Sector	Industrial Sector	Transportation Sector	Electric Power Sector	All Energy Sectors
Coal	0.0	0.3	7.3	0.0	67.8	75.4
Petroleum Products	4.6	0.9	5.8	53.8	0.8	65.9
Natural Gas	19.3	9.4	12.0	1.5	7.0	49.2
Total Energy-Related	23.9	10.6	25.1	55.3	75.6	190.5
Non-Energy 2002 GHG Emissions						29.3
Total 2005 GHG Emissions						219.8
NDC Goal 2025	26% Reduction from 2005					162.7
NDC Goal 2030	50% reduction from 2005					109.9
Whitmer Goal 2050	Net Zero by 2050					0.0
Energy Emissions Goal 2025	Assume 0% reductions in non-energy GHG emissions since 2005					133.4
Energy Emissions Goal 2030	Assume 25% reduction in non-energy GHG emissions since 2005					88.0
Energy Emissions Goal 2050	Assume elimination or offsets by 2050					0.0

2019 is the most recent full compilation of similar data available from EIA. As of 2019, the corresponding emissions were as shown in the following table:

[3] Executive Directive 2020-10 affirmed this goal that she first adopted in Executive Directive 2019-12.

[4] State Carbon Dioxide Emissions Data - U.S. Energy Information Administration (EIA), available at https://www.eia.gov/environment/emissions/state/, last checked May 6, 2022.

Michigan Energy GHG Emissions 2019 (million metric tons CO2 Equivalent)	Residential Sector	Commercial Sector	Industrial Sector	Transportation Sector	Electric Power Sector	All Energy Sectors
Coal	0.0	0.0	4.0	0.0	44.2	48.2
Petroleum Products	3.5	1.5	6.2	50.5	0.6	62.2
Natural Gas	20.2	11.1	10.6	0.0	16.8	58.7
Total Energy-Related	23.7	12.6	20.8	50.5	61.6	169.2
Energy Emissions Reduction Needed by 2025						35.8
Energy Emissions Reduction Needed by 2030						81.2

Since policy and economic trends related to the residential, commercial, industrial, and transportation sectors have not obviously caused a change in emissions trends in these sectors, I used those trends to project a similar table for 2025. In addition, I used EPA's facility-level GHG emissions inventory[5] to identify 2019 GHG emissions from Michigan power plants that have since retired or been committed to retire by 2025, including the Campbell plant, and assumed that reduction from Electric Power Sector emissions. That forecast provides the following comparable table:

2025 GHG Emissions Reductions (million metric tons CO2 equivalent)	Residential Sector	Commercial Sector	Industrial Sector	Transportation Sector	Electric Power Sector	All Energy Sectors
Replace Coal Generation with Clean Generation					-17.8	
EV Sales Ramp to 100% by 2035				-3.5		
Accelerate Heating Efficiency & Electrification to 3.5%/yr	-5.6	-2.6	-4.1			
2025 Remaining Energy-Related Emissions	18.1	9.9	16.7	47.0	43.8	135.5
2025 Gap						2.1

[5] EPA Facility Level GHG Emissions Data, available at: https://ghgdata.epa.gov/ghgp/main.do#/facility/, lasted checked May 9, 2022.

Assuming the Campbell retirement and no new gas-fueled generation, there is a gap of 2.1 million metric tons CO2 equivalent (MMT CO2eq) between the 2025 goal of the Michigan Healthy Climate Plan and what is likely to be achieved. Since the Campbell plant annual emissions are approximately 8.285 MMT CO2eq, it is clearly not possible to meet the 2025 goal of the Michigan Healthy Climate Plan without the retirement of the Campbell plant by 2025. The retirement of Campbell is therefore critical to meeting the Climate Plan's goal.

Further, the Michigan Healthy Climate Plan calls for the retirement of all coal generation by 2030, which would necessarily include the Campbell units.

Q. What does the settlement provide regarding solar generation?

A. By approving the PCA except as modified in the settlement agreement, paragraph 1 of the agreement approves Consumers' continued ramp-up of solar resources – an initiative first approved as part of Consumers' 2018 IRP. In the 2018 case, the Commission approved a plan that included approximately 5 GW nameplate of new solar resources in the 2020s. In this case, Consumers proposed to continue those additions and also procure an additional 2 GW of solar in the 2030s above the levels included in the 2018 IRP. Paragraph 8 of the settlement agreement provides that Consumers will continue to utilize annual competitive solicitations to procure these solar resources.

Q. In your opinion, is approval of Consumers' solar additions a reasonable and beneficial settlement term?

A. Yes. In approving the settlement in U-20165, the Commission recognized that Consumers

Energy's planned solar ramp-up was both groundbreaking and environmentally beneficial. The Commission also endorsed the use of the annual solicitations to promote competition that would keep costs down and benefit customers. These public interest benefits, which the Commission has already recognized, will continue with the new settlement.

Q. What does the settlement provide for regarding the acquisition of gas plants?

A. First, the parties agree at paragraph 2 to Consumers' acquisition of the Covert plant, and that the purchase costs for that plant of $815 million are reasonable and prudent.

Second, the parties agree at paragraph 2 that Consumers will not obtain ownership of the three CMS plants: DIG, Livingston, and Kalamazoo.

Q. In your opinion, are the settlement terms regarding the acquisition of gas plants reasonable and beneficial?

A. Yes. With respect to Covert, no party opposed Consumers' acquisition of that plant, and the PFD recommended approving it. As testimony by both Staff and Consumers pointed out, because Covert is currently in PJM, Consumers' acquisition of Covert will add 1,114 Zonal Resource Credits or ZRCs to MISO Zone 7. That action will support reliability for Consumers as well as overall resource adequacy for Zone 7. For these reasons, acquisition of Covert is both in the public interest from a reliability and resource adequacy standpoint, and it is supported by substantial evidence in the record of this case.

Consumers' agreement not to acquire the CMS plants is also in the public interest and supported by substantial evidence. The record in this case showed myriad concerns regarding the CMS acquisitions – including issues with respect to affiliate transactions; the

nature of the gas plant RFP solicitation that led to the proposed purchase of these plants; and related issues. Staff, the Attorney General, and MNS all submitted substantial testimony and exhibits regarding these issues, and the hearing included substantial live testimony concerning them as well. In addition, parties including MNS, the Clean Energy Organizations (CEOs), and the Great Lakes Renewable Energy Association also provided evidence concerning certain risks associated with acquisition of those plants. Based on all of this evidence, the PFD also recommended against acquisition of the CMS plants.

Consumers has since come up with prudent plans to backfill capacity from retiring Campbell units by other means. I describe those plans next. Finally, it is worth noting that Staff supported in testimony Consumers' acquisition of Covert but not the CMS plants. The acquisition of some, but not all, of the assets Consumers sought to acquire is a self-evidently reasonable compromise.

Q. Which resources would replace Campbell's retiring capacity?

A. Under the settlement, Campbell's capacity will be replaced by a mix of resources. First, acquisition of the Covert plant will provide Consumers most of the energy and capacity currently provided by Campbell. Second, the settlement includes a one-time solicitation for PPAs that will provide up to 700 ZRCs of energy and capacity. These PPAs would be added to the Company's resource portfolio in the 2025 Planning Year – coinciding with the retirement of Campbell.

Q. Please describe the one-time solicitation of capacity and energy for the 2025 Planning Year.

A. In paragraph 6 of the settlement, the parties agree that Consumers will issue a one-time competitive solicitation for PPAs to begin in PY 2025. The solicitation will contain two tranches. The first tranche will seek up to 500 ZRCs of energy and capacity for up to 10 years from dispatchable, non-intermittent generation. The second tranche will seek up to 200 ZRCs of energy and capacity for up to 25 years from clean energy resources (including battery storage).

Q. In your opinion, is the one-time competitive solicitation a reasonable and beneficial settlement term?

A. Yes. The first tranche will provide energy and capacity of similar characteristics to what Consumers sought via the proposal to acquire the CMS plants. However, soliciting 10-year PPAs instead of acquiring affiliate assets planned to remain in rate base until 2040 will reduce risks to customers. Further, a solicitation for PPAs addresses one of the issues with the earlier RFP identified by parties and the PFD, which was that the earlier RFP only sought assets for purchase. Obtaining power via PPAs also addresses some of the other risks identified in the record, namely, those related to environmental permitting and fixed operating and maintenance expenses. Finally, the PPA approach is consistent with MNS modeling plans 1 and 3 discussed by witnesses George Evans and Tyler Comings. Those plans proposed using capacity purchases as part of lower-cost portfolios that retired

Campbell 3 without buying most or all of the CMS plants.

The second tranche is also beneficial to the public interest and supported by substantial evidence. It will provide additional clean energy resources for Consumers' portfolio, with the attendant benefits I discussed earlier in my testimony. It is also consistent with my testimony that Consumers should solicit for up to 750 MW of solar resources per year rather than 500 MW – a recommendation the PFD also adopted.

Q. What does the settlement provide regarding Karn units 3-4?

A. Paragraph 4(i) of the settlement provides that Karn units 3-4 will not retire in 2023 but instead will continue operating and retire on or before their previously planned retirement date of May 31, 2031, absent extraordinary circumstances.

Q. In your opinion, is the Karn retirement date a reasonable and beneficial settlement term?

A. Yes. Karn 3-4 are large peaking units already owned by Consumers. They provide substantial capacity but operate infrequently. Continuing to operate Karn 3-4 supports Consumers' attainment of planning reserve margin requirements by maintaining more than 780 ZRCs in the Company's portfolio. It also supports resource adequacy in Zone 7, for the same reason. Public health and climate impacts from Karn 3-4 are minor because the units operate so infrequently; in recent years their capacity factor has been substantially less than 5%. Keeping Karn 3-4 in operation also removes its unrecovered net book value from the total balance of the regulatory asset that Consumers seeks, which will now be limited to the balance for the Campbell plant, lowering the costs of the regulatory asset for

customers.

Q. What does the settlement provide regarding Consumers' request for the regulatory asset you just mentioned?

A. In paragraph 5 of the settlement, the parties agree that after retirement of the Campbell plant in 2025, the return on equity used to calculate the WACC for the regulatory asset will be 9.0%.

Q. In your opinion, is this regulatory asset provision a reasonable and beneficial settlement term?

A. Yes. Consumers has taken a very firm position that it will not retire Campbell in 2025 without being able to recover a return of and on the unrecovered balance. Therefore, it was necessary for the other parties to agree with a regulatory asset based on WACC for this settlement to occur and to facilitate Consumers' permanent exit from coal generation three years from now. On the other hand, setting the ROE at 9.0% for the calculation of the WACC on the regulatory asset is a significant compromise for Consumers, as that figure is substantially lower than the authorized ROE of 9.9% that the Commission approved in Consumers Energy's last electric rate case, U-20963. In addition, it is my understanding that the Attorney General negotiated the low-income bill assistance provision I describe next in tandem with the compromise on the regulatory asset, which further balances the burdens and benefits of this important financial component of the agreement.

Q. What does the settlement provide regarding support from Company shareholders to low-income customer bill assistance programs?

A. Consumers agreed in paragraph 13 of the settlement to donate funds to its low-income bill assistance programs. These donated funds will not be recovered in rates. Consumers will donate $5 million in 2022 and $2 million per year for the rest of the term of the regulatory asset for the Campbell plant. Consumers will consult with the Attorney General and Staff on the recipient low-income fund, and will provide an annual report to the Commission.

Q. In your opinion, are the low-income assistance donations a beneficial settlement term?

A. Yes. The need for additional low-income customer bill assistance has been demonstrated both in recent Consumers electric rate cases and in recent Consumers EWR cases, and recognized by the Commission in a variety of orders.[6] Prohibiting recovery of these funds in rates will ensure that they come from shareholders, which is a reasonable component of the overall compromise on the regulatory asset and ROE.

Q. What does the settlement provide regarding the allocation of future solar procurements?

A. Paragraph 9 of the settlement requires Consumers to use commercially reasonable efforts to maintain the 50/50 split between owned resources and PPAs for new solar procurements

[6] See for example Case No. U-20963, December 22, 2021 Order, pp. 402-403 (agreeing "that a COSS with a low-income customer subclass may be beneficial and recommends the company include a low-income customer subclass in the COSS for the EAAC in Case No. U-20757[.]"); Case No. U-20875, March 17, 2022 Order Approving Settlement Agreement.

that was first approved in the U-20165 settlement. This provision creates an absolute cap of 60% on capacity that Consumers acquires for ownership in any annual solicitation, while setting no cap on the amount of new solar the Company may acquire via PPA. The term also maintains the bar on Consumers affiliates participating in the PPA portion of the solicitations.

Q. In your opinion, is continuing the 50/50 split a reasonable and beneficial settlement term?

A. Yes. The Commission found this allocation reasonable and in the public interest in Case No. U-20165 and this term maintains the essential components of that agreement. It promotes competition among third-party developers which reduces customer costs, and it helps support the solar industry in Michigan. This term represents a substantial compromise by Consumers, which had sought in this case to eliminate a maximum amount of solar it could procure for Company ownership. This provision is also consistent with the PFD recommendation on this issue.

Q. What does the settlement provide regarding the Financial Compensation Mechanism?

A. The settlement provides at paragraph 10 for an extension of the FCM approved in Case No. U-20165. The method for calculating the FCM will remain the same as approved in that case, using after-tax WACC and total capital structure. The FCM will not be applied to PPA amendments, PURPA PPAs, Voluntary Green Pricing PPAs, or PPAs executed under Consumers' renewable energy plan.

Q. In your opinion, is the FCM a reasonable and beneficial settlement term?

A. Yes. Consumers has substantially changed its business model by agreeing to shift its resource portfolio away from coal generation and toward solar generation, and by agreeing to procure the solar generation via competitive solicitations under which half of that capacity will be in the form of PPAs. An FCM is a reasonable incentive for the Commission to authorize under such circumstances. I supported the FCM under these terms in both U-20165 and this case for those reasons. The Commission approved the FCM in Case No. U-20165 over vigorous objection of a small minority of parties, and the Commission's reasoning in that case applies equally in this one. Further, Consumers has compromised on the methodology for calculating the FCM by using after-tax WACC and total capital structure rather than pre-tax WACC and permanent capital structure as the Company requested in this case. The calculation methodology is also supported by my testimony in this case.

Q. What does the settlement provide regarding transmission analysis?

A. Paragraph 16 of the settlement states that the parties agree in Consumers' next IRP to consider how transmission investments can improve reliability and access to economic sources of power from areas outside Zone 7.

Q. In your opinion, is the transmission provision a reasonable and beneficial settlement term?

A. Yes. MNS witness Jay Caspary described the importance of transmission for both reliability and economics in his direct testimony in this case. The PFD found that

Consumers' transmission analysis in this case was deficient and did not meet the terms of the settlement agreement in U-21065. Consumers' commitment to address transmission analysis further in its next IRP will maintain focus on this issue going forward.

Q. What does the settlement provide regarding battery storage investments?

A. The parties agree to approval of a battery deployment program in paragraph 3 of the settlement agreement. Consumers proposed in rebuttal testimony to advance investment in 75 MW of battery storage resources. The settlement reserves approval of the costs of the program to future electric rate cases.

Q. In your opinion, is the battery storage program a reasonable and beneficial settlement term?

A. Yes. Consumers made the battery proposal in response to testimony from Staff, MNS, and other parties that called for acceleration of battery storage investments as part of Consumers' resource portfolio for this IRP. The battery deployment will provide another clean energy resource to bolster Consumers' maintenance of its PRMR and support resource adequacy in Zone 7. It is also worth noting that the clean energy tranche of the one-time solicitation (paragraph 6(b)(ii)) may similarly lead to the development of new battery storage resources within Zone 7.

Q. What does the settlement provide regarding collection and analysis of line loss data and avoided transmission and distribution costs in the evaluation of distributed resources?

A. Consumers agrees in paragraph 14 of the settlement to collect further data on marginal line losses and to include marginal line losses and avoided transmission and distribution (T&D) costs in the evaluation of all distributed resources, including residential demand response, for its next IRP.

Q. In your opinion, is the line loss and avoided T&D provision a reasonable and beneficial settlement term?

A. Yes. This term is based on recommendations by CUB witness David Gard and MNS witness Chris Neme. Both of these witnesses explained the importance of these issues to the evaluation of EWR potential and DR potential for future IRPs. Consumers agreed to some but not all of their recommendations in rebuttal testimony, and has reached further agreement via this settlement term.

Q. What does the settlement provide regarding environmental justice and community outreach?

A. Paragraphs 17 and 18 of the settlement contain detailed provisions regarding environmental justice analysis and community outreach for Consumers' next IRP.

Q. In your opinion, are the environmental justice and community outreach provisions reasonable and beneficial settlement terms?

A. Yes. The CEOs and Urban Core Collective sought measures like these in their testimony in this case. The environmental justice analysis will provide vital information regarding the people and communities who bear disproportionate impacts of electric generation activities – information that has been lacking in Michigan IRP cases up until now. The community outreach provisions are important steps toward facilitating greater awareness and participation by people and communities who are normally excluded by the nature of proceedings like these.

Q. What does the settlement provide regarding community transition plans for the Campbell and Karn sites?

A. Paragraph 7 of the settlement agreement requires Consumers to publicly file its community transition plans for the Campbell and Karn sites.

Q. In your opinion, is the community transition plans provision a reasonable and beneficial settlement term?

A. Yes. MNS witness Tyler Comings testified in this case regarding the need for these plans to be public.

IV. CONCLUSION AND RECOMMENDATIONS

Q. What is your overall conclusion regarding the settlement agreement?

A. The settlement agreement in this case continues and significantly extends the progress of the settlement in U-20165. The settlement approves a major step by Consumers to address

the climate crisis while providing numerous protections for customers from future costs and risks. It is comprehensive, detailed, thorough, and embodies the input of many parties to this case. It is supported by the great weight of the evidence in the record of this case and consistent with many of the findings and recommendations in the PFD. It is the product of extensive negotiations and represents reasonable compromises on many fronts. I recommend that the Commission approve it.

Q. Does that complete your testimony?

A. Yes.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Midcontinent	)
Independent System Operator	)
(MISO)	)
	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 58

MISO Tariff Module E-1

This Module E-1 provides mandatory requirements to be met by the Transmission Provider, Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity (LSE), or other Market Participants, to ensure access to deliverable, reliable and adequate Planning Resources to meet Coincident Peak Demand and Local Resource Zone Peak Demand requirements on the Transmission System. These requirements recognize and are complementary to the reliability mechanisms of the states and the Regional Entities (RE) within the Transmission Provider Region. Nothing in this Module E-1 affects existing state jurisdiction over the construction of additional capacity or the authority of states to set and enforce compliance with standards for adequacy. The Resource Adequacy Requirements (RAR) in this Module E-1 are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction. To the extent that an LSE's Coincident Peak Demand is physically located within the Transmission Provider's Balancing Authority Area but is pseudo-tied out of the MISO Balancing Authority Area pursuant to the Transmission Provider's Business Practices Manuals (BPM), such Coincident Peak Demand is not subject to the RAR provisions if such Coincident Peak Demand is subject to another Balancing Authority Area's resource adequacy requirements. To accomplish these reliability requirements, Module E-1 includes provisions for: establishing Local Resource Zones and associated limits (*i.e.*, Capacity Import Limits (CIL) and Capacity Export Limits (CEL)); establishing Local Reliability Requirements (LRR); establishing Local Clearing Requirements (LCR); establishing External Resource Zones and associated limits (i.e., Capacity Export Limits (CEL)); determining the Planning Reserve Margin; Coincident Peak Demand forecasting; Local Resource Zone Peak Demand forecasting; qualifying and quantifying Planning Resources; participation of Demand and Planning Resources in the Planning Resource

Auction process; settlement provisions; and Planning Resource performance requirements for each Season.

Establishment of Planning Reserve Margins

The Transmission Provider will determine a Planning Reserve Margin (PRM) in terms of Unforced Capacity for each Season using analytical study methods described in Section 68A.2, provided that if a State Regulatory Authority establishes a PRM for its regulated entities that is higher or lower than the PRM determined by the Transmission Provider, then the State Regulatory Authority-established PRM will apply to the Coincident Peak Demand of LSEs under that state's jurisdiction.

Planning Reserve Margin Analysis

The Transmission Provider shall perform a technical analysis on an annual basis to establish the PRM for each Season for the Transmission Provider Region and the Transmission Provider will publish the results by November 1 preceding the applicable Planning Year. The PRM analysis shall be consistent with Good Utility Practice and the reliability requirements of the REs and the applicable states in the Transmission Provider Region. The PRM analysis shall consider factors including, but not limited to: the Generator Forced Outage rates of Capacity Resources; Generator Planned Outages; expected performance of Demand Response Resources (DRR), Load Modifying Resources (LMR), and Energy Efficiency Resources; load forecast uncertainty; and the Transmission System's import and export capability with external systems. The Transmission Provider annually will calculate and publish on its website the estimated PRM for each of the nine subsequent Planning Years, to provide information for long-term resource planning, without establishing any enforceable specific planning reserve requirements.

Loss of Load Expectation Analysis

The Transmission Provider shall coordinate with Market Participants to determine the appropriate PRM for the applicable Season in the Planning Year based upon the probabilistic analysis of being able to reliably serve the Transmission Provider Region's Demand for the applicable Season in the Planning Year. This probabilistic analysis shall use a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations within the Transmission Provider Region.

The following process will be utilized to determine the minimum PRM requirement for each Season in the Planning Year using the LOLE analysis. First, an LOLE analysis for the Planning Year will be conducted such that the LOLE for the Planning Year is one (1) day in ten (10) years, or 0.1 day per year, by either adding or removing capacity. If the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year. If the LOLE for a Season is equal to or greater than 0.01 day per year, the minimum PRM requirement for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year, an additional LOLE analysis will be performed to determine minimum PRM requirement for that Season by adding a perfect negative unit with zero forced outage rate to that Season until the LOLE in that Season reaches 0.01.

The minimum amount of capacity above Coincident Peak Demand in the Transmission Provider Region required to meet the reliability criteria will be used to establish the PRM for each Season.

The PRM will be established as a requirement in terms of the total Unforced Capacity for the Transmission Provider Region.

No later than September 1st of the year prior to a Planning Year, the Transmission Provider will, as necessary, develop new Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be located in the right physical locations within the Transmission Provider Region to reliably meet Demand and LOLE requirements. The geographic boundaries of each of the LRZs will be based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of LOLE studies; (5) the relative size of LRZs; and (6) natural geographic boundaries such as lakes and rivers. The Transmission Provider may re-evaluate the boundaries of LRZs if there are significant changes in the Transmission Provider Region based upon the preceding factors, including but not limited to, significant changes in membership, the Transmission System, and/or Resources.

An External Resource Zone (ERZ) will be created for each external Balancing Authority that has External Resources qualifying as Planning Resources, excluding those Balancing Authorities with only Coordinating Owner resources that are qualified to obtain local credit and/or Border External Resources.

Establishment of SRRZs, SRECs and SRICs

The Transmission Provider will establish and publish, on the Transmission Provider's public website, SRRZs, SRECs and SRICs for each Season as soon as practical but no later than the first business day of March for the following Planning Year. To calculate the SRECs and SRICs, the Transmission Provider will determine the transfer limit between SRRZs in accordance with applicable seams agreements, coordination agreements, or transmission service agreements. Next, the Transmission Provider will then complete a feasibility analysis in accordance with the Resource Adequacy Business Practices Manual to review operational events from each Coincident Peak Demand hour during the previous Planning Year, and forecasted expected conditions for each Season in the upcoming Planning Year, to determine if a further reduction to the transfer limit is warranted for reliability. If such a reduction is necessary, the Transmission Provider will reduce the regional directional transfer limit, as appropriate. The Transmission Provider will then subtract the sum of Firm Transmission Service Reservations on the MISO OASIS that utilize the contract path between SRRZs and are exporting from or wheeling through the Transmission Provider's Balancing Authority for the applicable Season in the Planning Year. This difference determines the SREC and SRIC to be utilized for the applicable Season in the Planning Year.

Prior to publishing the SRRZs, SRECs, and SRICs on its public website, Transmission Provider will present the feasibility analysis and resulting SREC and SRIC calculation to stakeholders.

Establishment of CIL and CEL Limits

On or before November 1st of each year, the Transmission Provider will determine preliminary values for the CIL and CEL for each of the LRZs for each Season in the following Planning Year by considering factors, including but not limited to, the following elements: (1) existing and planned Transmission System and Planning Resource additions; (2) transmission import and export capability; and (3) applicable NERC contingencies. To determine the CIL and CEL for each LRZ, the Transmission Provider will use models which contain the physical location of Load and Planning Resources for each Season. Generator output will be assigned to LRZs or ERZs consistent with the PRA representation of Planning Resources. Constraints that are identified as a result of determining the CIL and/or the CEL for each LRZ will be considered in the development of the MISO Transmission Expansion Plan (MTEP) in accordance with Attachment FF.

CIL will be equal to the Zonal Import Ability plus firm capacity commitments to non-MISO load. CEL will be equal to the Zonal Export Ability minus firm capacity commitments to non-MISO load.

The CIL and CEL values for each Season for each LRZ will be updated if needed prior to the Planning Resource Auction, but no later than eight (8) Business Days before the last Business Day in March, due to changes to firm capacity commitments from MISO resources to neighboring regions prior to the Planning Resource Auction.

MISO will determine the CEL for each Season for each ERZ no later than eight (8) Business Days before the last Business Day in March as equal to the ZRC quantity of the External Resources registered to participate in the PRA.

Establishment of Local Reliability Requirement

By November 1st prior to a Planning Year, the Transmission Provider will establish a Local Reliability Requirement (LRR) metric for each LRZ to determine the quantity of Unforced Capacity needed for each Season, without consideration of the benefit of the LRZ's CIL. First, the LOLE analysis for the Planning Year will be conducted by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. If the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year. If the LOLE for a Season is equal to or greater than 0.01 day per year for the LRZ, the LRR for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year for the LRZ, an additional LOLE analysis will be performed to determine the LRR for that Season by adding a perfect negative unit with zero forced outage rate to that season until the LOLE in that Season reaches 0.01 day per year for the LRZ.

The Transmission Provider will model the location of Load and Planning Resources based on their representation in the Planning Resource Auction to determine the LRR for each LRZ. The minimum amount of capacity above the Local Resource Zone Peak Demand in the LRZ required to meet the reliability criteria will be used to establish the LRR for each Season.

The per unit LRR in each LRZ initially will be established as the ratio of the LRR over the Local Resource Zone Peak Demand modeled in the LOLE study. An LRZ's LRR shall be calculated by multiplying the per unit LRR for the LRZ times the forecasted Local Resource Zone Peak

Demand for each Season as provided by LSEs or EDCs, or as developed by the Transmission Provider, pursuant to Section 69A.1.

Establishment of Local Clearing Requirement

The Local Clearing Requirement for each LRZ for each Season will be determined by subtracting Zonal Import Ability and controllable exports from the LRR, as set forth in the Resource Adequacy Business Practices Manual. Controllable exports are exports from MISO resources that have firm capacity commitments to non-MISO load and that may be committed and dispatched by the Transmission Provider during a declared Energy Emergency. The LCR values will be updated if needed prior to the Planning Resource Auction due to changes in controllable exports.

Establishing Planning Reserve Margin Requirements

a. The Transmission Provider will establish Planning Reserve Margin Requirements (PRMR) for each Season for an LSE's Load within any given LRZ. The Initial PRMR will be determined by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + Transmission Provider Region PRM).

b. The Transmission Provider will use the Transmission Provider Region PRM for the Initial PRMR calculation unless an alternate PRM is established by a State Regulatory Authority. In such event, the Transmission Provider will use the alternate PRM that a State Regulatory Authority has created for the geographic area in which the state has jurisdiction. The Transmission Provider will convert any State Regulatory Authority provided PRM to a comparable Unforced Capacity basis.

Calculation of Transmission Losses

a. The Transmission Provider shall calculate the LBA transmission loss percentages for each Season using the process described as follows:

1. The Transmission Provider's State Estimator calculates transmission losses (MW) as part of the solution output process every five (5) minutes.
2. The transmission losses (MW) are computed on all transmission lines and transformers by summing up real power at both ends for each transmission element (retaining the convention for flow direction) or as the difference in real power (without the sign convention for flow direction) for each State Estimator solution.
3. The individual transmission losses (MW) for each element are summed to a total transmission values for each Local Balancing Authorities (LBA) level.
4. These LBA transmission loss values are then integrated across each hour to calculate an hourly transmission loss value (MW) for each LBA.
5. The total transmission loss value (MW) for each LBA will be the hourly integrated transmission losses value (MW) for the hour of the Coincident Peak Demand from the calendar year two years prior to the upcoming Planning Year.
6. For the purposes of the Transmission Provider Region, the LBA transmission loss percentages are calculated as the total LBA transmission losses divided by the total LBA peak data at that MISO peak hour for each Season. For purposes of a Local Resource Zone, the LBA transmission loss percentages are calculated as the

total LBA transmission losses divided by the total LBA peak data at the LRZ peak hour for each Season.

b. The Local Balancing Authority (LBA) transmission loss percentage shall apply to the LSE's applicable LBA Coincident Peak Demand and Local Resource Zone Peak Demand forecast to determine the LSE transmission losses. Behind-the-Meter-Generation Resources that are interconnected to the Transmission System shall be treated like other Resources with respect to transmission losses. Behind-the-Meter-Generation Resources and Distributed Energy Aggregated Resources that are not interconnected to the Transmission System, Demand Resources, and Energy Efficiency Resources shall be adjusted to account for serving load without incurring transmission losses by grossing up the MW quantity of such resources by (1.0 + the appropriate LBA transmission loss percentage).

Marginal Reliability Impact (MRI) Curves

A. The following process will be used to determine the MRI Curves for the Transmission Provider Region for each Season of the upcoming Planning Year. The minimum PRM requirement for each Season established in the LOLE analysis, as described in Section 68A.2, will be the starting point. Then, for each Season, a perfect negative unit(s) with a capacity of at least 50MW and no more than 250MW, or perfect proxy unit(s) with a capacity of at least 50MW and no more than 250MW will be added to the model and the LOLE analysis will be performed. The capacity of both the perfect negative unit(s) and perfect proxy unit(s) will be of equal value. The change in EUE as a result of adding or removing capacity will be calculated. An additional unit(s) with the same capacity value will be added or removed in addition to the first increment or decrement and the LOLE analysis will be performed again. This process will be repeated until sufficient data is available to fit a curve that measures changes to EUE as MWs are added or removed from the minimum PRM requirement.

B. The First Planning Area MRI Curve is a smoothed representation of reliability changes as measured by EUE as more or less MWs are included in the LOLE analysis. The following process will be used to determine the MRI Curves for the First Planning Area for each Season in the Planning Year. Assignment of LOLE risk across the Seasons will be the same as described in Section 68A.2 for the Planning Reserve Margin analysis. A minimum PRM requirement for the First Planning Area for each Season will be established through additional LOLE analysis in which the First Planning Area and Second Planning Area each have the same reliability target established for the

Transmission Provider Region as the starting point. After establishing the starting point, the MW quantity associated with the minimum PRM requirement in the Second Planning Area will be fixed, and capacity in the First Planning Area will then be added or removed to calculate changes to EUE in the First Planning Area.

C. The Second Planning Area MRI curve is a smoothed representation of reliability changes as measured by EUE as more or less MWs are included in the LOLE analysis. The following process will be used to determine the MRI Curves for the Second Planning Area for each Season in the Planning Year. Assignment of LOLE risk across the Seasons will be the same as described in Section 68A.2 for the Planning Reserve Margin analysis. A minimum PRM requirement for the Second Planning Area for each Season will be established through additional LOLE analysis in which the First Planning Area and Second Planning Area each have the same reliability target established for the Transmission Provider Region as the starting point. After establishing the starting point, the MW quantity associated with the minimum PRM requirement in the First Planning Area will be fixed, and capacity in the Second Planning Area will then be added or removed to calculate changes to EUE in the Second Planning Area.

RAR Process

Once the Transmission Provider has established the PRM, LCR, LRR, preliminary Capacity Import Limits and Capacity Export Limits and published such values on the Transmission Provider's website, then LSEs shall provide forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data for the Planning Year. For Retail Choice areas, the EDC shall provide, on behalf of LSEs within the EDC, forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data for the Planning Year to be used by the Transmission Provider. The Transmission Provider will then calculate each LSE's Initial PRMR for each Season. LSEs will meet their RAR obligation by: (i) submitting a Fixed Resource Adequacy Plan; (ii) submitting ZRCs for an RBDC Opt Out; (iii) Self-Scheduling ZRCs; (iv) purchasing ZRCs through the Planning Resource Auction process; and/or (v) paying the Capacity Deficiency Charge to meet a portion of their PRMR. LSEs that submit an RBDC Opt Out may not use any of the other options to satisfy their Final PRMR. LSEs not submitting an RBDC Opt Out may use one or more of all other available options, or any combination of available options, to satisfy their Initial or Final PRMR. The Transmission Provider will enforce the LCRs, final Capacity Import Limits and Capacity Export Limits for each LRZ, and Capacity Export Limits for each ERZ in the Planning Resource Auction. An ACP will be determined through the PRA process for each LRZ and ERZ for each Season and the ACP will be used to credit ZRCs that clear in the auction and to debit LSEs for the volume of their PRMR that is procured through the auction. Market Participants that own Planning Resources used to create ZRCs which clear in the PRA (or are identified in either a submitted Fixed Resource Adequacy Plan or an RBDC Opt Out) must meet the applicable performance requirements as described in sections 69A.3.9 and

69A.5. The Transmission Provider shall provide states, upon request, with relevant resource adequacy information as available, subject to the data confidentiality provisions in Section 38.9 of the Tariff.

Load Serving Entity Responsibilities

a. LSEs shall provide Coincident Peak Demand (and also, if available, Local Resource Zone Peak Demand forecasts) forecasts as specified in Section 69A.1.1b and will also be responsible for meeting their Final PRMR for each LRZ where they serve Load by submitting Fixed Resource Adequacy Plans, by Self-Scheduling ZRCs, by purchasing ZRCs through the PRA process, by submitting ZRCs for an RBDC Opt Out and/or by paying the Capacity Deficiency Charge.

b. The Transmission Provider will use Coincident Peak Demand, Local Resource Zone Peak Demand, and Energy forecasts for each Season that are submitted by an EDC in combination with allocation procedures that are agreed to by the applicable LSEs. These procedures will allow the Transmission Provider to initially allocate appropriate portions of the total forecasted Coincident Peak Demand and Local Resource Zone Peak Demand to each LSE as applicable pursuant to 69A.1.2.1, and to re-assign ZRC-related charges caused by customer switching between suppliers to the appropriate LSE.

c. All LSEs shall report to the Transmission Provider, through the MECT, whether such LSE will meet their PRMR for each LRZ for each Season in which the LSE serves Load by: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process; (iv) submitting an RBDC Opt Out; and/or, (v) paying the Capacity Deficiency Charge.

Forecasted Demand Identification

a. The Demand forecasts required in Section 69A.1 shall include: (1) the Coincident Peak Demand within each LBA Area in the Transmission Provider Region for the upcoming Planning Year; (2) the monthly non-coincident peak Demand and net Energy for Load within each LBA Area, for the upcoming Planning Year and the following Planning Year; (3) the non-coincident peak Demand and net Energy for Load within each LBA Area, for each Season, for the eight Planning Years subsequent to the two for which monthly values are provided in (2); and (4) the available Local Resource Zone Peak Demand within each LBA Area in the Local Resource Zone for the upcoming Planning Year. All of these forecasts shall be submitted by November 1st prior to each Planning Year and shall be consistent with Good Utility Practice. Forecast providers shall use the MECT or other means described in the BPM for Resource Adequacy to submit the requisite information. Details regarding the items required in the Demand forecasts submittal are in the BPM for Resource Adequacy.

b. The supplied Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall include the Demand expected for the forecast time period (*e.g.* the Coincident Peak Demand hour) augmented to include the normal Demand from forecasted demand resources, whether registered or not registered with the Transmission Provider, including Demand from any retail demand side management programs and Demand behind a DEAR. Such forecasts shall include Demand that would have occurred but for the existence of Energy Efficiency Resources that have been in operation less than four (4) years. All submissions for such forecast values shall include distribution losses, but not transmission losses. The Transmission Provider will be responsible for the calculation of the applicable transmission losses for the forecasts provided

and for annually publishing such values for each LBA on its website by October 1, as specified in Section 68A.8 and the BPM for Resource Adequacy.

c. In order to assist with the development of the Coincident Peak Demand and Local Resource Zone Peak Demand forecasts, the Transmission Provider will make available the historical monthly peak hours for each of the four months June through September, since 2005, or as available, for the Transmission Provider Region and for each Local Resource Zone. On or before March 1st of each year, the Transmission Provider will review a sampling of submitted Demand forecast methodologies and inputs to ensure accuracy and consistency, in accordance with the BPM for Resource Adequacy. If the Transmission Provider determines that the Demand forecast methodologies are inaccurate or inconsistent, the Transmission Provider shall work with the applicable LSEs to reconcile such issues. If reconciliation is not achieved, or if Local Resource Zone Peak Demand forecasts are not available, then the Transmission Provider will provide the required forecast values.

d. All Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall reflect a 50% probability that the Demand will not exceed the forecasted Demand for the relevant period.

e. Consistent with Section 69A.1.2.1, the EDC must provide both the Transmission Provider and the respective LSEs with each retail customer's peak load contribution ("PLC") in each Season, including transmission losses and PRM as determined by the Transmission Provider, in the EDC's service territory by December 15th. At least five (5) Business Days before January 15, LSEs must notify the EDC and the Transmission Provider if they disagree with the EDC calculated PLC value.

f. If an LSE knows it will gain a wholesale customer by the beginning of any Season in the next Planning Year, then that LSE may provide the Transmission Provider with the Coincident Peak Demand and the Local Resource Zone Peak Demand forecast for such acquired load by November 1. In all other cases, the existing Market Participant serving such wholesale customer shall provide the Transmission Provider by November 1st with the Market Participant's forecast of the wholesale customer's Coincident Peak Demand and Local Resource Zone Peak Demand.

Accounting for Total Demand Forecasts Given Wholesale and Retail Load Switching

a. On or before January 15th, an EDC must notify the Transmission Provider through the MECT of the Initial PRMR for the LSE's proportion of the EDC's forecast Demand that it expects to serve on the 1st day of each Season in the next Planning Year. The LSE that is the provider of last resort ("POLR") for the EDC area in question will have the obligation to procure capacity for the required PRMR for the remaining Demand (*i.e.*, the remaining Demand is the EDC's forecast Coincident Peak Demand minus the sum of the LSE's allocated portion of forecast Coincident Peak Demand, identified as described above, in the EDC's service territory). The Transmission Provider will notify the POLRs of any remaining Initial PRMR within five (5) Business Days after January 15th.

b. On or before January 15th, to account for wholesale customers that may switch LSEs during the next Planning Year, the PRMR will be met as follows: (1) if an LSE has responsibility to serve a wholesale load on the 1st day of any Season in of the next Planning Year, then such LSE shall have the obligation to procure the required PRMR for such load for such Season; (2) if no LSE has responsibility for serving a wholesale load on of the 1st day of any Season in of the next Planning Year, then the LSE with an obligation to serve such load on November 1 before the Planning Year, shall have the obligation to procure capacity for the required PRMR for each Season in the upcoming Planning Year for such load, provided that such LSE anticipates that the contract for wholesale load will be extended; or (3) if the LSE advises the Transmission Provider that the LSE will not serve the contract for wholesale load, then the customer for such wholesale load shall inform the Transmission Provider by January

30th of the name of the Market Participant that will be responsible for the PRMR obligation for such wholesale load.

Daily Assignment of Coincident Peak Demand Obligations

a. For those areas of service where an LSE's Coincident Peak Demand forecast is included in the Coincident Peak Demand forecast submission of an EDC, the EDC will determine and report each LSE's portion of such Demand to the Transmission Provider, using the default method set forth in Section 69A.1.2.1.

b. In a state that permits retail load switching, the Transmission Provider shall allocate resource capacity costs on a daily basis to LSEs by multiplying the Final PRMR associated with identified customers served by the LSE times the applicable zonal Auction Clearing Price less any zonal deliverability benefits plus any Local Clearing Requirement Charges for the Local Resource Zone where the load is located, consistent with Section 69A.1.2.1.

c. In states where wholesale load may switch, the Transmission Provider shall allocate costs on a daily basis to LSEs. The LSE that acquires wholesale load will be charged for such load based upon the Final PRMR for the wholesale load's forecast Coincident Peak Demand times the applicable zonal Auction Clearing Price less any zonal deliverability benefits plus any Local Clearing Requirement Charges for the Local Resource Zone where the wholesale load is located.

d. An LSE may challenge the EDC Demand forecast under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

Default Method

a. The method submitted by an EDC must describe in detail the procedures and data used to determine the assignment of the EDC's forecast Coincident Peak Demand to its retail customers, including those served by LSEs providing service within the EDC's area.

b. EDC will assign a peak load contribution ("PLC") value to each retail customer, based on the most recent PLC values derived for each Season from each retail customer's Demand at the time of the Transmission Provider's peak Demand during each Season (*i.e.*, the Prior Seasonal Retail Customer Coincident Peak ("PSRCCP")). Retail customer peak demands should be increased to reflect any load reductions achieved and for which capacity credits are earned, either through retail programs or participation in wholesale markets (*e.g.* LMRs). In the aggregate, the PLCs determined by the EDC must equal the Initial PRMR that is calculated from the forecast Coincident Peak Demand provided by the EDC for each Season. This equality is achieved by multiplying each retail customer's demand at the time of the Transmission Provider's peak Demand during each Season prior to the Planning Year by the same adjustment factor, as shown in the equation below:

$$\Sigma_i \, PLC_i = \text{Initial } PRMR_{EDC}$$

$$\text{Factor} = \text{Initial } PRMR_{EDC} \div \Sigma_i \, PSRCCP_i$$

In other words, for each EDC, the sum of the individual retail customer (*i.e.*, i) PLC values must equal the EDC's Initial PRMR. In addition, a single value ("Factor") is defined as the ratio of the Initial PRMR for any EDC divided by the sum of all of the PSRCCP values for each of the EDC's retail customers. The EDC must use the same Factor in the following equation:

$$PLC_i = \text{Factor} \times PSRCCP_i \quad \forall i$$

Thus, for each EDC it must also be true that the PLC for any individual retail customer shall be equal to the product of that customer's PSRCCP times the same Factor identified in the second equation above. For the purposes of these equations, the following mathematical symbols are used: (1) Σ equals sum; (2) $_i$ equals individual retail customer, as in PLC_i or $PSRCCP_i$; and (3) ∀i equals for all i, as in: for each member of the set of retail customers.

c. The PSRCCP shall be adjusted (upward) to reflect any demand that was reduced during the Coincident Peak for each Season hour through the effect of a Load Modifying Resource, or through the effect of an Energy Efficiency Resource during the first four (4) full Planning Years of the EE Resource's existence. The Transmission Provider will provide to the EDC the amount of measured (or estimated if final settlement data is forthcoming) load reduction that occurred as a result of an ARC or LSE deploying a DRR, LMR or EDR following a Setpoint Instruction, Scheduling Instruction or EDR Dispatch Instruction during the Transmission Provider's Coincident Peak Demand.

Load Switching

Beginning the first Calendar Day of each Season in the Planning Year, the EDC will be responsible for tracking the individual customer Final PRMR values transferred from the originally supplying LSE to the newly supplying LSE now responsible for resource adequacy commitments.

Forecasted Demand for FRP/FRS Agreements

Full Responsibility Purchases/Sales (FRP/FRS) agreements are treated effectively like a transfer of Demand and all RAR obligations from one LSE to another Market Participant. A purchaser under an FRP/FRS agreement shall submit the forecasted Coincident Peak Demand and Local Resource Zone Peak Demand associated with such agreement to the Transmission Provider through the MECT for the applicable Planning Year. A seller under an FRP/FRS agreement is contractually obligated to comply with all of the RAR obligations for the transferred Demand during the Planning Year encompassing the planned Coincident Peak Demand. The purchaser under an FRP/FRS agreement no longer has the RAR obligations for the transferred Demand; provided however, that if the seller under an FRP/FRS agreement is not an LSE under the jurisdiction of the Transmission Provider, then the purchaser under the FRP/FRS agreement will remain responsible for any RAR obligations associated with the Demand transferred under the FRP/FRS agreement. A seller under an FRP/FRS agreement will be responsible for the transferred Demand to meet this additional obligation like it was their own Demand. If a seller and a purchaser under an FRP/FRS agreement cannot agree on whether a particular transaction is an FRP/FRS agreement, then either party may invoke the dispute resolution procedures in Section 12 of the Tariff.

Multiple Region Planning Resources

If an LSE serves Demand both in the Transmission Provider Region and outside the Transmission Provider Region, then the LSE must separately satisfy its Final PRMR in all areas of the Transmission Provider Region. Compliance with RAR shall not affect an LSE's obligation to maintain distinct and separate amounts of resources to cover its applicable planning reserve obligation for the amount of Demand outside the Transmission Provider Region.

Capacity Tracking Tool

To facilitate RAR, the Transmission Provider shall administer the MECT, a title tracking and registration tool that shall include the ability to enable Market Participants and LSEs to meet their RAR responsibilities.

Planning Resource Requirements

Nothing herein shall infringe upon the requirement that LSEs comply with applicable state safety standards, planning reserve margins, or be subject to the enforcement thereof. If the Transmission Provider becomes aware that any Planning Resource fails to meet the requirements of this section, then the Transmission Provider shall promptly notify the Market Participant and specify the reasons for any such failure. Wherever possible, the Transmission Provider and the Market Participant will work in good faith to remedy deficiencies, if any, in meeting the Planning Resource requirements, through informal communications rather than Commission filings.

Capacity Resources

As described below, a Generation Resource, External Resource, Demand Response Resource - Type II, Intermittent Generation, Dispatchable Intermittent Resource, Electric Storage Resource, or Hybrid Resource is eligible to become a Capacity Resource. The Transmission Provider will qualify a Capacity Resource for any applicable Season in the upcoming Planning Year, in accordance with processes specified in the BPM for Resource Adequacy. Electric Storage Resources can be Capacity Resources if they meet all the requirements as specified in the BPM for Resource Adequacy, including the requirement to be able to continuously discharge for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day, in accordance with the BPM for Resource Adequacy, provided that an Electric Storage Resource may de-rate its capacity in order to comply with this requirement.

Generation Resources that are not Dispatchable Intermittent Resources or Distributed Energy Aggregated Resources

1. Generation Resources and Electric Storage Resources that are not Dispatchable Intermittent Resources or Distributed Energy Aggregated Resources are eligible to qualify as Capacity Resources by a Market Participant that possesses ownership or equivalent contractual rights for the Resource by:

(a) registering such resource with the Transmission Provider as documented in the BPM for Market Registration;

(b) demonstrating GVTC capability for each Season in the Planning Year as established in the BPM for Resource Adequacy;

(c) submitting generator availability data (including, but not limited to, NERC Generation Availability Data System (GADS) information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy;

(d) by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing Capacity Resources unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.a.4; and

(e) demonstrating deliverability as described in Section 69A.3.1(g). All new Generation Resources and Electric Storage Resources that are not Dispatchable Intermittent Resources and Distributed Energy Aggregated Resources, or an existing Generation Resource and Electric Storage Resource that is not a Dispatchable Intermittent Resource and s Distributed Energy Aggregated Resource that has an increased installed capacity, shall submit their GVTC to the Transmission Provider prior to qualification, but no later

than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for a Generation Resource and Electric Storage Resource that is not a Dispatchable Intermittent Resource (including a Generation Resource and Electric Storage Resource that has the status of Suspend pursuant to Section 38.2.7) and a Distributed Energy Aggregated Resource that has not completed GVTC testing by the deadlines provided in 69A.3.1.a.1, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used in the PRA or in a FRAP (including through bilateral ZRC transactions), subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

3. Reporting generator availability data based on GVTC is not required for a Generation Resource or Electric Storage Resource that is not a Dispatchable Intermittent Resource and a Distributed Energy Aggregated Resource and that is less than 10 MW if the Market Participant has never provided such data for such Resource. A Market Participant that begins reporting generator availability data based on GVTC for a Generation Resource or Electric Storage Resource that is not a Dispatchable Intermittent Resource and that is less than 10 MW must continue to report such data. A Generation Resource or Electric Storage Resource that has provisional Interconnection Service does not qualify as a Capacity Resource.

4. A Market Participant for a Generation Resource required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning

Year. If circumstances prevent the Market Participant from submitting the GVTC results for the Generation Resource by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the Generation Resource from utilizing the ICAP Deferral process as described in Section 69A.7.9.

Demand Response Resources – Type II

1. Demand Response Resources – Type II backed by a Demand Resource are eligible to qualify as Capacity Resources. A Market Participant that possesses ownership or equivalent contractual rights in the DRR – Type II can register such resource as a Capacity Resource with the Transmission Provider for the upcoming Planning Year as documented in the BPM for Market Registration and by meeting the following requirements:
    a. For an existing DRR – Type II that is a Capacity Resource, the Market Participant shall demonstrate capability and availability to reduce Demand in response to instructions from the Transmission Provider for each applicable Season and shall submit such data to the Transmission Provider no later than October 31 prior to such Planning Year unless the Transmission Provider has granted an extension, as established in the BPM for Resource Adequacy.
    b. For a new DRR – Type II or for an existing DRR – Type II that has experienced an increase in its Capacity Rating, and that is backed by a Demand Resource, the Market Participant shall submit test data to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.
2. A Demand Response Resource – Type II that is backed by behind the meter generation is eligible to qualify as Capacity Resources. A Market Participant that possesses ownership or equivalent contractual rights in the DRR – Type II can register such resource as a Capacity Resource with the Transmission Provider for the upcoming Planning Year as

documented in the BPM for Market Registration and by meeting the following requirements:

a. A Market Participant shall demonstrate GVTC capability of the DRR – Type II backed by behind the meter generation for each Season in the Planning Year as established in the BPM for Resource Adequacy;

b. An existing DRR – Type II backed by behind the meter generation shall submit GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.b.4; and

c. A Market Participant shall submit generator availability data (including, but not limited to, NERC Generation Availability Data System information) for the DRR – Type II backed by behind the meter generation into a database provided by the Transmission Provider.

d. For a new DRR – Type II or an existing DRR – Type II that has an increased installed capacity, and that is backed by behind the meter generation, the Market Participant shall submit GVTC data to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.

3. Installed Capacity (ICAP) Deferral

If a Market Participant for a DRR – Type II has not completed GVTC testing by the deadlines provided in 69A.3.1.b.2, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs

from such capacity may be used in the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out (including through bilateral ZRC transactions) subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

4. Reporting generator availability data based on GVTC is not required for a DRR – Type II backed by behind the meter generation facility of less than 10 MW if the Market Participant has never provided such data for such behind the meter generation facility. A Market Participant that begins reporting generator availability data for behind the meter generation facility that is less than 10 MW based on GVTC must continue to report such data. A Demand Response Resource – Type II that has provisional Interconnection Service does not qualify as a Capacity Resource. In accordance with the qualification provisions in the BPM for Resource Adequacy, the Transmission Provider will qualify a Demand Response Resource – Type II for the applicable Season in the upcoming Planning Year.
5. A Market Participant for a DRR – Type II required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the DRR by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline.

Denial of an extension will not preclude the Market Participant for the DRR – Type II from utilizing the ICAP Deferral process as described in Section 69A.7.9.

External Resources:

1. External Resources, including those specified in Diversity Contracts and PPAs (which are subject to additional qualification requirements in section 69A.3.1.c.4), are eligible to qualify as Capacity Resources by a Market Participant that possesses ownership or equivalent contractual rights in External Resources by: (a) registering such resources with the Transmission Provider as documented in the BPM for Resource Adequacy; (b) demonstrating GVTC capability for each Season that the resource will be registered in as established in the BPM for Resource Adequacy by providing operational data, and by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing Capacity Resources unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.c.5; (c) submitting generator availability data (including, but not limited to, NERC Generation Availability Data System information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy; (d) identifying one or more specific External Resource(s) that can be verified by the Transmission Provider as Capacity Resource(s) and which does not include any portion(s) of an External Resource that has already qualified as a Capacity Resource; (e) demonstrating that there is firm transmission service for each Season that the resource is to be registered in from the External Resource to the border interface CPNode of the Transmission Provider Region and either that firm Transmission Service has been obtained to deliver capacity on the Transmission System from the border to a Load within an LRZ or demonstrating deliverability as described in Section 69A.3.1.g; and (f) certifying that any External

Resources being identified are not otherwise being used as capacity resources in any other RTO/ISO, in another resource adequacy construct, or in an external balancing authority's resource plan for its firm end-use load and capacity sales requirements within the external balancing authority area.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for an External Resource has not completed GVTC testing by the deadlines provided in 69A.3.1.c.1, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used in the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out (including through bilateral ZRC transactions) subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

3. Reporting generator availability data for an External Resource of less than 10 MW based upon GVTC is not required if the Market Participant has never provided such data for such External Resource. A Market Participant that begins reporting generator availability data for an External Resource that is less than 10 MW based on GVTC must continue to report such data. All new External Resources or an existing External Resource that has an increased installed capacity shall submit their GVTC to the Transmission Provider prior to qualification as established in the BPM for Resource Adequacy. In accordance with the qualification provisions in the BPM for Resource Adequacy, the Transmission Provider will qualify an External Resource for the applicable Season in the upcoming Planning Year.

4. In the case of a power purchase agreement (PPA), including, but not limited to a Diversity Contract, then the agreement shall meet the additional qualification requirements set forth below:

   i. A PPA that does not identify the full Installed Capacity of the External Resource from which power will be supplied must specify the portions of each such External Resource that is available under the PPA (i.e. slice-of-system resources) and that are verifiable by the Transmission Provider. Each External Resource specified in such PPA must meet the criteria for a Capacity Resource for all of the portion of the contract amount assigned to the External Resource(s). The capacity from the External Resource will be reduced proportionately to remove amounts that fail to meet such criteria.

   ii. A copy of every PPA must be provided by the Market Participant using External Resources from such PPA as a Capacity Resource to the Transmission Provider to enable it to verify the External Resource(s) that are backing the PPA and to confirm compliance with RAR. Any redacted versions of a PPA submitted by a Market Participant must contain sufficient information to allow the Transmission Provider to verify compliance with RAR. The Transmission Provider will maintain the confidentiality of these agreements in accordance with the confidentiality provisions in Section 38.9 of the Tariff.

   iii. For PPAs executed after April 3, 2014, one of the following must apply regarding the external balancing authority in which the External Resource is located:

(a) In the case of unit specific sales, if the MISO Balancing Authority Area is experiencing an Energy Emergency, the external balancing authority will not interrupt the PPA Schedule from the External Resource unless the generator being used to serve the unit specific sale has a forced outage.

(b) In the case of slice-of-system sales, if the external balancing authority area experiences an Energy Emergency and the MISO Balancing Authority Area is simultaneously experiencing an Energy Emergency, the external balancing authority will only interrupt the PPA Schedule on a pro rata basis with the shedding of firm end-use load in the external balancing authority area. Pro rata interruption of the PPA Schedule from the External Resource will be determined as the ratio of the PPA Schedule to the sum of the external balancing authority firm end-use load plus the PPA Schedule. (c) If the external balancing authority (1) is located within the Transmission Provider's reliability coordinator area; (2) participates in a contingency reserve sharing group with the Transmission Provider; and (3) has a Seams Operating Agreement with the Transmission Provider containing the following features, then in the event that the external balancing authority area experiences an Energy Emergency and the MISO Balancing Authority Area is simultaneously experiencing an Energy Emergency, the Transmission Provider and the external balancing authority will share interruption of PPA Schedules from an External Resource and load shedding in the external balancing authority area on a pro rata basis in proportion to the end-use load in the area under the Energy Emergency. Pro rata sharing shall be

determined as the respective ratio of each of the balancing authority's end-use load in the Energy Emergency Area divided by the sum of the end-use load of each balancing authority in the Energy Emergency Area. The Seams Operating Agreement must (1) ensure that the external balancing authority has established a planning reserve margin and qualifications for planning resources using processes and criteria comparable to the Transmission Provider; (2) specify the actions that will be taken by both entities during an Energy Emergency prior to implementing firm end-use load shedding, and (3) specify that the external balancing authority will submit end-use load estimates to the Transmission Provider in a comparable manner as submitted by Load entities in Module E-1, provide generator GVTC and GADS data for all resources used to serve firm requirements of the external balancing authority, and provide transparency in the form of submittal of fixed resource plans comparable to processes used by Market Participants for Fixed Resource Adequacy Plans in the Transmission Provider's Module E-1.

iv. A PPA executed prior to April 3, 2014 will continue to qualify as a Planning Resource for the full term of the PPA if it is only interruptible as a last resort under Requirement 2 of NERC Standard EOP-011-1. A Diversity Contract executed prior to April 3, 2014 will continue to qualify as a Planning Resource, if it is only interruptible as a last resort under Requirement 2 of the NERC Standard EOP-011-1 between June 1st and September 30th.

v. A Market Participant may only qualify a PPA as a Capacity Resource if such agreement establishes a firm obligation on the part of the seller of the Capacity to deliver the Capacity to the Market Participant.

vi. If the terms and conditions in a PPA do not explicitly conform with every requirement of Section 69A.3.1.c. 4 (i) through (iv) above, the Transmission Provider will use alternative documentation and verification procedures to determine if the PPA qualifies as a Capacity Resource. A party seeking Capacity Resource status for a non-conforming PPA must provide the Transmission Provider with written information regarding whether: (a) the PPA was executed prior to October 20, 2008; (b) an RE has accredited the PPA to satisfy resource adequacy requirement provisions; (c) the PPA has provided reliable capacity to the Transmission Provider Region; (d) the supplier(s) of capacity in the PPA commit(s) to provide the capacity to an LSE in the Transmission Provider Region in a defined amount at a defined location based upon the supplier(s)' portfolio of generation assets; (e) energy from the PPA cannot be interrupted for economic reasons and will only be interrupted for force majeure type conditions as a last resort during Emergency conditions; (f) either the purchaser(s) or the supplier(s) of capacity in the PPA has committed to offer energy into the Day-Ahead Energy and Operating Reserves Market and all pre-Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment processes for all periods for which energy is available under the PPA, consistent with the must offer provisions in Section 69A.5; (g) the physical resource(s) backing the PPA are identified by the

supplier of the PPA; (h) the portion of the physical resources backing the PPA has not otherwise been registered by any other entity as Capacity Resources in the Transmission Provider Region or as capacity resources in any other region; and (i) if the PPA is renewed, the PPA will be modified to comply with the terms of section 69A.3.1.c. 4 (i) through (iv) and (vi). The Transmission Provider will analyze all available alternative documentation and verification information. Based upon such analysis, the Transmission Provider will inform the party seeking Capacity Resource status for the PPA within 30 days whether the PPA qualifies as a Capacity Resource.

vii. No PPA may be qualified as a Capacity Resource if such agreement includes provisions permitting the seller to interrupt deliveries thereunder for reasons other than Force Majeure.

5. A Market Participant for an External Resource required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the External Resource by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline.

Denial of an extension will not preclude the Market Participant for the External Resource from utilizing the ICAP Deferral process as described in Section 69A.7.9.

6. Existing Resources that modify their registration, scheduling and market participation in the Energy and Operating Reserves Markets and become pseudo-tied External Resources after September 1, 2022 will be accredited at the lesser of class average SAC in Schedule 53 or the accreditation provisions governing External Resources in section 69A.4.1.b.

Use Limited Resources

The Market Participant shall identify eligible Generation Resources, Electric Storage Resources, Distributed Energy Aggregated Resources or External Resources to the Transmission Provider that are Use Limited Resources. The Market Participant that seeks to qualify a Generation Resource, Distributed Energy Aggregated Resource or External Resource as a Use Limited Resource under RAR shall meet all the requirements as specified in the BPM for Resource Adequacy. A Use Limited Resource must be able to operate for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day in each applicable Season in order to qualify as a Capacity Resource, in accordance with the BPM for Resource Adequacy.

Intermittent Generation, Dispatchable Intermittent Resources, and Distributed Energy Aggregated Resources

Intermittent Generation, Dispatchable Intermittent Resources, and Distributed Energy Aggregated Resources are resources that are eligible to qualify as a Capacity Resource by a Market Participant provided that the Market Participant: (a) possesses ownership or equivalent contractual rights for the resource; (b) supplies historical performance data or required documentation for the resource as established in the BPM for Resource Adequacy; and (c) registers the resource with the Transmission Provider in accordance with the BPM for Market Registration (if the resource is located within the MISO Balancing Authority Area metered boundary), or the BPM for Resource Adequacy (if the resource is located outside the MISO Balancing Authority Area metered boundary).

Curtailments

At its sole discretion, the Transmission Provider may curtail exports not being used as capacity by an external balancing authority and/or recall External Resources, PPAs, and Diversity Contracts sourced from a Capacity Resource during a declared Energy Emergency. Procedures for such actions shall be specified in the operating procedures. With respect to external balancing authorities that have a Seams Operating Agreement with the Transmission Provider pursuant to Section 69 A.3.1.c.4, during a declared Energy Emergency in the MISO Balancing Authority Area, the Transmission Provider shall only interrupt or reduce Export Schedules associated with a sale of capacity on a reciprocal pro rata basis to that required of the external balancing authority in Section 69A.3.1.c.4.(iii).

A. Determination of Deliverability of Generation Resources, Electric Storage Resources, and External Resources:

The Transmission Provider shall be responsible for determining whether Generation Resources, Electric Storage Resources, and External Resources eligible to be Capacity Resources are deliverable to Load. The deliverable amount of such Generation Resources, Electric Storage Resources, and External Resources will be any combination of the following:

i. The amount of Network Resource Interconnection Service under Attachment X;

ii. The amount of Energy Resource Interconnection Service under Attachment X that is coupled with firm Transmission Service;

iii. The amount of firm Transmission Service associated with a Grandfathered Agreement that can only be used to satisfy PRMR within the LRZ of the Load under the Grandfathered Agreement;

iv. The amount of aggregate deliverability that a Generation Resource or External Resource was granted through the market transition deliverability test by the Transmission Provider and could qualify for Network Resource Interconnection Service; or

v. The amount of non-aggregate deliverability that a Generation Resource or External Resource was granted by the transmission provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that corresponding Transmission Owner's integration date, will be accepted by the Transmission Provider as deliverable to the Network Loads of

the Network Customer for that term of the confirmed designation, as such term may be extended.

B. Determination of Deliverability of Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources:

The Transmission Provider shall be responsible for determining whether Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources eligible to be Capacity Resources are deliverable to Load. The deliverable amount of such Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources will be any combination of the following:

i. The amount of Network Resource Interconnection Service under Attachment X;

ii. The amount of Energy Resource Interconnection Service under Attachment X that is coupled with firm Transmission Service;

iii. The amount of firm Transmission Service associated with a Grandfathered Agreement that can only be used to satisfy PRMR within the LRZ of the Load under the Grandfathered Agreement;

iv. The amount of aggregate deliverability that the Intermittent Generation or Dispatchable Intermittent Resource was granted through the market transition deliverability test by the Transmission Provider and could qualify for Network Resource Interconnection Service; or,

v. The amount of non-aggregate deliverability that a Intermittent Generation or Dispatchable Intermittent Resource was granted by the transmission provider and confirmed by a Network Customer as a designated Network Resource under the

OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that corresponding Transmission Owner's integration date, will be accepted by the Transmission Provider as deliverable to the Network Loads of the Network Customer for that term of the confirmed designation, as such term may be extended.

C. Determination of Deliverability of Distributed Energy Aggregated Resources

The Transmission Provider shall be responsible for determining whether Distributed Energy Aggregated Resources eligible to be Capacity Resources are deliverable to Load. The Distributed Energy Resource Aggregator will coordinate with the Electric Distribution Company in order for the Electric Distribution Company to perform a technical review of the Distributed Energy Aggregated Resource's transmission system impacts. Any MW found to be injecting onto the transmission system as a result of the technical review must demonstrate deliverability by obtaining External Network Resource Interconnection Service or firm Transmission Service in order to qualify for the Planning Resource Auction or a FRAP.

Retirement, Suspension, Installed Capacity (ICAP) Deferral and Replacement of Planning Resources

a. Retirement, Suspension, ICAP Deferral and Replacement

A Planning Resource for which a Market Participant requests a change in status in accordance with the System Support Resource (SSR) provisions described in Section 38.2.7 will no longer qualify as a Planning Resource effective as of the actual date that the status of the Planning Resource changes to Retire pursuant to Section 38.2.7. A Generation Resource that has the status of Suspend pursuant to Section 38.2.7 will continue to qualify as a Planning Resource in accordance with the BPM for Resource Adequacy. A Planning Resource for which a Market Participant submits an ICAP Deferral Notice will be subject to ICAP Deferral Requirements and Charges pursuant to Section 69A.7.9. As used in this section, "cleared ZRCs" include ZRCs that cleared in the PRA, were used in a FRAP, were used in an RBDC Opt Out, or were used to replace ZRCs in accordance with this section. As used in this section, "uncleared ZRCs" include ZRCs that did not clear in the PRA, were not used in a FRAP, were not used in an RBDC Opt Out or were not used to replace ZRCs in accordance with this section. If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is Retired or Suspended prior to the end of the Season during the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs. If a Market Participant does not replace such ZRCs associated with a Retired or Suspended Planning Resource, a Capacity Replacement Non-Compliance Charge will be assessed as determined below in this Section. If a Market Participant's Planning Resource fails to satisfy the ICAP deferral requirements set forth in Section 69A.7.9 and the Market Participant does not replace

cleared ZRCs with uncleared ZRCs, an ICAP Deferral Non-Compliance Charge will be assessed pursuant to Section 69A.7.9. If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Section 69A.5 for greater than thirty-one (31) Days in total due to full or partial Generator Planned Outage during the Season of the Planning Year in which the ZRCs cleared, or for Planning Resources that are subject to Diversity Contracts for greater than one (1) Month during any Season of the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource. If a Market Participant does not replace such ZRCs associated with a Planning Resource, a Capacity Replacement Non-Compliance Charge will be assessed as determined below in this Section. A Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs that are used to replace cleared ZRCs must meet the applicable performance requirements as described in sections 69A.3.3.1 and 69A.5 for the balance of the Season of the Planning Year, subject to the same replacement requirements set forth above. Any combination of cleared or replaced ZRCs that are on full or partial Generator Planned Outage for greater than thirty-one (31) Days in total during a Season, or for any other reason including full or partial Generation Outages that were not planned but were known or could have been reasonably anticipated at the time of the PRA, as set forth in the Market Monitoring and Mitigation Business Practices Manual, or unavailable because subject to a Diversity Contract that is not available for greater than one (1) Month during a Season, will be assessed a Capacity Replacement Non-Compliance Charge. If a Planning Resource for which a Market Participant converts Seasonal Accredited

Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Sections 69A.3.3.1 and 69A.5 due to a Catastrophic Generator Outage any time during the Season(s) of the Planning Year in which the ZRCs cleared such Market Participant may replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource. A Planning Resource may not transfer its performance requirements by replacing the cleared ZRCs with uncleared ZRCs other than in the case of suspension, retirement, ICAP deferral, Catastrophic Generator Outage or full or partial Generator Planned Outages that may exceed thirty-one (31) Days in the Season as discussed immediately above. Cleared ZRCs can be replaced with uncleared ZRCs that are not from the same LRZ or ERZ by examining post-replacement clearing as if it were the PRA clearing results, so that such replacement: (1) does not violate any CIL used in the PRA; (2) does not violate any CEL used in the PRA; (3) does not reduce the remaining total ZRCs for any LRZ of cleared ZRCs below the LCR for that LRZ; and (4) does not exceed any intra-regional flow ranges established under applicable seams agreements, coordination agreements, or transmission service agreements. ZRC replacements from LRZs or ERZs other than that of the cleared ZRCs will be processed in accordance with the following parameters:

i. ZRC replacement shall be processed on a first come, first served basis.
ii. The amount of cleared ZRCs in each LRZ or ERZs at the time of a ZRC replacement shall be based upon the current amounts of cleared ZRCs, including any previous replacement transactions.

ZRC replacement shall have no impact on settlements from the PRA, FRAPs, and RBDC Opt Out, including any assessed Capacity Replacement Non-Compliance Charges.

b. Capacity Replacement Non-Compliance Charge and Distribution

i. Capacity Replacement Non-Compliance Charges will be calculated as follows: the number of days for which the Market Participant had a replacement requirement but failed to replace per section 69A.3.1.h.a above multiplied by the amount of ZRCs that failed to be replaced multiplied by the sum of the ACP for the applicable Season and the daily CONE value (1/365 times CONE). The ACP and the CONE values will be based on the LRZ where the Planning Resource cleared those ZRCs. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in the respective SRRZ. For External Resources represented in ERZs that are connected to multiple SRRZs or that are not connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs.

ii. Distribution of Capacity Replacement Non-Compliance Charges: Capacity Replacement Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs that have met their Final PRMR during the applicable Season of the Planning Year on a *pro rata* basis, based upon their respective LSEs' share of Final PRMR for the Transmission Provider Region.

Energy Efficiency Resources (EE Resource)

An Energy Efficiency Resource is a Planning Resource, in which the Market Participant possesses ownership or equivalent contractual rights, from an end-use customer project (including the installation of more efficient devices or equipment or implementation of more efficient processes or systems) that was implemented after July 20, 2011, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous reduction in electric energy consumption during On Peak daylight hours, as further described in the BPM for Resource Adequacy. EE Resources are eligible to qualify as Planning Resources by registering such EE Resources as Planning Resources with the Transmission Provider, as documented in the BPM for Resource Adequacy. An EE Resource can qualify as a Planning Resource for ZRCs for each Season for up to four (4) Planning Years immediately following the EE Resource's initial qualification provided that the energy efficiency measures are fully implemented prior to each Planning Year. ZRCs from EE Resources will be grossed-up by the amount of avoided transmission losses in accordance with Section 68A.8.b and also by the applicable PRM in accordance with Section 68A.2. EE Resources shall not require notice, dispatch, or operator intervention, such that the EE Resource will reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service, in accordance with the BPM for Resource Adequacy. The additional requirements for EE Resource measurement and verification are found in Attachment UU.

Demand Response Resources – Type I and Load Modifying Resources

Demand Response Resources – Type I and Load Modifying Resources can be offered as ZRCs in the PRA or can be used in FRAPs pursuant to Section 69A.9 or used in an RBDC Opt Out pursuant to Section 69A.9.1. As described below, a Demand Resource or behind the meter generation is eligible to qualify as a DRR – Type I or a Load Modifying Resource if it meets the following requirements. All DRR – Type I and LMRs that are cleared in the PRA or were submitted in a FRAP for a Season or submitted in an RBDC Opt Out must be available for use in the event of an Emergency as declared by the Transmission Provider, pursuant to the Emergency Operating Procedures of the Transmission Provider, unless replaced with other ZRCs pursuant to Section 69A.3.1.h. In accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify a DRR – Type I or LMR for the applicable Season in the upcoming Planning Year. The Seasonal Accredited Capacity for DRR – Type Is and LMRs will be calculated pursuant to Schedule 53B.

Deployment Procedures for LMR

Procedures for deployment of LMR are found in the BPM for Resource Adequacy and emergency operating procedures. Such procedures shall be consistent with the information provided by the Market Participant regarding availability and notice time. At a minimum the Market Participant will provide the deployment parameters of the LMR (as described in Sections 69A.3.5 and 69A.3.6), during declared Emergencies prior to the use of Operating Reserves to achieve energy balance. The Market Participant shall, at all times, notify the Transmission Provider or Local Balancing Authority when the status or availability of an LMR changes, except for de minimis changes that do not need to be reported, according to procedures specified in the BPM for Resource Adequacy and emergency operating procedures. The Transmission Provider or Local Balancing Authority shall coordinate with the Market Participant that owns or controls such LMR when necessary to deploy or notify such LMR of a planned deployment. The Transmission Provider or Local Balancing Authority shall coordinate with the Market Participant that owns or controls such LMR when necessary to notify such LMR of a planned deployment through the issuance of Scheduling Instructions. Market Participants may be issued Scheduling Instructions during a declared Emergency or in anticipation of an Emergency at the discretion of Transmission Provider. Market Participants shall acknowledge Scheduling Instructions issued in accordance with BPM for Resource Adequacy for its LMRs. In the event of an anticipated Emergency where the Transmission Provider does not declare the actual Emergency at least two hours prior to the anticipated Emergency event, Market Participants are not obligated to meet the Scheduling Instructions issued in anticipation of such Emergency and

will not be penalized for non-performance. This does not apply to Scheduling Instructions issued after the declaration of an Emergency.

A Market Participant that acknowledges Scheduling Instructions for its LMR(s) as required by the BPM for Resource Adequacy will receive credit for one (1) of the minimum deployments or interruptions required for the LMR for the applicable Season whether or not an Emergency is declared. However, a Market Participant that fails to acknowledge the Scheduling Instructions as required by the BPM for Resource Adequacy will not receive credit for such deployment or interruption for its LMR(s).

An LMR that does not perform consistent with the Market Participant's response to its Scheduling Instructions in the event of an Emergency is subject to the penalty provisions of Section 69A.3.9 and will not receive credit as one (1) of the minimum deployments or interruptions required for such resource for the applicable Season.

Demand Resources (DR) with an Emergency Obligation

Demand Resources registered as either a DRR – Type I or LMR may be deployed to reduce Demand consistent with the submitted Capacity Availability submitted by the Market Participant representing the Demand Resource. A Market Participant shall test, validate, and measure its Demand Resources and submit the results to the Transmission Provider, which shall verify all Demand reduction claimed by a Market Participant, consistent with the procedures specified in the BPM for Demand Response. The accrediting, testing, validation, and Measurement and Verification developed by the Transmission Provider shall take into account any applicable State Regulatory Authority, Regional Entity, or other non-jurisdictional entities' requirements regarding duration, frequency and notification processes for the candidate Demand Resource. A Demand Resource that is sensitive to temperature changes or that is using a Statistical Measurement and Verification methodology must identify, at the time of registration, the extent of such parametric sensitivity to the Transmission Provider with sufficient detail to enable the Transmission Provider to verify whether the Demand Resource would be subject to penalties in Section 69A.3.9 for failure to achieve the targeted Demand reduction amount using the appropriate consumption baseline set forth in Attachment TT. Parametric sensitive analysis must include, but is not limited to, identifying the parameter changes and the parameter's elasticity of the LSE's Load, as further described in the BPM for Demand Response. In accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify a DR for each Season in the upcoming Planning Year.

Demand Resource Eligibility

A Market Participant that possesses ownership or equivalent contractual rights in a Demand Resource can register a Demand Resource as a DRR – Type I or an LMR to participate in the Planning Resource Auction as documented in the BPM for Resource Adequacy. The Market Participant registering the Demand Resource must include the contracts with each end-use customer indicating rights to require the Demand Resource to curtail Load. Notwithstanding, a copy of a contract with an end-use customer will not be required if the Market Participant is the end-use customer. In addition, the Market Participant must meet the following requirements:

a. A Market Participant shall be prohibited from registering into the PRA any component of a Demand Resource that is concurrently registered, in whole or in part, under another DRR, LMR, or EDR whether by the same or a different Market Participant. A Demand Resource registering as an LMR shall not also register as either a DRR or EDR.

b. The Demand Resource must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together as a Load Modifying Resource that is capable of reducing an LSE's Demand for the applicable Season may qualify in meeting this standard).

c. The Demand Resource must be available to be scheduled for a Demand reduction with a notification time requirement: (i) less than or equal to six (6) hours to register in the PRA as a DRR – Type I or an LMR – Type I; or, (ii) less than or equal to thirty (30) minutes to register as an LMR – Type II, in the applicable Seasons.

d. When a Demand Resource is issued Setpoint Instructions or Scheduling Instructions, performance will be evaluated as set forth in Attachment TT using the applicable Measurement and Verification.

e. Once the Setpoint Instruction, Scheduling Instruction, or Firm Service Level is achieved, the Demand Resource must be able to maintain the Setpoint Instruction, Scheduling Instruction, or Firm Service Level for at least four (4) continuous Hours.

f. Unless the Demand Resource is unavailable due to Force Majeure:

(i) A Demand Resource participating as a DRR – Type I or an LMR – Type I that is unavailable to respond to all Setpoint Instructions or Scheduling Instructions shall be subject to the penalties set forth in Section 69A.3.9; and

(ii) A Demand Resource participating as an LMR – Type II that is unavailable to respond to any Scheduling Instructions shall be subject to the penalties set forth in Section 69A.3.9.

This obligation only applies to Seasons during which a Demand Resource clears the Planning Resource Auction.

g. A Demand Resource for which curtailment is not an obligation during Emergency events declared by the Transmission Provider pursuant to the Transmission Provider emergency operating procedures, will not qualify to participate in the PRA as a DRR – Type I or qualify as an LMR.

A Market Participant that submits an Offer into the Day-Ahead and/or Real-Time

Energy and Operating Reserve Markets for a Demand Resource is still subject to the requirements to be available during an Emergency pursuant to the Transmission Provider Emergency Operating Procedures, regardless of the projected or actual Real-Time Energy market LMP.

h. A Demand Resource shall submit Metered data at regular intervals as set forth in Attachment TT.

i. A Market Participant must demonstrate demand reduction capability for each Planning Year on an annual basis as established in the BPM for Resource Adequacy. Beginning with the 2020/2021 Planning Year each Demand Resource must validate its performance by meeting the Transmission Provider's Scheduling Instructions when called upon during the prior Planning Year or conducting a real power test. A Demand Resource for which a real power test is conducted will receive credit as one (1) of the minimum deployments or interruptions required for such resource for the applicable Season of the Planning Year in which such a test occurs.

A Demand Resource may provide operational data, or develop an alternative mechanism, subject to the approval of the Transmission Provider, by which the demand reduction capability can be demonstrated without requiring an actual demand reduction if a real power test is precluded or waived due to one of the two conditions as specified below:

1) Such a real power test is precluded by any applicable regulatory restriction and such a limitation is documented during DR registration; or

2) A Market Participant may waive the obligation to conduct a real power test by notifying the Transmission Provider during DR registration and accepting a penalty equal to three (3) times the Hourly Real-Time Ex Post LMP at the Load CPNode described in and distributed pursuant to Section 69A.3.9. A Demand Resource providing such notice must satisfy credit requirements by March 1 prior to the Planning Year totaling the ICAP value registered, but not tested, multiplied by $2,400/MW, where $2,400 is the product of 3 * 4 * $200 to account for the three (3) times energy penalty assumed under the waiver, the four (4) hours of LMR requirements, and a $200 LMP as a proxy for pricing under emergency conditions.

All existing accredited Demand Resources that neither conduct a real power test nor meet Scheduling Instructions issued by the Transmission Provider during the prior Planning Year must participate in training provided by the Transmission Provider on the deployment of LMRs during the prior Planning Year. Any existing accredited Demand Resource must submit (1) the real power test results, (2) reference performance of Scheduling Instructions for demand reduction when called upon during the calendar year prior to the upcoming Planning Year, (3) alternate testing mechanism, relevant data, and a reference of training participation to the Transmission Provider, or (4) a Demand Resource Deferral Notice pursuant to 69A.3.5(l) and a reference of training participation to the Transmission Provider no later than February 1 prior to such Planning Year for

existing accredited DR. For new Demand Resources, (1) a real power test must be conducted and results submitted to the Transmission Provider, (2) alternate testing mechanism must be submitted, or (3) a Demand Resource Deferral Notice must be submitted prior to qualifying as a Demand Resource, but no later than March 1 prior to the PRA in accordance with the BPM for Resource Adequacy. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 for existing accredited Demand Resource, and Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 prior to initially qualifying as a Demand Resource.

j. Market Participants providing physical, regulatory, or contractual limitations of the notice times and availability of Demand Resources must provide appropriate documentation to the Transmission Provider in accordance with the BPM for Resource Adequacy.

h. A Market Participant may defer the obligation to conduct a real power test, as set forth in section 69A.3.5(i), by providing a Demand Resource Deferral Notice to the Transmission Provider in writing and signed by an officer of the company no later than February 1st prior to the Planning Year. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 for existing accredited Demand Resource, and Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 prior to initially

qualifying as a Demand Resource. The Demand Resource Deferral Notice shall contain: (1) the expected Demand Resource test value (in megawatts) from such Demand Resource and if the Demand Resource is new, the LBA or external BA where it is represented; and (2) appropriate information validating that real power test results will be submitted to the Transmission Provider by the last Business Day of May prior to the Planning Year. A Market Participant that provides a Demand Resource Deferral Notice must satisfy credit requirements by March 1 prior to the Planning Year totaling the amount of Demand Resource test value provided in the Demand Resource Deferral Notice multiplied by $2,400/MW, where $2,400 is the product of 3*4* $200 to account for the three (3) times energy penalty assumed under the deferral, the four (4) hours of LMR requirements, and a $200 LMP as a proxy for pricing under emergency conditions. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants that have elected to submit a Demand Resource Deferral Notice must satisfy credit requirements by March 31, 2021. If the Market Participant submits the real power test results on or before the last Business Day of May prior to the Planning Year that are equal to or greater than the expected Demand Resource test value, then the Transmission Provider will adjust the Market Participant's credit requirement to account for these changes within twenty (20) Business Days after that real power test is submitted. In the event ZRCs associated with a Planning Resource for which Demand Resource testing has been successfully deferred are unconverted in accordance with section

69A.7.3, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred Demand Resource value, in which case the Transmission Provider will adjust the Market Participant's Demand Resource value and credit requirement within twenty (20) Business Days. A Market Participant that provides a Demand Resource Deferral Notice and that either (1) has not submitted any real power test result for such Demand Resource by the last Business Day of May prior to the Planning Year, or (2) has submitted a real power test result by the last Business Day of May prior to the Planning Year that demonstrates fewer megawatts are available than the expected Demand Resource test value submitted in the Demand Resource Deferral Notice, shall be subject to a penalty equal to three (3) times the Hourly Real-Time Ex Post LMP at the Load CPNode for any such deficiency described in and distributed pursuant to Section 69A.3.9. In addition, such Market Participant shall not have their credit released until a real power test result demonstrating the availability of all megawatts submitted in the Demand Resource Deferral Notice is submitted and verified by the Transmission Provider, or the end of the Planning Year, whichever is earlier.

Behind the Meter Generation Eligibility

1. A Market Participant that possesses ownership or equivalent contractual rights in a behind the meter generator can register such behind the meter generator as a DRR – Type I or an LMR to participate in the Planning Resource Auction as documented in the BPM for Resource Adequacy. A behind the meter generator registered as a DRR – Type I or an LMR is a BTMG. The Market Participant registering the BTMG must include the contracts with each end-use customer indicating rights behind the BTMG to generate behind-the-meter generation. Notwithstanding, a copy of a contract with an end-use customer will not be required if the Market Participant is, or has non-contractual legal rights to control, the end use customer. In addition, the Market Participant must meet the following requirements:

    a. A Market Participant shall be prohibited from registering into the PRA any BTMG that is concurrently registered, in whole or in part, under another DRR, LMR, or EDR, whether by the same or a different Market Participant. A BTMG registering as an LMR shall not also register as a DRR or EDR.

    b. The BTMG must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together as a Load Modifying Resource that is capable of reducing an LSE's Demand for the applicable Season may qualify in meeting this standard).

    c. A behind the meter generator for which curtailment is not an obligation during Emergency events declared by the Transmission Provider will not qualify to participate in the PRA as a DRR – Type I or qualify as an LMR.

A Market Participant that submits an Offer in the Day-Ahead Market and/or Real-Time Energy and Operating Reserve Markets for a BTMG is still subject to the requirement to be available during an Emergency pursuant to the Transmission Provider Emergency Operating Procedures, regardless of the projected or actual Real-Time Energy Market LMP.

d. A Market Participant shall demonstrate GVTC capability for applicable Season in each Planning Year on an annual basis as established in the BPM for Resource Adequacy, and by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing accredited BTMG unless the Transmission Provider has granted an extension pursuant to Section 69A.3.6.1.j. All new BTMGs or an existing accredited BTMG that has an increased installed capacity shall submit their GVTC to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA as established in the BPM for Resource Adequacy.

e. A Market Participant shall submit generator availability data (including, but not limited to, NERC GADS information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy. A Market Participant is not required to report generator availability data based on GVTC for a BTMG less than 10 MW if the Market Participant has never provided such data for such BTMG. A Market Participant that begins reporting generator availability data based upon GVTC for a BTMG that is less than 10 MW must continue to report such data.

f. A BTMG must be available to provide Energy with a notification time requirement: (i) of six (6) hours or less notice if registering in the PRA as a DRR – Type I or an LMR – Type I; or (ii) with thirty (30) minutes or less notice if registering as an LMR – Type II in the applicable Seasons.

g. A Market Participant shall demonstrate that the BTMG is able to sustain energy production at the MW level being registered for at least four (4) continuous Hours;

h. Unless unavailable due to Force Majeure:

(i) A BTMG participating as a DRR – Type I or LMR – Type I that is unavailable to respond to all Setpoint Instructions or Scheduling Instructions shall be subject to the penalties set forth in Section 69A.3.9; and

(ii) A BTMG participating as an LMR – Type II that is unavailable to respond to any Scheduling Instruction shall be subject to the penalties set forth in Section 69A.3.9.

This obligation only applies during Seasons which the BTMG clears the Planning Resource Auction.

i. A BTMG shall submit Metered data at regular intervals as set forth in Attachment TT.

j. A Market Participant registering a BTMG may not register as a DRR – Type II or Non-Emergency BTMG for three years (3) Planning Years. After three (3) Planning Years, a Market Participant may commit to participate as a BTMG for

an additional three (3) Planning Years or may elect to participate as a DRR – Type II or Non-Emergency BTMG. A BTMG may opt to participate as a DRR – Type I or LMR at any time by satisfying the requirement of such participation option.

k. A Market Participant for a BTMG required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the BTMG by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extent the GVTC deadline. Denial of an extension will not preclude the Market Participant for the BTMG from utilizing the ICAP Deferral process as described in Section 69A.7.9.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for a BTMG has not completed GVTC testing by the deadlines provided in 69A.3.6.1.d, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used the PRA, in a FRAP (including through bilateral ZRC transactions) or in an RBDC Opt Out, subject to the notification, credit, and non-compliance

provisions of Section 69A.7.9.

Transmission Provider Initiated Testing of Demand Resources

1. A Demand Resource participating as a DRR or a LMR that is registered in the PRA shall be subject to a Transmission Provider initiated test according to the following requirements:

   a. Test frequency:

      i. A Demand Resource using an Attachment TT defined Statistical Measurement and Verification methodology shall be tested once per Planning Year;

      ii. A Demand Resource participating as a DRR or LMR – Type I shall be tested once per three (3) Planning Years;

      iii. A Demand Resource participating as an LMR – Type II shall be tested once per Planning Year. A Market Participant representing a Demand Resource participating as an LMR – Type II may request a Transmission Provider initiated test opt out as set forth in Section 69A.3.8.2; or

      iv. Notwithstanding the provisions above, the Transmission Provider may test a resource at any time due to its non-performance.

   b. A Demand Resource that has successfully deployed in response to a Setpoint Instruction or Scheduling Instruction issued during an Emergency in either the past one (1) or three (3) Planning Years as applicable pursuant to sub-section a. above, shall count as a successful Transmission Provider initiated test. Provided there are no deployment failures for a Demand Resource participating as an LMR during the 2025/2026, 2026/2027, and 2027/2028 Planning Years, full

response to Setpoint Instructions or Scheduling Instructions issued during an Emergency shall count as a successful Transmission Provider initiated test for the first one (1) or three (3) Planning Year cycle, as applicable, beginning with the 2028/2029 Planning Year.

c. A new Demand Resource participating as a DRR or an LMR shall undergo a Transmission Provider initiated test during the first Planning Year it is registered for the PRA.

d. A Market Participant shall receive at least 24 hours notification prior to the initiation of a Transmission Provider initiated test. Additional requirements regarding the Transmission Provider initiated test shall be set forth in the BPM for Resource Adequacy.

2. A Demand Resource participating as an LMR – Type II may opt out of the annual Transmission Provider initiated test requirement if it has responded to all Scheduling Instructions and successfully passed all Transmission Provider initiated tests, within the past three (3) Planning Years.

a. If opting out of a test, a Demand Resource opting out of the test shall be subject to increased real-time penalties equal to the product of Pricing VOLL and the amount of specified Demand reduction, measured in MWh, not achieved in response to a Setpoint Instruction or Scheduling Instruction issued during an Emergency, in addition to any other penalty provisions set forth in 69A.3.9.

3. A Demand Resource will be deemed to have fully satisfied the Transmission Provider initiated test if the resource has met its performance obligations, as set forth in

Attachment TT, within the registered notification time, and maintained the Demand reduction or Firm Service Level as applicable for four (4) continuous hours.

4. A Demand Resource will have partially failed the Transmission Provider initiated test if the Demand Resource fully deploys outside of the registered notification time and within six (6) hours of initiating the test for participating as DRR – Type I or LMR – Type I, within thirty (30) minutes of initiating the test for participating as LMR – Type II, and within the Offered Shut-Down time for participating as a DRR – Type II. A partial failure of a Transmission Provider initiated test will result in:

   a. The Demand Resource being charged the product of the amount of the Demand shortfall, measured in MW at the Hour equal to the initiation of the Transmission Provider test plus the registered response time, and the Auction Clearing Price, for the lesser of:

      i. The remainder of the Season; or

      ii. Such time as the Demand Resource fully deploys in response to a Setpoint Instruction or Scheduling Instruction during a Transmission Provider declared Emergency.

   b. The Transmission Provider will adjust the resource's registered response time to reflect its tested response. A Market Participant must provide evidence to the Transmission Provider to register such resource with a response time less than the response time achieved during the Transmission Provider initiated test during subsequent Planning Years.

   c. The Demand Resource may be tested in subsequent Seasons during the same

Planning Year.

d. The Demand Resource shall be tested in the subsequent Planning Year.

5. A Transmission Provider initiated test shall be deemed to be fully failed if the Demand Resource failed to achieve its required Demand reduction, as measured per the applicable Attachment TT Measurement and Verification identified during the registration of the resource, within six (6) hours of initiating the test for participating as DRR – Type I or LMR – Type I, within thirty (30) minutes of initiating the test for participating as LMR – Type II, and within the Offered Shut-Down time for participating as a DRR – Type II.

a. A Demand Resource experiencing a complete test failure will be subject to penalties equal to the product of the cleared ZRCs and the ACP for the entire Season in which the test was performed.

b. The Transmission Provider shall perform a test in the subsequent Season the resource has cleared ZRCs.

c. A resource failing two (2) tests during a single Planning Year shall be fully disqualified for the remainder of the Planning Year and shall pay 2.748 times the applicable LRZ's CONE multiplied by the amount of cleared ZRCs for each Season.

Penalty Provisions for LMRs

Unless an LMR is unavailable as a result of maintenance requirements, for reasons of Force Majeure, or because the number of required deployments based on the registered number has been reached, the Market Participant representing the entity that had ZRCs from LMRs that cleared in the PRA, were used in a FRAP, or were used in an RBDC Opt Out will be subject to the following penalties in the event the LMR is called upon during an Emergency as declared by the Transmission Provider and the LMR fails to perform in accordance with its Market Participant's response to such Market Participant's Scheduling Instructions. The penalties defined below will only apply to the portion of the Market Participant's response to such Market Participant's Scheduling Instruction that is not followed during the Emergency declaration and will only be assessed by the Transmission Provider after giving the operator of the LMR an opportunity to provide documentation of the specific circumstances that would justify exemption from such penalties. There will not be an LMR penalty assessed for any portion of the Scheduling Instruction which had already been accomplished by an LMR for other reasons (*e.g.*, for economic considerations, self-scheduling at or above the credited amount of BTMG or local reliability concerns in accordance with instructions from the Local Balancing Authority) at the time the request for interruption is made by the Transmission Provider. Likewise, for certain Demand Resources that are temperature dependent (*e.g.*, a Demand Resource program involving air conditioning load), the specified Demand reduction may be adjusted in a manner defined in the measurement and verification procedures developed by the Transmission Provider to reflect the circumstances at the time a Demand Resource is called upon to reduce Demand.

a. The Transmission Provider shall assess the responsible Market Participant the costs that were otherwise incurred to replace the deficient Planning Resource at the time the Market Participant's LMR is called upon by the Transmission Provider and does not respond in full or in part consistent with the Market Participant's response to MISO's Scheduling Instructions. These costs will be the product of the amount of specified Demand reduction not achieved and the Hourly Real-Time Ex Post LMP at the Load CPNode, plus any applicable Revenue Sufficiency Guarantee charges. The Transmission Provider shall allocate any such penalty revenues only to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency that required the use of an LMR. Such revenues shall be distributed on a Load Ratio Share basis. For any situation where either an LMR does not respond to an interruption request, including those circumstances where the LMR is claimed to be unavailable as a result of maintenance requirements or for reasons of Force Majeure, the Transmission Provider shall initiate an investigation with the Market Participant which has registered the Demand Resource or BTMG and was qualified as an LMR into the cause of the LMR not being available when called upon to reduce Demand. If deemed appropriate by the Transmission Provider, the Transmission Provider will disqualify the Demand Resource or BTMG from further use as an LMR for the remainder of the current Planning Year, and will discontinue payment of the applicable ACP for the remainder of the current Planning Year when the LMR was unavailable. If such

LMR was used in a FRAP or cleared in the PRA or used in an RBDC Opt Out, then the Market Participant will be charged the applicable ACP for the remainder of the current Planning Year for the Unforced Capacity of the LMR. The revenues collected will be distributed on a *pro rata* basis in such LRZ based upon an LSE's Final PRMR.

b. In the event the same LMR is unavailable on a second occasion (with at least a separation period of 24 hours) when called upon to respond to Scheduling Instructions, except for a validated circumstance of maintenance requirements or for reasons of Force Majeure, the Market Participant taking credit for that LMR shall make the same penalty payment as indicated in Section 69A.3.9.a above, and the Demand Resource or BTMG will no longer qualify as an LMR and will not receive the applicable ACP for the remainder of the current Planning Year and will not be eligible for LMR status for the next Planning Year. If such LMR was used in a FRAP or cleared in the PRA or used in an RBDC Opt Out, then the Market Participant will be charged the applicable ACP for the remainder of the current planning year for the Unforced Capacity of the LMR. The revenues collected will be distributed on a *pro rata* basis in such LRZ based upon an LSE's Final PRMR.

Non-Emergency Behind the Meter Generation Eligibility

1. A Market Participant that possesses ownership or equivalent contractual rights in a behind the meter generator can register such behind the meter generator as a Non-Emergency BTMG to participate in the Planning Resource Auction as documented in the BPM for Resource Adequacy. The Market Participant registering the Non-Emergency BTMG must include the contracts with each behind the meter generator indicating rights behind the Non-Emergency BTMG to generate behind-the-meter generation. Notwithstanding, a copy of a contract with a behind the meter generator will not be required if the Market Participant is, or has non-contractual legal rights to control, the behind the meter generator. In addition, the Market Participant must meet the following requirements:

    a. A Market Participant shall be prohibited from registering into the PRA any Non-Emergency BTMG that is concurrently registered, in whole or in part, whether by the same or a different Market Participant.

    b. The Non-Emergency BTMG must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together as a single Non-Emergency Behind the Meter Generation resource may qualify in meeting this standard).

    c. At registration, a Market Participant registering a Non-Emergency BTMG must commit to participate as a Non-Emergency BTMG for three (3) Planning Years. After three (3) Planning Years, a Market Participant may commit to participate as a Non-Emergency BTMG for an additional three (3) Planning Years or may elect to participate as a DRR – Type I or an LMR. A resource participating as a Non-

Emergency BTMG may opt to participate as a DRR – Type II Resource at any time by satisfying the requirements of a DRR – Type II.

d. A Non-Emergency BTMG has no obligation to respond to a Transmission Provider Setpoint Instruction or Scheduling Instruction.

e. A Market Participant registering a Non-Emergency BTMG shall demonstrate GVTC capability for the applicable Season in each Planning Year on an annual basis as established in the Business Practices Manual for Resource Adequacy. A Market Participant of an existing Non-Emergency BTMG must submit the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the Non-Emergency BTMG by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the Non-Emergency BTMG from utilizing the ICAP Deferral process as described in Section 69A.7.9.

A Market Participant of all new Non-Emergency BTMGs, or an existing accredited Non-Emergency BTMG that have increased installed capacity, shall

submit their GVTC to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA.

A Market Participant may request an extension of these deadlines pursuant to Section 69A.3.10.2.

f. A Market Participant shall submit generator availability data (including, but not limited to, NERC GADS information) into a database provided by the Transmission Provider and as established in the Business Practices Manual for Resource Adequacy. A Market Participant is not required to report generator availability data based on GVTC for a Non-Emergency BTMG less than 10 MW if the Market Participant has never provided such data for such Non-Emergency BTMG. A Market Participant that begins reporting generator availability data based upon GVTC for a Non-Emergency BTMG that is less than 10 MW must continue to report such data.

g. A Market Participant for Non-Emergency BMTG shall submit Meter data at regular intervals as set forth in Attachment TT.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for a Non-Emergency BTMG has not completed GVTC testing by the deadlines provided in 69A.3.10(e), is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out, subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

Planning Resource Capacity Values

In order for the Transmission Provider to account for resource performance and availability, Capacity Resources, Demand Response Resources – Type I, Load Modifying Resources, and Non-Emergency Behind the Meter Generation will be given a capacity value for each applicable Season based on the Seasonal Accredited Capacity calculation applicable to its Resource type; and EE Resources will be given capacity values based on the measurement and verification data provided for such resources, as provided in the BPM for Resource Adequacy.

Seasonal Accredited Capacity of Capacity Resources

The Transmission Provider will determine the Seasonal Accredited Capacity for each Capacity Resource.

a. The Seasonal Accredited Capacity for a Capacity Resource that is a Generation Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation, Electric Storage Resource, External Resource, or Use Limited Resource, is based on an evaluation of the type and volume of interconnection service, GVTC value, and Real-Time offered availability of such Generation Resource or Electric Storage Resource for each Season as set forth in Schedule 53.

b. The Seasonal Accredited Capacity for a Capacity Resource that is an External Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation or Use Limited Resource, is based on the GVTC value and $XEFOR_d$ values of such External Resource for each Season. External Resources that are not required to report generator availability data will have a forced outage rate based on the class average forced outage rate of the resource type.

c. The Transmission Provider will determine the Seasonal Accredited Capacity for a DRR – Type II that qualifies as a Capacity Resource, for each Season, as set forth in Schedule 53B.

d. The Seasonal Accredited Capacity for a Capacity Resource that is a Dispatchable Intermittent Resource or Intermittent Generation will be determined by the Transmission Provider based on historical performance, availability, and type and volume of interconnection service, for each Season in accordance with the BPM

for Resource Adequacy.

e. The Seasonal Accredited Capacity value for a Capacity Resource that is a Hybrid Resource will be established by the Transmission Provider based on the sum of the Seasonal Accredited Capacity values of its respective Electric Facilities for the production and/or storage for later injection of electricity, up to the level of firm interconnection service, prior to a minimum amount of operating data becoming available. Once sufficient operation data is available, as defined in the BPM, the Seasonal Accredited Capacity value for a Hybrid Resource will be determined by the Transmission Provider based on historical performance, availability, and type and volume of interconnection service, for each Season in accordance with the BPM.

f. The Seasonal Accredited Capacity of a Capacity Resource that is an Electric Storage Resource will be established by the Transmission Provider based on an evaluation of the type and volume of interconnection service, a GVTC value based upon a power and energy test, and an $XEFOR_d$. Electric Storage Resources that are not required to report generator availability data will have an $XEFOR_d$ rate based on their class average forced outage rate.

g. The Seasonal Accredited Capacity for a Capacity Resource that is a Use Limited Resource will be determined by the Transmission Provider based on the type and volume of interconnection service, the GVTC and $XEFOR_d$ values of such Use Limited Resource in accordance with the BPM for Resource Adequacy.

Seasonal Accredited Capacity of Demand Resources

The Transmission Provider will determine the appropriate Seasonal Accredited Capacity value for Demand Resources that qualify as a Planning Resource as established in Schedule 53B.

Seasonal Accredited Capacity of Behind the Meter Generation and Non-Emergency Behind the Meter Generation

The Transmission Provider will determine the Seasonal Accredited Capacity for each BTMG and Non-Emergency BTMG as set forth in Schedule 53B. If such BTMG or Non-Emergency BTMG is interconnected to the Transmission System, the Transmission Provider will consider the type and volume of interconnection service when determining the Seasonal Accredited Capacity.

EE Resources

The Seasonal Accredited Capacity for a qualified EE Resource will be determined by the Transmission Provider based upon submitted measurement and verification documents, as provided in the BPM for Resource Adequacy.

Attributes of ZRCs

A Market Participant that owns or possesses equivalent contractual rights to a qualified Planning Resource can convert the convertible Seasonal Accredited Capacity of the Resource (Seasonal Accredited Capacity MW) as determined in section 69.A.3.1.g into ZRCs through the MECT in order to offer such ZRCs into a PRA. Market Participants also can unconvert and/or transfer ZRCs through the MECT to another Market Participant, as described in the BPM for Resource Adequacy.

A. Eligibility for Zonal Resource Credits for a Capacity Resource that is a Planning Resource that is not Intermittent Generation or Dispatchable Intermittent Resource.

For a Capacity Resource that is not Intermittent Generation or Dispatchable Intermittent Resource the amount of Capacity that is eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal Accredited Capacity value of the Capacity Resource. The convertible Seasonal Accredited Capacity shall be determined by:

i. Determining the Installed Capacity;

ii. Determining the Seasonal Accredited Capacity of the Capacity Resource;

iii. Allocating the Capacity Resource's Seasonal Accredited Capacity value where:

a. If the Capacity Resource has only Energy Resource Interconnection Service, the Seasonal Accredited Capacity will be allocated to the Capacity Resource's Energy Resource Interconnection Service Seasonal Accredited Capacity value, which will be calculated by multiplying the lesser of the Capacity Resource's ICAP or Energy Resource Interconnection Service by SAC divided by ICAP;

b. If the Capacity Resource has both Network Resource Interconnection Service and Energy Resource Interconnection Service, the Seasonal Accredited Capacity will be allocated first to the Capacity Resource's Network Resource Interconnection Service Seasonal Accredited Capacity value, which will be calculated by multiplying the lesser of the Capacity Resource's ICAP or Network Resource Interconnection Service by SAC divided by ICAP, as provided below:

   $NRIS\ SAC = MIN\ (NRIS, ICAP) \times (SAC/ICAP)$

c. Any remaining total Seasonal Accredited Capacity value will then be allocated to Energy Resource Interconnection Service Seasonal Accredited Capacity as provided below:

   $ERIS\ SAC = MAX\ (0, (ICAP\text{-}NRIS)) \times (SAC/ICAP)$

d. The resulting Network Resource Interconnection Service Seasonal Accredited Capacity value shall be eligible to be converted into Zonal Resource Credits; and

e. The resulting Energy Resource Interconnection Service Seasonal Accredited Capacity value that is coupled with firm Transmission Service shall be eligible to be converted into Zonal Resource Credits up to the Energy Resource Interconnection Service Unforced Capacity value of the Capacity Resource, by multiplying the firm Transmission Service amount by SAC divided by ICAP.

B. Eligibility for Zonal Resource Credits for a Capacity Resource that is an Intermittent Generation or Dispatchable Intermittent Resource

For Intermittent Generation and Dispatchable Intermittent Resources that are Capacity Resources, the amount of Capacity eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal Accredited Capacity value of the Intermittent Generation or Dispatchable Intermittent Resource, which is equal to the total Seasonal Accredited Capacity value multiplied by the quotient of the deliverability adjusted Capacity factor divided by the peak performance Capacity factor of the Capacity Resource where:

a. the deliverability-adjusted capacity factor is the average of the actual Energy output capped at the demonstrated deliverability of the Intermittent Generation or Dispatchable Intermittent Resource determined in Section 69A.3.1.g during the highest system peak load observances for each Season that the Capacity Resource was in service divided by the Installed Capacity of the Capacity Resource; and,

b. the existing peak performance Capacity factor is the average of the actual Energy output during the highest system peak load observances for each Season that the Capacity Resource was in service divided by the Installed Capacity of the Capacity Resource.

C. Eligibility for Zonal Resource Credits for a Capacity Resource that is a Distributed Energy Aggregated Resource

For Distributed Energy Aggregated Resources that are Capacity Resources, the amount of Capacity eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal

Accredited Capacity value of the Distributed Energy Resources within the aggregation according to their resource type as determined in section 69A.3.1.g.

Capacity Resource Must Offer and Performance Requirements

a. Market Participants that convert Seasonal Accredited Capacity from Capacity Resources into ZRCs that clear in a Season in the PRA or are used in a FRAP (and that do not replace such ZRCs in accordance with Section 69A.3.1.h) or used in an RBDC Opt Out, including Capacity Resources that are the subject of Diversity Contracts, must submit Self-Schedules or Offers for Energy, and Contingency Reserve if qualified, and offers for Short-Term Reserve if qualified, for the Installed Capacity value of the Capacity Resources converted to ZRCs and clear in a Season in the PRA or used in a FRAP or used in an RBDC Opt Out for each Hour of each Day during the applicable Season in the Planning Year, in the Day-Ahead Energy Market and all pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment process. This must offer obligation does not apply to the extent that the Capacity Resource is unavailable due to a full or partial forced or scheduled outage, in accordance with the BPM for Resource Adequacy and the BPM for Outage Operations. Additionally, this must offer obligation is modified to the extent the Capacity Resource is provided an operating limitation, such as thermal, voltage, or stability limits referenced in the BPM for Outage Operations, by the Transmission Provider or Transmission Operator to preserve the reliability of the Transmission System, that is lower than the must offer obligation described above, for the duration of such limitation.

Any such Capacity Resource with full or partial Generator Planned Outages that exceeds thirty-one (31) Days during any Season will be deemed not to have met its performance requirement for any Days greater than thirty-one (31) Days and must replace ZRCs in

accordance with Section 69A.3.1.h, provided that Capacity Resources subject to Diversity Contracts that are unavailable for greater than thirty-one (31) Days in total during any Season, will be deemed not to have met its performance requirement and will be subject to the ZRC replacement provisions set forth in Section 69A.3.1.h. Self-Schedules or Offers for Energy must be made consistent with requirements specified in Sections 39 and 40 of this Tariff as well as in the BPM for Resource Adequacy and the Business Practices Manual for Energy and Operating Reserves Markets. Partial or full forced or scheduled outages or derates of Capacity Resources must be reported in the Transmission Provider's Outage Scheduler, as described in further detail in the Business Practices Manual for Outage Operations. Must offer requirements specified in the BPM for Resource Adequacy will reflect resource operational limitations, including those related to Use Limited Resources, fuel limited, energy output limited or Intermittent Generation and including all state regulations and laws, including but not limited to, state safety standards, planning reserve margins, or the enforcement thereof. The Transmission Provider will monitor compliance with must offer requirements in accordance with the BPM for Resource Adequacy.

b. If a Capacity Resource that has ZRCs cleared in the PRA during any Season or is used in a FRAP during any Season or used in an RBDC Opt Out is capable of performing but fails to perform when called upon by the Transmission Provider for an Emergency, the Transmission Provider shall assess the owner of such Capacity Resource the costs that were otherwise incurred to replace the energy from the deficient Capacity Resource at the time that the Capacity Resource is called upon by the Transmission Provider and does not

respond in full or in part, for each day of non-performance of such Capacity Resource, provided that the planned or forced outage of the Capacity Resource is not properly reported in the Transmission Provider's Outage Scheduler, as set forth in the Business Practices Manual for Outage Operations. These costs will be the product of the amount of qualified ZRCs not achieved and the real-time LMP at the Capacity Resource's CPNode, plus any applicable related Revenue Sufficiency Guarantee charges. The Transmission Provider shall allocate any such revenues to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency. Such revenues shall be distributed on a Load Ratio Share basis.

c. Market Participants must input all Energy Efficiency Resource and Load Modifying Resource information into the MECT at least seven (7) Business Days prior to the Planning Resource Auction.

State RAR Standards

The Transmission Provider will assist states in meeting any state resource adequacy standards by providing relevant MECT information as available and as may be requested by states, subject to the data confidentiality provisions in Section 38.9 of this Tariff. Nothing in the RAR shall prohibit any state from requesting data relating to state safety standards, planning reserve margins, or the enforcement thereof.

Information regarding RAR Obligations

The Transmission Provider will maintain databases and will report to states and the affected LSEs, upon request, aggregated, non-confidential information regarding jurisdictional LSEs' RAR obligations during relevant time periods. Confidential Data regarding RAR status will be provided to states only in accordance with the data confidentiality provisions in Section 38.9 of this Tariff.

Facilitation of a Bilateral Capacity Bulletin Board

The Transmission Provider shall maintain an electronic bulletin board platform that may be used by Market Participants to facilitate voluntary bilateral ZRC transactions and to monitor the conversion of Seasonal Accredited Capacity to ZRCs.

Facilitation of LSE's RAR Information

The Transmission Provider shall, upon request, submit RAR information to the applicable RE, Electric Reliability Organization, state (in the case of an LSE subject to regulation or using delivery services rates, terms or conditions established by such State Regulatory Authority) or to the Commission, subject to the provisions of Section 38.9 of this Tariff.

Reliability Based Demand Curve Procedures

A. Translation of MRI Curves to RBDCs

The following process will be utilized to determine the RBDC for the Transmission Provider Region for each Season of the upcoming Planning Year. The MRI Curves for the Transmission Provider Region as described in Section 68A.9 will be multiplied by a scaling factor measured in $/MWh. The scaling factor for an RBDC is calculated to support ACPs that achieve annual Net CONE when the Transmission Provider Region is at the reliability requirement established by the LOLE analysis for each Season. LOLE risk across the Seasons is modeled as described in Section 68A.2.1. The scaling factors shall be determined as set forth in the Business Practices Manual for Resource Adequacy.

The process used to determine the RBDCs for each of the First Planning Area and the Second Planning Area for each Season in the Planning Year is similar to the process used for developing the RBDC curve for the Transmission Provider Region.

B. Monte Carlo Analysis

Every three Planning Years, the Transmission Provider will evaluate the ability of RBDCs, through probabilistic analysis, to reliably serve the Transmission Provider Region's Demand while supporting ACPs that achieve annual Net CONE when the Transmission Provider Region is at the reliability requirement established by the LOLE analysis for each Season. The probabilistic analysis shall use a Monte Carlo study that assumes there are no internal transmission limitations within the Transmission Provider Region.

The Monte Carlo analysis will model both in-market supply and demand based on historic supply and demand variability, respectively, observed through a minimum of the three

most recent PRAs. The Monte Carlo model will produce seasonal clearing prices and quantities with each draw. Overall model results will be assessed by comparing the average of seasonal prices from the study against the estimate of Net CONE described in section 69A.8. The scaling factor is adjusted in each successive Monte Carlo simulation so that long run equilibrium conditions are ultimately achieved, indicated by the average of seasonal prices from the study equal to the estimate of Net CONE. Net CONE values used for the Monte Carlo analysis will be the simple arithmetic average of all LRZ Net CONE values.

A separate Monte Carlo analysis will be performed to evaluate the RBDCs for the First Planning Area and the Second Planning Area. Separate scaling factors will be used in the Monte Carlo analysis for each of the First Planning Area and the Second Planning Area that supports achievement of Net CONE values for the corresponding Planning Area, indicated by the average of seasonal capacity prices under long run equilibrium conditions. Net CONE values used in the Monte Carlo analysis for the RBDCs for the First Planning Area and the Second Planning Area will be the simple arithmetic average of LRZ Net CONE values for the specific LRZs in the corresponding Planning Area.

Planning Resource Auction

Within twenty (20) Business Days after the last Business Day in March, the Transmission Provider will conduct a PRA to determine the ACP in each LRZ and ERZ for the upcoming Planning Year which begins on June 1st. The Transmission Provider will post the results of the PRA on its website, consistent with the standards and procedures set forth in the BPM for Resource Adequacy. The Transmission Provider shall ensure that each Market Participant submitting a ZRC Offer is qualified to submit such an offer consistent with the Transmission Provider's creditworthiness provisions. The Transmission Provider will ensure that the LCR, the CEL and CIL are respected for each LRZ, the CEL is respected for each ERZ, and the SREC and the SRIC are respected for each SRRZ, if applicable, when conducting the PRA.

PRA Procedures

a. **Participating ZRCs in the PRA:** All Market Participants that own or have contractual rights to the Planning Resources that are represented within an LRZ or ERZ and have converted Seasonal Accredited Capacity to ZRCs, will have an option to (consistent with withholding provisions) submit offers into the PRA for such ZRCs, to the extent that the Market Participant has not submitted a FRAP, or RBDC Opt Out, as described in Section 69A.9. Owners of jointly-owned facilities can individually offer their share of any such resources into the PRA, either as self-schedule price takers or with specific offers, or use their share of such resources as part of their FRAPs, or RBDC Opt Outs. These ZRC Offers must be submitted in price/quantity pairs on a monotonically increasing basis expressed as MW-day and must consist of a stepped ZRC Offer curve of up to five (5) segments for each Planning Resource. ZRC Offers shall be submitted to the Transmission Provider via the MECT during the PRA offer window. Only ZRCs that are not otherwise committed for the remainder of the Planning Year are permitted to participate in the PRA. The PRA offer window shall begin at 8:00 am EPT three (3) Business Days before the last Business Day in March and shall end at 6:00 pm EPT on the last Business Day in March. The Transmission Provider may extend or reopen the PRA offer window based on unanticipated events that: (i) interfere with the Transmission Provider's ability to receive and/or process accurate and complete ZRC Offers or (ii) are otherwise likely to have a widespread negative impact on the results of the PRA. The Transmission Provider shall notify Market Participants and post such notice of any extension or reopening of the PRA on its website. The notice shall state the extension or

reopening's circumstances, rationale, and duration. The price associated with these ZRC Offers cannot exceed the annual CONE value divided by the number of days in the Season for the LRZ where the ZRC is represented. ZRC Offers from External Resources represented in ERZs, which are connected to single SRRZ, cannot exceed the greatest CONE value of all LRZs in respective SRRZ. ZRC Offers from External Resources represented in ERZs, which are connected to multiple SRRZs or are not connected to any SRRZs, cannot exceed the greatest CONE value of all LRZs in those connected SRRZs. Owners of ZRCs may bilaterally sell or buy ZRCs; however if a ZRC has cleared in the auction, the Market Participant that registered the Planning Resource that is the subject of such ZRC shall be responsible for complying with all Tariff requirements. The Independent Market Monitor will review the actions of owners/operators of all qualified Seasonal Accredited Capacity from Planning Resources and conversion to ZRCs to evaluate potential withholding of Planning Resources from the PRA, consistent with Module D. External Resources, including Generation Resources pseudo-tied into the MISO Balancing Authority Area, will be granted ZRCs in the applicable External Resource Zone. Notwithstanding the above, External Resources located within a Coordinating Owner that (i) borders the Transmission Provider Region; (ii) whose external ties are predominantly to the Transmission System; and (iii) has Seams Operating Agreements that allow for coordinated operations, will be granted ZRCs in the LRZ where their firm transmission service crosses the border of the Transmission Provider Region, and Border External Resources will be granted ZRCs in the LRZ where the Transmission System connects to the substation with its interconnection facilities.

Generation Resources, Intermittent Generation, Electric Storage Resources, and Dispatchable Intermittent Resources will have to meet the terms of Section 69A.3.1.g. To the extent a Capacity Resource is located on the border of two or more LRZs (e.g., has transmission lines from two or more LRZs terminating at the substation containing the Capacity Resource's interconnection facilities), the Capacity Resource will be assigned to an LRZ as follows:

(i) if the Capacity Resource is located within the MISO BA, MISO will assign that Capacity Resource to the LRZ that contains the Local Balancing Authority in which the Capacity Resource is physically located; or

(ii) if the Capacity Resource is a Border External Resource, MISO will assign that Capacity Resource to the LRZ with which it has the greatest electrical connection. This connection will be determined by the impacts of the Resource on the system, including (i) the electrical loading of transmission facilities within and tying to the Zone and (ii) the transmission constraints which define the CIL and CEL for the Zone.

Once assigned, Capacity Resources which border two or more LRZs will not be reassigned unless significant changes occur in the Transmission Provider Region, including but not limited to, significant changes in LRZ boundaries, membership, the Transmission System, and/or Resources.

b. Participating Demand: All LSEs will be required to meet their Final PRMR through the PRA process, unless they have decided to pay the Capacity Deficiency Charge. LSEs can Self-Schedule ZRCs to meet their PRMR, consistent with the Self-

Scheduling Option in Section 69A.7.8. The Transmission Provider will conduct the PRA based upon the PRMR for the Transmission Provider Region minus the amount of PRMR associated with the Capacity Deficiency Charge, expressed as a variable reliability target through RBDCs for all of the LSEs located within the Transmission Provider Region.

c. Conducting the PRA: The Transmission Provider will conduct the PRA for each Season using the following auction procedures to determine the ACP for each LRZ and ERZ. The PRA shall be designed to commit resources equal to the Final PRMR determined by application of the RBDC for each LSE, minus the amount of PRMR associated with the Capacity Deficiency Charge but including resources used in a FRAP and an RBDC Opt Out, in each LRZ up to the total volume of offered ZRCs. All ZRCs offered at zero price will clear the PRA. The PRA shall clear for each LRZ and ERZ of the Transmission Provider Region. A multi-zone optimization methodology shall be employed to simultaneously perform the following tasks: (1) conduct the PRA to meet the supply and demand balance both for the Transmission Provider Region and for each of the First Planning Area and the Second Planning Area by clearing ZRC Offers and establishing the Final PRMR, as determined by application of the RBDCs, minus the amount of PRMR associated with the Capacity Deficiency Charge for each LRZ of the Transmission Provider Region to yield cleared ZRCs; (2) meet the LCR for each LRZ; (3) efficiently use transmission transfer capability between LRZs and from ERZs; and (4) respect the SREC and SRIC for each SRRZ, if applicable.

(i) **Objective Function:** The objective of the multi-zone optimization methodology shall be to maximize social surplus, using the as-offered overall

costs of capacity procurement and the as-bid overall benefits of capacity procurement reflected in the RBDCs over the time horizon, subject to LCR, network constraints, and SRICs and SRECs, if applicable. The overall costs will include the ZRC Offers of all Planning Resources selected for cleared ZRCs. CILs of each LRZ are simultaneous to the extent that imports into the LRZ are concurrently simulated; and CELs of each LRZ and ERZ are simultaneous to the extent that exports out of the relevant LRZ or ERZ are concurrently simulated. Network constraints will be represented by an initial set of zonal CELs and CILs, driven by the dispatch from planning models. The CELs and CILs will be reviewed by the Transmission Provider to determine if there are network loading violations when based on the geographical dispatch derived from the initial auction clearing. If no network violation is indicated, then the auction results are final. If a network violation is indicated, then reductions will be made to the affected export and import capabilities to avoid network violations and the auction will be cleared again with the new set of export and import capabilities. After a maximum of two (2) successive iterations per Season to address network violations, the auction clearing iteration with the fewest megawatts of network violations will be deemed as the final auction result.

(ii) **Time Horizon:** For purposes of clearing the system-wide PRMR the time horizon is an hour, representing the projected maximum Coincident Peak Demand. For a Local Resource Zone, the time horizon is the hour representing the Local Resource Zone Peak Demand, over each Season for the next Planning

Year for the Transmission Provider Region. Coincident Peak Demand is used to establish an LSE's Initial PRMR while Local Resource Zone Peak Demand is used to establish an LRZ's LRR.

(iii) **Capacity Market and Congestion Management:** The multi-zone optimization methodology will perform congestion management simultaneously with the scheduling of capacity for each Season in the Planning Year. Congestion management is the process where ZRCs are cleared to eliminate network constraint violations and to maximize the social surplus of procuring PRMR to meet applicable reliability standards.

(iv) **Model of Transmission Provider Transmission System:** The multi-zone optimization methodology will enforce network constraints represented by CILs, CELs and LCRs that are obtained by using a model of the transmission system including Planning Resources and Demand which will be updated annually to reflect existing and planned transmission and generation projects. Transmission and Planning Resources shall be modeled as part of the multi-zone optimization methodology to reflect their expected state during the peak Hour of each Season in the Transmission Provider Region. The model is of zonal form, which shall include all Planning Resources, Demand, and a representation of systems external to the Transmission Provider Region, and which will be consistent with seams agreements with neighboring regions.

Network Constraints. The multi-zone optimization methodology shall enforce constraints on transmission lines, transformers, and groups of

transmission branches that compose transmission interfaces represented by LCR, CIL, and CEL. Most of these constraints shall represent thermal limits on the power flow through transmission facilities. Certain constraints may impose more restrictive limits on power flow, taking into account contingencies and typically represented through operating guides.

Transmission Losses. The multi-zone optimization methodology will clear ZRCs to cover transmission losses; the PRMR will include estimates of transmission losses in its calculation for each Season.

(v) **LRZ ACP Calculation:** The Auction Clearing Price (ACP) for an LRZ is the marginal cost of serving the Demand in that LRZ. The ACP is composed of the system marginal cost of capacity, the regional marginal cost of capacity, the marginal cost of financially binding LCR, CEL, and CIL for a LRZ, (*i.e.*, network constraints that are active at the optimal solution prohibiting a lower cost outcome), and the marginal cost of financially binding SRECs and SRICs for SRRZs, if applicable. The ACP is calculated by considering the next increment or decrement to Demand for each LRZ. The Transmission Provider will calculate ACPs for each LRZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day ($/MW-day).

(vi) **External Resource Zone (ERZ) ACP:** The ACP for an ERZ is comprised of the system marginal cost of capacity, marginal cost of financially binding CEL for the ERZ, the marginal cost of financially binding SRECs and SRICs for SRRZ with which the ERZ interconnects. For ERZs which connect with more than one

SRRZ, or which do not directly connect to a single SRRZ, a weighted average of the marginal cost of financially binding SREC and SRIC will be applied, with weights derived from the distribution of annual energy flows into the SRRZs from the ERZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day ($/MW-day).

(vii) **ACP Inputs:** Primary inputs to the ACP calculation are network constraints represented by CIL, CEL, LCR, and other constraints established by the Transmission Provider associated with SRECs and SRICs for SRRZs in accordance with applicable seams agreements, coordination agreements, or transmission service agreements and the set of valid ZRC Offers and the Final PRMR for the Transmission Provider Region minus the amount of Initial PRMR associated with the Capacity Deficiency Charge for each LRZ. Valid ZRC Offers may include offers from ZRCs converted from confirmed Seasonal Accredited Capacity from Planning Resources. ZRC Offers can be submitted as Self-Schedules, in accordance with Section 69A.7.8.

(viii) **ACP Outputs:** For non-zero ACPs, Resources that set the ACP in a LRZ or ERZ will be cleared in proportion to the amount of ZRCs necessary to meet the Final PRMR. When more than one resource is marginal and offered at the ACP, then all resources offered at the ACP are cleared *pro rata* up to the amount required to meet the reliability requirement. This may result in a portion of multiple Resources clearing as the marginal resources that set the ACP.

(ix) **Eligibility Rules:** ACPs can be set by any ZRC Offers.

(x) **ACP for multiple Seasons with ZRC Shortage Conditions or ZRC Near-Shortage Conditions to meet Local Clearing Requirements:**

When an LRZ has more than one Season in any combination of ZRC Shortage Conditions and/or ZRC Near-Shortage Conditions the final Auction Clearing Price (ACP) for the LRZ will be set as the minimum of: (a) the original ACP as determined in Section 69A.7.1.c.(v) reflecting the effective financial binding of an LCR constraint; or (b) the summation of: (i) the amount composed of the system marginal cost of capacity, the regional marginal cost of capacity, and the marginal cost of financially binding SRECs and SRICs for SRRZs, if applicable; and (ii) the LCR price adder. The LCR price adder will be set as the amount obtained by dividing the applicable LRZ's annual CONE value by the summation of the number of days in Seasons in each Season of the Planning Year in which the LRZ was in ZRC Shortage Conditions in the Planning Resource Auction and the number of days in each Seasons of the Planning Year in which the LRZ was in ZRC Near-Shortage Conditions in the Planning Resource Auction.

(xi) **Notification:** ACPs and total summarized cleared ZRC Offers determined as described above shall be calculated and published by the Transmission Provider by 11:59 pm EST on the twentieth Business Day following the last Business Day in March. The Transmission Provider may extend the publishing deadline based on unanticipated events that: (i) interfered with the Transmission Provider's ability to receive and/or process accurate and complete ZRC Offers or (ii) were

otherwise likely to have a widespread negative impact on the results of the PRA. The Transmission Provider shall notify Market Participants and post such notice of any extension of publishing the results of the PRA on its website. The notice shall state the extension's circumstances, rationale, and duration.

Consequences of PRA

All PRA transactions will be financially binding. Market Participants with cleared ZRC Offers must comply with all of the ZRC requirements for all ZRCs that clear in the PRA.

Uncleared ZRCs

Once the PRA has concluded, a Market Participant may convert back to Seasonal Accredited Capacity any ZRCs that do not clear in the PRA.

PRA Reporting

The Transmission Provider will not reveal the ZRC Offers submitted by any Market Participant in a PRA until one (1) month following the completion of the PRA, except as required pursuant to the provisions of Section 38.9 of the Tariff. When the ZRC Offers are posted, price/quantity pairs will be made public, however the names of the Market Participants submitting such offers and the names of the Planning Resources offered shall not be publicly revealed.

Market Monitoring

All actions of Market Participants participating or failing to participate in the PRA shall be subject to the provisions of Module D, except to the extent that a Market Participant has opted out of the PRA as described in Section 69A.9. The Transmission Provider will report any known attempt to exercise market power by LSEs or by Market Participants in the PRA procedures to the Independent Market Monitor.

PRA Settlement

a. Cleared ZRC Offers will be settled at the ACP for the LRZ or ERZ where the ZRC is represented on a daily basis and the Market Participants submitting cleared ZRC Offers will be credited on a weekly basis by the Transmission Provider. The Transmission Provider will settle the LSEs cost of their Final PRMR minus the amount of PRMR associated with the Capacity Deficiency Charge at the ACP for the LRZ where the Demand is located on a daily basis and will debit LSEs weekly, to the extent that an LSE has not opted out of the PRA pursuant to Section 69A.9 or submitted an RBDC Opt Out pursuant to Section 69A.9.1. For LSEs not selecting RBDC Opt Out, the Final PRMR will be established based on the financial binding of RBDCs representing the Transmission Provider Region and applicable planning area (i.e., the First Planning Area or the Second Planning Area).

Final PRMRs will be determined as follows:

i. LSEs using the RBDC Opt Out will have Final PRMRs calculated by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + Transmission Provider Region PRM + RBDC Opt Out Adder).

ii. LSEs not using the RBDC Opt Out will have Final PRMRs calculated using the formula below:

$$\begin{aligned}&\textit{Final PRMR for a LSE not using the RBDC Opt Out}\\&\quad = \Big(\textit{PRA Cleared Capacity}\\&\quad - \sum \textit{Final PRMR for LSEs using the RBDC Opt Out}\Big)\\&\quad \times \frac{\textit{Initial PRMR of the LSE not using the RBDC Opt Out}}{\sum \textit{Initial PRMR of all LSEs not using the RBDC Opt Out}}\end{aligned}$$

iii. LSEs under state jurisdiction where the State Regulatory Authority has overridden the PRM established by the Transmission Provider will have Final PRMRs for each Season calculated by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + the planning reserve margin established by the State Regulatory Authority).

The Transmission Provider will financially net the ZRC credits and LSE debits for Market Participants. Market Participants with cleared ZRCs sourced from Diversity Contracts will receive reduced credit for any ZRC volumes cleared above their PRMR up to the cleared volume of ZRCs from Diversity Contracts. The reduced compensation will be based on the total number of days the capacity from the Diversity Contract is dedicated to Demand in the Transmission Provider Region in each Season divided by the total number of days in the Season.

b. An LSE that submits a FRAP or an RBDC Opt Out with PRMR in an LRZ and ZRCs in an ERZ or a separate LRZ may be subject to a ZDC, as described below:

(i) The Zonal Deliverability Charge will be the maximum of: (a) the difference between the ACP for the LSE's PRMR within an LRZ where an LSE has Demand

that is not met by ZRCs from Planning Resources that are represented in such LRZ and the ACP in the LRZ or ERZ where the LSE's ZRCs are represented; or (b) zero. The Transmission Provider will multiply the ZDC by the ZRCs to obtain the deliverability charge that the Transmission Provider will assess the LSE. The Zonal Deliverability Charge will only be assessed to an LSE's Load that is part of a FRAP or for LSEs submitting ZRCs for an RBDC Opt Out.

c. Any portion of an LSE's PRMR not covered by the FRAP, minus the amount of PRMR associated with the Capacity Deficiency Charge, shall be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is not recovered by ZRCs in a FRAP.

d. For instances where a LRZ clears under ZRC Shortage Conditions or ZRC Near-Shortage Conditions to meet Local Clearing Requirement in more than one Season in a Planning Resource Auction and final ACPs are adjusted per Section 69A.7.1.c.(x), certain cleared ZRC Offers may exceed the final ACPs. In this case, such cleared ZRCs may be eligible for a ZRC Offer Revenue Sufficiency Credit, to the extent that settlement amounts credited in paragraph 69A.7.6.a above for a Planning Year are insufficient to cover Allowable ZRC Offer Costs, needed to be incurred by the Planning Resource to be available for cleared Seasons.

ZRC Offer Revenue Sufficiency Credit will be calculated as the greater of: (i) zero; or, (ii) the difference between Allowable ZRC Offer Costs, and the total settlement amounts credited per paragraph 69A.7.6.a for the associated cleared

ZRC Offers for all Seasons in a Planning Year.

Where Allowable ZRC Offer Costs shall equal the minimum of: (i) the sum of all cleared ZRC Offer segment volumes multiplied by the ZRC Offer segment price, multiplied by the number of Days in the Season, calculated for all Seasons for which the ZRCs clear in the Planning Resource Auction; or, (ii) the annual CONE for the LRZ where the ZRCs are represented; or, (iii) the applicable facility-specific Reference Level costs for the Planning Resource, if a Market Participant received a facility-specific Reference Level per Section 64.1.4.

ZRC Offer Revenue Sufficiency Credits will be allocated pro-rata across the Seasons where the ZRC Offer cleared for settlement and distribution.

e. ZRC Offer Revenue Sufficiency Charges will be assessed as the sum of all ZRC Offer Revenue Sufficiency Credits for a Season distributed to Market Participants representing LSEs in an LRZ clearing under ZRC Shortage Conditions or ZRC Near-Shortage Conditions on a pro rata basis, based upon their respective LSE's share of Final PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge in the appropriate LRZ.

Distribution of Excess Auction Revenue

The following provisions address situations where LSEs will be entitled to receive financial benefits on contractual commitments and/or use of the Transmission System. These benefits will provide LSEs with financial hedges for ACP separation between LRZs and/or ERZs based on excess revenue from the Planning Resource Auction.

The Transmission Provider will distribute any such excess revenues in two stages:

(i) in the first stage, the Transmission Provider shall distribute such excess revenues to LSEs qualifying for Historic Unit Considerations (HUCs) as described in Section 69A.7.7(a) and ZDC Hedges as described in Section 69A.7.7.(b), then

(ii) any remaining excess revenue will be distributed in accordance with the Zonal Deliverability Benefit provisions of Section 69A.7.7(c).

The LSE will only receive excess PRA revenue if the ACP paid by the LSE is higher than the ACP received for such Planning Resources. If there are not sufficient excess revenues to fully fund all Historic Unit Considerations and ZDC Hedges, the revenues will be allocated on a pro rata basis to all HUCs and ZDC Hedges.

Historic Unit Considerations (HUCs)

The Transmission Provider will allocate excess PRA revenue to LSEs with ownership or contractual arrangements, limited to a) Grandfathered Agreements, b) arrangements that predate July 20th, 2011, or c) arrangements that predate March 26, 2018 and pertain to External Resource represented in External Resource Zones in which:

i. The LSE has Initial PRMR obligations equal to or greater than the amount of the Planning Resource designated in the arrangement;

ii. The Planning Resource designated in the arrangement and Initial PRMR obligation span multiple LRZs and/or ERZs;

iii. The LSE has long-term (five years or more) contracts for or ownership of the Planning Resource and has maintained continuous firm Transmission Service or firm Network Resource Interconnection Service, and in the case of External Resources, firm transmission service on the applicable external Balancing Authority transmission system, for that Planning Resource to the LRZ containing the LSE's associated Initial PRMR obligation; and

iv. LSEs must note qualification for HUCs and submit information supporting HUC eligibility to the Transmission Provider by January 15th prior to the upcoming Planning Year.

A combination of arrangements that require the delivery of capacity throughout the Planning Year will qualify to receive excess PRA revenue through a HUC, provided that the arrangements satisfy the criteria herein. The volume of MW eligible to receive excess PRA revenue will be the lesser of the cleared ZRCs from the Planning Resource(s) or the amount of Initial PRMR that are

associated with the qualified arrangement. A qualified arrangement shall remain eligible to receive excess PRA revenue for the current term of the executed contract, excluding any evergreen contract extension, or for two Planning Years, whichever is longer. In the event that the owned resource status is changed to retired, the transmission service is not maintained, or the arrangement is terminated or otherwise expires, the arrangement shall no longer be eligible to receive excess PRA revenue.

ZDC Hedges

An LSE will also be able to receive excess Planning Resource Auction revenue if the LSE qualifies for a ZDC Hedge. A ZDC Hedge can result from approved firm Transmission Service Request where the source and sink are in separate LRZs or between an LRZ and an ERZ that result in required Network Upgrades. The Market Participant that funds the Transmission System upgrades that result in an increase in the CIL, as determined by the Transmission Provider, for an LRZ where the sink is located, will receive a ZDC Hedge. The Market Participant submitting the Transmission Service Request will receive one hundred percent(100%) of the MW volume of the CIL increase. ZDC Hedges will be granted based upon the order that the Transmission Provider receives Transmission Service Requests. Market Participants must submit information supporting ZDC Hedges to the Transmission Provider by November 1st prior to a Planning Year. The volume of a ZDC Hedge will be the incremental increase in the CIL that resulted from the Network Upgrades identified in the approved firm Transmission Service Request. ZDC Hedges will be effective for thirty (30) years or the service life of the Transmission System facility or Network Upgrade, whichever is less.

Zonal Deliverability Benefit

If there are any remaining excess PRA revenues, the Transmission Provider will distribute the remaining amounts to Deliverability Benefit Zones.

First, the Transmission Provider will subtract PRMR and ZRCs associated with HUCs and ZDC Hedges to derive an adjusted PRMR (Adjusted PRMR) and ZRC (Adjusted ZRC). Second, the Transmission Provider shall create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint. Third, the Transmission Provider, for each DBZ, will subtract the sum of Adjusted PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of the Adjusted PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon a weighted average approach. Fourth, the Transmission Provider will calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

$$Weighted\ Average\ Export\ ACP = \frac{\sum(Net\ Export_j \times ACP_j)}{\sum Net\ Export_j}$$

Where j = Each net exporting DBZ

Fifth, the Transmission Provider will calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$ZDB\ Credit_k = Net\ Import_k \times (ACP_k - Weighted\ Average\ Export\ ACP)$$

Where k = Each net importing DBZ

Finally, the Transmission Provider will distribute the ZDB credit in each DBZk by dividing the ZDB credit by the sum of Adjusted PRMR of the LRZs within each DBZk. This distribution is a credit to the initial ACP calculated for each LRZ from the PRA.

The Transmission Provider will receive FRAP and RBDC Opt Out related revenue from Zonal Deliverability Charges. The Transmission Provider will allocate such revenue to the DBZ where the PRMR associated with the ZDC is physically located. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment. The Transmission Provider will also receive FRAP and RBDC Opt Out related revenues derived from ZRCs that would have received payments greater than the charges to the associated FRAP or RBDC Opt Out PRMR. The Transmission Provider will allocate such revenue to the DBZ where the ZRC associated with the FRAP or RBDC Opt Out is represented. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment. After calculating the ZDB rate(s), if there exists any remaining excess revenue (i.e. surplus), the surplus will be allocated back to the Deliverability Benefiting Zone(s) on a PRMR *pro-rata* basis.

Whenever an LRZ has an ACP that exceeds the System ACP because the LCR for that LRZ exceeds the sum of PRMR for LSEs within that LRZ, payments made to ZRCs in that LRZ will exceed the sum of receipts from LSEs within that LRZ plus any receipts from other LRZs related to such ZRCs. The revenue shortfall within such LRZ will be recovered from all LSEs within that LRZ on a PRMR pro-rata basis. PRMR covered by FRAPs and RBDC Opt Outs will be included in the pro-rata calculation, and the related amounts charged to the LSEs that use FRAPs and RBDC Opt Outs through this Local Clearing Requirement Charge.

Self-Scheduling Option:

LSEs with sufficient ZRCs within an LRZ where the LSE has forecasted Demand will be able to avoid the financial impact of that LRZ's ACP for the Final PRMR by Self-Scheduling such ZRCs into the PRA (*i.e.*, by Offering ZRCs into the PRA at a zero price so that the ZRCs will clear). For Planning Resources associated with ZRCs represented outside the LRZ where the LSE has PRMR, an LSE would also need to use the financial hedges described in Section 69A.7.7 to avoid the financial effects of potential price differences between LRZs or between an LRZ and an ERZ.

Installed Capacity (ICAP) Deferral Requirements and Charges

a. ICAP Deferral Notice. Market Participants that request ICAP deferral as provided in Sections 69A.3.1.a.2, 69A.3.1.b.2, 69A.3.1.c.2, and/or 69A.3.6.2. must provide an ICAP Deferral Notice to the Transmission Provider in writing by an officer of the company no later than February 15th prior to the Planning Year: (1) the expected ICAP value (in megawatts) from such Planning Resource and if the Planning Resource is new, the LBA or external BA where it is represented for any Season for which it wants to be eligible to offer ZRCs, (2) appropriate information validating that ICAP will be submitted to the Transmission Provider by the last business day of the Month prior to the start of any Season in which it wants to be eligible.

b. ICAP Deferral Credit Requirements. A Market Participant that provides ICAP Deferral Notice must satisfy credit requirements by March 1st prior to the Planning Year totaling the ICAP value provided in the ICAP Deferral Notice, multiplied by ninety (90) days of daily CONE values (i.e., 90/365 times CONE) for the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs, or which are not directly connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs. If the Market Participant: (1) submits GVTC results, demonstrates deliverability, and demonstrates commercial operation, or (2) registers replacement ZRCs in accordance with Section 69A.3.1.h, then the Transmission Provider will adjust the Market

Participant's credit requirement to account for these changes within ten (10) Business Days after ICAP is submitted or replacement ZRCs have been provided to the Transmission Provider. In the event ZRCs associated with a Planning Resource for which ICAP has been deferred are unconverted in accordance with 69A.7.3, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred ICAP value. Then the Transmission Provider will adjust the Market Participant's ICAP value and credit requirement within ten (10) Business Days.

c. ICAP Deferral Non-Compliance Charges.

i. A Market Participant that provides ICAP Deferral Notice and that either (1) has not submitted ICAP for such Planning Resources by the last business day of the Month prior to the start of any Season for which it has deferred, or (2) has submitted an ICAP value demonstrating fewer megawatts are available than the ICAP value submitted in the ICAP Deferral Notice, shall be assessed ICAP Deferral Non-Compliance Charges unless it completes ZRC replacement in accordance with Section 69A.3.1.h. Assessment of ICAP Deferral Non-Compliance Charges will commence on the first day of the any Season for which a Market Participant has an ICAP deferral and continue until ICAP is submitted and verified by the Transmission Provider, replacement ZRCs are registered per the BPM for Resource Adequacy, the ICAP value is forfeited, or the end of any deferred Season, whichever is earlier. Market Participants with Planning Resources subject to ICAP Deferral Non-Compliance Charges do not have to meet the applicable performance requirement as described in Sections 69A.3.9

and 69A.5 for such Resources, until such time that they are no longer subject to these charges.

ii. ICAP Deferral Non-Compliance Charges will be calculated as follows: the amount of ICAP that has not been submitted to the Transmission Provider multiplied by the sum of the ACP and the daily CONE value (i.e., 1/365 times CONE). The ACP and the CONE values will be based on the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs or which are not connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs.

iii. Distribution of ICAP Deferral Non-Compliance Charges: ICAP Deferral Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon the LSE's share of Final PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge for the Transmission Provider Region during the applicable Season.

Calculation of CONE and Net CONE

a. The CONE value shall initially be the rate proposed by the Transmission Provider in a 2012 Federal Energy Regulatory Commission filing and approved by the Commission for the Planning Year commencing on June 1, 2013. The Transmission Provider and the IMM shall consider factors, including, but not limited to: (1) physical factors (such as, the type of Generation Resource that could reasonably be constructed to provide Planning Resources, costs associated with locating the Generation Resource within the Transmission Provider Region, the estimated costs of fuel for the Generation Resource); (2) financial factors (such as, the hypothetical debt/equity ratio for the Generation Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). In calculating the CONE, the Transmission Provider and the IMM shall not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services. CONE values will be calculated for each LRZ. The Transmission Provider shall arrange for CONE values to be calculated in concert with the IMM no later than September 1 beginning on September 1, 2012. The recalculated CONE values shall be filed with the Commission annually thereafter.

b. The Transmission Provider shall calculate Net CONE values for each LRZ. Net CONE represents the difference between CONE values and Inframarginal Rents, for the Generation Resource type used in the CONE value calculation (the Reference Resource Type) . The following process will be used to estimate Net CONE:

To determine Inframarginal Rents, the most recent three Planning Years of historic data will be compiled for each Generation Resource of the Reference Resource Type operating in the Transmission Provider Region consisting of all revenues for the Generation Resource from the Transmission Provider's Energy and Operating Reserve Markets, on a per MW or MWh basis, whichever is applicable, calculated hourly, and Production Costs calculated hourly. The greater of the market revenues minus Production Costs, or zero, shall be calculated hourly, and summed across all Hours for each Planning Year, for each resource of the Reference Resource Type. Inframarginal Rents outside of two standard deviations from the sample mean are removed. The Generation Resources are then grouped into LRZs based on their location. An average Inframarginal Rents is calculated for each LRZ and then scaled using a capacity factor for each LRZ. The capacity factor is the ratio of the commitment hours of the Generation Resource of the Reference Resource Type that is committed for the maximum number of hours in the Planning Year amongst all Generation Resources of the Reference Resource Type to the average commitment hours of all Generation Resources of the Reference Resource Type that were committed in the LRZ in the Planning Year. This results in Inframarginal Rents values for each LRZ for each Planning Year, which will be averaged over a three-year period to determine an initial Inframarginal Rents for each LRZ.

To determine the final Inframarginal Rents values to be used for the upcoming Planning Year, the Transmission Provider will apply a scaling factor to the initial Inframarginal Rents. The scaling factor will be based on statistical models between: a) LMPs to gas, and; b) LMPs to Inframarginal Rents. Readily available settled futures gas prices for the

upcoming Planning Year will be applied to the statistical models to calculate the scaling factor.

Each LRZ's final Inframarginal Rents are then grouped and averaged into values in the First Planning Area and Second Planning Area. The values from the First Planning Area and Second Planning Area are then subtracted from the LRZ-specific CONE values to get an estimate of Net CONE for each LRZ. For use in the PRA, Net CONE values are sorted into values in the First Planning Area and Second Planning Area.

The Transmission Provider shall arrange for Net CONE values to be calculated no later than September 1 prior to the subsequent Planning Year beginning on September 1, 2024. The recalculated Net CONE values shall be filed with the Commission annually thereafter.

Use of FRAP in the Planning Resource Auction

An LSE electing to use a Fixed Resource Adequacy Plan (FRAP) in the PRA for any Season can continue to use its existing resource planning processes to meet all or any portion of its Initial PRMR by providing the Transmission Provider with a FRAP, as described below:

a. An LSE electing to use a FRAP for any Season must submit a FRAP for each LRZ to the Transmission Provider by the 7th Business Day of March prior to a Planning Year in order for the LSE to demonstrate that the LSE has designated ZRCs in order to meet all or any portion of the LSE's Initial PRMR for such LRZ. Market Participants submitting registrations for new and existing Load Modifying Resources can be included in the Module E Capacity Tracking Tool beginning as early as December prior to the Planning Year. Load Modifying Resources registrations submitted to the Transmission Provider will be evaluated to determine if Load Modifying Resources meet the qualification requirements. Market Participants that submit registrations by February 1 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome on or before February 21 that precedes the Planning Year.

Market Participants that submit registrations between February 2 and February 15 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome at least two Business Days prior to the FRAP deadline. The Transmission Provider will make a good faith effort to notify Market Participants that submit registrations after February 15 but not later than March 1 of the outcomes of such registrations no later than the FRAP deadline. The FRAP must include the LSE's forecasted Coincident Peak Demand for each LRZ for each Season and also identify the

ZRCs that the LSE owns, or has contractual rights to, in order to provide Planning Resources to meet the FRAP designated portion of its Initial PRMR and also its load ratio share of the LCR for each LRZ for each Season. The Transmission Provider will evaluate each LSE's FRAP to determine if it meets the designated portion of the LSE's Initial PRMR and the LSE's share of LCR and the Transmission Provider will notify the LSE via the MECT prior to March 15th before a Planning Year of the extent that the portion of an LSE's Initial PRMR or share of LCR for each LRZ is not covered by a submitted FRAP. The LSE will have until the PRA offer window opens to remedy any deficiencies in their FRAP for each Season.

b. To the extent that the LSE's ZRCs satisfy the portion of the LSE's Initial PRMR for the applicable Season(s) submitted through a FRAP, (1) the LSE will not have an obligation to make ZRC Offers for the ZRCs included in the FRAP into the PRA, or otherwise participate in the PRA for such Season; and (2) the LSE will not have an obligation to pay the applicable ACP for the LSE's Initial PRMR within such LRZ that is covered by the FRAP. The Transmission Provider will consider all PRMR and ZRCs, including PRMR and ZRCs in FRAPs, as part of the Transmission Provider's reliability assessment when conducting the PRA.

c. Any portion of an LSE's Initial PRMR not covered by the FRAP may be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is procured through the PRA.

d. If an LSE owns or controls ZRCs that are not included in the LSE's FRAP, then such LSE may submit ZRC Offers into the PRA for all such excess ZRCs, subject to Module D.

e. To the extent that an LSE designates ZRCs in a FRAP that are represented in the same LRZ as the LSE's Demand to meet the LSE's Initial PRMR for such LRZ, then the LSE will not be subject to a Zonal Deliverability Charge for such ZRCs.

f. An LSE that contains ZRCs from Planning Resources that are not represented in the same LRZ where the LSE has Demand may be subject to a Zonal Deliverability Charge, which will be calculated as described in Section 69A.7.6(b).

Use of RBDC Opt Out in the Planning Resource Auction

An LSE electing to use the RBDC Opt Out can continue to use its existing resource planning processes to meet its Final PRMR by providing the Transmission Provider with an RBDC Opt Out, as described below:

a. The RBDC Opt Out Lock-In Period will be three consecutive Planning Years for all Seasons. If an LSE fails to submit an RBDC Opt Out then the LSE will be required to participate in the PRA through any combination of the other Tariff-defined options, or pay the Capacity Deficiency Charge, for each Planning Year in which the LSE does not submit an RBDC Opt Out.

b. An LSE under state jurisdiction where the State Regulatory Authority has overridden the PRM established by the Transmission Provider is not eligible to select the RBDC Opt Out.

c. An LSE selecting the RBDC Opt Out will be required to meet its Final PRMR for the entirety of its load and losses, and its entire share of LCR for each LRZ, for each Season.

d. An LSE must provide an initial notification of its intent to elect the RBDC Opt Out no later than January 15th prior to the upcoming Planning Year. An LSE electing the RBDC Opt Out must submit its final plan for each LRZ to the Transmission Provider by the 7th Business Day of March prior to each Planning Year during the RBDC Opt Out Lock-In Period in order for the LSE to demonstrate that the LSE has designated ZRCs in order to meet the LSE's Final PRMR, and share of LCR for each LRZ, for each Season. Market Participants

using the RBDC Opt Out must submit all registrations for new and existing resources to be used in the RBDC Opt Out through the MECT consistent with the timelines established in the Business Practices Manual for Resource Adequacy. The RBDC Opt Out must include the LSE's seasonal forecasted Coincident Peak Demand for each LRZ and also identify the ZRCs that the LSE owns, or has contractual rights to, in order to provide Planning Resources to meet its Final PRMR, and also its share of the LCR for each LRZ for each Season. The Transmission Provider will evaluate each LSE's RBDC Opt Out on an annual basis to determine if it meets the LSE's Final PRMR and the LSE's share of LCR requirements for all Seasons. The Transmission Provider will notify the LSE prior to March 15th before the applicable Planning Year whether the submitted RBDC Opt Out meets the LSE's Final PRMR, and share of LCR for each LRZ, requirement for each Season during the applicable Planning Year. The LSE must remedy any deficiencies in its RBDC Opt Out for each Season before the PRA offer window opens.

e. The Transmission Provider will notify the RERRA(s) following the submission of an initial intent to elect the RBDC Opt Out by an LSE. RERRA(s) may elect to notify the Transmission Provider within twenty (20) Business Days whether the LSE's load subject to the RERRA's respective jurisdiction is authorized to select the RBDC Opt Out. Upon receipt of such a notification from the RERRA(s) that the LSE is not authorized to elect the RBDC Opt Out for the LSE's load subject to the RERRA's respective jurisdiction, the Transmission Provider will reject the

LSE's RBDC Opt Out for such load. If the Transmission Provider receives no notification from the RERRA(s) within the twenty (20) Business Day period, and an LSE has demonstrated that it has designated ZRCs in order to meet its Final PRMR, and share of LCR for each LRZ, for each Season, then the proposed RBDC Opt Out by the LSE will be deemed accepted by the Transmission Provider.

f. To the extent that the LSE's ZRCs satisfy the LSE's Final PRMR for the applicable Season(s) submitted through an RBDC Opt Out, (1) the LSE will not have an obligation to make ZRC Offers for the ZRCs included in the RBDC Opt Out into the PRA, or otherwise participate in the PRA for such Season; and (2) the LSE will not have an obligation to pay the applicable ACP for the LSE's Final PRMR within such LRZ. The Transmission Provider will consider all PRMR and ZRCs, including PRMR and ZRCs in RBDC Opt Outs, as part of the Transmission Provider's reliability assessment when conducting the PRA.

g. If an LSE owns or controls ZRCs that are not included in the LSE's RBDC Opt Out, then such LSE may submit ZRC Offers into the PRA for all such excess ZRCs, subject to Module D.

h. To the extent that an LSE designates ZRCs in an RBDC Opt Out that are represented in the same LRZ as the LSE's Demand to meet the LSE's Final PRMR for such LRZ, then the LSE will not be subject to a Zonal Deliverability Charge for such ZRCs.

i. An LSE that designates ZRCs from Planning Resources that are not represented in

the same LRZ where the LSE has Demand may be subject to a Zonal Deliverability Charge, which will be calculated as described in Section 69A.7.6(b).

j. LSEs that submit an RBDC Opt Out may not use any of the other options to satisfy their Final PRMR including: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process, and/or (iv) paying the Capacity Deficiency Charge to meet all or a portion of their Initial PRMR.

k. LSEs that elect the RBDC Opt Out that do not meet their Final PRMR shall pay the RBDC Opt Out Deficiency Charge, which is 2.748 times applicable LRZ's CONE multiplied by the difference in ZRCs between the LSEs Final PRMR and the amount of ZRCs submitted as the LSEs RBDC Opt Out for each Season in which the LSE fails to meet its Final PRMR.

l. RBDC Opt Out Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a pro rata basis, based upon their respective LSE's share of Final PRMR for the Transmission Provider Region minus the Final PRMR associated with the RBDC Opt Out Deficiency Charge. If the LRZ where LSEs incurred RBDC Opt Out Deficiency Charges failed to meet its Local Clearing Requirement ("LCR"), then RBDC Opt Out Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a pro rata basis, based upon their respective LSE's share of Final PRMR minus the Final PRMR associated with the RBDC Opt Out Deficiency Charge in such LRZ.

m. The Transmission Provider will determine the RBDC Opt Out Adder that will be applicable for the upcoming Planning Year every year on or before December 15. The RBDC Adder applicable during the first Planning Year in which an LSE elects to use the RBDC Opt Out will apply for such LSE's entire RBDC Opt Out Lock-In Period.

n. The Transmission Provider will determine the RBDC Opt Out Adder based on a Seasonal average of the RBDC based PRA clearing for the prior three Planning Years. If the prior year RBDC based PRA clearing is not available, simulated RBDC based PRA clearing will be used to determine the RBDC Opt Out Adder.

Capacity Deficiency Charge

a. The Transmission Provider will impose a Capacity Deficiency Charge on an LSE that has provided notification prior to the Planning Resource Auction that they will meet their Initial PRMR in part or in whole by removing Initial PRMR from the Transmission Provider's capacity construct for one or more Seasons by paying the Capacity Deficiency Charge. The Capacity Deficiency Charge will be calculated as follows: The CONE value for the LRZ(s) where the LSE has provided notice it will be meeting its Initial PRMR by paying the Capacity Deficiency Charge for each Season of the Planning Year will be multiplied by 2.748 times the Initial PRMR volume indicated by the LSE. The Capacity Deficiency Charge will be assessed to Market Participants representing their respective LSE paying the Capacity Deficiency Charge on the first Business Day after the results of the Planning Resource Auction have been published.

b. Distribution of Capacity Deficiency Charge Revenues: A Market Participant representing an LSE that provided notice it will be meeting all or part of its Initial PRMR by paying the Capacity Deficiency Charge will not be distributed any Capacity Deficiency Charge revenues for that LSE's Initial PRMR that was met by paying the Capacity Deficiency Charge. Capacity Deficiency Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon their respective LSE's share of Initial PRMR for the Transmission Provider Region minus the Initial PRMR associated with the Capacity Deficiency Charge. If the LRZ where LSEs incurred Capacity Deficiency Charges failed to meet its Local Clearing Requirement ("LCR"), then Capacity Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a *pro rata* basis,

based upon their respective LSE's share of Initial PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge in such LRZ.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Midcontinent	)
Independent System Operator	)
(MISO)	)
	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 59

MISO 2025–26 Prelim. PRA Report with Final Results

Total Installed Capacity (ICAP)	Installed Capacity (ICAP) is the lesser of a resource's net demonstrated capability submitted by the resource or its interconnection service. This field provides a summation for Local Resource Zones (LRZ), External Zones, and a MISO total. Values reflect the ICAP data as available in the Module E Capacity Tracking (MECT) tool and are subject to change the closer the Planning Resource Auction (PRA) approaches.
Total Seasonal Accredited Capacity (SAC)	SAC is the amount of Capacity, for a given Season, in MW, assigned to a Planning Resource after accounting for its historic availability. This field provides the sum of all "SAC (Max)" in the MECT based on the various accreditation methods used for each resource type by LRZ, ERZ, and a MISO total. This the maximum potential amount of capacity that is possible to be used towards meeting Resource Adequacy requirements assuming all SAC is deliverable. It is typical for not all SAC to participate in the PRA, as it is subject to Market Participant validation and confirmation and eligibility rules. This value reflects the SAC (Max) values as available in the Module E Capacity Tracking (MECT) tool. This value also reflects DR/BTMG/ER/EE which have completed and approved registrations.
Market Participant Confirmed SAC	This field reflects the "SAC (Max)" values in the MECT which have been confirmed by the Market Participants. The closer the PRA approaches the more Market Participants confirm their SAC values. SAC values must be confirmed by the Market Participant before capacity can be converted into Zonal Resource Credits (ZRCs).
Market Participant Converted SAC into Zonal Resource Credits (ZRC)	ZRCs are the fungible unit by which the PRA is conducted. ZRCs represent a MW unit of a Planning Resource that has been converted from a MW of Seasonal Accredited Capacity to a credit in the MECT, which is eligible to be offered by a Market Participant into the PRA, to be sold bilaterally, used as replacement capacity and/or to be submitted through a Fixed Resource Adequacy Plan. Once a Market Participant has confirmed their SAC values, any portion of SAC that is deliverable (NRIS or ERIS plus firm Transmission Service) may be converted into ZRCs. This field sums all SAC values that have been converted into ZRCs by Market Participants. This value is subject to change the closer the PRA approaches due to more Market Participants converting confirmed SAC into ZRCs.
Potential IMM Exclusion SAC	MISO Tariff Module D Market Monitoring Mitigation Measures, Section 64.1.1 g provides circumstances Market Participants are allowed to refuse to submit ZRC Offers into the PRA. This value reflects data in the MECT which has been uploaded by the IMM for SAC MWs seeking and/or allowed to be excluded from the PRA.
OASIS Attachment Y Approved Generation Retirement (MW)	The sum of approved & public generation retirement MW which starts in the auction period. This data is taken from the Attachment Y posting on the MISO OASIS. This value is nameplate not SAC.
Generation Suspension (MW)	The sum of approved generation suspension requested for this upcoming auction period. This value is nameplate not SAC.

BTMG Registrations In Progress	Behind the Meter Generation (BTMG) registrations that have been entered into the MECT but not yet approved. Once approved these values can propagate to the ICAP, SAC, Confirmed SAC, and ZRC tabulations contained in this report.
DR Registrations In Progress	Demand Response (DR) registrations that have been entered into the MECT but not yet approved. Once approved these values can propagate to the ICAP, SAC, Confirmed SAC, and ZRC tabulations contained in this report.
ER Registrations In Progress	External Resources (ER) registrations that have been entered into the MECT but not yet approved. Once approved these values can propagate to the ICAP, SAC, Confirmed SAC, and ZRC tabulations contained in this report.
EE Registrations In Progress	Energy Efficiency (EE) registrations that have been entered into the MECT but not yet approved. Once approved these values can propagate to the ICAP, SAC, Confirmed SAC, and ZRC tabulations contained in this report.
Sub Total of Registrations In Progress	Sums the above registrations.

Coincident Peak Forecast (CPF)	This value reflects a forecasted demand submitted with Load Serving Entities (LSE) and Electric Distribution Companies (EDC) into the MECT. CPF is the demand which is forecasted to coincide with the MISO peak.
Transmission Loss (TL) for CPF (MW)	LBA transmission loss percentages apply to the LSE's LBA Coincident Peak Demand forecast to determine the LSE's transmission losses (MW) for the calculation of the seasonal PRMR.
Initial Planning Reserve Margin Requirement (Initial PRMR)	The amount of ZRCs required of each LSE with Coincident Peak Demand in an LRZ to meet the LSE's Resource Adequacy Requirements in each Season.
Final Planning Reserve Margin Requirement (Final PRMR)	
Planning Reserve Margin Requirement (PRMR)	
Zonal Coincident Peak Forecast (ZCPF)	This value reflects a forecasted demand submitted with Load Serving Entities (LSE) and Electric Distribution Companies (EDC) into the MECT. ZCPF is the demand which is forecasted to coincide with the zonal peak.
Transmission Loss (TL) for ZCPF (MW)	LBA transmission loss percentages coincident with each LRZ's seasonal Peak Demand forecast will determine the LSE's transmission losses (MW) for the calculation of LRR (MW).

Local Clearing Requirement (LCR)	The minimum amount of Seasonal Accredited Capacity for an LRZ that is required to meet its LOLE for each Season while fully using the Zonal Import Ability for such LRZ and accounting for controllable exports.
Zonal Import Ability (ZIA)	The ability of an LRZ to import capacity from areas outside of that LRZ. Equal to an LRZ's base interchange plus the LRZ's incremental ability to import generation.
Capacity Export Limit (CEL)	The amount of Planning Resources in MWs for an LRZ or ERZ determined by the Transmission Provider that can be reliably exported from that LRZ or ERZ for each Season.
Capacity Import Limit (CIL)	The amount of Planning Resources in MWs for an LRZ determined by the Transmission Provider that can be reliably imported into that LRZ for each Season..
Local Reliability Requirement (LRR)	The minimum amount of capacity for an LRZ to meet its LOLE for each Season, without considering transmission ties to systems outside of the LRZ.
Controllable Exports	Firm capacity commitments from MISO units to non-MISO load and may be committed and dispatched by MISO during emergencies.

ACTUAL PRA DATA - PY25-26 SUMMER

2025 SUMMER

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW) [M]	16,668.1	12,013.0	9,866.0	8,412.4	7,541.1	16,712.2	19,143.1	7,696.9	19,859.9	4,683.9	90,355.9	32,240.7	122,596.6
Transmission Loss (TL) for CPF (MW) [N]	439.6	211.9	226.0	148.8	133.9	419.0	530.7	169.3	354.9	82.6	2,109.9	606.8	2,716.7
Planning Reserve Margin (PRM %) [P]	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%
Initial Planning Reserve Margin Requirement (Initial PRMR) (MW) [Q] = [(M+N)*(1+P)]	18,459.4	13,190.2	10,889.2	9,237.6	8,281.3	18,484.8	21,228.0	8,487.8	21,812.2	5,142.9	99,770.5	35,442.9	135,213.4
"Effective" Planning Reserve Margin (PRM %) [R] = [S] / [(M+N)-1]	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	8.7%	8.7%	8.7%	10.1%	8.7%	9.8%
Final Planning Reserve Margin Requirement (Final PRMR) (MW) [S]	18,843.5	13,464.4	11,116.0	9,430.1	8,453.5	18,868.9	21,669.2	8,552.6	21,978.8	5,182.3	101,845.6	35,713.7	137,559.3

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF) [A]	17,651.7	12,192.8	10,082.7	8,538.9	7,680.0	16,769.1	19,791.9	7,989.2	20,735.3	4,752.2
Transmission Loss (TL) for ZCPF (MW) [B]	525.6	220.7	239.2	135.2	151.0	428.0	639.0	199.7	370.3	83.9
Local Resource Requirement (LRR) [C]	1.195	1.135	1.318	1.280	1.301	1.262	1.138	1.350	1.136	1.447
Zonal Import Ability (ZIA) [D]	6,023	4,370	5,460	7,757	4,117	8,366	3,569	2,358	4,361	4,474
Controllable Exports [E]	2	0	95	768	0	285	0	210	0	0
Capacity Import Limit (CIL) [F] = [(D+E)]	6,025	4,370	5,555	8,525	4,117	8,651	3,569	2,568	4,361	4,474
Local Clearing Requirement (LCR) [G] = [(A+B)*C-D-E]	15,696.9	9,719.3	8,049.3	2,577.8	6,071.1	13,051.7	19,681.4	8,487.0	19,615.0	2,523.8

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	6,025	4,370	5,555	8,525	4,117	8,651	3,569	2,568	4,361	4,474
Capacity Export Limit (CEL)	3,991	4,614	4,618	4,584	3,939	6,881	5,726	6,299	4,286	2,097

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	27,943.5	16,415.3	23,085.0	12,250.0	7,522.5	19,449.0	25,511.5	12,476.2	23,413.1	6,685.9	396.5	648.8	32.5	158.9	0.0	171.1	280.0	176,439.8
Total Seasonal Accredit Capacity (SAC)	20,183.4	14,622.0	11,582.8	9,483.1	6,795.6	16,229.2	20,918.2	11,682.6	20,635.0	5,654.9	391.7	614.2	29.5	154.6	0.0	170.9	279.9	139,427.6
Market Participant Confirmed SAC	19,992.5	14,622.0	11,470.0	9,482.9	6,795.6	16,229.2	20,916.8	11,682.6	20,629.5	5,654.1	391.7	614.2	29.5	154.6	0.0	170.9	279.9	139,116.0
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	19,855.0	14,614.8	11,395.6	9,414.9	6,758.0	16,197.6	20,885.1	11,652.3	20,557.3	5,566.6	391.7	614.2	29.5	154.6	0.0	170.9	279.6	138,537.7
Potential IMM Exclusion SAC	419.0	0.0	118.4	191.2	0.0	415.0	2.7	134.6	505.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,786.1
OASIS Attachment Y Reported MW of Approved Generation Retirement	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.0
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	0.0	0.0	0.0	43.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0

ACTUAL PRA DATA - PY24-25 SUMMER

2024 SUMMER

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW)	16,337.3	11,985.1	9,447.6	8,460.3	7,459.7	16,610.4	19,215.6	7,509.1	19,755.0	4,534.0	89,516.0	31,798.1	121,314.1
Transmission Loss (TL) for CPF (MW)	815.9	304.7	448.6	166.3	152.1	421.0	568.7	225.2	325.3	87.7	2,877.3	638.2	3,515.5
Planning Reserve Margin (PRM %)	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%
Planning Reserve Margin Requirement (PRMR) (MW)	18,697.0	13,395.8	10,786.8	9,402.8	8,297.0	18,564.5	21,564.7	8,430.5	21,887.6	5,037.7	100,708.6	35,355.8	136,064.4

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF)	17,023.5	12,143.1	9,543.5	8,565.0	7,532.3	16,657.2	19,867.5	7,839.9	20,497.8	4,674.0
Transmission Loss (TL) for ZCPF (MW)	691.2	309.9	340.2	110.8	147.9	375.5	606.7	156.7	370.1	79.3
Controllable Exports	2	0	58	892	0	284	10	164	511	0
Local Clearing Requirement (LCR)	13,591.0	9,354.2	7,662.4	451.5	7,014.3	12,787.9	19,270.5	7,523.3	18,380.1	3,651.5

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	6,462	4,506	4,969	10,749	3,208	7,481	4,500	3,608	5,305	3,564
Capacity Export Limit (CEL)	4,537	3,971	5,490	2,771	4,644	5,619	5,709	6,099	3,025	1,840

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	28,432.6	16,352.7	23,017.0	11,838.6	8,256.6	18,890.8	26,656.0	11,460.7	24,568.5	6,505.7	395.9	1,016.3	32.2	158.9	22.0	243.9	280.0	178,128.4
Total Seasonal Accredit Capacity (SAC)	21,146.8	15,260.4	11,613.6	9,273.0	7,541.9	16,191.8	22,023.2	11,002.2	22,795.8	5,704.6	392.0	998.7	29.4	156.9	22.0	241.1	280.0	144,673.4
Market Participant Confirmed SAC	20,954.3	14,895.4	11,401.8	9,153.5	7,473.5	16,191.8	22,023.2	11,002.2	22,565.8	5,704.6	392.0	998.7	29.4	156.9	22.0	241.1	280.0	143,486.2
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	20,815.5	14,836.9	11,275.8	9,059.8	7,442.1	16,191.8	21,967.3	10,979.5	22,534.5	5,704.6	392.0	994.0	29.4	156.9	22.0	239.6	280.0	142,921.7
Potential IMM Exclusion SAC	29.6	401.2	226.4	229.6	14.2	384.7	23.7	186.3	1,172.5	0.0								2,668.2
OASIS Attachment Y Reported MW of Appoved Generation Retirement	7.8	0.0	12.0	0.0	0.0	0.0	0.0	0.0	335.0	0.0								354.8
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	24.9	0.0	0.0	0.0	0.0	257.9	0.0								282.8

ACTUAL PRA DATA POSTING - PY25-26 FALL

2025 FALL

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW) [M]	14,539.8	10,319.8	8,601.1	7,610.5	6,723.2	15,049.4	17,272.0	6,835.8	18,495.8	4,402.6	80,115.8	29,734.2	109,850.0
Transmission Loss (TL) for CPF (MW) [N]	508.5	199.4	258.1	179.2	151.1	563.9	564.4	143.6	283.8	73.1	2,424.6	500.5	2,925.1
Planning Reserve Margin (PRM %) [P]	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%
Initial Planning Reserve Margin Requirement (Initial PRMR) (MW) [Q] = [(M+N)*(1+P)]	17,290.4	12,086.4	10,179.1	8,950.4	7,898.3	17,939.5	20,493.9	8,019.3	21,578.1	5,142.6	94,838.0	34,740.0	129,578.0
"Effective" Planning Reserve Margin (PRM %) [R] = [S] / [(M+N)-1]	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	15.2%	15.2%	15.2%	18.4%	15.2%	17.5%
Final Planning Reserve Margin Requirement (Final PRMR) (MW) [S]	17,811.7	12,450.6	10,486.1	9,220.3	8,136.3	18,480.2	21,111.9	8,037.5	21,627.0	5,154.3	97,697.1	34,818.7	132,515.8

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF) [A]	15,376.9	10,533.0	8,891.0	7,750.0	6,851.7	15,178.9	17,957.3	7,245.2	19,391.5	4,449.4
Transmission Loss (TL) for ZCPF (MW) [B]	485.7	210.1	301.2	99.8	134.5	581.3	617.3	137.6	395.3	101.4
Local Resource Requirement (LRR) [C]	1.288	1.222	1.537	1.320	1.365	1.312	1.255	1.469	1.198	1.557
Zonal Import Ability (ZIA) [D]	5,688	6,537	7,704	7,013	4,679	8,672	5,115	5,675	4,741	4,508
Controllable Exports [E]	52	0	93	760	0	280	0	164	0	0
Capacity Import Limit (CIL) [F] = [(D+E)]	5,740	6,537	7,797	7,773	4,679	8,952	5,115	5,839	4,741	4,508
Local Clearing Requirement (LCR) [G] = [(A+B)*C-D-E]	14,691.0	6,591.1	6,331.4	2,588.7	4,857.2	11,725.4	18,196.1	5,006.3	18,963.6	2,577.6

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	5,740	6,537	7,797	7,773	4,679	8,952	5,115	5,839	4,741	4,508
Capacity Export Limit (CEL)	6,115	4,259	5,831	4,309	5,816	5,191	5,168	4,055	4,173	3,164

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	26,744.9	16,212.3	23,081.8	12,151.3	7,663.1	19,066.4	24,921.1	12,268.7	23,435.7	6,667.6	375.1	670.1	32.6	158.9	0.0	171.1	280.0	173,900.7
Total Seasonal Accredit Capacity (SAC)	19,481.4	14,342.5	14,114.0	9,096.4	6,913.6	15,751.7	19,559.1	11,125.1	21,312.1	5,634.1	372.1	651.0	30.4	154.7	0.0	170.3	277.4	138,985.9
Market Participant Confirmed SAC	19,248.9	14,342.5	13,864.5	9,096.3	6,913.6	15,751.7	19,557.8	11,125.1	21,312.1	5,634.1	372.1	651.0	30.4	154.7	0.0	170.3	277.4	138,502.5
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	19,043.7	14,332.9	13,767.3	9,068.2	6,855.9	15,717.2	19,518.6	11,081.4	21,242.7	5,546.6	372.1	650.0	30.4	154.7	0.0	170.3	272.1	137,824.1
Potential IMM Exclusion SAC	391.4	0.0	126.4	183.4	0.0	649.8	3.5	88.9	550.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,993.5
OASIS Attachment Y Reported MW of Approved Generation Retirement	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.0
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	0.0	0.0	0.0	43.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0

ACTUAL PRA DATA - PY24-25 FALL

2024 FALL

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW)	13,807.4	10,324.4	8,511.7	7,534.4	6,839.1	15,271.0	17,008.8	6,481.7	17,834.0	4,088.9	79,296.8	28,404.6	107,701.4
Transmission Loss (TL) for CPF (MW)	425.0	184.5	195.6	96.6	139.8	289.7	410.2	175.0	251.4	70.6	1,741.4	497.0	2,238.4
Planning Reserve Margin (PRM %)	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%
Planning Reserve Margin Requirement (PRMR) (MW)	16,253.6	12,001.3	9,943.9	8,714.7	7,969.8	17,770.1	19,892.6	7,602.0	20,653.4	4,750.0	92,546.0	33,005.4	125,551.4

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF)	14,773.2	10,543.9	8,715.6	7,606.5	6,911.9	15,347.7	17,752.9	6,970.4	18,780.9	4,246.3
Transmission Loss (TL) for ZCPF (MW)	481.0	191.1	226.2	154.3	168.2	331.9	434.2	139.3	328.0	83.8
Controllable Exports	2.0	0.0	62.0	895.0	0.0	298.0	10.0	195.0	501.0	0
Local Clearing Requirement (LCR)	12,336.9	7,152.3	5,280.7	3,673.5	6,416.4	10,750.3	19,443.3	5,499.1	16,630.6	2,482.3

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	6,502	5,719	6,746	6,594	3,786	8,959	4,400	5,137	6,109	4,736
Capacity Export Limit (CEL)	5,711	4,512	6,956	3,906	5,402	3,514	5,381	4,115	2,803	2,889

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	27,927.1	16,310.6	22,865.2	11,492.0	8,156.9	18,784.9	26,047.0	11,303.9	24,555.3	6,497.0	372.7	1,463.3	32.3	158.9	22.0	242.9	280.0	176,512.0
Total Seasonal Accredit Capacity (SAC)	20,210.5	14,875.4	11,224.6	8,895.6	7,415.8	16,084.2	21,193.1	10,546.4	22,803.6	5,807.4	370.4	1,371.4	30.1	153.9	22.0	240.2	280.0	141,524.6
Market Participant Confirmed SAC	20,083.5	14,638.4	11,024.7	8,776.9	7,348.2	16,084.2	21,193.1	10,546.4	22,523.3	5,807.4	370.4	1,371.4	30.1	153.9	22.0	240.2	280.0	140,494.1
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	19,938.5	14,575.2	10,875.3	8,668.7	5,562.3	16,084.2	21,072.8	10,544.3	22,502.8	5,807.4	370.4	1,362.3	30.1	153.9	22.0	237.7	280.0	138,087.9
Potential IMM Exclusion SAC	80.4	276.9	225.2	252.3	1,754.7	604.6	95.9	120.2	1,686.2	0.0								5,096.4
OASIS Attachment Y Reported MW of Approved Generation Retirement	4.9	0.0	6.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0								11.0
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	25.6	0.0	0.0	0.0	0.0	262.4	0.0								288.0

*Disclaimer - Values displayed on this posting demonstrates progress to date by Market Participants and MISO and is subject to change. The capacity displayed is not a prediction of final capacity values prior to the upcoming Planning Resource Auction. The capacity that will ultimately participate in the upcoming auction are still in progress. Capacity changes will likely stem from: Behind the Meter Generators (BTMG) / Demand Response (DR) / External Resources (ER) / Energy Efficiency (EE) programs that are still in the process of completing registration, Market Participants resolution of GVTC extensions, Market Participants utilizing ICAP Deferral, March Commercial Model updates and the March 14 deadline for Market Participants to request the IMM grant PRA exclusions as outlined in Module D Section 64.1.1 paragraph g. As per the Tariff Module E-1 Section 68A.4 and BPM-011 Appendix K, final Preliminary PRA data posting will be posted by March 25.

Data Export Time: 3/18/2025

Total (row 20), Confirmed (row 21) and Converted (row 22) SAC do not include the following: Potential IMM Exclusions (row 23), Retirements (row 24), and Suspensions (row 25).

ACTUAL PRA DATA POSTING - PY25-26 WINTER

2025-26 WINTER

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW) [M]	14,605.7	8,960.7	8,087.2	7,059.4	6,547.0	14,766.6	13,277.3	7,076.0	18,032.2	4,211.9	73,303.9	29,320.1	102,624.0
Transmission Loss (TL) for CPF (MW) [N]	448.2	152.2	265.1	161.5	171.7	384.4	340.6	141.6	434.0	126.0	1,923.7	701.6	2,625.3
Planning Reserve Margin (PRM %) [P]	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%
Initial Planning Reserve Margin Requirement (Initial PRMR) (MW) [Q] = [(M+N)*(1+P)]	17,823.8	10,789.8	9,889.1	8,549.5	7,954.8	17,939.1	16,123.6	8,545.6	21,864.3	5,136.1	89,069.7	35,546.0	124,615.7
"Effective" Planning Reserve Margin (PRM %) [R] = [S] / [(M+N)-1]	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%	27.3%	27.3%	27.3%	23.3%	27.3%	24.5%
Final Planning Reserve Margin Requirement (Final PRMR) (MW) [S]	18,565.6	11,238.7	10,300.8	8,905.4	8,285.9	18,685.6	16,794.7	9,189.1	23,510.9	5,522.8	92,776.8	38,222.7	130,999.5

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF) [A]	14,993.5	9,059.3	8,175.6	7,138.1	6,669.4	14,931.7	13,626.6	7,272.5	18,931.9	4,188.5
Transmission Loss (TL) for ZCPF (MW) [B]	506.9	159.9	332.6	116.0	162.1	306.3	376.3	152.6	352.4	106.4
Local Resource Requirement (LRR) [C]	1.267	1.353	1.632	1.186	1.254	1.247	1.447	1.566	1.297	1.628
Zonal Import Ability (ZIA) [D]	5,575	6,435	5,785	6,457	4,922	7,690	4,762	3,432	4,418	3,458
Controllable Exports [E]	602	87	92	775	0	237	0	181	0	0
Capacity Import Limit (CIL) [F] = [(D+E)]	6,177	6,522	5,877	7,232	4,922	7,927	4,762	3,613	4,418	3,458
Local Clearing Requirement (LCR) [G] = [(A+B)*C-D-E]	13,462.0	5,951.6	8,008.4	1,371.4	3,644.7	11,074.8	15,500.2	8,014.7	20,593.7	3,534.1

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	6,177	6,522	5,877	7,232	4,922	7,927	4,762	3,613	4,418	3,458
Capacity Export Limit (CEL)	2,991	4,706	7,388	4,756	4,814	1,674	5,712	3,602	3,618	2,028

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	26,213.3	14,989.9	23,093.1	11,021.5	7,399.4	18,394.5	24,923.1	11,995.8	24,737.2	6,681.8	420.1	808.7	33.8	158.9	0.0	171.1	280.0	171,322.2
Total Seasonal Accredit Capacity (SAC)	20,268.4	13,300.9	12,472.8	7,767.5	6,379.1	14,842.1	20,055.5	10,952.4	22,466.0	5,977.6	418.8	757.7	31.2	155.3	0.0	169.9	277.7	136,292.9
Market Participant Confirmed SAC	20,043.5	13,300.9	12,328.3	7,767.1	6,379.1	14,842.1	20,053.7	10,952.4	22,466.0	5,977.6	418.8	757.7	31.2	155.3	0.0	169.9	277.7	135,921.3
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	19,849.7	13,286.5	12,171.9	7,658.9	6,362.0	14,734.3	19,958.4	10,913.2	22,435.3	5,968.8	418.8	757.7	31.2	155.3	0.0	169.9	273.0	135,144.9
Potential IMM Exclusion SAC	1,042.7	629.6	83.2	198.1	0.0	845.2	39.2	105.5	502.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,446.2
OASIS Attachment Y Reported MW of Approved Generation Retirement	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.0
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	0.0	0.0	0.0	43.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0

ACTUAL PRA DATA - PY24-25 WINTER

2024-25 WINTER

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW)	14,085.5	8,964.9	7,918.2	7,076.2	6,328.1	14,613.6	13,217.8	6,881.4	17,102.8	3,926.1	72,204.3	27,910.3	100,114.6
Transmission Loss (TL) for CPF (MW)	457.3	222.2	423.8	223.1	245.3	441.7	413.1	165.2	317.8	98.1	2,426.5	581.1	3,007.6
Planning Reserve Margin (PRM %)	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4
Planning Reserve Margin Requirement (PRMR) (MW)	18,527.8	11,703.9	10,628.0	9,299.5	8,374.5	19,180.0	17,365.6	8,977.1	22,193.8	5,126.6	95,079.3	36,297.5	131,376.8

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF)	14,438.3	9,166.1	7,919.6	7,122.7	6,397.0	14,833.3	13,542.1	7,387.5	17,800.2	4,194.7
Transmission Loss (TL) for ZCPF (MW)	585.6	160.5	291.6	231.5	247.8	448.7	305.4	140.3	338.6	112.2
Controllable Exports	2.0	0.0	68.0	896.0	0.0	246.0	0.0	102.0	577.0	0
Local Clearing Requirement (LCR)	16,971.5	7,189.2	10,803.7	3,132.9	4,061.6	10,219.0	17,596.9	7,379.4	18,888.3	4,809.1

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	4,693	5,523	5,668	6,707	4,477	8,532	4,656	4,364	5,200	3,219
Capacity Export Limit (CEL)	5,174	4,772	9,011	4,674	6,229	1,401	5,753	5,780	2,323	2,993

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	27,590.2	15,940.1	23,123.8	11,102.2	8,382.1	18,724.5	26,387.9	11,809.3	25,616.2	6,683.8	410.1	1,644.2	33.5	158.9	22.0	161.7	280.0	178,070.4
Total Seasonal Accredit Capacity (SAC)	25,255.0	15,161.3	16,173.9	8,821.5	7,227.8	16,347.1	23,218.5	10,808.6	24,346.8	6,366.9	409.0	1,541.2	30.9	153.1	22.0	231.2	280.0	156,394.8
Market Participant Confirmed SAC	24,847.9	14,764.0	15,701.7	8,702.8	7,162.0	16,347.1	23,218.5	10,808.6	24,092.2	6,366.9	409.0	1,541.2	30.9	153.1	22.0	231.2	280.0	154,679.1
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	24,467.0	14,687.6	15,339.4	8,459.7	5,995.9	16,297.5	23,082.8	10,788.9	23,983.5	6,366.9	409.0	1,504.4	30.9	153.1	22.0	231.1	280.0	152,099.7
Potential IMM Exclusion SAC	682.9	539.4	258.5	233.8	1,154.7	339.2	21.3	102.3	1,240.3	0.0								4,572.4
OASIS Attachment Y Reported MW of Appoved Generation Retirement	19.3	0.0	29.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0								48.6
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	19.5	0.0	0.0	0.0	0.0	299.5	0.0								319.0

*Disclaimer - Values displayed on this posting demonstrates progress to date by Market Participants and MISO and is subject to change. The capacity displayed is not a prediction of final capacity values prior to the upcoming Planning Resource Auction. The capacity that will ultimately participate in the upcoming auction are still in progress. Capacity changes will likely stem from: Behind the Meter Generators (BTMG) / Demand Response (DR) / External Resources (ER) / Energy Efficiency (EE) programs that are still in the process of completing registration, Market Participants resolution of GVTC extensions, Market Participants utilizing ICAP Deferral, March Commercial Model updates and the March 14 deadline for Market Participants to request the IMM grant PRA exclusions as outlined in Module D Section 64.1.1 paragraph g. As per the Tariff Module E-1 Section 68A.4 and BPM-011 Appendix K, final Preliminary PRA data posting will be posted by March 25.

Data Export Time: 3/18/2025

Total (row 20), Confirmed (row 21) and Converted (row 22) SAC do not include the following: Potential IMM Exclusions (row 23), Retirements (row 24), and Suspensions (row 25).

ACTUAL PRA DATA POSTING - PY25-26 SPRING

2026 SPRING

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW) [M]	13,680.6	9,463.7	7,677.0	6,436.5	5,989.1	13,813.9	15,448.8	6,254.3	17,408.2	4,053.1	100,305.1	27,715.6	100,225.2
Transmission Loss (TL) for CPF (MW) [N]	578.1	232.1	425.2	190.8	162.7	438.4	395.8	112.6	261.3	71.2	2,858.0	445.1	2,868.2
Planning Reserve Margin (PRM %) [P]	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%
Initial Planning Reserve Margin Requirement (Initial PRMR) (MW) [Q] = [(M+N)*(1+P)]	17,866.7	12,149.2	10,152.2	8,304.0	7,707.9	17,858.6	19,853.2	7,977.8	22,139.8	5,167.9	93,891.8	35,285.5	129,177.3
"Effective" Planning Reserve Margin (PRM %) [R] = [S] / [(M+N)-1]	27.5%	27.5%	27.5%	27.5%	27.5%	27.5%	27.5%	25.0%	25.0%	25.0%	-7.4%	25.0%	26.8%
Final Planning Reserve Margin Requirement (Final PRMR) (MW) [S]	18,174.4	12,358.5	10,327.4	8,447.4	7,840.9	18,166.5	20,195.4	7,955.9	22,079.3	5,153.8	95,510.5	35,189.0	130,699.5

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF) [A]	14,267.9	9,687.1	7,906.8	6,514.3	6,108.0	13,849.6	15,983.2	6,525.6	18,759.9	4,141.9
Transmission Loss (TL) for ZCPF (MW) [B]	414.2	212.6	181.2	151.8	165.7	440.1	407.7	110.9	315.6	77.2
Local Resource Requirement (LRR) [C]	1.283	1.331	1.588	1.495	1.459	1.388	1.319	1.587	1.292	1.788
Zonal Import Ability (ZIA) [D]	6,396	6,439	7,726	7,373	4,453	9,176	5,166	6,085	4,855	4,365
Controllable Exports [E]	202	0	103	769	0	281	0	204	0	0
Capacity Import Limit (CIL) [F] = [(D+E)]	6,598	6,439	7,829	8,142	4,453	9,457	5,166	6,289	4,855	4,365
Local Clearing Requirement (LCR) [G] = [(A+B)*C-D-E]	12,239.1	6,737.5	5,014.7	1,823.8	4,700.3	10,377.1	16,453.6	4,243.1	19,790.5	3,178.8

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	6,598	6,439	7,829	8,142	4,453	9,457	5,166	6,289	4,855	4,365
Capacity Export Limit (CEL)	5,083	6,119	5,936	5,111	5,797	6,425	5,499	3,520	4,146	3,072

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	25,715.0	16,013.6	23,303.8	12,246.7	7,052.1	18,984.1	24,160.5	12,236.7	24,512.1	6,649.8	393.3	697.6	33.5	158.9	0.0	171.1	280.0	172,608.8
Total Seasonal Accredit Capacity (SAC)	19,155.6	14,643.1	12,684.3	9,409.4	6,193.5	15,989.2	19,498.0	11,745.7	21,282.7	5,983.6	392.3	638.4	30.8	158.5	0.0	170.0	278.7	138,253.8
Market Participant Confirmed SAC	18,954.5	14,643.1	12,497.2	9,408.9	6,193.5	15,958.5	19,496.3	11,745.7	21,282.7	5,983.6	392.3	638.4	30.8	158.5	0.0	170.0	278.7	137,832.7
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	18,755.9	14,588.0	12,420.2	9,281.0	6,131.3	15,886.1	19,452.1	11,709.3	21,172.2	5,896.1	392.3	638.4	30.8	158.5	0.0	170.0	276.2	136,958.4
Potential IMM Exclusion SAC	1,051.0	257.2	87.3	220.2	655.1	1,338.2	743.4	565.8	604.8	155.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,678.4
OASIS Attachment Y Reported MW of Approved Generation Retirement	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.0
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	0.0	0.0	0.0	43.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0

ACTUAL PRA DATA - PY24-25 SPRING

2025 SPRING

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW)	13,193.5	9,451.0	7,650.3	6,158.0	5,953.1	13,824.5	15,167.2	6,100.0	17,149.2	4,051.0	71,397.6	27,300.2	98,697.8
Transmission Loss (TL) for CPF (MW)	394.8	164.1	235.9	141.1	133.3	261.4	357.7	128.1	266.9	79.8	1,688.3	474.8	2,163.1
Planning Reserve Margin (PRM %)	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%
Planning Reserve Margin Requirement (PRMR) (MW)	17,216.9	12,182.5	9,991.8	7,981.1	7,711.2	17,846.6	19,670.2	7,891.0	22,065.7	5,233.6	92,600.3	35,190.3	127,790.6

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF)	13,886.7	9,657.6	7,811.1	6,200.8	6,023.0	13,903.9	15,702.2	6,453.3	18,303.8	4,274.6
Transmission Loss (TL) for ZCPF (MW)	325.3	176.3	257.7	142.1	117.6	268.6	375.9	135.6	284.7	84.5
Controllable Exports	2.0	0.0	58.0	899.0	0.0	315.0	0.0	165.0	515.0	0.0
Local Clearing Requirement (LCR)	13,944.7	8,369.6	5,781.3	4,559.9	6,043.5	11,385.5	16,372.2	4,413.1	18,684.1	3,558.4

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	4,943	5,034	6,572	6,982	3,892	8,045	4,883	6,195	6,113	4,628
Capacity Export Limit (CEL)	6,318	4,601	5,815	5,102	4,984	3,414	5,601	4,865	4,298	2,740

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	27,641.8	16,729.6	23,073.6	11,969.9	8,316.6	19,258.1	26,423.1	11,983.9	24,986.0	6,702.4	378.1	1,511.4	32.7	158.9	22.0	239.9	280.0	179,707.9
Total Seasonal Accredit Capacity (SAC)	20,182.1	15,274.4	11,357.2	9,499.6	7,337.0	16,759.3	21,524.6	11,741.1	23,303.0	6,182.4	376.7	1,455.8	30.1	155.5	22.0	235.7	280.0	145,716.5
Market Participant Confirmed SAC	19,608.0	15,010.6	11,140.9	9,377.7	7,272.2	16,759.3	21,524.6	11,741.1	23,011.7	6,182.4	376.7	1,455.8	30.1	155.5	22.0	235.7	280.0	144,184.3
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	19,427.7	14,932.0	10,995.7	9,255.7	5,862.3	16,719.3	21,268.4	11,722.4	22,974.7	6,182.4	376.7	1,437.0	30.1	155.5	22.0	233.2	280.0	141,875.1
Potential IMM Exclusion SAC	263.8	308.2	213.3	611.4	1,348.7	1,691.4	447.7	178.7	2,151.4	0.0								7,214.6
OASIS Attachment Y Reported MW of Approved Generation Retirement	7.4	0.0	9.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0								17.1
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	34.7	0.0	0.0	0.0	0.0	321.8	0.0								356.5

*Disclaimer - Values displayed on this posting demonstrates progress to date by Market Participants and MISO and is subject to change. The capacity displayed is not a prediction of final capacity values prior to the upcoming Planning Resource Auction. The capacity that will ultimately participate in the upcoming auction are still in progress. Capacity changes will likely stem from: Behind the Meter Generators (BTMG) / Demand Response (DR) / External Resources (ER) / Energy Efficiency (EE) programs that are still in the process of completing registration, Market Participants resolution of GVTC extensions, Market Participants utilizing ICAP Deferral, March Commercial Model updates and the March 14 deadline for Market Participants to request the IMM grant PRA exclusions as outlined in Module D Section 64.1.1 paragraph g. As per the Tariff Module E-1 Section 68A.4 and BPM-011 Appendix K, final Preliminary PRA data posting will be posted by March 25.

Data Export Time: 3/18/2025

Total (row 20), Confirmed (row 21) and Converted (row 22) SAC do not include the following: Potential IMM Exclusions (row 23), Retirements (row 24), and Suspensions (row 25).

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Midcontinent	)
Independent System Operator	)
(MISO)	)
	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 60

MISO Tariff Section 38.2.7

38.2.7 Generation Suspension, Generation Retirement, and System Support Resources

a. Generator or SCU Notification of Change in Status.

(i) Notification Procedures for Units.

An owner of a Generation Resource, Synchronous Condenser Unit (SCU), or a Generator that is directly interconnected to the Transmission System but is Pseudo-tied out of the Transmission Provider's Balancing Authority Area that is planning to Suspend operations of all or any portion of that resource must notify the Transmission Provider of such a plan by submitting a completed Attachment Y Notice to the Transmission Provider. This notification provision also applies to a Generation Resource connected to the underlying lower voltage facilities within Transmission Provider region and to Generation Resources that are not directly interconnected to the Transmission System, but are External Resources that are Pseudo-tied into the Transmission Provider's Balancing Authority Area. The Transmission Provider shall coordinate with the entity to which the External Resource is directly connected to determine whether the External Resource is necessary for reliability of the Transmission System, in accordance with applicable coordinated planning provisions between the Transmission Provider and the regional planning entity to which the External Resource is interconnected.

The owner of a Generation Resource or SCU shall submit an Attachment Y Notice to the Transmission Provider at least four full Quarterly Study Periods prior to changing to Suspend status, unless the Generation Resource or SCU is inoperable due to Forced Outage in which case Attachment Y Notice must be submitted to the Transmission Provider at least thirty (30) days prior to changing to Suspend status. A Generation Resource that has undergone a Reliability Assessment Study that performs an Attachment Y equivalent study as part of the Generating

Facility Replacement process and all reliability violations identified through such study have been mitigated must submit an Attachment Y Notice to the Transmission Provider at least thirty (30) days prior to changing to Suspend status. The owner of a Pseudo-tied out Generator shall submit an Attachment Y Notice to the Transmission Provider at least thirty (30) days prior to the anticipated effective date of change of status.

A Generation Resource or SCU that is inoperable due to Forced Outage or a Pseudo-tied out Generator shall not be designated as an SSR Unit. The provisions for time limitations on suspension within Section 38.2.7 shall apply to a Generation Resource or SCU that is inoperable due to Forced Outage and a Pseudo-tied out Generator.

A Generation Resource that is designated as a Blackstart Unit by a Transmission Operator in its System Restoration Plans shall not be designated as an SSR Unit to solely provide Blackstart Service. However, the Transmission Provider may determine that SSR Unit status is justified if such Generation Resource is required to maintain the reliability of the Transmission System based on its Attachment Y Reliability Study. Section 38.2.7 shall not modify or alter a Transmission Operator’s obligations under the Tariff to identify Blackstart Units that are included in its System Restoration Plans, or a Blackstart Unit Owner's obligations to comply with the terms of any Blackstart Service agreement, in accordance with Schedule 33, or the requirements of Commission approved reliability standards.

The following exception applies to the Generation Suspension, Generation Retirement and System Support Resource (SSR) provisions in Section 38.2.7: The owner of a Generation Resource or SCU that requests a Generator Planned Outage or submits a Generator Forced Outage through the Transmission Provider’s outage scheduling system (Control Room

Operations Window – CROW or its successor) does not need to submit an Attachment Y Notice to the Transmission Provider if the request does not involve a change of status to Suspend.

An owner of a Generation Resource, SCU, or a Pseudo-tied out Generator certifies by submitting an Attachment Y Notice that it has elected to Suspend such resource and the Attachment Y Notice shall be executed by an officer of such owner attesting to that claim. The decision to Suspend may be modified by rescission as specifically provided in this Section 38.2.7.

An owner may not submit a new Attachment Y Notice to Suspend that supersedes a prior notification unless the prior Attachment Y Notice is rescinded. The new Attachment Y Notice shall be submitted to the Transmission Provider at least four full Quarterly Study Periods prior to changing to Suspend status.

(ii) Confidentiality of Attachment Y Notice.

The Transmission Provider shall treat all Attachment Y Notices as Confidential Information unless the Attachment Y Reliability Study is complete and any of the following occurs: 1) the owner has elected to waive its rescission rights; 2) the resource fails to return to operation before the period for rescission has lapsed; 3) public release is required under Section 38.2.7.b in order to evaluate the need for an SSR Agreement; or 4) the information is otherwise publicly disclosed by the owner of a Generation Resource, SCU, or a Pseudo-tied out Generator. The Transmission Provider shall promptly post on OASIS that an Attachment Y Notice was submitted, along with the effective date of retirement, under the first three of these circumstances.

(iii) Notification of the Outage Scheduler After Submittal of Attachment Y Notice.

After receipt of an Attachment Y Notice, the Transmission Provider shall schedule such outage notification through the Transmission Provider's Control Room Operations Window ("CROW") outage scheduling system, or successor system, to coordinate the outage planning of a Generation Resource or SCU through CROW, on behalf of the owner.

b. SSR Unit Procedures.

System Support Resource (SSR) procedures provide a mechanism for the Transmission Provider to enter into agreements with Market Participants that own or operate Generation Resources or Synchronous Condenser Units (SCUs) that are required by the Transmission Provider to maintain reliability of the Transmission System, if all or a specified portion of the capacity of such Generation Resources or SCUs would otherwise either Retire or Suspend. SSR Agreements are a last-resort measure to address a reliability issue on the Transmission System facilities under the functional control of the Transmission Provider and shall only be entered into once all potential SSR Agreement alternatives have been examined.

An owner of a Generation Resource or SCU must submit all necessary information to enable the Transmission Provider to evaluate whether SSR Unit status is appropriate for such Generation Resource or SCU. If, after completing a reliability study (Attachment Y Reliability Study) and analyzing potential alternatives (Attachment Y Alternatives Study), the Transmission Provider determines that SSR Unit status is justified for a Generation Resource or SCU, that is not subject to an exception under Section 38.2.7.a, then the Transmission Provider and Market Participant of such Generation Resource or SCU shall enter into an SSR Agreement, in

accordance with the Attachment Y-1 form of agreement. The SSR Unit will be operated in accordance with the terms of the SSR Agreement, which contains detailed terms and conditions regarding operation and compensation of such Generation Resource or SCU. The Transmission Provider shall periodically review the reliability requirements of the Transmission Provider Region and shall determine which, if any, SSR Agreements should be extended.

The Transmission Provider shall use reasonable efforts to respond to the owner within 150 Calendar Days after the start of the individual Attachment Y Reliability Study, regarding whether the subject of an Attachment Y Notice appears to be required for transmission system reliability, unless an alternative date is agreed to by the owner and the Transmission Provider.

If the Attachment Y Reliability Study determines that a reliability concern exists, and a response is provided by the Transmission Provider to the owner, the Transmission Provider shall promptly post on OASIS: (1) that an Attachment Y Notice was submitted; (2) that the Transmission Provider's Attachment Y Reliability Study concluded that the Generation Resource or SCU was required for the reliability of the Transmission System; (3) the draft report on the Attachment Y Reliability Study with the CEII information redacted from the report; and (4) how the associated SSR Unit costs would be allocated in the event that the Generation Resource or SCU is required to provide service under an SSR designation.

The Transmission Provider shall discontinue Confidential treatment of an Attachment Y Notice and Attachment Y Reliability Study in the event that the Attachment Y Reliability Study results determine that the Generation Resource or SCU is required to maintain system reliability and would be eligible for treatment as an SSR Unit. The Transmission Provider may use information related to Retire or Suspend status in its Transmission Planning processes (pursuant

to Attachment FF and the Transmission Planning BPM) and in its Generator Interconnection process (pursuant to Attachment X and the Generation Interconnection BPM), provided that recipients of the information have signed appropriate Non-Disclosure Agreements with the Transmission Provider.

c. Evaluation of Need for the SSR Designation.

The Transmission Provider will perform an Attachment Y Reliability Study to determine whether the Generation Resource or SCU is necessary for the reliability of the Transmission System based on the analyses described in this section and the criteria set forth in the Business Practices Manuals, but will not determine in this initial analysis the available alternatives to designating the Generation Resource or SCU as an SSR Unit. The Transmission Provider will start the study process at the beginning of the Quarterly Study Period. A request to Suspend operations submitted in an Attachment Y Notice received during a quarter will be studied individually, beginning in the subsequent Quarterly Study Period.

In collaboration with the affected Transmission Owners, the Transmission Provider will cause an evaluation to be performed of transmission system conditions (an Attachment Y Reliability Study) that result from the change in status of the unit(s) subject to Attachment Y notification requirements. The evaluation will consider the performance of the transmission system to determine if thermal or voltage violations of applicable NERC Standards and Transmission Owner planning criteria occur when the unit is offline compared to conditions when the unit is online. The scope of this evaluation will include a steady state analysis, and may require analyses of stability and import limitations for the particular study area. Study cases will be derived from approved MTEP models that are representative of the period of time for

which the suspension of the unit(s) is requested, and will include models that represent near-term and/or longer-term scenarios as appropriate for the study period. Models that are developed to reflect both the online and offline status of the unit being evaluated will be analyzed to compare the differences in results to determine the impact of the unit on the transmission system. The results of the evaluation will be reviewed with the participating Transmission Owners to verify the Transmission Provider's findings and to evaluate proposed solutions that should be considered to address the reliability issues. The need to retain a unit(s) as a System Support Resource, absent implementation of a feasible alternative, shall be determined by the presence of unresolved reliability violations on the Transmission System that is under the functional control of the Transmission Provider.

The Transmission Provider shall post the determination of reliability need on the Transmission Provider's OASIS and shall: (1) begin negotiations of a potential SSR Agreement with the Market Participant owning or operating the Generation Resource or SCU; and (2) use reasonable efforts to hold a stakeholder meeting pursuant to Attachment FF within thirty (30) Calendar Days to review alternatives to the potential SSR Unit designation or designations (if multiple Attachment Y Notices apply). The Transmission Provider will schedule subsequent stakeholder meetings as needed. The Transmission Provider shall complete the Attachment Y Alternatives Study within four full Quarterly Study Periods after receipt of an Attachment Y Notice, if the Attachment Y Notice provides only four full Quarterly Study Periods of advance notification, unless otherwise agreed to by the owner of the potential SSR Unit. If no alternative is identified as available by the Attachment Y Notice date to Suspend, then the Transmission

Provider shall file the SSR Agreement with an effective date as of the Attachment Y Notice date to Suspend.

Before entering into an SSR Agreement with any Generation Resource or SCU, the Transmission Provider shall assess, in an open and transparent planning process in accordance with the provisions of the Transmission Expansion Planning Protocol Attachment FF to the Tariff, feasible alternatives to the proposed SSR Agreement. The list of alternatives to SSR Unit status that the Transmission Provider shall consider and expeditiously approve as applicable include (depending upon the type of reliability concern identified): (i) redispatch/reconfiguration through operator instruction; (ii) remedial action plans; (iii) special protection schemes initiated upon Generation Resource trips or unplanned Transmission Outages; (iv) contracted demand response or Generator alternatives; and (v) transmission expansions. Consistent with Section B.1.b of Attachment FF, the Transmission Provider will review and evaluate alternatives to an SSR Agreement on a comparable basis and select the most appropriate solution. Comparability includes the ability of the Transmission Provider to require contractual assurances that the party who provides the alternative solution will implement the solution before the Generation Resource or SCU with the Attachment Y Notice is permitted to Retire or Suspend. The executed contractual arrangements must provide a binding arrangement that obligates the Market Participant who provides the alternative solution to complete any required infrastructure changes that are needed to avoid the reliability issues that would otherwise be addressed by transmission upgrades. While the contractual arrangements will vary based on the particular solution, the terms of the contractual arrangements must further obligate the party who provides the alternative solution to implement actions when required by the Transmission Provider to provide

necessary relief. A Generator alternative may be a new Generator, an existing Generator that is made available after the Attachment Y Reliability Study is completed, or an increase to existing Generator capacity that has an executed Generator Interconnection Agreement pursuant to Attachment X for a Commercial Operation Date that is prior to the commencement of the change of status date of the Generation Resource or SCU that has submitted an Attachment Y Notice and must be registered as a Generation Resource that is obligated to offer into the market and respond to instructions from the Transmission Provider. Contractual commitments associated with demand-side resource alternative solutions shall require demonstration to the Transmission Provider of an executed contract between LSE or ARC and Energy Consumers as well as necessary procedures and protocols for responding to Transmission Provider instructions. Such demand-side contracts must be in place by the time that the SSR Agreement alternative solution would otherwise need to be committed in order to ensure a timely solution to the identified planning need, and must be of a sufficient duration such that a reliable alternative solution can be assured. In assessing applicability for SSR status, the Transmission Provider will not require continued operation when the continued operation of a portion or all of Generation Resources or SCUs would be contrary to applicable law, regulations, or court or agency orders (such as a settlement with an environmental agency or a consent decree approved by a court). In performing the Attachment Y Reliability Study and the Attachment Y Alternatives Study to an SSR Agreement, the Transmission Provider shall collaborate with the affected Transmission Owners and NERC-registered Transmission Planners, and if appropriate, may consult with a retained consultant. The Transmission Provider will appropriately identify any Confidential Information regarding a decision to Suspend before the Transmission Provider transfers such

information to any entity. An entity that receives Confidential Information must agree in writing to maintain such confidentiality, to comply with any confidentiality obligations owed to Transmission Provider under the Tariff or pursuant to a related non-disclosure agreement, and to comply with applicable Standards of Conduct found in 18 C.F.R. § 358. The owner of the Generation Resource or SCU subject to review under this section shall make good faith efforts to minimize the costs to be incurred by seeking any available waivers or exemptions from environmental or other regulatory requirements that would necessitate improvements to the potential SSR Unit. The Transmission Provider will reasonably assist the owner of a potential SSR Unit in working with regulatory agencies to obtain environmental or other waivers or exemptions to the extent necessary to maintain the reliability of the Transmission System. For purposes of determining whether a Generation Resource or SCU qualifies as an SSR Unit, the Transmission Provider will process multiple Attachment Y Notices in the order in which the Attachment Y Notices are received. If a subsequent Attachment Y Notice is received before a determination is made for a Generation Resource or SCU that is the subject of a prior Attachment Y Notice, the Generation Resource or SCU that is the subject of a prior Attachment Y Notice will not be the subject of an SSR Agreement to avoid reliability issues caused by the subsequently noticed suspension of another Generation Resource or SCU.

The filing of a SSR Agreement with FERC shall be accompanied by a corresponding report on the Attachment Y Reliability Study and the Attachment Y Alternatives Study that details the methodologies used, study assumptions, Transmission Owner planning criteria used (including when the criteria became effective and the approving regulatory body, if any), analysis results, an evaluation of alternatives and the conclusion of the study (including a short

explanation of the proposed solution to any reliability issue identified and estimated timetables for implementing the preferred solution). An affirmation that the results, in whole or in part, from a previously filed report remain applicable may substitute for filing an entirely new report on the Attachment Y Reliability Study and the Attachment Y Alternatives Study.

d. Modification or Rescission of an Attachment Y Notice.

(i) Rescission of an Attachment Y Notice Prior to the Transmission Provider's Reliability Study Response.

The Transmission Provider shall notify the owner prior to publicizing the Attachment Y Notice and Attachment Y Reliability Study results that the Attachment Y Reliability Study is complete. However, the Transmission Provider shall not provide any information related to the Attachment Y Reliability Study results to the owner at that time. The owner may rescind its Attachment Y Notice by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention, not more than fifteen (15) Business Days after receiving notice from the Transmission Provider that the Attachment Y Reliability Study is complete. In the event of such rescission, the confidentiality of the Attachment Y Notice shall be preserved.

(ii) Modification or Rescission of an Attachment Y Notice After the Owner of Generation Resource or SCU Receives the Results of Attachment Y Reliability Study, but Prior to Commencing Suspension, Retirement, or an SSR Agreement.

(1) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the Transmission Provider has determined that the Generation Resource or SCU is not necessary for the reliability of the

Transmission System, may rescind its decision to Suspend any time prior to the end of the period for rescission following the effective date or may modify the start of the suspension any time prior to the original effective date by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention. If the revised date for suspension is prior to the original date specified in the Attachment Y Notice, a new Attachment Y Notice shall be submitted to the Transmission Provider at least four full Quarterly Study Periods prior to the effective date of suspension.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is not necessary for the reliability of the Transmission System, may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice. After the owner has waived the right to both rescind and modify the Attachment Y Notice, the requested status of the Generation Resource will change to Retire, and the interconnection service will be terminated in accordance with Section 38.2.7.k. The Attachment Y Notice will no longer be treated as Confidential Information once the owner has elected to waive its right to both rescind and modify the Attachment Y Notice and committed to retirement of the Generation Resource or SCU.

(2) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the Transmission Provider has determined that the Generation Resource or SCU is required as an SSR Unit may rescind its decision to Retire or Suspend or modify the date of suspension at any time while designated as

an SSR Unit by submitting an amended Attachment Y Notice specifying the modified effective date or stating its decision to rescind.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is required as an SSR Unit may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice for the initial rescission period of the Attachment Y Notice. The owner that provides such notification will retain rescission rights (*i.e.* those additionally acquired by virtue of operating as an SSR Unit) only while designated as an SSR Unit after which time the Generation Resource or SCU will have a Retire status and the interconnection service will be terminated in accordance with Section 38.2.7.k.

(iii) Modification or Rescission of an Attachment Y Notice After Commencing a Suspension, Retirement, or an SSR Agreement.

(1) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the resource has not been designated as an SSR Unit or is not continuing to operate pursuant to an SSR Agreement, may rescind its decision to Suspend by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention to rescind any time during the period for rescission following the effective date.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is not necessary for the reliability of the Transmission System, may elect to convert the Attachment Y Notice to

retirement by notifying the Transmission Provider of its intent to waive the right to rescind and modify the Attachment Y Notice. After the owner has waived the right to rescind, the Generation Resource will have a Retire status, and the interconnection service will be terminated in accordance with Section 38.2.7.k. The Attachment Y Notice will no longer be treated as Confidential Information once the owner has elected to waive their right to rescind and committed to retirement of the Generation Resource or SCU.

(2) An owner of an SSR Unit may rescind its decision to Suspend or to Retire or modify the effective date prior to the termination date of the SSR Agreement by submitting an amended Attachment Y Notice specifying the modified effective date or stating its intention to rescind. After receiving an amended Attachment Y Notice from an owner of an SSR Unit to rescind or modify its decision to Suspend or to Retire, the Transmission Provider will then exercise the termination provisions of the SSR Agreement.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is required as an SSR Unit may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice for the initial rescission period of the Attachment Y Notice. The owner that provides such notification will retain rescission rights (*i.e.* those additionally acquired by virtue of operating as an SSR Unit) only while designated as an SSR Unit after which time the Generation Resource or SCU will have a Retire status and the interconnection service will be terminated in accordance with Section 38.2.7.k.

e. Refund of Costs.

(i) If the owner of a Generation Resource or SCU that notifies the Transmission Provider of a decision to Suspend and for which the Transmission Provider has not determined the Generation Resource or SCU is needed for reliability rescinds an Attachment Y Notice prior to commencing suspension, then such owner shall pay the Transmission Provider all of the costs that the Transmission Provider incurred in conducting an Attachment Y Reliability Study.

(ii) The Market Participant that owns or operates an SSR Unit must refund to the Transmission Provider with interest at the FERC-approved rate, all costs, less depreciation, for repairs and capital expenditures that were needed to continue operation of the Generation Resource or SCU and to meet applicable regulations and other requirements (including environmental) while the Generation Resource or SCU was subject to an SSR Agreement if the owner: (1) rescinds its decision to Suspend or to Retire the unit while it is designated a SSR; (2) rescinds its decision to Suspend following its previous designation as an SSR Unit; or **(**3**)** returns a unit to service following its previous designation as an SSR Unit and later retirement of the unit.

(iii) An owner of a Generation Resource or SCU that returns the unit to service upon failure to Retire or Suspend according to an Attachment Y Notice (*i.e*. returns from retirement or rescinds the Attachment Y Notice, including a Generation Resource or SCU that was not a SSR Unit, a former SSR Unit that no longer operates pursuant to an SSR Agreement, or an SSR Unit) will be allocated the total costs of Network Upgrades incurred or financially committed to as of the date of the notification of modification of the decision to Retire or Suspend if all the following apply:

- the rescission obviates the need for such Network Upgrades that were identified by the Transmission Provider in an Attachment Y Reliability Study;
- such Network Upgrades were necessitated solely by the Attachment Y Notice to Suspend; and
- such Network Upgrades were approved by the Transmission Provider's Board of Directors as Attachment FF Appendix A projects.

The total costs will include all pre-construction costs and interest at the FERC-approved rate. Such an owner will also be allocated the costs of expedited construction of such Network Upgrades that were approved for purposes other than dealing with needs identified in an Attachment Y Reliability Study to the extent that such expedited construction was necessitated by the Attachment Y Notice to Suspend.

In the event that multiple Attachment Y studies identified reliability issues that required the Network Upgrades and the owners of the units subject to the studies return their units to operation upon failure to Retire or Suspend (*i.e*. return from retirement or rescind the Attachment Y Notices, including Generation Resources and/or SCUs that were not SSR Units, former SSR Units that no longer operate pursuant to an SSR Agreement, or SSR Units), the owners will be allocated the total costs of such Network Upgrades incurred or financially committed to as of the date of notification of the last modification of a decision to Retire or Suspend if all the following apply:

- the rescission obviates the need for such Network Upgrades that were identified by the Transmission Provider in the Attachment Y Reliability Study;

- such Network Upgrades were necessitated solely by the Attachment Y Notice to Suspend; and
- such Network Upgrades were approved by the Transmission Provider's Board of Directors as Attachment FF Appendix A projects.

The total costs will include all pre-construction costs and interest at the FERC-approved rate. Such owners will also be allocated the costs of expedited construction of such Network Upgrades that were approved for purposes other than dealing with needs identified in an Attachment Y Reliability Study to the extent that such expedited construction was necessitated by an Attachment Y Notice to Suspend.

Except as provided in this Section, cost responsibility is assigned only for Network Upgrades that are identified to fully alleviate the violations identified in the Attachment Y Reliability Study in connection with a change in a plan to Retire or Suspend a Generation Resource or SCU. Costs of Network Upgrades that have been identified in the MTEP to address Transmission issues other than the issues identified in the Attachment Y Reliability Study of a unit that requests suspension will not be allocated to the owner of that unit if such costs of construction were not expedited as the result of an Attachment Y Notice to Suspend. In accordance with Attachment FF of the Tariff, the estimated costs of such Network Upgrades are included in the MTEP when it is approved by the Board of Directors of the Transmission Provider for inclusion in the MTEP. The Transmission Provider will solicit from the constructing Transmission Owner the actual costs (including the costs of expediting construction, and pre-construction costs, if any) incurred or committed to as of the date of notification for the last modification of a decision to Retire or Suspend. Each owner shall pay its pro rata share of

the incurred or committed Network Upgrade costs, based on the relative Generation Verification Test Capacity of each resource whose operation causes the assignment of Network Upgrade costs to its owner. The Transmission Provider will promptly notify the responsible owner of their share of the total costs once actual costs are determined.

f. Execution and Filing of SSR Agreement.

The Transmission Provider shall enter into an SSR Agreement with the Market Participant owning or operating a Generation Resource or SCU that is needed for SSR purposes based on the *pro forma* Attachment Y-1. The SSR Agreement shall state that it incorporates by reference the compensation authorized by the Commission. Resources that are ineligible to continue operating for legal or regulatory reasons, however, shall not be required to enter into an SSR Agreement. If a potential SSR Unit is ineligible or an existing SSR Unit becomes ineligible to continue operation, then the Transmission Provider shall seek to minimize the impact to Load by operating the Transmission System in the same manner as for any Resource that becomes ineligible to continue operation due to Forced Outage.

The Transmission Provider will file an SSR Agreement with the Commission for approval if the Transmission Provider's analysis determines that the Generation Resource or SCU is required for reliability of the Transmission System. All potentially affected parties will receive notification of such Commission filing. SSR service is a contracted service between the Market Participant that owns or operates an SSR Unit and the Transmission Provider and shall be for a term of twelve (12) months, unless the Transmission Provider requires a different term. The Transmission Provider must have available the entire capacity specified in the SSR Agreement of each SSR Unit.

g. Operation of SSR Unit.

Once the Transmission Provider has entered into an SSR Agreement with a Generation Resource or SCU, the Transmission Provider shall have the right to dispatch the SSR Unit at any time for reliability of the facilities within the Transmission Provider Region. The Transmission Provider shall make every attempt to minimize the use of an SSR Unit for reliability purposes. The Transmission Provider will commit the SSR Unit when conditions are identified that require the use of the SSR Unit and will make best efforts to minimize the uneconomic commitment of the SSR Unit. The SSR Agreement found in Attachment Y-1 to this Tariff shall provide for equitable compensation to an SSR Unit when it is dispatched by the Transmission Provider.

h. Scheduling Rules for SSR Units.

The Transmission Provider shall notify Market Participants with SSR Units as to the time period of Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve, and/or Other Ancillary Services required from each SSR Unit in accordance with Section 39.1.5 for the Day-Ahead Energy and Operating Reserve Markets, Section 40.1 for Reliability Assessment Commitment processes, and Section 40.1.A.3 Look Ahead Commitment processes.

i. SSR Unit Participation in Markets.

A Market Participant may offer Energy or Ancillary Services from SSR Units into the Day-Ahead Energy and Operating Reserve Market, RAC, or Real-Time Energy and Operating Reserve Market during times when the Transmission Provider has not requested the Market Participant to run the SSR Unit at full capacity unless this would impair the ability of the SSR

Unit to provide the Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve, or Other Ancillary Services when requested by the Transmission Provider.

Market Participants that own or operate an SSR Unit shall not use the SSR Unit to: (i) participate in Interchange Schedules; (ii) except for plant auxiliary Load obligations under the SSR Agreement, use the SSR Unit as a Self-Scheduled Resource to submit Self-Schedules for Energy and/or Operating Reserve; or (iii) submit Self-Schedules for Other Ancillary Services, if applicable, to the extent that Other Ancillary Services are required by the Transmission Provider under this Section.

j. SSR Unit Compensation.

(i) The Market Participant will be compensated for only costs incurred for the extended operation as an SSR Unit that do not exceed the full cost-of-service (including the fixed cost of existing plant). The hourly component of compensation will be provided as stated in this Tariff. For the determination of any additional compensation, the Market Participant shall submit a filing to the Commission under Section 205 of the FPA that states the additional compensation the Market Participant deems appropriate that is associated with the SSR Agreement filed by the Transmission Provider, but the Market Participant shall not separately file an SSR Agreement. The Market Participant shall provide the Transmission Provider and the Independent Market Monitor with a copy of all compensation-related filings regarding a SSR-designated unit.

(ii) Any compensation for the SSR Unit will be reduced by payments for operation of the SSR Unit, according to the provisions in this Tariff. Monthly compensation under Schedule 2 of this Tariff and payments under resource adequacy programs (a percentage of such payments

to a Market Participant whose generating unit designations are not made) shall be identified in the filing for compensation submitted by the Market Participant.

Hourly compensation will be provided for those hours in which the SSR Unit has Actual Energy Injections and the SSR Unit is committed by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market or committed by the Transmission Provider in any of the RAC processes, or in the Look Ahead Commitment ("LAC") process, including any Reliability Assessment Commitment ("RAC") process conducted prior to the Day-Ahead Energy and Operating Reserve Market, in which hours the Transmission Provider shall calculate the Market Participants' Production Cost and Operating Reserve Cost. For the purposes of this calculation, "Production Cost" means the Energy output cost pursuant to Section 39.3.2B Day-Ahead Revenue Sufficiency Guarantee Payments of the Tariff for commitments by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market or the Energy output cost pursuant to Section 40.2.19 Real-Time Sufficiency Guarantee of the Tariff for commitments by the Transmission Provider in any of the RAC processes, or in the LAC process, including any RAC process conducted prior to the Day-Ahead Energy and Operating Reserve Market, of each SSR Unit based upon Start Up, No Load, and Energy Offer cost components that reflect the actual costs of physically operating the SSR Unit(s). "Operating Reserve Cost" mean the actual cost to provide Operating Reserves. All Production Costs and Operating Reserve Costs will be subject to audit by the Transmission Provider, and will be subject to audit and enforcement by the Independent Market Monitor.

Through the Transmission Provider settlement process, the Transmission Provider will compare the "SSR Unit Compensation," which (for each SSR Unit) is equal to the sum of

Production Cost and Operating Reserve Cost, to the SSR Unit Energy, Operating Reserve Credit, and Short-Term Reserve. The SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit are those charges and credits calculated pursuant to Sections 39.3 Day-Ahead Energy and Operating Reserve Market, 40.3 Real Time Energy and Operating Reserve Market Settlement and 40.7 Determination of Inadvertent Energy of the Tariff, plus any revenues from Schedule 2 associated with the SSR Unit or from Planning Resource designation and any charges assessed through Schedule 17 and Schedule 24. In those hours where the SSR Unit Compensation is greater than the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit for that SSR Unit, the Transmission Provider will make the applicable make-whole payment to Market Participant (such make-whole payment to be equal to the difference between the SSR Unit Compensation and the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit). In those hours where the SSR Unit Compensation is less than the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit, the Transmission Provider will debit from Market Participant (such debit to be equal to the difference between the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit and the SSR Unit Compensation). If the SSR Unit receives revenue pursuant to Sections 39.3 Day-Ahead Energy and Operating Reserve Market and 40.3 Real Time Energy and Operating Reserve Market Settlement of the Tariff in hours other than those described above, the Transmission Provider will debit those revenues from the Market Participant.

(iii) The Market Participant shall file with the Commission for a Monthly SSR Payment for compensation not covered by the hourly compensation stated in the previous sub-section. The Market Participant's filing shall state the requested Monthly SSR Payment along

with its sub-components (including amounts for monthly Schedule 2 payments for each SSR Unit) and applicable cost support, including an affidavit executed by an officer of the Market Participant attesting to the accuracy of the submitted cost information. The Market Participant shall provide the Monthly SSR Payment information for each SSR Agreement, including any renewals of an SSR Agreement, and may update the information in a Section 205 filing to revise such Monthly SSR Payment following any material, unforeseen circumstances affecting the SSR Unit that changes the costs incurred by the Market Participant. The Transmission Provider shall pay the Market Participant the Monthly SSR Payment as directed by the Commission, commencing on the effective date established by the Commission.

The filing for the additional compensation should evaluate, at a minimum, the following factors in negotiating compensation for an SSR Unit: (1) operations and maintenance labor expenses directly related to the SSR Unit; (2) administrative expenses directly related to employees at the SSR Unit, including employee expenses environmental fees, safety and operator training, office supplies, communications, and plant inspection/testing expenses; (3) non-labor maintenance expenses, including chemical and materials consumed during maintenance of the SSR Unit and rental expenses for maintenance equipment used to maintain the SSR Unit; (4) taxes, permit and licensing fees, site security expenses, and insurance; (5) carrying charges**,** including charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operating unit decisions based on Good Utility Practice; (6) corporate expenses, including those incurred for legal services, environmental reporting, and procurement; (7) costs associated with capitalized projects; (8) depreciation, and (9) return on the undepreciated plant costs for the SSR Unit.

k. Termination of Interconnection Service.

Except as provided in Attachment X, the Transmission Provider shall file with the Commission to terminate the interconnection service to the Transmission Provider's system held by an owner of a Generation Resource or SCU or Pseudo-tied out Generator, that certifies by submitting an Attachment Y Notice that it plans to Suspend a Generation Resource or SCU or Pseudo-tied out Generator, upon the latter of: (1) the termination of an SSR Agreement; (2) the effective date for which the owner has elected to convert the Attachment Y Notice to retirement by waiving the right to rescind the decision; or (3) the end of the period for rescission for which the owner has not waived the right to rescind. Such termination of interconnection service shall be contained in a filing with the Commission and also posted by the Transmission Provider on its OASIS to the extent that such interconnection service was filed with the Commission, and shall otherwise be terminated by the Transmission Provider by a posting on its OASIS. If the owner rescinds or modifies the Attachment Y Notice in accordance with Section 38.2.7.d, the owner of such resource may retain its interconnection service and continue to operate after the conclusion of an SSR Agreement or the date specified in the Attachment Y Notice.

l. Allocation of SSR Unit Costs.

The costs pursuant to the SSR Agreement shall be allocated to the LSE(s) which require(s) the operation of the SSR Unit for reliability purposes.

m. Annual Review of SSR Unit Status.

On at least an annual basis, the Transmission Provider will review Generation Resource or SCU characteristics to determine whether the Generation Resource or SCU is qualified to remain as an SSR Unit in coordination with a review of the Transmission Provider’s annual

regional transmission expansion plan in accordance with Attachment FF. If an SSR Unit continues to be required for reliability of the Transmission System, then the Transmission Provider will have the unilateral right to negotiate and enter into a subsequent SSR Agreement by providing the Market Participant at least ninety (90) days advance notice prior to the termination date of the existing SSR Agreement and by negotiating and filing a new SSR Agreement at the Commission. If not, the SSR Agreement will expire by its own terms and the Generation Resource or SCU will lose its SSR Unit status and will resume suspension in accordance with the Attachment Y Notice or Retire. Any subsequent SSR Agreement also shall be filed with the Commission.

n. Time Limitations on Suspension.

An owner of a Generation Resource or a SCU or a Pseudo-tied out Generator may request suspension pursuant to the provisions of this Section 38.2.7 and remain for a maximum of thirty-six (36) cumulative months during any five (5) year period under any combination of suspended and SSR-designated statuses. An owner of a Generation Resource or a SCU or a Pseudo-tied out Generator that had not exhausted its maximum period may request an additional suspension period by submitting a new Attachment Y Notice four full Quarterly Study Periods prior to the effective date of the extension period, provided that the combined period is not greater than thirty-six (36) months in a five (5) year period. If a Generation Resource or a SCU or a Pseudo-tied out Generator does not return to service at the end of the thirty-six (36) month maximum suspension period, the Transmission Provider will terminate interconnection service of the resource pursuant to Section 38.2.7.

o. Non-Binding Informational Studies.

An owner of a Generation Resource or a SCU may complete an Attachment Y-2 to request that the Transmission Provider conduct a study to determine whether it is likely that a portion or all of such Generation Resource of SCU would qualify as an SSR Unit. The Transmission Provider will collaborate with the affected Transmission Owners and NERC-registered Transmission Planners, and if appropriate, will consult with a retained consultant to evaluate whether the facility is required for the reliability of the Transmission System. The Transmission Provider will appropriately identify any Confidential Information regarding a decision to Suspend that the Transmission Provider transfers to any entity. An entity that receives Confidential Information must agree in writing to maintain such confidentiality, or to any confidentiality obligations owed to Transmission Provider under the Tariff or related non-disclosure agreement, and to comply with applicable Standards of Conduct found in 18 C.F.R. § 358. The owner will not be bound to the change of status indicated in an Attachment Y-2 request. Along with a completed Attachment Y-2, such owner shall submit a study deposit of $70,000 to the Transmission Provider for the reasonable costs and expenses of such study. The Transmission Provider shall invoice such owner for all costs and expenses incurred in addition to the deposit amount, or shall refund any unused portion of such deposit upon completion of the study.

The Transmission Provider will process multiple Attachment Y-2 requests in the order in which the Attachment Y-2 requests are received. The Transmission Provider shall use reasonable efforts to submit the results of such study to the owner upon its completion within 150 days of receipt of the deposit and completed Attachment Y-2, unless an alternative period is mutually agreed to. The Transmission Provider shall treat Attachment Y-2 as Confidential

Information. If an owner rescinds an Attachment Y-2 study request, then such owner shall not receive the results of the study and the owner shall pay the Transmission Provider all of the costs incurred in conducting the study up until the date of such rescission.

Once a response is provided by the Transmission Provider to the owner, the Transmission Provider shall promptly notify the Independent Market Monitor of any Resource that may qualify as an SSR Unit. The results of such study will provide the owner with the outcome if the owner elects to submit an Attachment Y Notice to request SSR status in the future and does so in accordance with Section 38.2.7.p.

The Transmission Provider shall maintain regional power flow models pursuant to Section I.C of Attachment FF, for use by the owner of a Generation Resource or a SCU choosing to conduct a study.

p. Submission of Attachment Y Notice Following Non-Binding Reliability Studies Under Y-2.

The Attachment Y Notice following a non-binding Y-2 request must be submitted at least four full Quarterly Study Periods prior to the date of the planned change of status. The Transmission Provider shall conduct the subsequent Attachment Y process consistent with timeline and milestones in Section 38.2.7.